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Brazil
Hydro and Thermal Power Sector Study

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PURPOSE

The Joint UNDP/World Bank Energy Sector Management Assistance Programme (ESMAP) is a special global technical assistance program run by the World Bank's Industry and Energy Department. ESMAP provides advice to governments on sustainable energy development. Established with the support of UNDP and 15 bilateral official donors in 1983, it focuses on policy and institutional reforms designed to promote increased private investment in energy and supply and end-use energy efficiency; natural gas development; and renewable, rural, and household energy.

GOVERNANCE AND OPERATIONS

ESMAP is governed by a Consultative Group (ESMAP CG), composed of representatives of the UNDP and World Bank, the governments and other institutions providing financial support, and the recipients of ESMAP's assistance. The ESMAP CG is chaired by the World Bank's Vice President, Finance and Private Sector Development, and advised by a Technical Advisory Group (TAG) of independent energy experts that reviews the Programme's strategic agenda, its work program, and other issues. ESMAP is staffed by a cadre of engineers, energy planners, and economists from the Industry and Energy Department of the World Bank. The Director of this Department is also the Manager of ESMAP, responsible for administering the Programme.

FUNDING

ESMAP is a cooperative effort supported by the World Bank, UNDP and other United Nations agencies, the European Community, Organization of American States (OAS), Latin American Energy Organization (OLADE), and public and private donors from countries including Australia, Belgium, Canada, Denmark, Germany, Finland, France, Iceland, Ireland, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Sweden, Switzerland, the United Kingdom, and the United States.

FURTHER INFORMATION

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BRAZIL

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Acknowledgements

This report was prepared by a joint ESMAP - ELETROBRAS team, comprising P. Law (Task Manager and Energy Specialist) and H. Garcia (Principal Power Engineer) of the World Bank, and Messrs. A. Ventura Filho, J. Trinkenreich, J. Rosenblatt, M. Pereira dos Santos, and N. Paciornik of ELETROBRAS. The peer reviewer for the study was N. de Franco, Principal Power Engineer at the World Bank.

The study assesses the economic viability of the installation of gas fueled power plants in the Brazilian South-Southeast (SSE) electrical system[1] in connection with the proposed Bolivia-Brazil pipeline. The methodology for developing the least cost power expansion plan was developed and executed by ELETROBRAS. Updating the costs of hydro projects was carried out by the Brazilian Consultant HIDROSERVICE with ESMAP financing, and data for thermoelectric options were provided by Sociedade Privada de Gas (SPG).

[1] The analysis was made on the interconnected system which covers the regions of the South, South-East and Mid-West. Though the three regions are interconnected, some energy transfer restrictions exist. This report refers to the SSE system as the integration of the above three subsystems.

ABBREVIATIONS AND ACRONYMS

ANP	Agencia Nacional do Petroleo
CPI	Consumer price index
CTEM	Committee for Market Studies
DNC	Departamento National de Combustiveis
ESI	Electric Sector Industry
LNG	Liquefied natural gas
MOF	Ministry of Finance
MME	Ministry of Mines & Energy
MW	Mid-West
NNE	North-Northeast
PCG	Planning Coordinating Group
PD	Plano Decenal
SPG	Sociedade Privada de Gas
SSE	South-Southeast
YPFB	Yacimientos Petroliferos Fiscales Bolivia

UNITS

CFD	Cubic Feet per Day
MMCFD	Million CFD
CM	Cubic Meter
CMD	Cubic Meter per Day
MMCMD	Million CMD
CMY	Cubic Meter per Year
MMCMY	Million CMY
BCM	Billion Cubic Meter
BCF	Billion Cubic Feet
TCF	Trillion Cubic Feet
BTU	British Thermal Unit
MMBTU	Million BTU
TOE	Ton of Oil Equivalent
MMTOE	Million TOE
MMT	Million Tonnes
MMTPA	Million Tons per Annum
GWh	Gigawatt hour
KWh	Kilowatt hour
TWh	Terawatt hour
GW	Gigawatt
KW	Kilowatt
MW	Megawatt
kV	Kilovolt
Kcal	Kilocalorie
Kg	Kilogram
bbl	barrel

EXECUTIVE SUMMARY

Introduction

1. The electricity sector in Brazil is undergoing important institutional transformations which will increasingly allow the private sector to build new power plants and participate more intensively in distribution activities. The possibilities of introducing gas fueled thermal plants into the system have been stimulated by the agreement recently signed between YPFB and PETROBRAS for the importation of large volumes of gas from Bolivia.

2. The objective of this study is to assess the economic viability of the inclusion of gas turbine and combined cycle power plants in the Brazilian South-Southeast (SSE) Electrical system over the timeframe 1996 to 2015, using natural gas at an economic cost consistent with that to be expected from the Bolivia-Brazil gas import project. The study is based on a comprehensive least cost simulation of the whole Brazilian power system using the ELETROBRAS planning models, and places future thermal power generation within the context of the operation of all plants, hydro and thermal, existing plus expansion. A key feature includes the rationalization of the methods traditionally used by ELETROBRAS to update their database on construction costs of hydro plants in Brazil, so that the relative merits of hydro and thermal plants can be properly considered in the selection process.

Demand for Power

3. During 1995-2005, the annual demand for electricity in Brazil is expected to grow from 243 TWh to 385 TWh as shown in Table 1, which represents an average growth of 4.7%/y.

Table 1 BRAZIL - Electricity Demand by Region (1995 to 2005)

(TWh)

Region	1995	1998	2002	2005
North	12.6	16.0	23.8	31.6
Northeast	38.2	44.8	55.0	65.4
Southeast	143.3	157.7	183.7	205.2
South	37.4	43.1	52.2	60.8
Midwest	11.8	14.7	18.6	22.2
Total	243.3	276.3	333.3	385.2

4. To meet this demand, about 27,600 MW of installed capacity should be added to the system over the next 10 years. By the year 2000, ELETROBRAS has estimated electricity sector investment needs of US$38 billion, of which US$20 billion (or US$4 billion/year) are for additional generation. Until recently, about 85% of the planned capacity increments were hydro-based. However, the Bolivia-Brazil pipeline project opens the possibility to include additional gas based options.

Current Expansion Plans

5. The SSE Interconnected System covers the South, Southeast and the Center-West regions of Brazil. Hydro generation accounts for 92% of total installed capacity, with over 200 hydro plants of installed capacity 40,800 MW. The system also includes 23 thermal units (coal fired, oil fired and nuclear plants) with a total capacity of 3,080 MW.

6. A review of proposed international interconnections with neighboring countries, and the proposed North-South interconnection linking the Brazilian SSEMW and the NNE systems, showed that only the latter would impact on this study. The others would be either too small or too far in the future to exert any influence. It was assumed that the North-South interconnection would be implemented by the year 2000, with an initial transfer capacity equivalent to 1,000 MW.

7. The latest Plano Decenal recommends additions of 20.4 GW over the decade for the SSE-MW system, of which 15.0 GW would be hydro. During the execution of this study, it became apparent that some increments of gas based thermal generation are needed in the short term, because it will not be possible to complete some of the unfinished hydro projects in time to ensure system reliability. These include two 450 MW gas turbine plants for 1999 and 2000 which could use gas from the Brazil-Bolivia pipeline, to be located in Sao Paulo and Rio de Janeiro. The supply situation in the short term is also becoming critical in Mato Groso do Sul and Mato Groso, mainly due to transmission constraints. This has prompted ELETROBRAS to plan for an additional 400 to 450 MW to be located in Corumba and Campo Grande, and 450 MW in Cuiaba, and which can be expected to operate at or near base load.

Cost Update of Hydro Candidates

8. Cost estimates for a large catalogue of hydro candidates are periodically updated by ELETROBRAS to prepare the Plano Decenal. The reliability of these estimates varies widely, some having been prepared 20 years ago. A review of the cost estimates of sixteen hydro projects with installed capacities between 22 MW and 1800 MW showed that, for projects where the basic design and original cost estimate were prepared in the 1980s, the costs should be updated using fifteen selected price indices instead of the CPI traditionally used by ELETROBRAS. This better reflects the cost of different types of civil works, mechanical and electrical equipment, and engineering services. Projects updated in this way show implementation costs 20%-30% lower than with the traditional method.

Selection of Thermal Candidates

9. Given the predominantly hydro characteristics of the SSE system, there will be enough peaking capacity in the system for many years ahead, and any thermal additions need to be designed for base load operation.

10. To ensure a consistent comparison between the different thermal options, three base load thermal plant alternatives using proven technologies, standard design and appropriate sizes to ensure economy of scale were selected. Available fuel sources were assumed to be local and imported coal and gas, and plants would be constructed on greenfield sites but close to the existing electrical system. Thermal options were: (i) gas fueled combined cycle (CC) thermal plants in modules of 907 MW; (ii) steam thermal plants using imported coal, in modules of 744 MW, and, (iii) fluidized bed combustion (FBC) steam thermal plants using domestic coal, in modules of 125 MW. The selection of FBC was made given the poor quality of local coals and the need to maintain environmental safeguards. The cost and operational characteristics of these plants include purchase of equipment, erection and contractors' services assuming turn-key arrangements, all estimated in 1995 dollars including reasonable contingencies.

Optimum Power System Expansion

11. The system expansion was simulated through: (i) the long term expansion optimization using the ELETROBRAS linear programming model, DESELP, and (ii) the medium term optimization of selected configurations using the OLADE-IDB dynamic programming model. The economic cost of gas for the first 1,800 MW gas fueled power plants was set at about US$2.6/MMBTU. This includes the cost of gas to be supplied at Santa Cruz under the agreement between Petrobras and YPFB (about US$1.1/MMBTU at a crude oil price of US$18/bbl), plus an average gas transport cost to Sao Paulo only, of about US$1.3/MMBTU (US$395/MW of firm capacity), plus an allowance for distribution from the city gate to the power plant. For additional capacity over 1,800 MW, the cost of gas from Santa Cruz was increased to US$1.45/MMBTU to reflect the higher costs of transporting gas from S.Bolivia or N.Argentina. These costs reflect specific assumptions made at the time of the analysis concerning the expected utilization factor of the pipeline to Sao Paulo, and recent developments suggest that a higher utilization factor will be acheived in the early years. This would make the average economic cost of gas transportation to Sao Paulo as used in this study conservatively high, and so make the conclusions of the analysis more robust. The cost of imported coal was estimated at US$45/tonne (US$1.8/MMBTU), with national coal at US$9.4/tonne (US$0.9/MMBTU).

12. *Long-term* simulations were made assuming the maximum risk of power shortages should be equal or below 5% (1 in 20 years) with the economic value assigned to an energy deficit of US$ 480/MWh. Several scenarios using a range of costs for the hydro and thermal plants were simulated, with the most likely scenario reflecting the revised costs of new hydro plants adjusted down by 30%, the cost of gas fueled plants based on current international costs, the cost of gas delivered to the power plant gate as noted above, and a discount rate of 15%. The results are summarized in Table 2, which show that 6,800 MW of gas fueled generation could be inserted by 2005. If a 10% discount rate is used, 3,400 MW could be inserted by this time.

Table 2 Long-Term Evolution of Available Generation Capacity

(GW)

	2000	2005	2010	2015	2020	2025
Hydro	66.4	76.8	82.9	110.4	123.8	152.6
Coal	0	0	0	0	0	1.0
Gas	0	6.8	14.6	21.1	27.2	27.2

Assumes 15% discount rate

13. *Medium-term* simulations assumed operational policies based on optimization of the marginal cost of water, which represents the economic value of water storage. Common features of the simulations were (i) the SSE system and the North system will become interconnected in the year 2000, and (ii) the first 907 MW increments of gas fueled capacity would become part of the system in 1999/2000. This is because, having demonstrated that gas plants are economic, given the increasing risk of energy shortages in the short term, the only realistic options for meeting the deficits are gas fueled plants which have the shortest implementation periods.

14. The operational characteristics of the gas fueled plants were analyzed using dynamic simulation with synthetic generated hydrological series. This showed an uneven operation of the thermal plants along the years. Thermal plants may be operating full capacity for several years in cases of prolonged draught or may be standing idle during periods of high hydraulicity. The average load factor of the thermal plants would be low throughout the entire time horizon, and the average plant factors for each year over the planning horizon would be variable. Typical results are shown below:

Table 3 Typical Average Plant Factor of Thermal Plants (1999-2005)

year	Plant Factor (%)
1999	37
2000	31
2001	30
2002	32
2003	39
2004	43
2005	46
Average	37

15. This demonstrates that plant factor increases over time, because when the system starts including more thermal capacity, the absolute proportion of hydro diminishes leaving yet more room for thermal generation. As noted above, the long-term optimization of the system demonstrates the economic justification of installing gas fueled combined cycle plants, even assuming these plants would be required to accept gas through take-or-pay contracts compatible with 80% Load Factor of operation. However, actual fuel consumption under these circumstances would be not compatible with the operation of the Bolivia-Brazil gas import pipeline if water is not to be spilled by some hydro plants.

16. In practice, the full firm cost of gas from the pipeline will have to be paid for whether the thermal plants are operating or not, with such cost comprising the reserved pipeline capacity charge plus the gas commodity charge. When the plants are not operating, the gas could be diverted to industrial consumers, and this would require the generators to enter into special gas supply contracts with such consumers. This form of operation may require some constraints on the upper limit of load factor of operation of the thermal plants (less than 50%), in order to provide a minimum load factor of supply which would be acceptable to the industrial consumers. The tradeoffs between these load factors, the electricity price, and the discount on gas price which may be offered to the industrial consumers are matters of commercial negotiation for the investors and the consumers, but some spillage of water may still occur. Although this concept will not produce an absolute optimum mode of operation from the perspective of the power system, it can be a practical solution to address the near term shortfall in generating capacity in the SSE while ensuring a base load offtake of natural gas from the Bolivia-Brazil pipeline. However, the load factors of operation realized in practice by the thermal plants could be higher than those noted in Table 3, because the risk of deficit is higher than the 5% target level used by ELETROBRAS over the next 3-5 years, and the actual load factors will be influenced by constraints imposed by commercial agreements.

17. Recent market surveys of the industrial market over the SSE indicate that there is potential to develop a secondary industrial market, where the major fuels displaced would be the higher sulfur and higher viscosity 'A' series of fuel oils. The current fuels usage of the industrial market indicates that there is potential to develop a secondary industrial market to support up to 1,000 to 2,000 MW of gas fired thermal capacity operating in complementarity over the whole SSE within the next 5 - 10 years.

Conclusions

* The introduction of substantial increments of gas fueled generation capacity in the SSE system is economically justified for a wide range of assumptions regarding fuel prices and other economic parameters. Moreover, the system capacity to accommodate such generation goes well beyond reasonable expectations gas resources available and therefore does not exclude other thermal options (such as coal, LNG).

* The system simulation shows that for revised costs of hydro, 30% lower than considered until now, and using a 15% discount rate, about 6,800 MW of gas fired combined cycle generation capacity would be economically justified for inclusion within the SSE interconnected system by 2005 (or 3,400 MW at 10% discount rate).

* With no operational Load Factor constraints on the gas fueled plants, hydrological simulation over a long time series indicates that such plants would operate with average Load Factors of 34% to 37%. However, the high regulating capacity of the hydrological reservoirs in Brazil shows that over a smaller time series (say up to 5 years), the annual operational load factor is highly unpredictable under a constraint which avoids the spillage of water.

* Market studies suggest the existence of a secondary industrial market in SSE Brazil, of sufficient absorptive capacity to consume natural gas which would become available from 1,000 to 2,000 MW gas fueled plants over the next 5 - 10 years. Although the practicalities of entering into commercial contracts with such industrial users could impose some limited sub-optimal constraints on the operation of the whole power system, such constraints would likely be a necessary precondition to the implementation of gas fueled plants by the private sector.

