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Incentive policies for natural gas-fired cogeneration in Brazil's industrial sector — case studies: chemical plant and pulp mill

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Abstract

Although recent restructuring of Brazil's power sector has increased the stakes held by private enterprise in the sector, the role of combined heat and power generation (CHP) is still undefined. Currently, this generation alternative is used only in a few industrial plants, being faced with an unfavorable institutional panorama. Issues related to the buyback rate, backup energy contracts and transmission rates are just some of the main barriers to cogeneration development in Brazil. This article assesses the economic performance of three natural gas-fired cogeneration systems at two specific industrial plants, one in the chemical sector and the other in the pulp and paper sector. As shown by international experience, these two sectors make intensive use of self-produced power. The results show that small and medium-size units, less than 20 MWe, are feasible for electric-intensive industrial plants, due to the current high risk of power outages of the Brazilian electrical system. Large units are only feasible with the adoption of incentive policies for selling off surplus power generated by the self-producer.

Keywords: Gas-fired cogeneration; Industrial sector; Brazil's power system

1. Introduction

The recent restructuring of Brazil's power sector tends to boost the share held by the natural gas-fired thermo-power in the nation's energy grid through private sector investments in expanding installed capacity. The expansion of the power generation park is spurred by high risks of shortfalls in the electricity system, encouraging low sunked cost technologies with reduced construction time. This is exactly the case of gas-fired turbines whose initial investment has been dropping over the past few decades, while their thermodynamic efficiency is on the rise (Smith, 1995). Simultaneously, internal supplies of natural gas are designed to increase in Brazil, due to: (1) the start-up of operations by the Bolivia–Brazil gas pipeline and its expansion in 2003[1]; (2) an increase in domestic natural gas output; and (3) the importation of natural gas from Argentina.

As cogeneration is an energy alternative that results in lower primary energy consumption compared to independent heat and electricity generation (Olano, 1995), the prospects of its use should be assessed for expanding Brazil's installed capacity. This assessment naturally focuses on industrial plants which consume larger quantities of process steam and power — implying a larger scale for the equipment to be installed and more electricity produced through, and have a quite uniform operation, with a long-base steam load duration (Joskow and Jones, 1983).

However, there is as yet no clear-cut definition in Brazil of the role of the cogenerator in the expansion of the nation's power generation park. In historical terms, due to the easy availability and low cost of hydro-power, cogeneration is only used in very specific cases in Brazil, mostly in industrial plants that use wastes fuels to generate power[2] Currently, it can be viewed as a possible alternative to expanding installed capacity through thermo-power plants. However, cogeneration is faced

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[1] This expansion would allow the transportation of 30 million m^3/day of natural gas.

[2] Hydro-power generation accounts for 91.4% of the total installed capacity of Brazil's power generation park (Eletrobrás, 1999).

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with an unfavorable institutional panorama. Issues related to the buyback rate, backup energy contracts and transmission rates are just some of the main barriers to the development of cogeneration in Brazil.

In view of this situation, gas-fired cogeneration units were assessed for Brazil's industrial sector, operating on a topping cycle.[3] This assessment was carried out through simulations on the COGEN model developed by the authors to select natural gas-fired cogeneration systems.

2. The chemical and pulp and paper segments in gas-fired cogeneration

The Chemical and Pulp and Paper Industries together represented 21% of Brazil's industrial sector energy consumption in 1998 (Ministry of Mines and Energy, 1999).[4] The end-use "process heat", which corresponds to steam generation in boilers, represented 37% of the Chemical Industry energy consumption in 1998, with residual fuel oil accounting for 53% of this consumption (Ministry of Mines and Energy, 1999). Its power-to-heat ratio[5] as a whole for Brazil in 1998 corresponds to 0.53. Thus, two factors foster the use of gas-fired cogeneration cycles in this industry: initially, possible incentives to replace residual fuel oil by natural gas to generate process steam; second, the low heat-to-power ratio of the plant, opening up the possibility of generating surplus power through installing gas-fired cogeneration facilities, after meeting process heat demands. In fact, gas-fired systems are commonly appropriate for industrial cogeneration uses with a power-to-heat ratio between one-third and one, which is exactly the case of the chemical sector (Tolmasquim *et al.*, 1999).

In the pulp and paper industry, the demand for process steam is met mainly by burning residual fuel oil and fuelwood, which together service 51% of this demand. This industry features the specific characteristic of recycling a waste material — black liquor — produced through processing eucalyptus pulp, in order to generate heat and power. Normally, in an integrated pulp and paper plant, all black liquor produced is used to generate power and heat, through a cogeneration system based on steam turbine and boilers. In this case, the remainder of the heat demand is supplemented by burning other energy

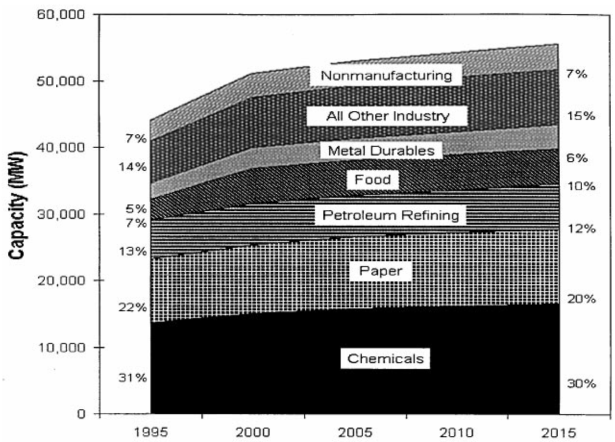

Fig. 1. Industrial cogeneration capacity projection by industry in USA Source: GRI (1998).

sources, specially natural gas, and the remainder of the electricity requirements is covered through the power distribution grid.

