ENERGY ISSUES
THE WORLD BANK

26349

No.17
Feb 1999

Gas Market Development in Brazil

How Gas-Fueled Power Plants Can Operate in Brazil's Hydro Dominated System

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This paper discusses the issues faced in introducing new gas fired power generation plants into Brazil's hydropower dominated system. Ordinarily, power project developers seek to operate their plants at high load factor over the plant lifetime to ensure financial viability. However, the year to year variation of rainfall in Brazil—which could result in a surplus of hydropower in some periods and a shortfall in others—posed major questions concerning how the gas fired plants would operate.

In 1993 two state oil companies, YPFB of Bolivia and PETROBRAS of Brazil, signed an agreement for the export of up to 16 million cubic meters a day of natural gas from Bolivia to Brazil over a 20-year period. Gas will be transported from gas-rich areas around Santa Cruz to the industrial markets of south-southeast Brazil—including São Paulo—through a 3,000 kilometer, 32-inch pipeline costing about $2 billion. The World Bank approved financing for the project in December 1997, and construction of the pipeline is under way and scheduled for commissioning in 1999. (For the history of the project and the evolution of hydrocarbon sector reforms in Bolivia and Brazil, see Viewpoint Note No. 144 http://www.worldbank.org/html/fpd/notes/energy.htm)

Imports of Bolivian gas will allow Brazil to increase the share of natural gas in primary energy supply from 2 percent to at least 10 percent within 10 years. Eventual use of the pipeline's full capacity—30 million cubic meters a day at full compression—offers substantial upside potential. Moreover, the project will improve air quality by displacing polluting fuels, such as fuelwood and high-sulfur fuel oil, that are currently used by industrial consumers in urban areas.

After the gas sales agreement was signed, Brazilian agencies commissioned several studies to assess the financial viability of the pipeline project. In general, these studies concluded that viability would be enhanced if new gas-fueled power generation were located in São Paulo, thereby ensuring that large volumes of gas would be absorbed in the early years of the agreement. But these studies evaluated the viability of gas-fueled thermal plants operating in isolation from Brazil's hydropower-dominated electrical system, where in periods of high rainfall it might be expected that hydroplants would be dispatched in preference to thermal plants to avoid spillage of water. And so a key question was left unanswered: Is gas-fueled power generation an economically viable option in Brazil's hydropower-dominated power system? If it is, how will the gas plants operate under different hydrological conditions?

Brazil's Power Sector

Over the past 30 years Brazil's power sector has grown rapidly under an investment policy that gave

The World Bank Group • Energy, Mining & Telecommunications • Finance, Private Sector and Infrastructure Network

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priority to domestic natural resources. This approach favored the development of large hydro projects and a controversial nuclear program. Thermal generation was relegated to a minor role, with only a few plants using low-quality indigenous coal. Thermal generation based on imported fuels—including hydrocarbons and coal—was not favored because it would have increased dependence on external resources.

The electricity industry developed as two unconnected power grids. Today the combined installed capacity of these grids is 54 gigawatts, of which 96 percent is hydro-based. The larger grid supplies 74 percent of Brazil's electricity consumption, serving 10 states in the south-southeast and midwest, including São Paulo and Rio de Janeiro. The grid's more than 200 hydro plants are supplemented by 23 thermal units (coal, oil, and nuclear), which account for a small portion of installed capacity. The smaller grid supplies 23 percent of electricity consumption and serves 11 states in the north-northeast.

In 1995 ELETROBRAS—the state-owned national electricity company responsible for integrated power sector development—forecast that power consumption in Brazil would grow by 4.7 percent a year. At this rate about 28 additional gigawatts of installed capacity would be needed within 10 years, most of it in the south-southeast. Investment requirements were estimated at $7 billion a year, about half of which was for additional generation. In line with its traditional planning philosophy, ELETROBRAS anticipated that nearly all this capacity would be met through hydro plants. But the prospect of Bolivian gas imports has opened the door for gas-based thermal options.

The Planning Exercise

Recognizing that gas-fueled power generation could improve the financial viability of the Bolivia-Brazil pipeline through the use of upside capacity, ELETROBRAS, in cooperation with the World Bank, set out to analyze the economics of thermal generation—including gas, oil, and coal—operating within the hydro system.

A systematic review was made of the cost of a large catalog of hydro projects identified by ELETROBRAS. The review found that for projects where basic designs and cost estimates had been prepared in the 1980s, costs needed to be updated using 15 price indices instead of the single consumer price index used by ELETROBRAS in earlier evaluations. The newly considered price indices better reflect the current cost of civil works, and of mechanical and electrical equipment, as well as engineering services. Following review, the estimates of implementation costs of the projects were 20 to 30 percent lower than previously calculated.

Methodology

Brazil's power system expansion was defined in two stages. First, a ***long-term*** (30-year) expansion optimization plan was prepared using a linear programming model. The model defines the system least-cost

Power Sector Reforms

The Brazilian government is making efforts to demonopolize and create competition in the power sector. The Concessions Law (1993) provides the basis for delegating traditional government responsibilities--as provider of public services--to the private sector. The law eliminated the uniform tariff and guaranteed rate of return systems, identifies separate sector activities (generation, transmission, and distribution), and mandates that bulk energy supply be contracted for among generators and distributors. It also provides for open access to transmission systems to promote competition in generation.