1

Introduction

Background

1.1 In 1993 PETROBRAS signed a natural gas importation agreement with YPFB for the importation of 8-16 MMCMD natural gas over a twenty year timeframe. This would allow Brazil to increase the share of natural gas in primary energy from the current level of 2% to about 10% within a decade. The gas import project will require the construction of a gas pipeline from Santa Cruz in Bolivia to Sao Paulo in Brazil, and continuing with a spur line to the Porto Alegre in South East Brazil. The total project cost is estimated at US$ 1.6 bn excluding financial charges. For Brazil, the importation of natural gas will bring a number of benefits including the amelioration of atmospheric pollution through the displacement of less clean fuels in Sao Paulo, and opens the possibility to construct gas-fired turbine power plants to supplement the country's hydro-dominated system.

1.2 Since the original gas supply agreement was signed in 1993, several studies have examined the economic and financial viability of the gas pipeline project. The most recent, commissioned by Sociedade Privada do Gas (SPG), concluded that the viability of the pipeline project is dependent on new base load gas-fired power generation located in Sao Paulo, to ensure that large volumes of Bolivian gas are absorbed in the early years of the project. Although these studies have provided valuable analysis concerning the economics of thermal power generation options, they have generally evaluated the generation costs of gas fueled thermal plants operating in isolation from the system expansion plan.

Objectives of the Study

1.3 The objective of this study is to assess the economic viability of the installation of gas turbine and combined cycle power plants in the Brazilian South-Southeast (SSE) Electrical system between 1996 to 2015, using natural gas at an economic cost consistent with that to be expected from the Bolivian gas import project. The study makes an analytical step forward in that thermal generation is placed in the context of the rest of the system to simulate the operation of all plants. The study is a classical planning exercise and analyzes the economics of thermal generation under constraints imposed by the need to coordinate hydro and thermal electricity production. It does not intend to define how such generation would be implemented.

14. The assessment was carried out in the following phases:

(i) ***Definition of planning methods, criteria and parameters:*** This phase was aimed at a definition of the most suitable methodology for the analysis and defining economic parameters to be used. It examined ELETROBRAS' analytical tools used for power system expansion planning and assessed whether the current planning methods are appropriate with respect to attaining a fair evaluation of hydro-thermal mix. Appropriate technical and economic parameters for the study were also defined.

(ii) ***Preparation of power demand forecasts:*** This phase included the preparation of most likely scenario for the power demand projections.

(iii) ***Review of the costs of hydro plants:*** This entailed a review of the existing data on hydroelectric projects under consideration for generation expansion, and was made with assistance of Brazilian consultants (Hidroservice). Its primary objective was to update the costs of these projects and bring them to a common basis so that their relative merits would be properly considered in the project selection process. The methods used by ELETROBRAS for updating the costs of hydro plants through the use of indices were reviewed and a more precise method suggested. Then, the possible variation of costs of hydro projects due to new construction methods were analyzed. Also, a confidence band for costs estimates of hydro projects was defined and later used for sensitivity analyses.

(iv) ***Estimate of costs and technical operation characteristics of thermal plants:*** Feasible thermal plant options and site locations for generation expansion were agreed with ELETROBRAS. Updated costs were prepared for each plant (including coal-fired, oil-fired, gas-fired combined cycle and gas fired simple cycle plants), reflecting local construction costs in Brazil, but using primarily benchmark international costs. Relevant associated costs including port facilities and pollution control equipment were included where appropriate. The SPG study was used to provide cost data for this stage.

(v) ***Preparation of Alternative Expansion Plans:*** ELETROBRAS planning models were applied to prepare the least cost system power generation plan. The objective was to test the economic viability of the insertion of increments of thermal power plants in the least cost plan considering the economic cost of plant and fuels. Sensitivity studies to hydro project implementation costs with the variation range defined in (iii) above, and to the discount rate, were made.

(vi) ***Estimate of gas demand for gas for power generation:*** Using the output from steps (i)-(v) above, preliminary scenarios were drawn for the economic demand for gas in power generation. The annual and inter annual variations of gas demand for power generation were assessed and tested against international contractual practices for power supply. The likelihood of developing secondary gas markets for any necessary smoothing of aggregate gas demand characteristics was also assessed.

2

POWER and GAS SECTOR OVERVIEW

Primary Energy Resources and Consumption

2.1 Brazil is endowed with substantial energy resources as shown in Table 1.1. Proven resources of fossil fuels are estimated at about 3,300 million tonnes of oil equivalent (MTOE) which comprise about 77% coal, 17% oil and 4% natural gas. In addition, there are large reserves of shale oils and gases which, although not properly evaluated, are believed to be of similar size to the proven reserves of oil and natural gas. Proven reserves of firm hydro are estimated at 82.7 GWy.

Table 2.1 Brazil Proven Energy Resources

	Specific Unit	MTOE
Natural Gas	146 BCM	124
Oil	659 MMCM	575
Coal	10,157 MMT	2,566
Peat	129 MMT	40
Hydro (firm)	82.7 GW/y	210/y

Source: National Energy Balance-1994

2.2 Almost half of Brazil's proven reserves of natural gas are located in the South South East. The reserves offshore Rio de Janeiro are 63 BCM which is almost all associated gas, and account for almost 40% of the nation's total. About 5.5 BCM of non-associated gas are located offshore Sao Paulo. Taken together, Bahia and the Amazonian basin hold a further 40%. About 70% of proven gas reserves in Brazil are associated with oil.

2.3 The domestic production and imports of primary energy are shown in Table 1.2. This shows that hydropower accounts for about one-third of primary energy. Petroleum also provides almost one third of primary energy, and the remainder is derived mainly from wood and sugar cane derivatives. Natural gas, when adjusted for reinjection and losses, contributes only 2% to the country's primary energy supplies.

Table 2.2 Primary Energy Supply and Consumption

	Unit	Domestic Production (unit/y)	Domestic Production (10 3 TOE)	Net Imports (unit/y)	Net Imports (103 TOE)
Natural Gas	BCM	8.8	7,508	-	
Petroleum	MMCM	38.7	33,803	32.0	27,918
Coal	MMT	6.9	1,980	11.4	8,370
Hydropower	Gwh	243	70,446	-	
Wood	MMT	78.8	24,110	-	
Baggase	MMT	102.1	21,357	-	
Other			3,105		
TOTAL			162,309		36,288

Source: BRAZIL National Energy Balance-1994

The Power Sector

2.4 The Brazilian power sector has shown an impressive history of rapid growth and technological development over the last 30 years, under a sector organization dominated by central planning and investment selection criteria oriented by the need to give priority to Brazil's own natural resources. Large hydro projects and a controversial nuclear program were favored in part by such policies. Thermal generation has played little role, limited to the implementation of coal based plants using low quality indigenous coals. Thermal generation based on hydrocarbons or imported coal have not been considered viable options in the past, since these would increase external dependence.

2.5 The power sector is dominated by hydro power, and official development plans include substantial additional hydro generation capacity for at least the next decade. To attract higher levels of investments to the sector, the Government's objectives include increasing the efficiency of the sector, introducing competition and encouraging private sector participation. Under these policies, thermal power generation by independent power producers will become an important feature of the system.

Power Sector Organization

2.6 The Ministry of Mines and Energy (MME) is responsible for policy making and coordination of development plans for the sector, and regulation is vested with DNAEE (National Department of Water and Energy Development), a department of the Ministry of Energy. The planning and finance ministries have traditionally had authority over the levels of tariffs.

2.7 Sector utilities include several major generation and transmission companies (e.g. Furnas, Chesf, Eletronorte, Eletrosul, and Cesp), many distribution companies, (e.g. Light, Eletropaulo, Paulista, Celesc, Escelsa, and Coelba), a few major integrated generation, transmission and distribution companies (e.g. Cemig, Copel, and CEEE), some 100 minor distribution companies and the Brazil-Paraguay power plant (ITAIPU).

2.8 Most of the companies are organized as corporations, and ownership of the shares is widely varied. Federal control is concentrated through ELETROBRAS, the sector holding company, in the major generation companies (Eletronorte, Chesf, Furnas and Eletrosul) and the distribution companies serving the city of Rio de Janeiro and the state of Espirito Santo (Light and Escelsa)[2]. ELETROBRAS also holds minority and/or non voting stock in most of the other utilities. The majority of shares in the utilities are state owned, and there are about 90 privately owned utilities, mostly in the distribution segment of the ESI.

Power Sector Planning

2.9 ELETROBRAS has the responsibility for sector planning, and prepares a ten-year expansion plan for the sector (the Plano Decenal, PD). This is supported by a Planning Coordinating Group (PCG) for the interconnected systems, in which 35 regional utilities are represented. The PDs are prepared each year for the ten subsequent years, using as a starting point the nation's socio-economic prospects which influence demand projections. Expansion planning is based on the integrated development of the systems taking into account energy interchange possibilities under security of supply criteria which is defined by the MME. More often than not, financial restrictions constitute an important constraint to development. The result of the planning exercise indicates plants to be implemented and their scheduling, as well as the transmission reinforcements that are required. These results are sub-optimum under financial restrictions.

2.10 There is currently much private sector interest in the generation expansion in Brazil and private sector participation is expected to increase in the future, with the result that the PDs are expected to take more the form of "indicative planning".

Power Sector Reform Initiatives

2.11 The electricity sector in Brazil is undergoing important transformations. In February 1995, the National Congress approved Law No. 9074, of Concessions for Public Services. This law established a new regime for awarding concession contracts for public works and services, which will allow increased private sector participation in power, transport, telecommunications and water supply. The law is intended to attract private investments by delegating constitutional authority to provide public services to private investors. Also, on July 7, 1995 the Congress approved Law N0. 9074, known as Conversion Law, which further defines the role to be played by private investors in the supply of electricity services. Additionally, the government has sold two distribution companies (ESCELSA and LIGHT) and announced its intention to sell other distribution

[2] Control of Light and Escelsa have recently been sold to private investors.

companies (CERJ) and at least its controlling shares in some of the major utilities. In parallel, efforts are being made to establish clear rules for granting fair access by producers to transmission grids and to define wheeling changes. The policy with respect to sector ownership has caused the Government to initiate a review of the power sector structure and regulations, with the objective of determining how best to modernize the sector in line with sector reforms in countries such as Chile, Argentina and Colombia. This transition will increasingly allow the private sector to build new power plants and participate more intensively in distribution activities throughout Brazil. Although the reforms are still in the transitional phase, they will eventually alter the present model of the power sector planning and operations.

Power Facilities, Supply and Demand

2.12 Brazil's electricity production in 1994 reached 270 TWh --of which 96% was hydroelectricity-- to serve 37 million customers. The electricity service coverage is about 90%, and per capita consumption is about 1,780 KWh/y.

Existing Facilities

2.13 The ESI consists of 54,100 MW of installed capacity and about 152,000 km. of HV lines (over 69 kV), organized in two major grids:

* The South-SouthEast and MidWest interconnected system (SSE system), serving the states of Sao Paulo, Rio de Janeiro, Minas Gerais, Parana, Rio Grande do Sul, Espirito Santo, Goas, Mato Grosso, Santa Catarina and Mato Grosso do Sul, with about 74% of the energy consumption, and

* The North-NorthEast grid, serving the states of Bahia, Pernambuco, Alagoas, Sergipe, Rio Grande do Norte, Paraiba, Ceara, Piaui, Maranhao, Para, and Tocantins, with about 23% of the country's energy consumption.

2.14 These two grids are not interconnected, and there are in addition several minor isolated systems in the more remote areas of the country.

2.15 Total generating capacity in the SSE-MW system is 40,784 MW, which takes into account 6,300 MW (or half) of the capacity of Itaipu. The installed capacity in the SSE system accounts for about 73% of the total installed and in operation in Brazil. Potential development of the system will use part of the available hydro projects with a total of 55,500 MW which have been evaluated and taken into account for preparing expansion plans.

Prospects for Supply and Demand

2.16 The Technical Committee for Market Studies (CTEM) has estimated that, during the period 1995-2005 annual power demand will grow from 243 TWh to 385 TWh as shown in Table 2.3. This represents an average of about 14,500 GWh per year, and reflects an average annual growth of 4.7% in electricity consumption. This is rather modest when compared with past trends (annual demand growth was 5.8% during 1980-1990, and 3.9% during 1990-1995).

Table 2.3 BRAZIL - Electricity Demand by Region (1995 to 2005)

(TWh)

Region	1995	1998	2002	2005
North (including Maranhao)	12.6	16.0	23.8	31.6
Northeast (less Maranhao)	38.2	44.8	55.0	65.4
Southeast	143.3	157.7	183.7	205.2
South	37.4	43.1	52.2	60.8
Midwest	11.8	14.7	18.6	22.2
Total	**243.3**	**276.3**	**333.3**	**385.2**

Source. ELETROBRAS

2.17 The current ELETROBRAS Master Plan indicates that to meet this demand, about 27,600 MW of installed capacity should be added to the system in the 10 year period. Sector investment needs in the period 1996-2000 are estimated at US$ 37.7 bn, of which US$ 19.3 bn (average US$ 3.9 bn/y) are for additional generation.

Prospects for Gas Fueled Thermal Generation

2.18 Hydro plants represent a large proportion of the expansion in installed capacity. In the PD 1994-2003, about 85% of the additional capacity planned would be hydro based. The dominance of hydro solutions is in part due to the existence of low cost hydro and in part to the lack of available thermal options. The Bolivia-Brazil pipeline project opens the possibility of additional thermal options with reasonable fuel costs, and the definition of the role of gas fired power plants in the SSE integrated power system is essential to confirm the demand for natural gas in power generation from the pipeline.

Power Sector Issues

2.19 Due to the scarcity of financial resources, financing the power sector expansion has become increasingly difficult to the point that several generation projects have suffered execution delays. Public utilities' self-generated funds are only 10%-30% of the funding needed for future investments, and multilateral sources of financing are unlikely to exceed 6-10% of the sector capital needs. Given the limited capability of the government to provide subsidies to the power sector, there is an urgent need to increase self-generated funds and attract private investors.

2.20 Increasing cash generation requires increasing the efficiency of power utilities, and adjustments in the structure and level of tariffs to reflect economic costs. Until very recently, low tariff levels were a major problem. In the period 1990-1994 for instance, the weighted average revenue per unit from power sales varied between US$ cents 4.4 and 5.2 per KWh, and rates covered only about 60% of economic costs. ELETROBRAS has calculated a long run marginal cost of generation of US cents 3.4/kWh for the SSE system and 3.8 US cents/KWh for the NNE system. As generation costs account for about 40 to 50% of total production costs, full economic costs to the final user would be about US cents 7-9/KWh. A sustainable participation of the private sector in power supply cannot be envisaged without prices which reflect economic costs, and the current efforts by the government to set clear rules for private investors are expected to soon increase their participation in the power sector.

The Gas Sector

2.21 The gas sector in Brazil is far less dominant than the power sector in terms of energy supply. Until recently, little attention was paid to the organizational requirements which would encourage the efficient development of natural gas. This is rapidly changing with the prospects for the importation of Bolivian gas. A large section of industry is now eager to secure a share of the imported gas, and this has pushed the various participants in the gas sector to play a more active role in its future development. Funding the accelerated gas sector development will depend on access to domestic and foreign capital, and a condition for such investment is that a legal and regulatory framework for the gas industry is established, which offers the prospect of stability, acceptable risk and reasonable rewards.

The Gas Sector Organization

2.22 The Federal Government has, through the Constitution, the national monopoly for exploration, production, import, export and bulk transport of petroleum, petroleum products and natural gas. The monopoly was devolved to PETROBRAS through the law which created the company, and PETROBRAS has since fully exercised its monopoly powers. In oil and gas operations, the only area where other entities have had substantial involvement is at the retail distribution level. For distribution of petroleum products, private sector have about 65% market share with the remainder taken by the PETROBRAS subsidiary, BR-Distribuidora. The states have the monopoly of gas distribution, which until recently could only be exercised through State gas distribution companies, with each company regulated by the corresponding State Secretariat of Energy.