The potential of gas-fired cogeneration in these two industries is also corroborated by international experience. Growth expectations for self-generated electricity in the USA (Fig. 1) stress this (GRI, 1998). Another study (Khrushch *et al.*, (1999) indicates an outstanding potential for natural gas-fired cogeneration of 32.0 GW for the US chemical industry, and 17.8 GW for its pulp and paper sector. These potentials together correspond to approximately the generation capacity of Brazil's power generation park in 1997. Particularly noteworthy in Europe are the data for Spain, where the two industries account for 34.9% of self-production in this country in 1992 (de Brito, 1993).

3. Barriers to cogeneration in Brazil

Despite the marked thermodynamic potential identified in Brazil's chemical and pulp and paper industries, their installed cogeneration capacity is still marginal.[6] According to Eletrobrás (1998), the thermodynamic potential of cogeneration identified for the chemical sector, for efficient generation systems, is 9876 MW, while the installed capacity in 1998 reached 389 MW. For Brazil's pulp and paper sector, a thermodynamic potential was identified of 7830 MW, with an installed capacity of 718 MW noted for this sector in 1998. Although some of this difference should be attributed to technical issues as not all thermodynamic potential can be used in technical

[3] In a topping cycle, a fuel such as natural gas is burnt in an engine to provide mechanical power which is used to drive a rotating machine or electrical generator, and the exhaust heat from the engine is used to provide hot air, hot water or steam to an industrial process.

[4] Considering the total consumption by source and all end-uses, including heating, driving power, lighting and electro-chemical purposes.

[5] Ratio between the electric power demand and the heat power demand in the process.

[6] The thermodynamic potential considers only the process heat demand and the upper electric generation of CHP units. It does not consider the technical and economical feasibility of these units.

terms,[7] a relevant portion of this derives from issues of an economic and political nature.

In a survey carried out by Brazilian entrepreneurs, five main barriers were indicated, blocking the implementation of gas-fired cogeneration units in Brazil's industrial sector (Tolmasquim *et al*., 1999):

- *Backup tariff:* The annual maintenance procedures for cogeneration equipment requires backup contracts covering supplementary power demand for certain times of the year, in order to ensure electricity supplies for the industrial plant. Although these rates, representing intermittent demand, should be higher than those in the regular contracts, they are nevertheless comparatively high in terms of what would be desirable for cogeneration, at some 3–4 times above the normal power purchase rates. Additionally, there is no guarantee of backup power supplies from the power utility during periods when the cogeneration plant is halted for maintenance.
- *Sale of surplus cogenerated power:* Brazil still lacks regulations on the sale of surplus power generated by self-producers. In general, the utility do not accept mandatory purchase of these surpluses, regardless of the criteria established for this purpose. Additionally, no transmission rates have yet been established for cogenerated power, although free access to the transmission grid has already been regulated for power producers.
- *Gas and electricity rates:* A major barrier blocking the feasibility of cogeneration in Brazil is the value of natural gas and electricity rates currently in effect. Electricity represents the revenue for the investor in cogeneration, while gas is a cost. Power rates are considered low by possible future investors in thermopower generation, while gas supply contracts — which depend on exchange rate variations — generate price imbalances between electricity which is quoted in *reais* and gas which is quoted in dollars.
- *Financing and interest rates:* The financing available in Brazil is offered under relatively unfavorable conditions due to the high interest rates currently in effect in the Brazilian economy,[8] although they are dropping. The alternative foreign funding brought in through private foreign banks implies the acceptance of uncertainty over exchange rate variations, which boosts investor risks.
- *Foreign exchange rate:* The instability of Brazil's foreign exchange rate noted since early 1999,[9] undermines the feasibility of cogeneration projects, with adverse effects on the prices of equipment and gas rates.

With regard to these barriers, the Brazilian Government has the power to intervene through the direct actions of its regulatory agency - ANEEL,[10] in terms of the first four points, by either encouraging the sale of surplus cogenerated power through appropriate standards and rates, or guaranteeing backup power supplies, introducing financing mechanisms for cogeneration projects through tax incentives or subsidies on equipment purchases. The issue of the foreign exchange rate is more complex. The regulatory agency has no power to work on this barrier and is limited to merely minimizing its impact for the private investor by lowering the other barriers, particularly those linked to financing. In fact, introducing incentive mechanisms for cogeneration equipment purchases, the agency can reduce the risk perceived by the private investor, faced with foreign exchange rate oscillations.

This article used the COGEN model to assess the effects of actions on natural gas and electricity rates, feeling that these are the barriers blocking cogeneration in Brazil's industrial sector that can be transposed most easily through government policies.

4. The COGEN model

This article presents a brief description of the COGEN model. A detailed description of this model can be found in Szklo *et al*. (2000).

The COGEN model has been developed for use in economic feasibility analyses of cogeneration plants powered by natural gas, set up by ventures in the commercial and industrial sectors. Through this model, economic assessments are carried out from the standpoint of the private investor, pinpointing barriers and incentives for possible future cogeneration ventures.