The Electricity Services Law (1995) regulates power services and introduced competition in the bulk supply market by permitting large consumers to contract supply directly with generating companies. Decree 2655 (July 1998) mandates the creation of an independent system operator responsible for dispatch and supervision of generation and transmission facilities and creation of a wholesale market. A regulatory commission (ANEEL) was created in late 1996 and started functioning in the late 1997. The new legal and regulatory framework enables the private sector to play a larger role in power generation and distribution.

expansion by selecting a set of generation plants and their commissioning dates from a group of hydro and thermal candidates under a maximum risk of power deficits lower than or equal to 5 percent (the planning criterion used by ELETROBRAS). The price of gas to thermal plants was set at the economic cost of gas to be imported from Bolivia, rather than the current cost of domestic gas from the Campos and Santos basins. The investment and operating costs of gas-fueled plants (and other thermal candidates, including power plants fueled by oil and imported coal) were based on recent international costs. An important feature of the simulation was the assumption that the systems in the south-southeast and the north would be connected by 2000, a project that is now being implemented. This interconnection will allow energy transfers between the two systems because of their hydrological complementarity.

Second, a detailed ***medium-term*** (15-year) simulation of selected configurations was made using a dynamic programming model. This model defines the detailed expansion of the system by simulating the system operations on a monthly basis for different hydrological situations over the planning period, and the behavior of the hydro reservoirs under operational policies based on the economic optimization of stored water.

The results

The ***long term*** optimization process resulted in a least cost solution which includes 6,800 megawatts of gas-fueled generation inserted by 2005, increasing to 21,000 megawatts by 2015. Of this capacity, about 2,000 megawatts could be commissioned almost immediately because, due to delayed investments in additional hydro capacity, the risk of power deficits in south-south east Brazil had become much higher than the 5% criterion noted above. The optimization selected gas fueled plants because: (i) the capital costs of gas fueled combined cycle plants are lower than hydro plants, and (ii) increasing the proportion of thermal to hydro capacity in the system upgrades a block of secondary energy (with low economic value) to firm energy (with higher economic value)[1], which makes the thermal plants economically very attractive. Future expansion of Brazil's power system will easily absorb all the gas-fueled generation that can be built using the gas supplies that are likely to become available.

The ***medium term*** simulation of the system showed that, in the first five years of gas imports, due to the short term capacity constraints noted above, gas-fueled generation would operate at high plant factors—typically 75 percent (Figure 1). After this period the risk of deficits would reduce to a normal level and gas-fueled plants would be economically dispatched at lower average load factors, which would then increase over time. But due to the need to optimize the use of water stored (the simulation model includes a reservoir dynamic optimization sub-routine) the operation of gas-fueled plants is uneven. Thermal plants would operate at full capacity during periods of drought, or stand idle during periods of high hydraulicity. However, even though the plant factors for each year over the planning horizon would vary, the average plant factor would increase steadily over time as shown in Fig 1.

The Secondary Market for Gas

Power generators using natural gas from the pipeline will have to pay the full firm cost—that is, the reserved pipeline capacity charge plus the gas commodity charge—regardless of whether or not their plants are operating. It will also be necessary to develop a secondary (industrial) market for the gas that is not required by gas-fueled power plants during periods of high hydraulicity. Such arrangements will differ from the conventional interruptible contracts for industrial consumers used by many of the world's gas markets. Usually such contracts do not include a reserved pipeline capacity charge within the gas price, since the gas supply can be interrupted at a moment's

[1] In a system dominated by hydropower, the total installed capacity to supply a given demand is usually higher than in a system which has a substantial proportion of thermal generation. This is because the hydro system must be designed to provide sufficient energy (firm energy) to meet demand during periods of low rainfall, thus leaving additional energy (secondary energy) which could be generated during periods of higher rainfall not dispatched. Installing thermal plants in such a system can be considered a risk mitigation measure, since by using them to complement the operation of the hydro plants, it allows secondary hydro energy to be dispatched and sold rather than being stored or spilled.

notice to accommodate load balancing requirements of the supply (transmission) system. Brazil's power system, however, offers a novel opportunity for the secondary market to share the pipeline capacity charge with the power plants. This feature is made possible by the large (five-year) capacity of the country's hydro reservoirs, which will allow the plant factors of gas-fueled plants to be anticipated with confidence. Thus industrial consumers will be able to plan their fuel supplies well in advance.

The proposed contract arrangement would be to charge a small priority fee to power plants when they are not running, and charge secondary (industrial) consumers the full firm gas price less the priority fee. Power plants would be given priority in using the gas supply, and industrial consumers would have an incentive to accept a programmed interruption of supply if required. When power plants are running, they would pay the full firm cost of gas supply and industrial consumers would switch to an alternative fuel.

The interruption times and schedules, gas price (commodity and reserved pipeline capacity charge), and priority fee are matters of commercial negotiation between the gas supplier, power plant developers, and secondary consumers. These arrangements would offer a practical way to include gas-fueled power plants, while ensuring a base load offtake of natural gas from the Bolivia-Brazil pipeline.

Conclusion

Introducing gas-fueled generation capacity in Brazil's south-southeast power system is shown to be the optimum solution for a wide range of assumptions on fuel prices and other economic parameters. Due to the large existing reservoir capacity, the production schedules of these plants can be predicted with enough confidence to allow the development of a secondary market for gas. The contractual framework based on the priority fee as described in this paper could be applied in other countries where there is an opportunity to develop gas-fueled power generation within a hydro-dominated system.

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Figure 1
National Average Plant Factor of Gas Fired Plants