2.23 At the federal level, responsibility of regulating the gas sector is shared by the Ministry of Mines and Energy (MME) and the Ministry of Finance (MOF). Through the National Secretariat of Energy, the MME has responsibility for formulation and implementation of the national energy policy, and for guiding and the activities of PETROBRAS. This mandate is carried out by the Departamento National de Combustiveis (DNC) which is under the National Secretariat of Energy, and is the regulatory agency for the oil and gas sector. The DNC authorizes allocation of supply and proposes price adjustments of oil products. In fact the MOF, through their Secretariat of Economic Policy, is in charge of prices and tariffs of public and administrated goods.

2.24 The two largest gas distribution companies in Brazil are COMGAS (Sao Paulo) and CEG (Rio de Janeiro). Both were originally established as private sector companies to distribute manufactured gas, and are currently converting their networks to distribute domestic natural gas. The other industrial natural gas distribution companies along the north east coast are small in comparison, with BR Distribudora (the distribution subsidiary of PETROBRAS) having about 40% of the capital in these companies.

2.25 Although the State Secretariats of Energy approve gas prices to final consumers, their effectiveness in regulating gas distribution has been small. This is because: (i) the States own the distribution companies and have a close relationship with their administration; (ii) the Federal Government controls the bulk supply price of gas from PETROBRAS to the distributors as well as final price of competing fuels.

Gas Sector Policies

2.26 The Constitutional Amendment No.9 (November 9, 1995), removed all constitutional barriers to private sector participation in oil and gas activities in Brazil. Through revisions to Article 177, the Federal Government can contract state-owned and private companies for the activities related to the petroleum monopoly, covering the research or exploration and prospecting or production of the oil reserves, including natural gas and other fluid hydrocarbons; the refining of Brazilian and foreign petroleum; the importation and exportation of crude petroleum and basic petroleum derivatives, as well as transportation, by means of a conduit, of crude petroleum, its derivatives, and natural gas of any origin. A Hydrocarbon Law was approved in 1997 which defines how the Constitutional Amendment will be implemented and which creates the new hydrocarbon sector regulatory agency (the ANP). In addition, the 1995 Concession Law for Public Services referred to earlier spells out that all concessions for public services (which includes gas distribution) must be awarded under a competitive bidding process. These events have greatly improved the possibilities for private sector investments in Brazil's gas sector.

Existing Gas Infrastructure

2.27 The existing gas pipeline systems and the proposed Bolivia - Brazil pipeline are shown in the Annex, Fig 1.

2.28 There are five existing gas pipeline systems located along the Atlantic coast, and all operated by PETROBRAS. *The Ceara System* comprises 56 km of onshore pipeline to transport about 0.2 MMCMD of gas in the Fortaleza area. *The Rio Grande do Norte System* comprises 654 km of onshore pipeline and transports gas from the offshore field of Ubarana in the state of Rio Grande to Recife. *The Bahia System* originates in the state of Alagoas, and delivers gas to Alagoas, Sergipe and Bahia and on to Salvador through 900 kms of onshore pipelines. The gas production from these three states amounts to about 8 MMCMD. *The Espirito Santo System* comprises 205 km of onshore pipeline from Sao Mateus to Victoria, transporting about 0.6 MMCMD from the field of Caçao.

2.29 *The Rio de Janeiro - Sao Paulo System* connects the offshore gas reserves of Campos and Santos fields to Rio de Janeiro and Greater Sao Paulo through 870 km of onshore pipelines. The total gas production of Campos fields was about 8.7 MMCMD in

1995, of which 1.1 MMCMD was distributed by CEG in Rio de Janeiro and a further 2.5 MMCMD supplied to industrial consumers served direct by PETROBRAS. Gas available for sale from existing fields in Campos would be about 30 BCM. In the Santos basin, the Merluza field came on stream in 1993 to provide additional supplies to COMGAS, and during 1995 supplies distributed by COMGAS reached about 3 MMCMD from both Campos and Santos. The Merluza field would account for 17 BCM of available reserves, corresponding to a production plateau of 2.5 MMCMD.

2.30 The Southern areas of Parana and Santa Catarina area have not yet developed gas pipeline systems, despite high potential demand in the industrial sector. Although there are as yet no gas transmission systems in the Amazon region, several projects are currently under study, in particular gas transmission to markets of Manaus and Porto Velho by pipeline and as LNG. It is unlikely that any future Amazon gas system would be interconnected with other regions.

Bolivia - Brazil Gas Pipeline Project

2.31 The proposed gas pipeline from Bolivia comprises a 32 inch gas pipeline running from Santa Cruz in Bolivia to Sao Paulo, continuing with a smaller diameter southern leg to Porto Alegre. This pipeline will integrate into the existing PETROBRAS pipeline system which runs from Sao Paulo to Rio de Janeiro and north to Belo Horizonte, and which currently transports gas from three offshore fields in the Campos and Santos basins. The total investments in the pipeline are estimated at US$1.6 billion excluding IDC. The capacity of the pipeline will be 30 MMCMD at full compression which is almost double the gas supply plateau of 16 MMCMD specified in the agreement with Bolivia.

2.32 The project structure requires PETROBRAS to be the purchaser of the gas produced by the companies which resulted from the capitalization of YPFB, with YPFB now acting as the aggregator. The transport of gas will be handled by the two transport companies with one on the Bolivian side and the other on the Brazilian side. PETROBRAS will then sell the gas to the Brazilian state gas distribution companies at a price made up of the price it pays for the gas commodity in Bolivia, plus the transport charges. The price paid for the commodity is linked to a basket of petroleum fuels at their international prices as specified in the gas sales agreement between PETROBRAS and YPFB.

Natural Gas Demand

2.33 The gas demand studies carried out to date have focused on the regions expected to be supplied by the Bolivian gas pipeline project, in particular Sao Paulo, Rio de Janeiro and the Southern States of Parana, Santa Catarina, Rio Grande Do Sul, and Minas Gerais.

2.34 The main components of gas demand are for industrial use and power generation. Studies carried out so far show a consistently large future industrial demand for natural gas in comparison with the likely available supplies. The most recent studies indicate that the potential industrial market for gas in the seven states along the route of the pipeline will reach about 20 MMCMD and 30 MMCMD by the years 2000 and 2010 respectively. This includes those markets currently supplied from domestic gas in Rio de Janeiro and Sao Paulo (about 6.7 MMCMD), but excludes the potential markets for power generation. This compares with total gas production from the Santos and Campos basins plus Bolivian imports (under the Gas Supply Agreement) of 21 MMCMD in 2000 and 26 MMCMD in 2005. It is evident that the implementation of large gas fired power projects will require additional gas supplies, probably from S. Bolivia and N. Argentina.

3

THE SOUTH-SOUTHEAST - MID-WEST ELECTRICAL SYSTEM

Existing Facilities

3.1 The SSE Interconnected System covers the South, Southeast and the Center-West regions of Brazil (Annex, Fig 2), and includes the states of Sao Paulo, Rio de Janeiro, Espiritu Santo, Minas Gerais, Goias and Brasilia, Mato Grosso, Parana, Santa Catarina, Rio Grande do Sul, and Mato Grosso do Sul. Hydro generation is predominant with over 200 hydro plants for a total installed capacity of about 40,800 MW which represents 92% of total installed capacity (including half of the installed in capacity of Itaipu). The system also includes 23 thermal units which amount to 3,080 MW, or 8% of installed capacity. These are coal fired steam plants (1,400 MW), oil fired plants (1,380 MW) and a nuclear unit (660 MW).

3.2 The transmission system is complex with voltage levels of 750, 500, 440, 345, and 230 kV in AC and ± 600 kV in DC. It interconnects the large number of generation centers to consumption centers. Despite the large size of the system, some transfer restrictions exists which must be taken into account when planning the system expansion.

System Demand

3.3 The SSE system demand grew vigorously at 11% pa during 1970-1980 and maintained growth at an average rate of 6% pa between 1980-1995. The past power consumption and growth rates are shown in Table 3.1:

Table 3.1 SSE and MidWest System Electricity Consumption (1970-1995) (TWh)

	Southeast	South	Midwest	Total
Consumption (TWh)				
1970	28.4	3.6	0.6	32.6
1980	80.7	14.1	3.4	98.2
1990	124.0	28.2	8.4	160.6
1995	143.3	37.4	11.8	192.5
Demand Growth (% p.a.)				
1970-1980	11.0	14.6	18.9	11.7
1980-1990	4.4	7.2	9.5	6.3
1990-1995	2.9	5.8	7.0	6.2

3.4 Demand projections are prepared annually by ELETROBRAS and are based on different scenarios for macroeconomic growth, demographic projections, goals for electricty coverage to residential consumers, and specific development plans of large consumers and autoproducers. Lately, variables for price elasticity, conservation, and fuel substitution measures have been taken into account. A key factor in projecting demand is the expected population growth of the country, which is forecast to increase by 1.6% p.a. from 157 million (1995) to 184 million (2005).

3.5 The projections are based on macroeconomic assumptions which represent government growth objectives. These assume that, after a recession period due to the economic adjustment program, there will be a sustained economic growth, and four scenarios were prepared which cover a range of economic growth options. However, taking into account that, in the short term the growth would be constrained by deficit reduction and inflation targets, the two high growth scenarios are considered unlikely. The lowest growth scenario was also considered unlikely as it would reflect a continuous depressive trend. The scenario adopted for this study, (Scenario II of Plano 2015) is based on GDP growth of 5.0% p.a. for the period 1996-2005 and the demographic parameters shown in Table 3.2. The elasticity of electricity consumption to GDP for 1996-2005 period would be 0.94. It is noted that elasticity in the past has shown large fluctuations due to the instability of the economy (0.74 for 1970-1980; 3.93 for 1980-1990 and 1.55 for 1990-1995).

Table 3.2 South-Southeast and Midwest System Population
(millions)

	Southeast	South	Midwest	Total
1995	66.4	23.1	10.6	100.1
2000	71.0	24.5	12.2	107.7
2005	75.3	25.9	13.9	115.1
Ave. Growth (% p.a.)	1.3	1.2	2.7	1.4

3.6 The resulting demand projections for the period 1996-2005 are shown below:

Table 3.3 SSE and MW System Electricity Demand Forecasts (1996-2005)
(TWh)

	Southeast	South	Midwest	Total
1995	143.3	37.4	11.8	192.5
1996	147.0	38.9	12.6	198.5
1997	153.2	41.1	13.6	206.9
1998	157.7	43.1	14.7	215.5
1999	163.7	45.2	15.5	224.4
2000	170.3	47.6	16.5	234.4
2001	177.0	49.8	17.5	244.3
2002	183.7	52.2	18.6	254.5
2003	190.7	54.9	19.8	265.4
2004	197.8	57.9	21.0	276.7
2005	205.2	60.8	22.2	288.2
Ave. Growth (% p.a.)	3.7	5.0	6.5	4.1

Regional and International Interconnections

3.7 Potential expansions of transmission facilities that would affect the SSE system are the reinforcements of the existing interconnections between the sub-systems (SSE-MW), the interconnection with the North-Northeast (NNE) system, and the international interconnections with Argentina, Uruguay, Bolivia and Venezuela, which have been promoted within the framework of the MERCOSUR treaty and bilateral agreements. A preliminary review of these potential expansions shows that the link of the

SSEMW and the NNE systems (NS interconnection) would impact the results of this study. The others would either be too small or too far in the future exert any influence.

3.8 The latest studies on the NS interconnection have shown that there are important economic benefits of implementing this interconnection. The project appears justified if implemented as early as 1999, and for purposes of this study it was assumed that the interconnection will be implemented by this time, with an initial capacity of transfer equivalent to 1,000 MW.

System Operations and Security of Supply

3.9 Operational planning of the SSEMW system is prepared by ELETROBRAS under agreements worked out in the Coordination Group for the Operation of the Interconnected System (GCOI) in which major generators are represented. The activities of the GCOI include the preparation of long term operation plans, their review and adjustments for short term operations and system supervision and control through the ELETROBRAS dispatch center in Brasilia. The operational planning takes into account the main characteristics of the system which are:

- the existence of large reservoirs with multi annual storage capacity
- large distances from production to consumption centers
- hydro energy generation interdependence between basins
- hydrological complementarity between river basins
- high degree of interconnection between sub-systems

3.10 Currently the GCOI is responsible for deciding when and how to operate thermal facilities held in reserve for complementing of the large hydro based generation plant. These plants are called to generate full capacity as base load whenever the reservoir levels and the current hydrological conditions indicate a risk of deficit higher than the adopted standards.

Expansion Plans

3.11 The most recent PD covers the period 1996-2005. It provides forecasts of the power market for the region, the sub-regions, and for the utilities within in the regions, and provides information on the power plants and transmission lines expected to come on line in the period 1996-2005. For the SSEMW system, it recommends additions to the installed capacity of 20,393 MW over the decade, of which 15,035 MW would be hydro. The PD departs from previous PD in that it includes some gas based thermal generation. This is because the time required to complete some of the unfinished hydro projects would not permit their commissioning in time to ensure system reliability. Thus, the 1996 PD includes two 450 MW gas turbine plants for years 1998 and 1999 which would utilize gas from the Brazil-Bolivia pipeline. They would be placed in the consumption areas of Sao Paulo and Rio de Janeiro and would be implemented by the private sector. In case of further delays in gas supply they would start operations with distillate fuel.

4

UPDATE OF HYDRO CANDIDATES

Existing Information

4.1 Brazil's potential hydro resources are estimated at 261,000 MW for a production of 129 GW-year of firm energy. About 20% of this potential has been already installed, and not all the rest would be economically competitive. Besides, many large projects, specially in the Amazon basin are unlikely to be developed due to environmental concerns. Nevertheless, resources that can be economically developed and are environmentally sustainable are large by any standards.

4.2 Cost estimates of a large catalogue of hydro plants, constructed over time by ELETROBRAS and several state companies, are periodically updated by ELETROBRAS on the basis of the specific characteristics of each project. However, since the designs and costs of these plants are largely outdated, some having been prepared 20 years ago, the reliability of the cost estimates varies widely. Investment selection then faces the problem of updating the cost of projects to place them, as well as thermal options, on comparable basis. In particular, it is difficult to update in a reliable and efficient manner, costs of hydro projects which have been prepared by different engineers under diverse assumptions.

4.3 In the case of Brazil, several factors complicate these estimates, which are:

- the instability shown by the economy with periods of high inflation rates, which led to several changes of currency in the last 20 years,
- fluctuating exchange rates due to government interference in the market, local currency sometimes undervalued and at other times overvalued,
- changes in the composition of the basket for estimating inflation factors,
- the vast hydro potential of the country which requires the study of a large number of projects, each with more than one alternative which should be simultaneously studied,
- some features of current legislation, mostly with regard to labor costs and environmental protection.

Cost of Hydro Projects

4.4 The ESMAP study considered it necessary to review the methodology for updating costs of hydro plants and try to develop a method for estimating the range of uncertainty that current ELETROBRAS estimates may have. To this end the services of a Brazilian Consultant (HIDROSERVICE) were secured to review current ELETROBRAS procedures for updating cost of hydro projects and define a variation range into which sensitivity analyses should be made. The study entailed the review of a sample of existing projects, their total costs and the factors which could be affected by new procedures for costs estimates. On this basis, the study was able to:

- define the historic variations of implementation cost of projects and make a critical review of the procedures used for updating such costs,
- estimate the possible influence of modern construction methods if applied in the future to new projects,
- estimate the extent to which savings could be made by the implementation of projects by private enterprises

4.5 The study aimed at providing key adjustment parameters which would permit the definition of a range of confidence for the current cost estimates of the hydro projects contained in the ELETROBRAS catalogue of projects. The work was based on the main characteristics of sixteen projects, selected by ELETROBRAS and are deemed to be representative of the whole set of projects. The sample included plants with installed capacity between 22 MW and 1800 MW.