For the industrial sector, two integrated modules are available, running on Stella software:[11] the combined cycle gas turbine module and the gas turbines for industrial sector module. In the first module, one configuration

[7] The technical potential in cogeneration is defined as the portion of the Thermodynamic Potential that could be effectively used through the equipment and technology available on the market.

[8] The interest rates in the Brazilian economy dropped from 38% in February 1999 to 19% in August 1999 (FGV, 1999).

[9] The nominal foreign exchange rate rose from R$ 1.2054 to R$ 1.9137 / US$ 1.00 from December 1998 through February 1999, when constraints were lifted on the floating exchange rate for the Brazilian currency.

[10] Brazilian electricity regulatory agency (ANEEL – Agência Nacional de Energia Elétrica).

[11] *Stella* software is a multi-level hierarchical environment for constructing and interacting with mathematical models, developed by high performance systems, Inc. (HPS).

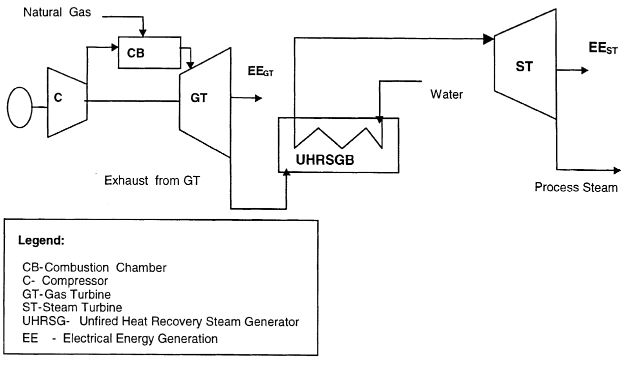

Fig. 2. Combined cycle gas turbine (CCGT) — simplified scheme for industrial cogeneration.

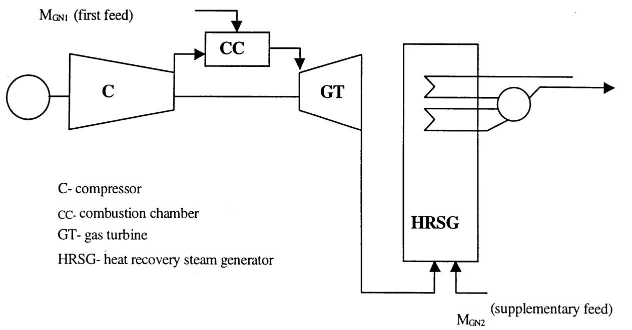

Fig. 3. Schematic outline of cogeneration system using LPGT or HPGT systems (the system based on HPGT differs from that shown here only through the fact that no additional gas is consumed). Source: Szklo *et al.* (2000).

has been defined (Fig. 2), based on high-performance gas turbines and back-pressure steam turbines without extraction (CCGT–combined cycle gas turbine). In the second module, two configurations have been defined (Fig. 3):

1. Open cycle for high-performance gas turbines (HPGT). Under this system, there is no supplementary fuel burned in the heat recovery steam generator, being the peak heat load demand of the venture met by the exhaust gases produced by the gas turbine;
2. System based on low-performance gas turbine (LPGT). Under this system, the gas turbine meets the heat load for the bottom of the heat load curve (Fig. 4), with the remainder supplied by the heat recovery steam generator burning additional fuel.

Therefore, in the gas turbine for industrial sector module, the main difference between the high-performance turbines and the low-performance ones is their ability to produce useful heat. In general, the high-performance turbines are sized at larger power-to-heat ratios and smaller heat rates, meaning that their electricity generation, related to the other turbines, is maximized.

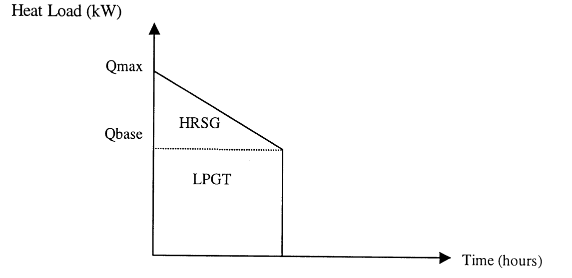

Fig. 4. Example of heat load curve applied to the LPGT System (key: Q_{max}: maximum heat load; Q_{base}: base heat load; LPGT: system based on low-performance gas turbines; HRSG: heat recovery steam generator). Source: Szklo *et al.* (2000).

Table 1
Curve fitting of gas turbine technical data in the COGEN model

Parameters	HPGT	LPGT
Rated power (kW) × Useful heat (kW)[a]		
Slope *a*	0.892	0.598
Linear coefficient *b*	− 1480.14	− 96.32
Correlation coefficient	0.997	0.998
Rated efficiency (%) × Rated power (kW)[b]		
A	38.021	36.660
B	− 10.361	− 24.491
C	− 24.974	− 1168.484
Correlation coefficient	0.996	0.993

[a]Rated power $= b + a$. Useful heat.
[b]Rated efficiency: $A\ \exp[(\ln(\text{Rated power}) + B)^2/C]$.

Nevertheless, this advantage of the HPGT system is compensated by its difficulty to match non-uniform heat loads, being the system sized to meet the maximum heat load demanded.

In practice, the classification in two classes of the gas turbines available on Brazilian market was made in the data-base of the COGEN model, through curve fitting (Table 1). This data-base refers to 60 gas turbines with power ranging from 0.5 to 30 MW, including technical and thermodynamic data (heat rate, rated power, useful heat, exhaust temperature and exhaust mass flow) and economical data (capital costs and maintenance costs).

Based on this gas turbines data-base, the model establishes curves correlating: (1) capital cost with rated power; (2) rated power with rated efficiency; and (3) usable heat produced by the turbine with rated power. The economic assessment and sizing of these equipments under the COGEN model work on the hypothesis that the cogeneration system should be sized to meet the process heat needs of the user. Thus, being properly characterized by the user of the model the heat demands of his venture, the gas turbine for industrial module obtains:

- the rated and the effective operating values for the gas turbines power capacity;

- the rated and the effective operating values for the gas turbines efficiency;
- the gas turbines fuel consumption;
- the electricity and steam production of the cogeneration system;
- and the heat recovery steam generator size and fuel consumption (in the case of the LPGT configuration).

For the CCGT module, the sizing of the power generation systems works on the same hypothesis described above. Nevertheless, in this module, the gas turbine should meet the heat demands of the steam turbine, instead of meeting process heat demands, which is met by the cogeneration configuration as a whole. The steam turbine is sized based on the heat demand patterns of the process. Therefore, its steam outlet flow is characterized by the user of the model. The steam turbine data-base of the COGEN model includes:

1. rated efficiency curves for back-pressure turbines, correlating electric generation efficiency with three variables: the rotation speed, the number of stages of the steam turbine and its rated power;
2. heat recovery steam generator curves for gas turbine exhaust temperatures between 400 and 600ºC and gas turbine exhaust mass outflows between 8 and 32 kg/s.

In the latter curves, the ordinate is given as the ratio between the flow of steam produced by recovery and the exhaust outflow generated by the gas turbine; the abscissa gives the pressure of the steam produced in the heat recovery steam generator (Szklo *et al*., 2000). Through these curves, the CCGT module obtains the steam conditions (temperature and pressure) in the outlet of the heat recovery steam generator and estimates the steam turbine inlet conditions. Thereafter, the CCGT module sizes the steam turbine, whose outlet flow should match the process steam demand defined by the user of the model, and the gas turbine, whose exhaust outflow should provide the heat requirements of the heat recovery steam generator.

Having sized the systems under each module, the COGEN model then calculates its economic balance. In this balance, cogeneration revenues consist of: (1) electricity saved, not acquired from the network; (2) the sale of possible surpluses generation to the network; (3) the impacts avoided of a possible shortage of power supplies, which is only entered in the accounts should the entrepreneur be averse to risks. In the case of industrial sector, this involves a loss in revenues which is avoided after the installation of a cogeneration plant, completely eliminating the risk of any power shortages for the user (Woo and Pupp, 1992).

The costs consist of : (1) the purchased electricity from an utility to cover system down-time and supplement electric demand if the cogeneration unit does not supply all the electric demand of the entreprise; (2) investments and maintenance of the cogeneration system;[12] (3) investment in heat recovery steam generators and accessories for the cogeneration system; (4) engineering and installation costs of the cogeneration equipment; and (5) balance of expenditures on fuel, taking into consideration the cogeneration plant and the original process.

Under the COGEN MODEL, the selection criteria for cogeneration ventures is the internal rate of return, which should exceed a basic figure established by the user of the model.

5. Case studies

The COGEN model was applied to two specific enterprises: a chemical plant and a pulp mill. In this assessment, in order for a specific system to be deemed economically feasible, its internal rate of return had to top the highest rate of return on the Brazilian market for investments not involving appreciable risks, named fixed income investments. The upper limit of the rates of return for these investments on the Brazilian market is the inter-bank deposit certificate (IDC), whose 1999 income reached 14.8% in real terms (almost half the yield in 1998 at 30.8%). This is the figure used in this simulation, which is expected to develop with no major variations over the next five years.

Notwithstanding, although a reduction in this figure may be admitted for the years ahead, it is also expected that short-term investments will still demand a certain amount of prudence from private investors, particularly with regard to activities other than their core businesses, which is the case of power generation facilities in industrial plants.

5.1. Chemical plant

At the Brazilian chemical plant studied in this article, heat demands are met by consuming BTE-type fuel oil purchased at a price of US$ 100/t in stationary water-tube boilers with an average steam generation efficiency rating of 80%. The installation cost of the boiler and its ancillary equipment has already been amortized. The heat load factor — ratio between the average heat load demand and maximum heat load required — is equivalent to 0.88. Table 2 summarizes the energy demands of the plant (Balestieri, 1994).

This chemical plant has a high-power load factor of 0.9, working with three shifts right around the clock, with its peak period lasting 6 h during the day. This factor

[12] In some cases, this amount may correspond to an investment balance, meaning that the entrepreneur decides to invest in cogeneration system instead of acquiring other steam or cold generation equipment (Joskow and Jones, 1983).

Table 2
Energy parameters for a Brazilian chemical plant[a]

Electromechanical demand (GWh/year)		29.7
Steam Demand (10^6 kg/year)	MP[a]	105
	LP[b]	6.2

[a]MP: saturated steam at medium pressure (1.8 MPa and 205°C).
[b]LP: superheated steam at low pressure (0.6 MPa and 180°C).

Table 3
Power purchase rates — Industrial Sector[a]

	Peak period	Off-peak period
Consumption (R$/MWh)	47.45	33.73
Demand (R$/kW)	8.74	2.02

[a]US$ 1.00 = R$ 1.90.