4.6 Estimates were based on current local costs of civil works and international prices for equipment duly corrected by price inflation and local factors. The factors included:

Historical Variations of Cost Estimates

4.7 This review comprised the following stages:

- **Selection of Price Indices**. It was found that the methods used traditionally by ELETROBRAS to update costs, on the basis of CPIs published by the G. Vargas Foundation is flawed, primarily because the structure of costs of an hydro plant is not necessarily reflected by the CPI. The study then defined a set of fifteen indices which better reflect the cost structure of different types of civil works, mechanical and electrical equipment, and engineering services. Fourteen of these indices are published in Brazil and the fifteenth, which represent costs of turbines and generators, is published by the US Bureau of Reclamation.
- **Transposition of Indices to a Uniform Basis**. Series of indices for the period 1974-1995 were collected and placed on uniform basis.
- **Testing the Procedures**. Indices developed were applied to several cases.

- **Results**. The application of ELETROBRAS updating method and the method developed for the ESMAP study show that cost of hydro projects have been overvalued by about 20-30%.

Influence of Modern Construction Methods

4.8 Based on the main characteristics of the sample, the study estimated the extent for which there is room for introducing new construction techniques which would result in cost reductions. The results were however inconclusive. The only new technique found to have meaningful cost saving was the use of rolled concrete (rollcrete) in dams, which could result in reductions of up to 5% in the total costs of a project. However, the use of rollcrete could increase the cost of associated works, resulting in an overall negligible effect.

Expected Efficiency Gains in Project Implementation

4.9 It is expected that most of generation in Brazil will be developed by private investors in the future. In view of this the study tried to estimate to what extent project implementation by commercially oriented companies would result in a more efficient, lower cost implementation, in contrast with the traditional implementation by government and state owned utilities. It was found that savings could be achieved mostly through: (i) increasing the efficiency of the design and supervision processes and, (ii) use of more competitive contracting procedures. However, these factors were found difficult to quantify and were not accounted for in the analysis, which in turn represents a conservative assumption.

Environmental Costs

4.10 The study considered the trend of new policies established by ELETROBRAS with regard to environmental protection and its influence in future costs of projects. It is expected that environmental costs will increase because of safeguards implied by new enacted legislation and the pressure of NGOs. Also in this case, quantification was not possible.

Conclusions

4.11 The above studies concluded that:

- the cost estimates of hydro projects whose basic designs were prepared in the 1980's are better represented when applying the updated methodology which considers fifteen selected price indices, instead of the CPI traditionally used by ELETROBRAS.
- results of the application of ELETROBRAS' updating method and the method developed for the ESMAP study show that cost of hydro projects are generally overvalued for about 20%-30%.

4.12 These conclusions were taken into account in the developing of expansion plans by including sensitivity analyses with up to 30% lower than currently estimated costs for hydro projects.

5

COSTS OF THERMAL OPTIONS

5.1 This section summarizes the costs and characteristics of the thermal options used for the study. It draws heavily on a recent study prepared by SPG which incorporates good quality data on the cost of thermal options[3], and which was provided through ELETROBRAS for use in this study. The cost estimates of thermal installations are conservative as they assume a degree of inefficiency due to lack of extensive involvement of private sector in implementing power projects in Brazil. Once private sector gains experience, the costs could be expected to coincide more closely with those reported in developed countries.

Selection of Thermal Candidates

5.2 Given the predominantly hydro characteristics of the SSE system, there is -- and there will be for many years ahead-- enough peaking capacity in the system and thus capacity additions (in particular thermal additions) need to be designed for base load operation. Preliminary screening studies showed that peaking options such as open cycle combustion turbines would not be selected by the optimization program and were thus discarded.

5.3 To ensure a consistent comparison between the different thermal options for system expansion, three base load thermal plant alternatives using proven technologies, standard design and appropriate sizes to ensure economy of scale were selected. Fuel sources were assumed to be available (local and imported coal and gas) and plants would be constructed on greenfield sites but close to the existing electrical system.

5.4 The following thermal options for system generation expansion were selected:

- gas fueled combined cycle (CC) thermal plants in modules of 907 MW,
- steam thermal plants using imported coal, in modules of 744 MW, and
- fluidized bed combustion (FBC) steam thermal plants using domestic coal, in modules of 125 MW.

[3] "Bolivia" - Brazil Integrated Gas Project: Prospects for the Introduction of Gas-Fired Power Plants in S/SE/MW Brazil" - June 1995.

5.5 A broader range of alternatives would have unnecessarily complicated the study without adding value.

5.6 For Combined Cycle and steam thermal plants, the largest sizes compatible with the safe and reliable operation in accordance with international practices were selected. The large size of the system would comfortably accept plants in the 700-900 MW range. For FBC plant, current technology does not go much over 125 MW, which was the selected plant size. The selection of coal based thermal generation follows recommendations of a study prepared by ELETROBRAS in 1993[4] which concluded that, given the poor quality of local coals and the need to maintain environmental safeguards, no conventional steam plants should be installed based on domestic coals, but only FBC plants which are considered a clean coal technology. Thermal options using imported coal would have no such restrictions as this coal would be low sulfur and ash, and emission control equipment could be installed to comply with environmental regulations prevailing in Brazil.

5.7 The cost and operational characteristics of thermal plants were taken from SGP study. Direct costs are estimated at 1995 price level and include purchase of equipment, erection and contractors' services assuming turn-key arrangements and reasonable physical and price contingencies but exclude taxes. Facilities included in the cost estimates are site, enclosures, buildings, electromechanical equipment, water intake, treatment and cooling facilities, electrical yard and substation, connecting transmission lines, security and fire protection systems, fuel and water storage tanks, and air quality control equipment in compliance with national standards. The main data of these plants is presented in the Annex, Table A-1.

Gas Fueled Combined Cycle Plants

5.8 These plants would be factory assembled "topping cycle" arrangements of combustion gas turbines of advanced technology, heat recovery steam generators and condensing steam turbine generators. Fuel would be natural gas or No. 2 fuel oil. The plant efficiency at 80% load would be 50%. Natural gas would be available with the chemical conditions and pressure to meet manufactures' requirements. The installed capital costs of the plants were estimated by SPG at US$663/KW excluding IDC, US$742/KW including IDC, and US$824/KW based on the firm capacity of the plants (obtained by dividing the net installed capacity by the annual availability factor of the plant). An allowance of US$395/MW (about US$1.3/MMBTU) was added to this to cover the average cost of gas transport through the import pipeline to Sao Paulo at a pipeline utilization factor[5] of about 55%. This results in a total unit cost for firm available energy of US$1,219/KW.

[4] "Plano Nacional de Energia Eletrica 1993-2015; Projeto 4; A Oferta de Energia Eletrica; Carvao Mineral"; Eletrobras, 1993.

[5] A higher pipeline utilization factor would result in a lower gas transport cost to Sao Paulo

Steam Thermal Plants

5.9 The technology assumed would feature a thermal steam generator and condensing steam turbine generator of proven conventional but state-of-the-art reheat steam conditions. The plant efficiency at 80% load would be 36%[6]. Fuel would be low sulfur imported coal pulverized for injection into the burner. The steam generator would be mounted in structural steel but not enclosed. Coal would be available at the site, but coal marine fuel handling facilities and delivery system as well as in site storage facilities are included as part of the project. Pollution control would include electrostatic precipitator for removal of particles. Flue gas scrubbers would be used for reduction of sulfur-dioxide emissions. The installed capital costs of the plants were estimated by SPG at US$997/KW excluding IDC, US$1,274/KW including IDC, and US$1,516/KW based on the firm capacity of the plants.

Fluidized Bed Combustion Plants

5.10 These plants were considered the only option for using locally produced coals because this technology would be the only one to be able to handle high level sulfur coals without major detrimental environmental effects. The size of the plants was selected at 125 MW because the technology is currently proven only for rather small size plants. Local coals would be burned mixed with locally produced limestone in a turbulent combustion bed. Heat recovery would be made by conventional steam cycle. Particulates would be removed from by separation and ash recycle and from the flue gas by precipitators. The efficiency of the plant at 80% load would be 36%. The full capital costs including IDC and based on firm capacity were estimated at US$ 2,544/KW. Clearly these plants would not be economically viable.

Operational Parameters

5.11 For the purpose of defining the optimum system expansion, gas fueled thermal plants were assumed to operate under contracts with minimum take-or-pay of 80%. For this reason the system operations assume that the plants would be operating even under circumstances of favorable hydrological conditions in which some of the hydro plants, either existing or new, would be spilling water. This assumption is pessimistic in the sense that the operation of the electrical system is sub-optimal. In practice it is expected that the system would use essentially all available hydro which cannot be stored, with gas fueled thermal displacing hydro in such cases.

Generation Costs for Thermal Options

5.12 On the basis of data indicated above, the competitivity of gas fueled options is clearly superior to the coal based options (for a 10% discount rate). The total base load operational costs of thermal plants would be as shown in Table 5.1:

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[6] A conservative assumption. Modern steam plants are expected to reach 38-40% efficiency.

Table 5.1 Differences in Generation Costs for Base Load Operation

(US$/MWh)

Thermal Options	Plano 2015	ESMAP Study
Natural Gas	61	29
Imported Coal	57	44
Brazilian Coal	64	63

6

OPTIMUM SYSTEM EXPANSION

6.1 This section summarizes the methods and assumptions used for defining the system optimum expansion. The objective of a power expansion planning study is to determine a sequence of capacity additions and transmission expansions which will meet the forecast electricity demand under specific reliability criteria. The process is intended to find the least cost option which would minimize the present value of the investment, operation and maintenance costs. It is based on the demand forecast and selects the best expansion sequence by selecting, from a catalogue of viable options, the least cost solution through an optimization process. The results define the timing, amount and location of additions to the existing system. Usually, the exercise needs to consider financial, geographical and environmental constraints, which adds to the complexity of an already complex problem.

Planning Methodology and Criteria

6.2 The Brazilian power system presents two complications for the analysis, which are its large size and the predominance of hydro power. In order to simulate the expansion, the study used the current ELETROBRAS' methodological approach, which comprises: (i) the preparation of the demand forecast, (ii) the long term expansion optimization of the system using a linear programming model, and (iii) the medium term detailed simulation and optimization of selected configurations through the use of a dynamic programming model. Previous decisions with regard to the economic parameters and assumptions are required as inputs to the methodology.

Economic Parameters

6.3 The important economic parameters used for the study are the economic cost of gas and coals used for the thermal options, the discount rate and the exchange rate, which are described below:

Gas Price

6.4 Natural gas imports from Bolivia could be available to supply thermal power plants in the SSE region by 1999. In the longer term, additional gas could be available from the development of new discoveries in Brazil, from new discoveries in Bolivia, from North Argentina, or as imported LNG. This leads to the following potential sources:

(i) Gas imported from Bolivia under the current agreement between PETROBRAS and YPFB;

(ii) Gas from existing fields in Brazil, comprising associated gas from Campos fields and free gas from the Merluza field in Santos basin;

(iii) Gas from future discoveries in Brazil (and Bolivia);

(iv) Complementary volumes through additional pipeline supplies from North Argentina, or possibly Peru; and

(v) LNG imports.

6.5 With respect to the first source, Bolivia has sufficient volumes of known economically deliverable reserves (at the sales contract price agreed between PETROBRAS and YPFB), to meet in full the supply agreement with Brazil for at least 10 to 12 years, after which there would be some shortfall. However, there is good exploration potential for new discoveries in Bolivia with less than 20% of the country having been explored. If Bolivia continues with the past level of exploration effort, it should be possible to build up sufficient reserves to meet the contractual volumes for Brazil for the 20 years specified in the supply agreement. For the gas supplies to be made available under this supply agreement, a benchmark cost of about 1.27 US$/MMBTU (8.7 US$/MWh) was assumed. This includes the cost of gas (the commodity) to the inlet to the pipeline of 1.1 US$/MMBTU, and with the remainder covering the cost of local distribution to the power facility in Brazil. The average cost of transmission from Bolivia to Sao Paulo was taken as US$1.3/MMBTU, which is a conservatively high estimate if the pipeline is to be operated at high utilization factors.

6.6 The economic cost of gas from second and third sources (already producing fields in Campos and Santos and new discoveries in SSE Brazil) is subject to much uncertainty, but includes the Average Incremental Cost (AIC) of gas production plus a Depletion Cost. Levelised over the planning period, the economic cost is broadly estimated at between 1.5 and 2.0 US$/MMBTU, which is less than the cost of Bolivian gas delivered to SSE Brazil when long distance transmission costs are taken into account. Therefore, in view of the limited volumes of gas to be made available under the current agreement with Bolivia (up to 16 MMCMD), the cost gas was fixed at the delivered cost of Bolivian gas 1.27 US$/MMBTU for the first tranch of gas fired generation capacity (2 x 907 MW units consuming about 8 MMCMD assuming Combined Cycle plants operating at base load). This cost of gas represents a conservative assumption since using a lower cost of gas (to represent a true weighted average cost of Bolivian and domestic gas), would only serve to increase the economic viability for incremental gas fired capacity.

6.7 With respect to the fourth and fifth sources (incremental imports from Argentina, and as LNG), these will all cost equal to or more than the first sources. Future volumes delivered from Argentina via flow reversal through the existing Argentina-Bolivia pipeline will be higher cost to reflect higher transportation costs over longer distances. Imported LNG may become a feasible in medium to long term, and although the border price of LNG delivered to the SSE would be higher than that of pipeline gas from Bolivia and Argentina, there would be less capital investment required in pipelines. LNG could be imported from existing plants in Africa, or future plants in Latin America. LNG imported from Nigeria, Algeria, Venezuela or South Argentina has a benchmark reference price regasified on the Brazilian coast of US$3.30/MMBTU in 1995, and could be assumed to increase by about 1% per year until 2010. This increase assumes that the international transaction price of gas, indexed on a mix of low sulfur fuel oil and gas oil, will roughly follow the price of crude oil.

6.8 Although the above estimates of the cost of gas delivered to SSE Brazil are inherently approximate, they are sufficient to lead to robust conclusions with respect to the viability of increments of gas fired thermal generation in the SSE. For the first two gas fueled power plants, the cost of gas at the plant gate was fixed at 1.27 US$/MMBTU corresponding to the cost of Bolivian gas as noted above and excluding gas transmission costs. For subsequent plants, the cost of gas (the commodity) delivered to power plants in the SSE was assumed to be 30% higher.

Other Economic Parameters

6.9 A discount rate of 10% p.a. was used, with sensitivity analyses using 15% p.a. The costs excluded taxes, duties, and allowances for integrating nationally manufactured equipment which usually results in cost increases, this a price base on December 1994.

Power Demand Scenario

6.10 The power demand forecast used was that considered to be the most likely, known as the Scenario II of the official ELETROBRAS Plano 2015. For the SSE system this corresponds to an average consumption growth of 4.1% p.a. for the period 1996 - 2005.

Sensitivity Analyses

6.11 Sensitivity analyses were made with respect to the discount rate as noted above. For the project costs, the costs of hydro used were 30% lower than ELETROBRAS' current estimates to test the robustness of the gas fueled options to low cost hydro.

Long Term System Optimization

6.12 This consisted of a long term analysis of the system expansion, using as a base ELETROBRAS' Plano 2015 but modifying key parameters for different options as appropriate.

6.13 ELETROBRAS' methodology for long term expansion planning is based on a linear programming model, DESELP. This solves the problem of defining the expansion option which results in the minimum present value of investment, operation (including fuel usage), and maintenance of the system. The problem is formulated in linear programming techniques which include variables for demand, supply, maximum flow through transmissions lines, and the operational characteristics and economic parameters of thermal and hydro plants.