Table 4
Chemical plant — base case[a]

Tariff context	HPGT	LPGT	CCGT
Electricity rate (R$/MWh)	53.7	53.7	53.7
Buyback rate (R$/MWh)	0.0	0.0	0.0
Back-up purchase rate (R$/MWh)	161.1	161.1	161.1
Natural gas rate (US$/MMBTU)	2.7	2.7	2.7
Results			
Internal rate of return (% p.a.)	≅0	≅0	≅0
Capital cost – cogeneration Unit (US$/kW)	482.5	457.2	1000.0
Rated power – gas turbine (MW)	9.4	5.0	14.5
Rated power – steam turbine (MW)	0.0	0.0	2.2
System availability (%)	96.4	96.4	96.4
Cogeneration efficiency (%)	78.7	74.1	60.4
Electricity generation (GWh/year)	54.7	36.0	112.1
Supply level[b]	1.8	1.2	3.8
Gas consumption (10^6 m^3/year)	15.4	13.5	26.2
Exhaust temperature (°C)	464	443	600
Exhaust outflow (kg/s)	39.2	18.5	32.0

[a]Foreign exchange rate: US$ 1.00 = R$ 1.90.
[b]Ratio between electricity produced and electricity demands.

corresponds to that of the inorganic product segment as a whole in Brazil, including intermediate products for fertilizers for 1997 (ABIQUIM, 1998). The number of hours in operation is high, at 7218 h a year. The power-to-heat ratio of the plant is equivalent to 0.34, which is close to the average for chemical industries in Rio de Janeiro for 1995 at 0.39 (de Oliveira, 1995), and is higher than the average adopted by Khrushch *et al*. (1999) for the US chemical and pulp and paper industries at 0.2. However, it should also be noted that this is a specific plant rather than an average for the Brazilian chemical sector.

Specific power consumption by this plant corresponds to 70 kWh/t, with the average unit value of its output at US$ 21/t, consisting of an intermediate product for goods with a higher added value. In the base case simulation, the risk of a shortfall is not taken into consideration in the cogeneration economic balance. The annual average temperature in the district where the plant is located is 25°C, at sea level.

For the base case within the current regulatory and rates context, the natural gas rate was simulated at US$ 2.70/MMBTU, slightly higher than the figure for gas contracted from Bolivia (Eletrobrás, 1999). The electricity rate is obtained on the basis of data supplied by the Brazilian Electricity Regulatory Agency (ANEEL, 1999) (see Table 3).

The results of the COGEN model for the base case demonstrated the lack of economic feasibility for the three cogeneration systems assessed (Table 4). Nevertheless, the first two systems — HPGT and LPGT — were technically more adequate for the chemical plant under study than the CCGT system whose immense generation of surplus power reflects the low value of the power-to-heat ratio of the plant.

In order for a cogeneration plant to be feasible, by definition the savings it offers in terms of electricity should offset the additional fixed costs incurred through its implementation (Joskow and Jones, 1983). There are three basic incentive policies for cogeneration: the first focuses on the power rates, through either higher prices or guaranteed purchase of cogenerated surplus power; the second centers on the gas rates which represent an appreciable portion of the variable costs of the plant; finally, the third targets equipment through government subsidies underwriting purchases.[13] These policies could be applied together or separately.

In the case of the chemical plant under assessment, the simulation of the stand-alone cogeneration incentive policy based on higher rates did not produce satisfactory results for minor price hikes, with non-mandatory purchase of surplus cogenerated power by the utility (Table 5). The most promising cogeneration system is the LPGT, which operates with the lowest gas supply and consumption levels, and is better adapted to the heat and power demands of the plant (by burning additional fuel in a recovery boiler, this system is more flexible than the others that generate appreciable surplus power). The internal rate of return of this system for an increase of 40% in the power sale rate varies between 11.0 and 16.7% p.a., almost underpinning its feasibility within a favorable context for selling off surplus electricity with

[13]These subsidies may be viewed by the private entrepreneur as a measure equivalent to reducing the fixed costs of gas-fired cogeneration technologies as perceived by him.

Table 5
Sensitivity analysis – variation in power purchase rates: chemical plant[a]

Average rate (R$/MWh)	Internal rate of return (% p.a.)								
	SF: 0.5 BF: 1	SF: 0.5 BF: 2	SF: 0.5 BF: 3	SF: 0.75 BF: 1	SF:0.75 BF: 2	SF: 0.75 BF: 3	SF: 1 BF: 1	SF: 1 BF: 2	SF: 1 BF: 3
HPGT system									
53.7	0.0	0.0	0.0	0.0	0.0	0.0	5.2	4.4	4.0
64.4	2.1	1.0	0.0	7.1	6.4	5.6	11.0	10.7	10.0
75.2	7.6	6.5	5.7	12.6	11.5	10.7	16.7	15.7	15.1
85.9	12.1	11.1	10.2	17.0	16.0	15.5	21.0	20.0	19.5
96.7	16.0	15.3	14.3	21.0	20.1	19.3	25.0	24.1	23.2
107.4	20.0	19.0	18.4	24.6	23.5	23.0	29.0	28.0	27.3
LPGT system									
53.7	0.0	0.0	0.0	2.5	1.0	0.0	4.4	3.1	1.7
64.4	7.7	6.5	5.1	9.6	8.4	7.2	11.5	10.4	9.0
75.2	13.3	12.2	11.0	15.0	14.0	13.0	16.7	15.7	15.1
85.9	18.3	17.0	15.7	19.7	18.9	17.0	22.0	21.0	19.5
96.7	22.7	21.8	20.0	24.5	23.0	20.7	26.3	25.0	23.8
107.4	26.5	24.0	24.0	28.2	27.2	26.0	30.5	27.8	27.5
CCGT system									
53.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
64.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
75.2	0.0	0.0	0.0	0.0	0.0	0.0	4.2	4.0	3.8
85.9	0.0	0.0	0.0	2.3	2.0	1.7	7.8	7.6	7.3
96.7	0.0	0.0	0.0	5.5	5.3	5.0	11.0	10.6	10.4
107.4	1.4	1.0	0.0	8.3	8.0	7.6	13.5	13.4	13.2

[a]SF (surplus factor): ratio between the buyback tariff and the power purchase tariff; BF (back up factor): ratio between the back up purchase tariff and the power purchase tariff.US$ 1 = R$ 1.9.

guaranteed power backup at reduced rates. These results could be even better for the LPGT system, if the private investor receives government incentives to implement this system, such as tax breaks, for example.[14] In turn, the CCGT system proved completely inadequate for the case under study, regardless of the tariff context simulated.

By varying the gas rates and keeping the other parameters constant in relation to the base case, the better economic performance of the LPGT system was also proven (Table 6). This system posted relatively favorable results for cogeneration at gas rates between US$ 1.6 and 1.8/MMBTU, revealing greater economic potential in areas where natural gas is cheaper, particularly near the Campos Basin in Rio de Janeiro.[15] The wellhead price of natural gas varies from US$ 0.90 to 1.10/MMBTU. The cost of converting natural gas to boiler gas and the distribution cost together correspond to approximately US$ 0.70/MMBTU (Turdera *et al*., 1997). This means that a rate between US$ 1.6 and 1.8/MMBTU could represent the level for the consumption of gas produced in Brazil.

Table 6
Sensitivity analysis — gas rate variation: chemical plant

Gas rate (US$/MMBTU)	Internal rate of return (% p.a.) HPGT	LPGT	CCGT
1.6	1.4	14.6	0.0
1.8	0.0	11.5	0.0
2.0	0.0	8.4	0.0
2.2	0.0	4.6	0.0
2.4	0.0	0.0	0.0
2.6	0.0	0.0	0.0

In fact, the most appropriate cogeneration incentive policy at this industrial plant should blend gas and electricity rates measures. This is yet another complicating factor for Brazil, as the electricity and natural gas sectors are regulated by two different agencies that have recently been established: the National Petroleum Agency (ANP), established in 1998 for natural gas and oil, and the Brazilian Electricity Regulatory Agency (ANEEL), established in 1996 for electricity. Additionally, the supply contract covering natural gas imported from Bolivia is a take-or-pay scheme,[16] which means that the amounts

[14] The tax load on imported equipment may reach 70% of the value thereof (ANEEL, 1998).

[15] This Basin accounts for 39.3% of Brazil's natural gas production in 1997 (ANP, 1998).

[16] Under a take-or-pay contract, the country importing or purchasing natural gas is obliged to pay for the volumes contracted, regardless of whether or not they are consumed.

Table 7
Sensitivity analysis — shortfall risk accounting: chemical plant

Risk of shortfall (%)	Internal rate of return (% p.a.) HPGT	LPGT	CCGT
9.0	25.0	41.0	0.0
7.0	9.6	25.0	0.0

stipulated for the gas rates are not very flexible, with gas supplies being linked mainly to its consumption by large thermo-power plants that guarantee the return on investments in the Bolivia–Brazil gas pipeline. Within this context, the cogenerator has little bargaining power.

An interesting analysis covers the high risk of shortfalls in Brazil's current power system. The electricity sector is working with an acceptable limit of 5.0% for the shortfall risk. However, this system is currently operating with an expected risk of over 9.0%, topping 15% at certain times of the year (Eletrobrás, 1999). This prompts a certain instability in the industrial sector as a whole, particularly at more electric-intensive plants. In fact, when the reduction in the shortfall risk is included in the economic balance of the COGEN model, maintaining the base case conditions (tariff context and current regulatory structure) the possible loss of billings avoided due to the installation of the cogeneration plant underpin the feasibility of both the HPGT and LPGT systems for a shortfall risk at 9.0% (Table 7). Even if the shortfall risk should drop to 7.0%, the LPGT system still proved feasible. This means that, as the risk of shortfall is directly related to the expansion of the power system generation park, any delay in this expansion could ensure the feasibility of cogeneration units at industrial plants, as is the case with the chemical plant under study here.

The installation of the cogeneration unit at this industrial plant is thus justified, even without any government incentive policy, provided that the entrepreneur is eager to avoid the possible risks of power outages, and that no expansion work takes place for Brazil's power generation park. However, government incentives for gas and electricity rates could enhance the economic performance of the cogeneration unit even further.

5.2. Pulp mill

The data used come from a mill producing 1000 t of pulp a day (Table 8).[17] Its power-to-heat ratio is 0.17, almost equivalent to that given by Khrushch *et al.* (1999) for the USA at 0.2. The power demands of the plant studied here correspond on average to those for similar-sized industrial pulp mills run by Companhia Votorantim de Papel and Aracruz (Jaakko Pöyry, 1998), established in Brazil.

[17] Kraft process.