6.14 The system is modeled as three regions linked by transmission lines, and these lines are represented by their individual unit costs and transmission capacities. The transmission expansion is then a solution recommended by the model. Thermal and hydro plants are represented individually by their guaranteed energy, installation cost (including the incremental cost of additional installed capacity), annual cost of operation and maintenance, fuel costs and other operational data. The demand is represented by a load curve, assimilated to a three stage ladder.

6.15 Because of the large number of parameters used as constraints in the model, the procedure was simplified through simulation in periods of five years over the time horizon 1996-2025. Thus, the simulation defines the system configuration at the end of period, without analyzing in detail the system configuration within the 5 year period.

Case Studies

6.16 The case studies analyzed are indicated in Table 6.1:

Table 6.1 Case Studies Analyzed

Case Name	Hydro Costs	Thermal Costs	Discount Rate
Plano 2015	EB	EB	10%
Alternative 1 (A1)	EB	SPG	10%
Alternative 2 (A2)	-30%	SPG	10%
Alternative 3 (A3)	EB	SPG	15%
Alternative 4 (A4)	-30%	SPG	15%

Results

6.17 The results of the simulations are summarized in Table 6.2 and indicate that, for the Plano 2015 case study, thermal options would not compete with hydro before the period 2016-2020, and then the best option would be imported coal. For the other case studies, the optimization process recommends increments of gas fueled generation between 2000 and 2005 primarily due to the cost of fuel assumed for gas generation capacity in the simulations.

Table 6.2 Results of the Long Term Simulation

Evolution of Available Generation Capacity (GW)

Period	Resource	Plano 2015	Case Studies			
			A1	A2	A3	A4
2000	Hydro	66.6	66.2	63.1	66.2	66.4
	Coal	0.0	0.0	0.0	0.0	0.0
	Gas	0.0	0.0	0.0	0.0	0.0
2005	Hydro	87.3	69.1	81.8	68.7	76.8
	Coal	0.0	0.0	0.0	0.0	0.0
	Gas	0.0	7.7	3.4	10.6	6.8
2010	Hydro	105.6	64.3	87.1	70.1	82.9
	Coal	0.0	0.0	0.0	0.0	0.0
	Gas	0.0	18.7	10.7	20.0	14.6
2015	Hydro	131.1	84.3	100.5	76.8	110.4
	Coal	0.0	0.0	0.0	0.9	0.0
	Gas	0.0	24.9	16.6	27.2	21.1
2020	Hydro	153.4	100.5	121.5	109.2	123.8
	Coal	2.9	0.0	0.0	9.0	0.0
	Gas	0.0	27.2	23.0	27.2	27.2
2025	Hydro	163.1	131.0	145.8	127.4	152.6
	Coal	16.2	7.5	0.0.	21.2	1.0
	Gas	0.0	27.2	27.2	27.2	27.2

6.18 With respect to the above results, the following observations can be made:

Plano 2015

- Gas fueled thermal option is not contemplated neither in the SSE nor in the South system
- Imported Coal option appears only in 2020 (with about 4,000 MW) in the SE region.

- Imported Coal option appears in the S and NE regions in 2025 (with about 1,000 MW and 4,000 MW respectively)

Case A1

- Gas option is competitive from 2005, substituting some hydro plants and all coal. Highest demand is in the SE region, with about 6,600 MW in 2005 and 9,070 MW -- which is the maximum available-- in 2010. In other regions the gas is demanded progressively reaching the maximum available in 2025.
- Imported coal appears only in 2025 both in the S and SE regions, but only when gas availability is exhausted --which indicates that thermal is better than hydro and gas is better than coal.

Case A2

- Imported coal option disappears due to the reduction of hydro costs.
- Gas fueled option still good option, but installation is displaced by one period (5 years) despite lower hydro costs.
- more hydro is demanded with regard to Alternative 1 (Case A1), which shows that some hydro projects are very competitive under these assumptions.

Case A3

- Coal option appears more competitive starting in 2015 reaching about 9,000 MW in 2020 and 21,000 MW in 2025. Coal appears more competitive for discount rates over 10%.
- Demand for gas fueled thermal remains within the levels of Alternative 1 (Case A1) which shows that this option is not sensible to the discount rate, in other words coal enters to substitute the most expensive hydro.

Case A4

- Gas option still shows strong, though there is a small reduction of gas demand in the SE in 2005 from 10,600 MW to 6,800 MW due to cheaper hydro. Beyond 2010 gas options retake a pace similar to the one without cost reductions for hydro up to exhausting availability.
- Coal option disappears because of lower costs of hydro.
- This solutions seems robust with regard to hydro, which fills out all remaining demand within gas supply limitations.

System Simulation

Simulation Characteristics

6.19 System simulation studies have the purpose of providing a finer definition of system configuration and expansion costs, and are based on the results of the long term optimization discussed above. The system simulation was made using MODDHT, Hydro Thermal Dispatch Model, which is a module of the OLADE-IDB model for electricity expansion planning (known as SUPER OLADE/BID model). MODDHT is able to design an operational policy and simulate the operation of an hydro thermal system.

6.20 The system is represented as a set of sub-systems interconnected by transmission lines. For the SSE system, two sub-systems are represented on the basis of current transfer limitations. These subsystems are the South East and the South. Each sub-system is considered as one hydro plant, equivalent to the integration of the set of hydro plants existing in the sub-system and several thermal plants, which may be equivalent or individual plants. The "equivalent" hydro plant represents the set of hydro plants of each sub-system, and has an "equivalent" reservoir.

6.21 Thermal plants are grouped by class into those plants which have similar production characteristics (fuel, efficiency, O&M costs). On the basis of input data, the model calculates a set of operating data for each class of thermal plant, such as capacity, unit generation cost, forced and scheduled maintenance. Energy demand is represented for each node as the integrated load of the area represented in the node through main parameters of the load curve: power demand for characteristic steps of the curve. Nodes are interconnected by lines, characterized by flow transfer capacity for each month and losses indices as a percentage of the flow.

6.22 Operational policies are based on the marginal cost of water (MCW), which represents the economic value of water storage. System operation can be simulated either by the historic sequence of water inflows or for synthetic series generated by stochastic methods for the same model. In both cases the model uses the same algorithm to simulate the system operation each month and hydrological sequence. This algorithm, called Monthly Balance, provides for supplying the power required for each step of system demand curve taking into account supply capability and costs from all energy sources, the cost of non-supplied energy, the transfer capacity and the losses of interconnections.

Results of Inclusion of Gas Fueled Options in the System

6.23 The first phase long term system optimization above demonstrated the economics of including gas fueled thermal options in the system over the period 1996-2025. The second phase carried out detailed simulations of the system operations for a medium term period of fifteen years. It analyzed the total development costs and the system operation through submitting four different options for the system development. These options are concrete, plant by plant, year by year development plans based on the general directions given by the long term optimization study. These four options were designed by ELETROBRAS to fit the system requirements with differing hydro and thermal content and were designated : (i) hydro, (ii) thermal, (iii) higher thermal, and (iv) higher hydro.

6.24 Common features of the four scenarios are: (i) it is assumed that the SSE system and the North system would become interconnected in the year 2000 with a interconnection capacity limit of 1,000 MW, and (ii) a basic set of gas fueled plants would become part of the system with a first 907 MW plant installed in the SE system in January 1999, followed and a second 907 MW unit installed in January 2000. This is because, having demonstrated that gas plants are economic and given the increasing risk of energy shortages in the short term, the gas fired plants offered the most economic options for meeting the deficits together with the shortest implementation periods.

6.25 The results of the studies show that a higher participation of gas fueled thermal plants in the development of the SSE system with regard to options considered in the Plano 2015 would be economically justified. The total costs of options with higher participation of gas are considerably lower than those which do not consider gas. The participation of gas fueled plants in the four cases tested are shown in Table 6.3, and Table 6.4 (a) - (d).

Table 6.3 Gas Fueled Thermal Plants Scheduling

Unit/Case	Hydro	Thermal	Higher Thermal	Higher Hydro
1	Jan 1999	Jan 1999	Jan 1999	Jan 1999
2	Jan 2000	Jan 2000	Jan 2000	Jan 2000
3	Jul. 2007	Jan 2002	Jan 2002	-
4	Jul. 2008	Jan 2003	Jan 2003	-
5	Jul. 2009	Jan 2009	Jan 2005	-
6	Jul. 2010	Jan 2010	Jan 2007	-
7	-	-	Jan 2009	-
8	-	-	Jan 2010	-

TABLE 6.4(a) Detailed Simulation Results

GN: 1999 (907 MW) 2000 (907MW) - INTERLIGAÇÃO 2000 (1000 MW) - Caso Hidro				
ANO	SUL	SE/C.OESTE	NORTE	NORDESTE
1995				
1996	04 - Desv. Jordão 11 - J. Lacerda IV			
1997	10 - Corumbá 1 - OD	05 - Guilman	11 - Curuá-Una	
1998		01 - Miranda 01 - Corumbá I 05 - Serra da Mesa 07 - Canoas I		
1999	01 - Corumbá 1 - GN 07 - Itá 07 - Salto Caxias	01 - GNSE-1 01 - Santa Branca 01 - Canoas II 01 - Igarapava 01 - Porto Estrela 06 - P. Primavera 06 - Sobragi 07 - Angra-II		
2000	01 - Corumbá 2 - GN 01 - Jacui 02 - Cubatão-Sul 08 - D. Francisca 10 - C. Grande 1 - GN 10 - C. Grande 2 - GN	01 - Int N -> 1000MW 01 - GNSE-2 01- Funil-Grande 07 - Bocaina 09 - Rosal	01 -Int SE -> 1000MW	
2001	10 - C. Grande 3 - GN	04 - Sapucaia 04 - Simplício 04 - Irapé		
2002	07 - Garabi	01 - Manso 01 - Piraju 04 - Cana Brava 04 - Capim Branco 04 - Funil-Ribeira 04 - Anta 04 - Baguari I 10 - Franca Amaral	02 - Tucurui II 02 - Int NE -> 2480MW	01 - Pedra do Cavalo 01 - Maceió 02 - Sacos 02 - Int N -> 1370MW 08 - Itapebi
2003	01 - Campos Novos 04 - Corumbá 3 - GN 10 - Machadinho 10 - C. Grande 4 - GN	01 - Picada 01 - Baú I 01 - REPLAN-1 04 - Queimado 04 - C. Magalhães 04 - Formoso 04 - Viradouro 04 - Itaocara 04 - Resplendor II 04 - Serra do Facão	01 - Int NE -> 2600MW	
2004	01 - Candiota-I 04 - Corumbá 4 - GN 06 - Jataizinho 07 - Cebolão 10 - C. Grande 5 - GN 10 - C. Grande 6 - GN	01 - Pilar I 04 - Barretos 04 - Peixe 04 - Batatal 04 - Murta	01 - Int NE -> 2690MW 04 - S. Quebrada	04 - Araçá
2005	07 - São Jerônimo 10 - C. Grande 7 - GN 10 - C. Grande 8 - GN	04 - Barra do Peixe 04 - Manhuaçu 04 - Jaborandi	04 - Int NE -> 3000MW	01 - GN-I
2006	07 - Mauá 10 - Fundão	04 - F. do Bezerra	04 - Lajeado	
2007	07 - Telêmaco Borba 07 - F. Chapecozinho 07 - Carvão-PI-1 10 - Barra Grande	01 - Angra III 07 - GNSE-3	04 - Estreito	01 - GN-II
2008	07 - Curucaca 07 - Abelardo Luz 10 - Ivaiuva	04 - Torixoréu 07 - GNSE-4		01 - GN-III
2009	01 - Carvão-PI-2 07 - Xanxerê 10 - Foz do Alonzo	04 - Mirador 07 - GNSE-5	04 - Tupiratins	01 - GN-IV
2010	01 - Carvão-PI-3 07 - S. Domingos 07 - Ubaúna	04 - Aimorés 07 - GNSE-6		
2011				

TABLE 6.4(b) Detailed Simulation Results

GN: 1999 (907 MW) 2000 (907MW) - INTERLIGAÇÃO 2000 (1000 MW) - Caso Gás				
ANO	SUL	SE/C.OESTE	NORTE	NORDESTE
1995				
1996	04 - Desv. Jordão 11 - J. Lacerda IV			
1997	10 - Corumbá 1 - OD	05 - Guilman	11 - Curuá-Una	
1998		01 - Miranda 01 - Corumbá I 05 - Serra da Mesa 07 - Canoas I		
1999	01 - Corumbá 1 - GN 07 - Itá 07 - Salto Caxias	01 - GNSE-1 01 - Santa Branca 01 - Canoas II 01 - Igarapava 01 - Porto Estrela 06 - P. Primavera 06 - Sobragi 07 - Angra-II		
2000	01 - Corumbá 2 - GN 01 - Jacuí 02 - Cubatão-Sul 08 - D. Francisca 10 - C. Grande 1 - GN 10 - C. Grande 2 - GN	01 - Int N -> 1000MW 01 - GNSE-2 01- Funil-Grande 07 - Bocaina 09 - Rosal	01 -Int SE -> 1000MW	
2001	10 - C. Grande 3 - GN			
2002	10 - Garabi	01 - Manso 01 - Piraju 01 - GNSE-3 07 - Sapucaia 07 - Simplício 07 - Irapé 10 - Cana Brava 11 - Funil-Ribeira	02 - Tucuruí II 02 - Int NE -> 2480MW	01 - Pedra do Cavalo 01 - Maceió 02 - Sacos 02 - Int N -> 1370MW 08 - Itapebi
2003	04 - Corumbá 3 - GN 10 - C. Grande 4 - GN	01 - Picada 01 - Baú I 01 - REPLAN-1 01 - GNSE-4 04 - Queimado 07 - Anta	01 - Int NE -> 2600MW	
2004	01 - Candiota-I 01 - Campos Novos 04 - Corumbá 4 - GN 10 - Machadinho 10 - C. Grande 5 - GN 10 - C. Grande 6 - GN	01 - Pilar I 01 - Capim Branco 01 - Franca Amaral	01 - Int NE -> 2690MW 04 - S. Quebrada	04 - Araçá
2005	01 - Jataizinho 07 - Cebolão 10 - São Jerônimo 10 - C. Grande 7 - GN 10 - C. Grande 8 - GN	01 - Barretos 01 - Formoso 04 - Viradouro 04 - C. Magalhães 04 - Baguari I 04 - Serra do Facão 04 - Peixe 04 - Itaocara	04 - Int NE -> 3000MW	01 - GN-I
2006	07 - Maua 10 - Fundão	01 - Batatal 01 - Resplendor II	04 - Lajeado	
2007	07 - Telêmaco Borba 07 - F. Chapecozinho 07 - Carvão-PI-1 10 - Barra Grande	04 - Barra do Peixe 04 - Murta	04 -Estreito	01 - GN-II
2008	10 - Carvão-PI-2	01 - Manhuaçu 01 - Angra III 04 - F. do Bezerra		01 - GN-III
2009	07 - Carvão-PI-3	01 - Jaborandi 01 - GNSE-5	04 - Tupiratins	01 - GN-IV
2010	07 - Carvão-PI-4	01 - GNSE-6		
2011				