Table 8
Power parameters: pulp mill[a]

		Demand per ton of pulp
Steam	MP	3.30 t (2.55 MWh)
	LP	3.33 t (2.52 MWh)
Electricity		0.85 MWh

[a] MP: Medium-pressure saturated steam (1.3 MPa); LP: Low-pressure saturated steam (0.3 MPa). *Source*: Eletrobrás (1998).

Table 9
Energy demands not met by black liquor: pulp mill

	GWh/year	Portion of demand not met by black liquor (%)
Process heat	953.5	51.5
Electricity	59.0	19.0

However, the value of the power-to-heat ratio of the pulp mill drops on removal of the energy demand fractions met by black liquor.[18] It was considered that all the black liquor produced at the mill, at a rate of 1.0 t of black liquor for 1.0 t of pulp (Eletrobrás, 1998), is assigned to generate steam and electricity through a conventional Rankine cycle. The power generation of this cycle for the black liquor has an average efficiency of 18.5% (Tolmasquim *et al.*, 1998). The steam generation has an efficiency of 66%, assuming the conversion factor of 3.1 t of steam per t of black liquor based on the HHV (Peixoto and Balestieri, 1994).

This study assessed natural gas-fired cogeneration systems for meeting the electricity and heat energy demands of the industrial plant not covered by black liquor consumption (Table 9). In the original process, the demand for steam not met by black liquor is covered by boilers burning residual fuel oil, while power demands not met by black liquor are covered by the power distribution grid.

The electric load factor for the plant corresponds to 0.93 (Peixoto and Balestieri, 1994) with a 2 h peak period per day. Its heat load factor is equivalent to that of the chemical plant. The efficiency of the boiler used originally in the process to supplement the heat demand is established on the basis of a conversion factor of 13.8 t of steam per t of residual fuel oil (Peixoto and Balestieri, 1994). The average unit value of pulp is equivalent to US$ 434/t, based on the average price of this product in 1998, earmarked for export (CVM, 1999).

[18] Low heat value: 13.4 GJ/t. High heat value: 15.0 GJ/t.

Due to its low power-to-heat ratio, and considering the results produced for the chemical plant, it did not seem pertinent to simulate the CCGT system for the pulp mill, as this is more appropriate for industrial plants with a high power-to-heat ratio.

The sizing of the cogeneration systems demonstrated the significant technical potential of natural gas-fired cogeneration for Brazil's pulp industry (Table 10). The rated power of these two systems proved similar to the results for pulp and paper mills in the USA, where some 62% of the outstanding cogeneration potential is noted in units producing 30–70 MW (Khrushch *et al*., 1999). However, in contrast to the United States, a performance of the two systems assessed was not satisfactory for the current rates and regulatory context in Brazil. Much of the power generated is surplus, as there is a considerable gap between the heat and electricity demands which should be met by a natural gas-fired cogeneration unit. Additionally, the size of the units demands heavy initial investment in dollars, which not only extends the maturation period of the systems but also highlights the difficulty of recovering these investments through electricity rates quoted in *reais*. These results indicate that, for the base case, it is better to continue generating electricity through black liquor and purchasing power from the distribution grid without investing in supplementary gas-fired cogeneration units.

An analysis was then undertaken of a possible future incentive for cogeneration through electricity rates. This incentive consists basically of three measures: (1) an increase in the rates for electricity purchased from the power utility; (2) mandatory purchase of surplus cogenerated power by the utility at predetermined prices[19] and power supplies for the cogenerator during emergency periods at reasonable prices.

In contrast to the chemical plant, the systems assessed for the pulp mill proved feasible with minor alterations in the Brazilian electricity rates and regulatory context. In fact, establishing a value for the buyback rate and an increase of 20% in the electricity purchase rate resulted in more satisfactory rates of return for the systems assessed (Table 11). Thus, as the size of these systems is considerable, which means not only energy savings but also and more specifically the generation of surplus power, the key variables for ensuring the feasibility of gas-fired cogeneration are the buyback rate and the electricity purchase rate. The most adequate system was the LPGT, which proved feasible with an increase of 20% in the electricity rates and a surplus power sales factor of 0.75. For a surplus power sales factor of 0.5, the system proved feasible with tariff hikes of 60%. Without higher rates, equalizing the buyback rate and the electricity purchase rate ensures the feasibility of the two cogeneration systems assessed. This is an interesting result, as in this case the cogeneration incentive policy affects only the utility through higher buyback rates, without affecting the final consumer.

On the other hand, a stand-alone incentive policy based on a reduction in gas rates did not indicate any substantial improvements in the economic performance of the systems assessed. The fixed costs of these systems are relatively high, which explains this result. In other

Table 10
Base case results: pulp mill[a]

Rates context	HPGT	LPGT
Electricity rate (R$/MWh)	49.6	49.6
Buyback rate (R$/MWh)	0.0	0.0
Backup power purchase rate (R$/MWh)	148.8	148.8
Natural gas rate (US$/MMBTU)	2.6	2.6
Results		
Internal rate of return (% p.)[a]	≅ 0	≅ 0
Capital cost of cogeneration unit (US$/kW)	457.0	260.0
Rated power - gas turbine (MW)	69.9	47.7
Electricity produced (GWh/yr)	494	384
Supply level[b]	8.4	6.5
Gas consumption (10^6 m^3/year)	15.4	13.5
Gas turbine exhaust temperature (°C)	464	443
Gas turbine exhaust flow rate (kg/s)	39.2	18.5

[a]Foreign exchange rate: US$ 1.00 = R$ 1.90.
[b]Ratio: Electricity produced / electricity demand.

Table 11
Sensitivity analysis — variation in electricity rates: pulp mill[a]

Average purchase electric rate (R$/MWh)	Internal rate of return (% p.a.)		
	SF = 0.5	SF = 0.75	SF = 1.0
HPGT			
49.6	0.0	6.6	14.5
59.5	2.1	12.5	20.0
69.4	7.0	16.9	25.0
79.4	11.0	21.5	30.0
89.3	15.0	25.2	35.0
99.2	17.9	29.3	38.0
LPGT			
49.6	0.0	7.0	20.0
59.5	0.0	16.7	28.0
69.4	8.3	25.0	35.5
79.4	15.2	31.0	43.0
89.3	20.5	37.0	50.0
99.2	26.5	41.0	55.0

[a]SF (surplus factor): ratio between the buyback tariff and the power purchase tariff; BF (backup factor) : ratio between the backup purchase tariff and the power purchase tariff. 1US$ = 1.90 R$.

[19] In general, these figures correspond to the fractions of the electricity sell rate. Rose and McDonald (1991) took a figure 60% lower for the buyback rate compared to the electricity rate. Although in certain cases, particularly for buyback rates valued according to the avoided cost, this ratio could be inverted.

words, variable costs have lower impacts on the economic balances of large-scale units.

Finally, the inclusion of the risk of power shortfalls in the economic balance of the two systems assessed failed to ensure their feasibility for the base case, although revenues coming from the inclusion in the accounts of the avoided impacts of power outages were considerable. The heavy initial investment in these systems due to their size and the fact that the equipment is quoted in dollars blocked the feasibility of cogeneration ventures. In contrast to the chemical plant whose cogeneration plants did not exceed a rated power of some 17 MW, it is not the high risk of shortfalls in the Brazilian electricity system that ensures the feasibility of cogeneration at the pulp mill studied, but rather the possibility of selling off surplus power associated with an increase in electricity rates for industrial consumers.

6. Conclusion

The application of the COGEN model to two specific industrial plants in the chemical and the pulp and paper sectors proved the relevant technical potential of cogeneration for these two sectors. Although the results should not be generalized for all Brazilian industrial plants in these sectors, given their heterogeneity, they are representative for large and medium plants with uniform heat load and power-to-heat ratio varying between 0.2 and 0.5. In this sense, the power-to-heat ratio of the chemical plant studied is close to the average for chemical industries in Rio de Janeiro state for 1995, and the power-to-heat ratio of the pulp mill studied corresponds to those ratios for similar-sized industrial pulp mills run by Companhia Votorantim de Papel and Aracruz Celulose, both established in Brazil.

The sizing of the cogeneration systems for the chemical plant studied resulted in units sized below 17 MW. This upper limit refers to the combined-cycle system assessed, which is installed only in a favourable context for selling surplus cogenerated power. Actually, this is not the case in Brazilian electric system. Although industrial cogenerators can join the recently created open electricity market, the buyback rates are still low in Brazil. For example, in 1999, the buyback rate established by an electricity enterprise located in Sao Paulo state, the CPFL, was US$ 8.1/MWh (Costa, 2000), not reflecting the electricity generation avoided costs of Sao Paulo state. Additionally, the economic performance of the cogeneration systems proved very sensitive to the entry in the accounts of the effects of power outages at a plant. In fact, even for the current rates and regulatory context, the cogeneration systems assessed, particularly the LPGT system, proved feasible through the inclusion of these avoided impacts on corporate revenues. This leads to the conclusion that if an entrepreneur is eager to avoid the risks of power outages, investments in a natural gas-fired cogeneration system at the chemical plant are feasible, even without a cogeneration incentive policy.

For the pulp mill, the considerable size of the cogeneration systems assessed at 48–70 MW blocked their feasibility within the current context of the Brazilian economy, even when including the impacts of power outages at this plant. This was due to high initial fixed costs, quoted in dollars. In this case, as there is an appreciable amount of surplus power generated, the economic performance of these systems would be improved through incentive policies encouraging gas-fired cogeneration, particularly in terms of buyback rates.

Thus, this study reveals that investments in gas-fired cogeneration for Brazilian industrial plants are feasible at the moment for medium-size industrial plants affected by possible power outages, as well as larger plants provided that adequate rates and standards are established for selling off surplus cogenerated power.

These results are nevertheless dependent on the lower limit of the internal rate of return established that ensures the feasibility of investments in cogeneration. A drop in this threshold through alterations in Brazil's macro-economic context affects the results and helps ensure the feasibility of cogeneration systems that are not currently feasible.

This study has the limitation that it is based on only three configurations for gas-fired cogeneration. More complex configurations could be drawn up for the system based on combined cycle (CCGT) generation. However, this did not prove necessary for the power-to-heat ratios of the industrial plants studied. It would be interesting to carry out another analysis studying new gas-fired cogeneration configurations for other Brazilian industrial plants. Another noteworthy point is the possibility of taking advantage of the steam turbine used for black liquor-fueled cogeneration at the pulp mill in a combined cycle with natural gas. In this case, the LPGT system would be used associated with the steam turbine, with no additional fixed costs for its acquisition. However, this would only be possible if the steam turbine originally associated with the black liquor-fueled generation cycle has idle capacity.

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