TABLE 6.4(c) Detailed Simulation Results

GN: 1999 (907 MW) 2000 (907MW) - INTERLIGAÇÃO 2000 (1000 MW) - Caso Mais Gás - 04				
ANO	SUL	SE/C.OESTE	NORTE	NORDESTE
1995				
1996	04 - Desv. Jordão 11 - J. Lacerda IV			
1997	10 - Corumbá 1 - OD	05 - Guilman	11 - Curuá-Una	
1998		01 - Miranda 01 - Corumbá I 05 - Serra da Mesa 07 - Canoas I		
1999	01 - Corumbá 1 - GN 07 - Itá 07 - Salto Caxias	01 - GNSE-1 01 - Santa Branca 01 - Canoas II 01 - Igarapava 01 - Porto Estrela 06 - P. Primavera 06 - Sobragi 07 - Angra-II		
2000	01 - Corumbá 2 - GN 01 - Jacuí 02 - Cubatão-Sul 08 - D. Francisca 10 - C. Grande 1 - GN 10 - C. Grande 2 - GN	01 - Int N -> 1000MW 01 - GNSE-2 01- Funil-Grande 07 - Bocaina 09 - Rosal	01 -Int SE -> 1000MW	
2001	10 - C. Grande 3 - GN			
2002	10 - Garabi	01 - Manso 01 - Piraju 01 - GNSE-3 07 - Sapucaia 07 - Simplício 07 - Irapé 10 - Cana Brava 11 - Funil-Ribeira	02 - Tucuruí II 02 - Int NE -> 2480MW	01 - Pedra do Cavalo 01 - Maceió 02 - Sacos 02 - Int N -> 1370MW 08 - Itapebi
2003	04 - Corumbá 3 - GN 10 - C. Grande 4 - GN	01 - Picada 01 - Baú I 01 - REPLAN-1 01 - GNSE-4 04 - Queimado 07 - Anta	01 - Int NE -> 2600MW	
2004	01 - Candiota-I 01 - Campos Novos 04 - Corumbá 4 - GN 10 - Machadinho 10 - C. Grande 5 - GN 10 - C. Grande 6 - GN	01 - Pilar I 01 - Capim Branco 01 - Franca Amaral 04- Formoso	01 - Int NE -> 2690MW 04 - Lajeado	04 - Araça
2005	01 - Jataizinho 07 - Cebolão 10 - São Jerônimo 10 - C. Grande 7 - GN 10 - C. Grande 8 - GN	01 - GNSE-5	04 - S. Quebrada 04 - Int NE -> 3000MW	01 - GN-I
2006	07 - Mauá 10 - Fundão	04- Barretos 04 - Viradouro 04 - C. Magalhães 04 - Serra do Facão 04 - Itaocara		
2007	07 - Carvão-PI-1	01 - GNSE-6 04 - Baguari I 04 - Peixe 04 - Batatal 04 - Resplendor II	04 -Estreito	01 - GN-II
2008		07 - Angra III		01 - GN-III
2009		01 - GNSE-7	04 - Tupiratins	01 - GN-IV
2010	01 - Carvão-PI-2 07 - Carvão-PI-3	01 - GNSE-8		
2011				

TABLE 6.4(d) Detailed Simulation Results

GN: 1999 (907 MW) 2000 (907MW) - INTERLIGAÇÃO 2000 (1000 MW) - Caso B.Monte				
ANO	SUL	SE/C.OESTE	NORTE	NORDESTE
1995				
1996	04 - Desv. Jordão 11 - J. Lacerda IV			
1997	10 - Corumbá 1 - OD	05 - Guilman	11 - Curuá-Una	
1998		01 - Miranda 01 - Corumbá I 05 - Serra da Mesa 07 - Canoas I		
1999	01 - Corumbá 1 - GN 07 - Itá 07 - Salto Caxias	01 - GNSE-1 01 - Santa Branca 01 - Canoas II 01 - Igarapava 01 - Porto Estrela 06 - P. Primavera 06 - Sobragi 07 - Angra-II		
2000	01 - Corumbá 2 - GN 01 - Jacuí 02 - Cubatão-Sul 08 - D. Francisca 10 - C. Grande 1 - GN 10 - C. Grande 2 - GN	01 - Int N -> 1000MW 01 - GNSE-2 01- Funil-Grande 07 - Bocaina 09 - Rosal	01 -Int SE -> 1000MW	
2001	10 - C. Grande 3 - GN	04 - Sapucaia 04 - Simplício 04 - Irapé		
2002	07 - Garabi	01 - Manso 01 - Piraju 04 - Cana Brava 04 - Capim Branco 04 - Funil-Ribeira 04 - Anta 04 - Baguari I 10 - Franca Amaral	02 - Tucuruí II 02 - Int NE -> 2480MW	01 - Pedra do Cavalo 01 - Maceió 02 - Sacos 02 - Int N -> 1370MW 08 - Itapebi
2003	01 - Campos Novos 04 - Corumbá 3 - GN 10 - Machadinho 10 - C. Grande 4 - GN	01 - Picada 01 - Baú I 01 - REPLAN-1 04 - Queimado 04 - C. Magalhães 04 - Formoso 04 - Viradouro 04 - Itaocara 04 - Resplendor II 04 - Serra do Facão	01 - Int NE -> 2600MW	
2004	01 - Candiota-I 04 - Corumbá 4 - GN 06 - Jataizinho 07 - Cebolão 10 - C. Grande 5 - GN 10 - C. Grande 6 - GN	01 - Pilar I 04 - Barretos 04 - Peixe 04 - Batatal 04 - Murta	01 - Int NE -> 2690MW 04 - S. Quebrada	04 - Araçá
2005	07 - São Jerônimo 10 - C. Grande 7 - GN 10 - C. Grande 8 - GN	04 - Barra do Peixe 04 - Manhuaçu 04 - Jaborandi	04 - Int NE -> 3000MW	01 - GN-I
2006	07 - Mauá 10 - Fundão	04 - F. do Bezerra	04 - Lajeado	
2007	01 - Int SE -> 5742 MW	01 - Int S -> 6033 MW 01 - Int N -> 8000 MW	01 - Belo Monte 01 - Int SE -> 8000 MW 01 - Int NE -> 5000 MW	01 - Int N -> 3370 MW
2008	07 - Telêmaco Borba 07 - F. Chapecozinho 10 - Barra Grande	01 - Angra III	04 - Estreito	
2009	07 - Curucaca 07 - Abelardo Luz 10 - Ivaturva			
2010	04 - Xanxerê 07 - Foz do Alonzo			
2011				

Economic Evaluation

6.26 Results of the simulation runs are shown in Table 6.5. These indicate that option 3 (Higher Thermal) is the less expensive for all combinations of discount rate and assumptions regarding hydro costs, as shown in the table below, which shows the cost difference between the less expensive option (Higher Thermal) and the remaining cases.

Table 6.5 Cost Differences Between Cases

(US$ million - present value)

Case	Discount Rate	Hydro Cost	Alternative			
			1 Hydro	2 Thermal	3 Higher Thermal	4 Higher Hydro
1	10%	EB	1,506	895	0	3,180
2	10%	-30%	505	431	0	404
3	15%	EB	1222	553	0	2822
4	15%	-30%	527	286	0	1020

6.27 For the table above it should be noted that figures show Investment differences between each option and option 3. The total cost differences made up by the difference in investments plus the total operation cost. Total operation cost in turn is composed by fuel costs plus the expected value of the energy curtailed. Also each option has been structured following the criterion that the maximum risk of curtailment should be equal or below 5%, or one in twenty years. The economic value assigned to energy deficits was estimated at US$ 480/MWh; thus annual cost of deficit was evaluated multiplying the expected energy deficit by US$ 480/MWh.

Operational Characteristics of Thermal Plants

6.28 Despite the fact that gas fueled thermal plants are shown to be highly competitive, their operational regime will determine the volumes and of consumption patters of gas to be consumed. To this end dynamic simulation studies with synthetic generated hydrological series were made under two different hypothesis:

- minimum operation level of 80% and maximum operation level of 90%;
- no minimum operation level and maximum operation level of 90%.

Imposed Minimum of 80% Plant Factor

6.29 When a minimum generation level of 80% plant factor is imposed on the gas fueled thermal plants, the actual plant factors are around 85% each year. This represents a condition of fairly steady gas consumption and would be the ideal situation for a gas supply contract between the power producer and the Bolivia-Brazil pipeline company, since it represents an efficient utilization of the dedicated pipeline capacity. This situation is unrealistic, however, since there will be cases under favorable hydrological conditions when the thermal power plants are consuming imported gas when some hydro plants would be spilling water

No Imposed Minimum Operational Level

6.30 Without the constraint of a minimum generation level for the thermal plants, the system optimization starts by placing all available hydro energy in the system in an optimum way. Only the gaps for ensuring system reliability are filled up with thermal generation, which results in uneven operation of the thermal plants year by year. The thermal plants may be operating at full capacity for several years in cases of prolonged drought, or may be standing idle during periods of favorable hydrological conditions. The simulations show that the average load factor of the thermal plants would be low over the time series of the analysis (Annex, Fig 5), and the average plant factor each year throughout the time series would be variable. In addition, the plant load factors depend upon the cost of gas, as shown in Table 6.6:

Table 6.6 Average Plant Factor of Thermal Plants (1999-2005)

	P.F. (%)*	P.F. (%)**
1999	37	35
2000	31	29
2001	30	28
2002	32	29
2003	39	36
2004	43	40
2005	46	42
Average	37	34

Cost of Gas to Plant : * US$ 11/Mwh; ** US$ 13/MWh

6.31 A particular feature of this mode of operation is that, in general, the plant factors tend to increase over time. This is because, when the system starts including more thermal capacity, the overall proportion of hydro diminishes which leaves more room for thermal generation. In the short to medium term, these operational characteristics require that gas fueled power plants are developed in conjunction with a secondary industrial market which is willing to accept the gas when not needed by the power plants. The aggregate gas consumption by the power plants and the secondary market would then be equivalent to a steady base load take from the pipeline company leading to efficient utilization of pipeline transportation capacity.

The Secondary Market for Natural Gas

6.32 The concept of a secondary industrial market in this context is unusual. The thermal power generator would be obliged to take volumes of gas continuously from the pipeline company as though it were running at base load in order to fully utilize the capacity of the pipeline. However, under favorable hydrological conditions the thermal plants would be required to operate far from base load to avoid the spillage of water, and so the power producer may seek an industrial market for natural gas to ensure all gas contracted for transport from the pipeline company can be sold under all circumstances to avoid spillage of water.

6.33 The thermal power plant generators will have to pay the full firm cost of gas to the pipeline company whether the plants are operating or not, comprising the reserved pipeline capacity charge plus the gas commodity charge. When the plants are not operating, the gas would be diverted to the secondary industrial consumers, and this will require the generators entering into special gas supply contracts with these consumers. Because of the uncertainties concerning the regularity of gas supply, these industrial consumers would seek a gas price below the firm gas price, as an incentive for operating intermittently with gas. This general form of operation is likely to require some constraints on the upper limit of load factor of operation of the thermal plants (less than 50%), in order to provide a minimum load factor of supply which would be acceptable to the industrial consumers. The tradeoffs between these load factors, the electricity price, and the discount on gas price are matters of commercial negotiation for the investors and industrial consumers. Although this concept will not produce an absolute optimum mode of operation from the perspective of the power system, it can be a practical solution to address the near term shortfall in generating capacity in the SSE under the constraints to ensure a base load offtake of natural gas from the Bolivia pipeline.

6.34 Recent market surveys of the industrial market over the SSE indicate that there is potential to develop a secondary industrial market, where the major fuels displaced would be the higher sulfur and higher viscosity 'A' series of fuel oils. The current fuels usage of the industrial market indicates that there is potential to develop a secondary industrial market to support up to 1,000 to 2,000 MW of gas fired thermal capacity operating in complementarity over the whole SSE within the next 5 - 10 years. However, it is noted that in developing a secondary industrial market, the gas pricing mechanism will ultimately have to recognize the environmental benefits of natural gas. This can be through a pollution tax on the less clean burning high sulfur fuels, or financial penalties for industries which do not operate exhaust gas cleanup facilities. In any event, the relative price of natural gas and high sulfur fuel oils displaced in the secondary industrial market will eventually have to take account of the environmental advantages of natural gas.

ANNEX

TABLE A-1 Cost of Thermal Generation Options

Gas Fueled

Technology	Combined Cycle
Size	907 MW
Maximum Capacity Factor	90%
Minimum Capacity Factor	80%
Investment Cost:	
- Baseline Cost	US$ 663 /KW
- Cost including IDC	US$ 742 /KW
- Cost of Firm Capacity (at 90% P.F.)	US$ 824 /KW
- Cost Gas Transport	US$ 395 /KW
- Unit Net Cost	US$ 1219 /KW
O&M Fixed Cost	US$ 8.0 /KW-year
O&M variable Cost	US$ 2.00/MWh
Fuel Costs; First Two Modules	US$ 8.7/MWh = US$ 1.27/MMBTU
Fuel Costs; Following Modules	US$ 11.3/MWh = US$ 1.65/MMBTU
Heat Value of Gas	9,400 Kcal/cubic meter
Efficiency	50%

note: Due to the design of the DESELP model, annual investments in plant construction incurred during the construction period are discounted to the first year of the optimization period with a 12% discount rate, which is the average for the discount rates used in the optimization analysis. This is sufficiently accurate and convenient, as it avoids the need to include the construction period within the optimization period.

TABLE A-1 Cost of Thermal Generation Options (continued)

Imported Coal Fueled

Technology	Steam (Pulverized Coal)
Size	744 MW
Maximum Capacity Factor	84%
Minimum Capacity Factor	50%
Investment Cost including IDC	US$ 1516/kW
O&M Fixed Cost	US$ 16/kW-year
O&M variable Cost	US$ 3.00/MWh
Fuel Costs	US$ 1.73/MMBTU or 45/ton
Heat Value of Coal	6,544 Kcal/kg
Efficiency	36%

National Coal (Candiota) Fueled

Technology	Fluidized Bed Combustion
Size	125 MW
Maximum Capacity Factor	84%
Minimum Capacity Factor	50%
Investment Cost including IDC	US$ 2544/kW
O&M Fixed Cost	US$ 18.3/kW-year
O&M variable Cost	US$ 6.1/MWh
Fuel Costs	US$ 9.4/ton
Heat Value of Coal	2,700 Kcal/kg
Efficiency	36%

FIG. 1 - EXISTING AND PROPOSED GAS PIPELINES

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FIG. 2 - ELECTRICAL TRANSMISSION SYSTEMS

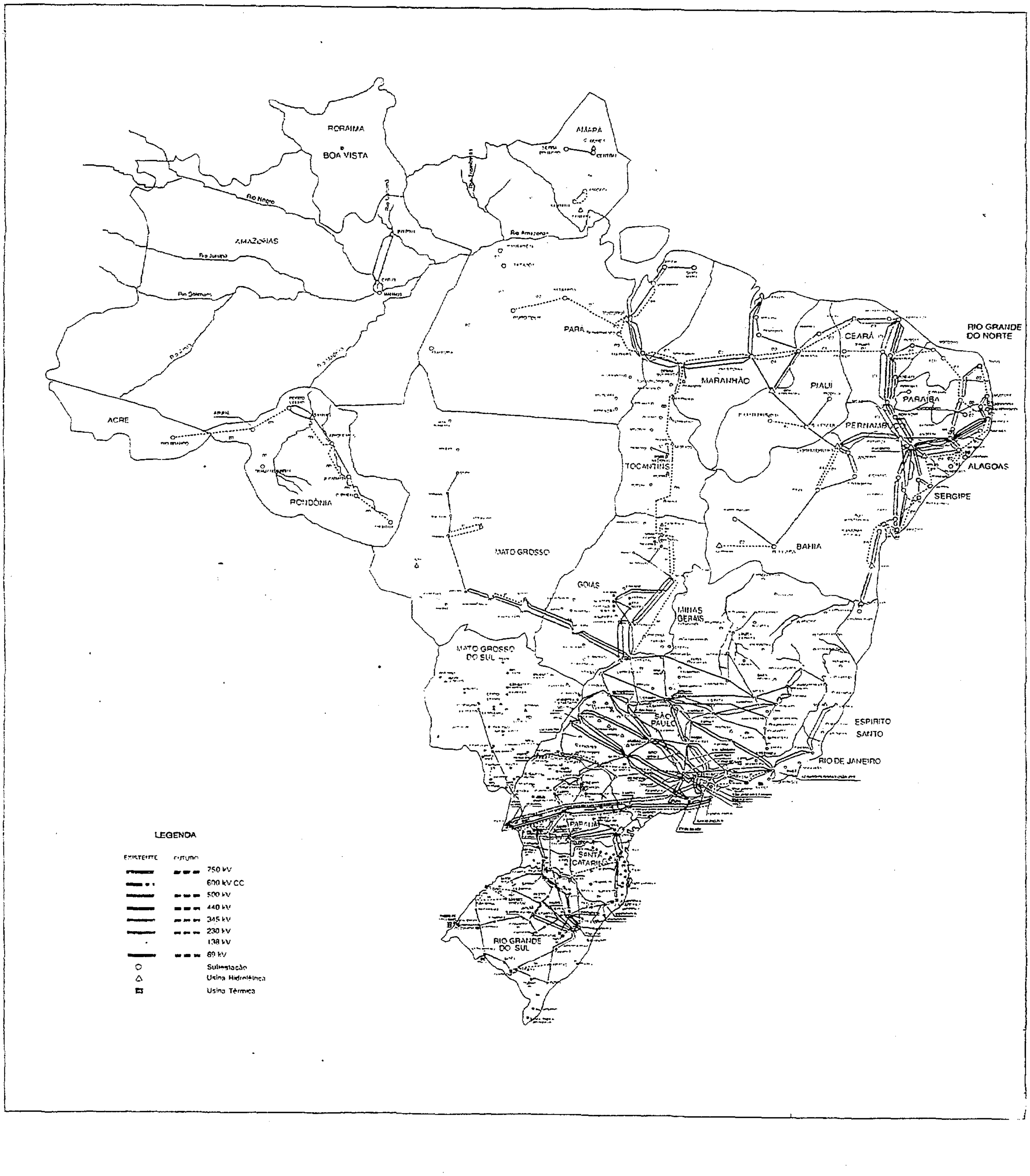
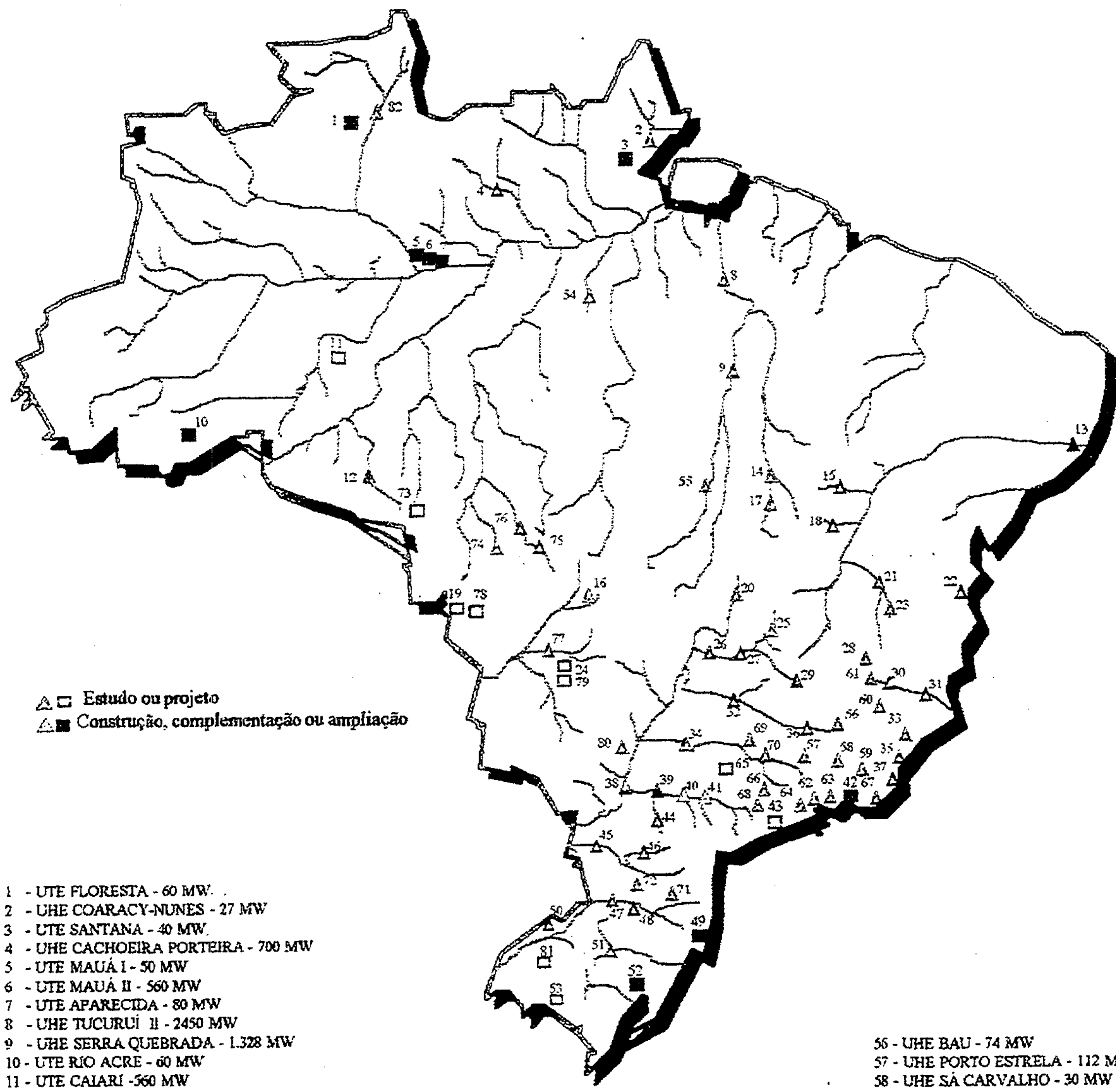


FIG. 3 - LOCATION OF *EXISTING* HYDRO PLANTS

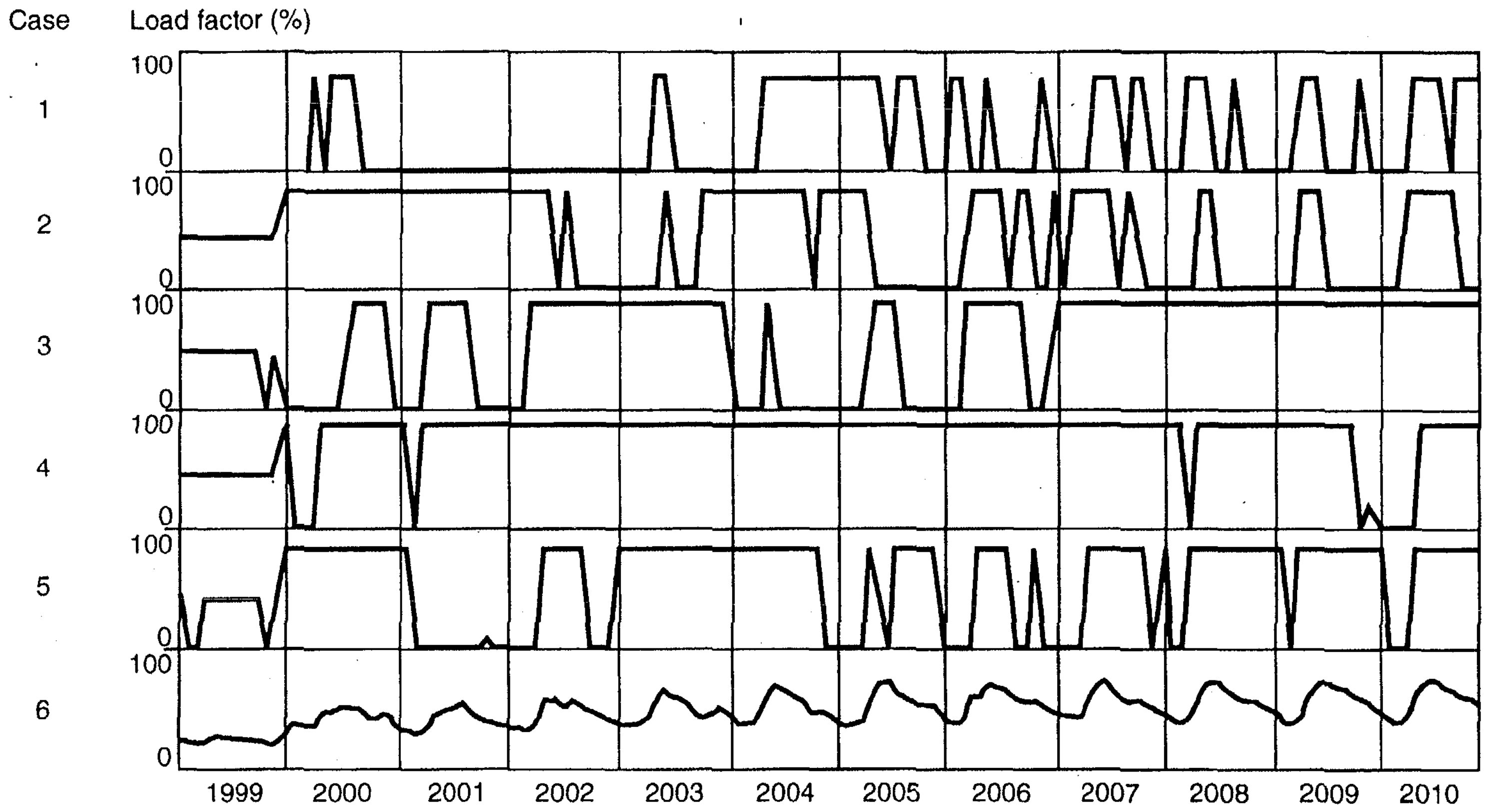
01 - Alegrete
02 - P. Médici A/B
03 - Charqueadas
04 - Itaúba
05 - Jacuí
06 - Passo Real
07 - Passo Fundo
08 - J. Lacerda A/B
09 - G. B. Munhoz
10 - Segredo
11 - Salto Santiago
12 - Salto Osório
13 - Itaipu
14 - G. P. Souza
15 - A. A. Laydner
16 - Chavantes
17 - L. N. Garcez
18 - Capivara
19 - Taquaruçu
20 - Rosana
21 - Jupiá
22 - Três Irmãos
23 - N. Avanhandava
24 - Promissão
25 - Ibitinga
26 - A. S. Lima
27 - Barra Bonita
28 - Carioba
29 - Henry Borden
30 - Piratininga 1234
31 - Paraibuna
32 - Funil
33 - Angra I
34 - Santa Cruz
35 - Nilo Peçanha
36 - I. Pombos
37 - P. Passos/Fontes ABC
38 - R. Silveira
39 - Mascarenhas
40 - Salto Grande
41 - Igarapé
42 - Camargos
43 - Itutinga
44 - Furnas
45 - Caconde/E.Cunha/ A. S. Oliveira
46 - M. de Moraes
47 - Estreito
48 - Jaguara
49 - Volta Grande
50 - Porto Colômbia
51 - Marimbondo
52 - Agua Vermelha
53 - Ilha Solteira
54 - São Simão
55 - C. Dourada
56 - Itumbiara
57 - Nova Ponte
58 - Emborcação
59 - Três Marias
60 - Camaçari
61 - Xingó
62 - P. Afonso 1234
63 - Moxotó
64 - Itaparica
65 - Sobradinho
66 - Boa Esperança
67 - Tucuruí

FIG. 4 - LOCATION OF *UNCOMPLETED AND PROPOSED* HYDRO PLANTS



1 - UTE FLORESTA - 60 MW
2 - UHE COARACY-NUNES - 27 MW
3 - UTE SANTANA - 40 MW
4 - UHE CACHOEIRA PORTEIRA - 700 MW
5 - UTE MAUÁ I - 50 MW
6 - UTE MAUÁ II - 560 MW
7 - UTE APARECIDA - 80 MW
8 - UHE TUCURUÍ II - 2450 MW
9 - UHE SERRA QUEBRADA - 1.328 MW
10 - UTE RIO ACRE - 60 MW
11 - UTE CAIARI -560 MW
12 - UHE SAMUEL - 43,4 MW
13 - UHE XINGÓ - 3.000 MW
14 - UHE CANA BRAVA - 450 MW
15 - UHE SACOS -114 MW
16 - UHE MANSO - 210 MW
17 - UHE SERRA DA MESA - 1200 MW
18 - UHE QUEIMADO - 111 MW
19 - UTE CORUMBA 1 a 3 - 68,8 MW
20 - UHE CORUMBÁ I - 375 MW
21 - UHE QUARTEL - 100 MW
22 - UHE ITAPEBI -375 MW
23 - UHE IRAPÉ - 420 MW
24 - UTE CAMPO GRANDE 1 a 8 - 210 MW
25 - UHE BOCAINA - 150 MW
26 - UHE CAPIM BRANCO - 600 MW
27 - UHE MIRANDA - 390 MW
28 - UHE GUILMAN/AMORIM - 140
29 - UHE NOVA PONTE - 510 MW
30 - UHE PILAR - 150 MW
31 - UHE ROSAL - 55 MW
32 - UHE IGARAPAVA - 210 MW
33 - UHE PICADA - 100 MW
34 - UHE TRÊS IRMÃOS - 646 MW
35 - UHE SÍMPLICIO - 180 MW
36 - UHE FUNIL GRANDE - 180 MW
37 - UHE SAPUCAIA - 300 MW
38 - UHE ROSANA - 320 MW
39 - UHE PORTO PRIMAVERA - 1.814,4 MW
40 - UHE TAQUARUÇÚ - 504 MW
41 - UHE CANOAS I - 82,5 MW
42 - UTN ANGRA II - 1309 MW
43 - UTE REPLAN I - 350 MW
44 - UHE JATAIZINHO - 156 MW
45 - UHE SALTO CAXIAS - 1240 MW
46 - UHE CEBOLÃO - 156 MW
47 - UHE ITÁ - 1450 MW
48 - UHE MACHADINHO - 1200 MW
49 - UTE JORGE LACERDA 4 - 350 MW
50 - UHE GARABI - 900 MW
51 - UHE DONA FRANCISCA - 125 MW
52 - UTE JACUÍ - 350 MW
53 - UTE CANDIOTA III 1 - 350 MW
54 - UHE CURUÁ-UNA - 30 MW
55 - UHE LAJEADO - 800 MW
56 - UHE BAU - 74 MW
57 - UHE PORTO ESTRELA - 112 MW
58 - UHE SÁ CARVALHO - 30 MW
59 - UHE SOBRAGI - 60 MW
60 - UHE BARRA DO BRAÚNA - 48 MW
61 - UHE AIMORÉS - 396 MW
62 - UHE LAJES - 60 MW
63 - UHE ITAOCARA - 210 MW
64 - UHE FRANCA AMARAL - 33 MW
65 - UTE GÁS - 1.812 MW
66 - UHE FUNIL-RIBEIRA - 150 MW
67 - UHE CAMPINHO - 45 MW
68 - UHE SANTA BRANCA - 49 MW
69 - UHE OURINHOS - 44 MW
70 - UHE PIRAJU - 70 MW
71 - UHE CUBATÃO SUL - 45 MW
72 - UHE CAMPOS NOVOS - 880 MW
73 - UTE MADEIRAS - 80 MW
74 - UHE ITIQUIRA I - 62 MW
75 - UHE ITIQUIRA II - 94 MW
76 - UTE CUIABÁ I e II - 450 MW
77 - UHE PONTE DA PEDRA - 176 MW
78 - UTE CORUMBÁ 2 e 4 - 47 MW
79 - UTE C.GRANDE 3 e 6 - 60 MW
80 - UHE CANOAS 2 - 72 MW
81 - UTE CARVÃO PIE 1 - 350 MW
82 - UHE COTINGO - 34 MW

Figure 5
BRAZIL
Operation Modes of Typical Gas Fired Power Generation Plant



Note: Cases 1-5: Simulated load factor of a typical gas fired power plant operating under five different hydrological conditions.
Case 6: Average plant factor simulated over a very long time horizon.

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Joint UNDP/World Bank

ENERGY SECTOR MANAGEMENT ASSISTANCE PROGRAMME (ESMAP)

LIST OF REPORTS ON COMPLETED ACTIVITIES

Region/Country	*Activity/Report Title*	*Date*	*Number*
	SUB-SAHARAN AFRICA (AFR)		
Africa Regional	Anglophone Africa Household Energy Workshop (English)	07/88	085/88
	Regional Power Seminar on Reducing Electric Power System Losses in Africa (English)	08/88	087/88
	Institutional Evaluation of EGL (English)	02/89	098/89
	Biomass Mapping Regional Workshops (English)	05/89	--
	Francophone Household Energy Workshop (French)	08/89	--
	Interafrican Electrical Engineering College: Proposals for Short- and Long-Term Development (English)	03/90	112/90
	Biomass Assessment and Mapping (English)	03/90	--
	Symposium on Power Sector Reform and Efficiency Improvement in Sub-Saharan Africa (English)	06/96	182/96
Angola	Energy Assessment (English and Portuguese)	05/89	4708-ANG
	Power Rehabilitation and Technical Assistance (English)	10/91	142/91
Benin	Energy Assessment (English and French)	06/85	5222-BEN
Botswana	Energy Assessment (English)	09/84	4998-BT
	Pump Electrification Prefeasibility Study (English)	01/86	047/86
	Review of Electricity Service Connection Policy (English)	07/87	071/87
	Tuli Block Farms Electrification Study (English)	07/87	072/87
	Household Energy Issues Study (English)	02/88	--
	Urban Household Energy Strategy Study (English)	05/91	132/91
Burkina Faso	Energy Assessment (English and French)	01/86	5730-BUR
	Technical Assistance Program (English)	03/86	052/86
	Urban Household Energy Strategy Study (English and French)	06/91	134/91
Burundi	Energy Assessment (English)	06/82	3778-BU
	Petroleum Supply Management (English)	01/84	012/84
	Status Report (English and French)	02/84	011/84
	Presentation of Energy Projects for the Fourth Five-Year Plan (1983-1987) (English and French)	05/85	036/85
	Improved Charcoal Cookstove Strategy (English and French)	09/85	042/85
	Peat Utilization Project (English)	11/85	046/85
	Energy Assessment (English and French)	01/92	9215-BU
Cape Verde	Energy Assessment (English and Portuguese)	08/84	5073-CV
	Household Energy Strategy Study (English)	02/90	110/90
Central African Republic	Energy Assessement (French)	08/92	9898-CAR
Chad	Elements of Strategy for Urban Household Energy The Case of N'djamena (French)	12/93	160/94
Comoros	Energy Assessment (English and French)	01/88	7104-COM
Congo	Energy Assessment (English)	01/88	6420-COB
	Power Development Plan (English and French)	03/90	106/90
Côte d'Ivoire	Energy Assessment (English and French)	04/85	5250-IVC
	Improved Biomass Utilization (English and French)	04/87	069/87
	Power System Efficiency Study (English)	12/87	--
	Power Sector Efficiency Study (French)	02/92	140/91
	Project of Energy Efficiency in Buildings (English)	09/95	175/95

Region/Country	*Activity/Report Title*	*Date*	*Number*
Ethiopia	Energy Assessment (English)	07/84	4741-ET
	Power System Efficiency Study (English)	10/85	045/85
	Agricultural Residue Briquetting Pilot Project (English)	12/86	062/86
	Bagasse Study (English)	12/86	063/86
	Cooking Efficiency Project (English)	12/87	--
	Energy Assessment (English)	02/96	179/96
Gabon	Energy Assessment (English)	07/88	6915-GA
The Gambia	Energy Assessment (English)	11/83	4743-GM
	Solar Water Heating Retrofit Project (English)	02/85	030/85
	Solar Photovoltaic Applications (English)	03/85	032/85
	Petroleum Supply Management Assistance (English)	04/85	035/85
Ghana	Energy Assessment (English)	11/86	6234-GH
	Energy Rationalization in the Industrial Sector (English)	06/88	084/88
	Sawmill Residues Utilization Study (English)	11/88	074/87
	Industrial Energy Efficiency (English)	11/92	148/92
Guinea	Energy Assessment (English)	11/86	6137-GUI
	Household Energy Strategy (English and French)	01/94	163/94
Guinea-Bissau	Energy Assessment (English and Portuguese)	08/84	5083-GUB
	Recommended Technical Assistance Projects (English & Portuguese)	04/85	033/85
	Management Options for the Electric Power and Water Supply Subsectors (English)	02/90	100/90
	Power and Water Institutional Restructuring (French)	04/91	118/91
Kenya	Energy Assessment (English)	05/82	3800-KE
	Power System Efficiency Study (English)	03/84	014/84
	Status Report (English)	05/84	016/84
	Coal Conversion Action Plan (English)	02/87	--
	Solar Water Heating Study (English)	02/87	066/87
	Peri-Urban Woodfuel Development (English)	10/87	076/87
	Power Master Plan (English)	11/87	--
	Power Loss Reduction Study (English)	09/96	186/96
Lesotho	Energy Assessment (English)	01/84	4676-LSO
Liberia	Energy Assessment (English)	12/84	5279-LBR
	Recommended Technical Assistance Projects (English)	06/85	038/85
	Power System Efficiency Study (English)	12/87	081/87
Madagascar	Energy Assessment (English)	01/87	5700-MAG
	Power System Efficiency Study (English and French)	12/87	075/87
	Environmental Impact of Woodfuels (French)	10/95	176/95
Malawi	Energy Assessment (English)	08/82	3903-MAL
	Technical Assistance to Improve the Efficiency of Fuelwood Use in the Tobacco Industry (English)	11/83	009/83
	Status Report (English)	01/84	013/84
Mali	Energy Assessment (English and French)	11/91	8423-MLI
	Household Energy Strategy (English and French)	03/92	147/92
Islamic Republic of Mauritania	Energy Assessment (English and French)	04/85	5224-MAU
	Household Energy Strategy Study (English and French)	07/90	123/90
Mauritius	Energy Assessment (English)	12/81	3510-MAS
	Status Report (English)	10/83	008/83
	Power System Efficiency Audit (English)	05/87	070/87

Region/Country	*Activity/Report Title*	*Date*	*Number*
Mauritius	Bagasse Power Potential (English)	10/87	077/87
	Energy Sector Review (English)	12/94	3643-MAS
Morocco	Energy Sector Institutional Development Study (English and French)	07/95	173/95
Mozambique	Energy Assessment (English)	01/87	6128-MOZ
	Household Electricity Utilization Study (English)	03/90	113/90
	Electricity Tariffs Study (English)	06/96	181/96
	Sample Survey of Low Voltage Electricity Customers	06/97	195/97
Namibia	Energy Assessment (English)	03/93	11320-NAM
Niger	Energy Assessment (French)	05/84	4642-NIR
	Status Report (English and French)	02/86	051/86
	Improved Stoves Project (English and French)	12/87	080/87
	Household Energy Conservation and Substitution (English and French)	01/88	082/88
Nigeria	Energy Assessment (English)	08/83	4440-UNI
	Energy Assessment (English)	07/93	11672-UNI
Rwanda	Energy Assessment (English)	06/82	3779-RW
	Status Report (English and French)	05/84	017/84
	Improved Charcoal Cookstove Strategy (English and French)	08/86	059/86
	Improved Charcoal Production Techniques (English and French)	02/87	065/87
	Energy Assessment (English and French)	07/91	8017-RW
	Commercialization of Improved Charcoal Stoves and Carbonization Techniques Mid-Term Progress Report (English and French)	12/91	141/91
SADC	SADC Regional Power Interconnection Study, Vols. I-IV (English)	12/93	--
SADCC	SADCC Regional Sector: Regional Capacity-Building Program for Energy Surveys and Policy Analysis (English)	11/91	--
Sao Tome and Principe	Energy Assessment (English)	10/85	5803-STP
Senegal	Energy Assessment (English)	07/83	4182-SE
	Status Report (English and French)	10/84	025/84
	Industrial Energy Conservation Study (English)	05/85	037/85
	Preparatory Assistance for Donor Meeting (English and French)	04/86	056/86
	Urban Household Energy Strategy (English)	02/89	096/89
	Industrial Energy Conservation Program (English)	05/94	165/94
Seychelles	Energy Assessment (English)	01/84	4693-SEY
	Electric Power System Efficiency Study (English)	08/84	021/84
Sierra Leone	Energy Assessment (English)	10/87	6597-SL
Somalia	Energy Assessment (English)	12/85	5796-SO
South Africa Republic of	Options for the Structure and Regulation of Natural Gas Industry (English)	05/95	172/95
Sudan	Management Assistance to the Ministry of Energy and Mining	05/83	003/83
	Energy Assessment (English)	07/83	4511-SU
	Power System Efficiency Study (English)	06/84	018/84
	Status Report (English)	11/84	026/84
	Wood Energy/Forestry Feasibility (English)	07/87	073/87
Swaziland	Energy Assessment (English)	02/87	6262-SW
Tanzania	Energy Assessment (English)	11/84	4969-TA
	Peri-Urban Woodfuels Feasibility Study (English)	08/88	086/88
	Tobacco Curing Efficiency Study (English)	05/89	102/89
	Remote Sensing and Mapping of Woodlands (English)	06/90	--
	Industrial Energy Efficiency Technical Assistance (English)	08/90	122/90
Togo	Energy Assessment (English)	06/85	5221-TO

Region/Country	*Activity/Report Title*	*Date*	*Number*
Togo	Wood Recovery in the Nangbeto Lake (English and French)	04/86	055/86
	Power Efficiency Improvement (English and French)	12/87	078/87
Uganda	Energy Assessment (English)	07/83	4453-UG
	Status Report (English)	08/84	020/84
	Institutional Review of the Energy Sector (English)	01/85	029/85
	Energy Efficiency in Tobacco Curing Industry (English)	02/86	049/86
	Fuelwood/Forestry Feasibility Study (English)	03/86	053/86
	Power System Efficiency Study (English)	12/88	092/88
	Energy Efficiency Improvement in the Brick and Tile Industry (English)	02/89	097/89
	Tobacco Curing Pilot Project (English)	03/89	UNDP Terminal Report
	Energy Assessment (English)	12/96	193/96
Zaire	Energy Assessment (English)	05/86	5837-ZR
Zambia	Energy Assessment (English)	01/83	4110-ZA
	Status Report (English)	08/85	039/85
	Energy Sector Institutional Review (English)	11/86	060/86
	Power Subsector Efficiency Study (English)	02/89	093/88
	Energy Strategy Study (English)	02/89	094/88
	Urban Household Energy Strategy Study (English)	08/90	121/90
Zimbabwe	Energy Assessment (English)	06/82	3765-ZIM
	Power System Efficiency Study (English)	06/83	005/83
	Status Report (English)	08/84	019/84
	Power Sector Management Assistance Project (English)	04/85	034/85
	Power Sector Management Institution Building (English)	09/89	--
	Petroleum Management Assistance (English)	12/89	109/89
	Charcoal Utilization Prefeasibility Study (English)	06/90	119/90
	Integrated Energy Strategy Evaluation (English)	01/92	8768-ZIM
	Energy Efficiency Technical Assistance Project: Strategic Framework for a National Energy Efficiency Improvement Program (English)	04/94	--
	Capacity Building for the National Energy Efficiency Improvement Programme (NEEIP) (English)	12/94	--

EAST ASIA AND PACIFIC (EAP)

Asia Regional	Pacific Household and Rural Energy Seminar (English)	11/90	--
China	County-Level Rural Energy Assessments (English)	05/89	101/89
	Fuelwood Forestry Preinvestment Study (English)	12/89	105/89
	Strategic Options for Power Sector Reform in China (English)	07/93	156/93
	Energy Efficiency and Pollution Control in Township and Village Enterprises (TVE) Industry (English)	11/94	168/94
	Energy for Rural Development in China: An Assessment Based on a Joint Chinese/ESMAP Study in Six Counties (English)	06/96	183/96
Fiji	Energy Assessment (English)	06/83	4462-FIJ
Indonesia	Energy Assessment (English)	11/81	3543-IND
	Status Report (English)	09/84	022/84
	Power Generation Efficiency Study (English)	02/86	050/86

Region/Country	*Activity/Report Title*	*Date*	*Number*
Indonesia	Energy Efficiency in the Brick, Tile and Lime Industries (English)	04/87	067/87
	Diesel Generating Plant Efficiency Study (English)	12/88	095/88
	Urban Household Energy Strategy Study (English)	02/90	107/90
	Biomass Gasifier Preinvestment Study Vols. I & II (English)	12/90	124/90
	Prospects for Biomass Power Generation with Emphasis on Palm Oil, Sugar, Rubberwood and Plywood Residues (English)	11/94	167/94
Lao PDR	Urban Electricity Demand Assessment Study (English)	03/93	154/93
Malaysia	Sabah Power System Efficiency Study (English)	03/87	068/87
	Gas Utilization Study (English)	09/91	9645-MA
Myanmar	Energy Assessment (English)	06/85	5416-BA
Papua New Guinea	Energy Assessment (English)	06/82	3882-PNG
	Status Report (English)	07/83	006/83
	Energy Strategy Paper (English)	--	--
	Institutional Review in the Energy Sector (English)	10/84	023/84
	Power Tariff Study (English)	10/84	024/84
Philippines	Commercial Potential for Power Production from Agricultural Residues (English)	12/93	157/93
	Energy Conservation Study (English)	08/94	--
Solomon Islands	Energy Assessment (English)	06/83	4404-SOL
	Energy Assessment (English)	01/92	979-SOL
South Pacific	Petroleum Transport in the South Pacific (English)	05/86	--
Thailand	Energy Assessment (English)	09/85	5793-TH
	Rural Energy Issues and Options (English)	09/85	044/85
	Accelerated Dissemination of Improved Stoves and Charcoal Kilns (English)	09/87	079/87
	Northeast Region Village Forestry and Woodfuels Preinvestment Study (English)	02/88	083/88
	Impact of Lower Oil Prices (English)	08/88	--
	Coal Development and Utilization Study (English)	10/89	--
Tonga	Energy Assessment (English)	06/85	5498-TON
Vanuatu	Energy Assessment (English)	06/85	5577-VA
Vietnam	Rural and Household Energy-Issues and Options (English)	01/94	161/94
	Power Sector Reform and Restructuring in Vietnam: Final Report to the Steering Committee (English and Vietnamese)	09/95	174/95
	Household Energy Technical Assistance: Improved Coal Briquetting and Commercialized Dissemination of Higher Efficiency Biomass and Coal Stoves (English)	01/96	178/96
Western Samoa	Energy Assessment (English)	06/85	5497-WSO

SOUTH ASIA (SAS)

Bangladesh	Energy Assessment (English)	10/82	3873-BD
	Priority Investment Program (English)	05/83	002/83
	Status Report (English)	04/84	015/84
	Power System Efficiency Study (English)	02/85	031/85
	Small Scale Uses of Gas Prefeasibility Study (English)	12/88	--
India	Opportunities for Commercialization of Nonconventional Energy Systems (English)	11/88	091/88

Region/Country	*Activity/Report Title*	*Date*	*Number*
India	Maharashtra Bagasse Energy Efficiency Project (English)	07/90	120/90
	Mini-Hydro Development on Irrigation Dams and Canal Drops Vols. I, II and III (English)	07/91	139/91
	WindFarm Pre-Investment Study (English)	12/92	150/92
	Power Sector Reform Seminar (English)	04/94	166/94
Nepal	Energy Assessment (English)	08/83	4474-NEP
	Status Report (English)	01/85	028/84
	Energy Efficiency & Fuel Substitution in Industries (English)	06/93	158/93
Pakistan	Household Energy Assessment (English)	05/88	--
	Assessment of Photovoltaic Programs, Applications, and Markets (English)	10/89	103/89
	National Household Energy Survey and Strategy Formulation Study: Project Terminal Report (English)	03/94	--
	Managing the Energy Transition (English)	10/94	--
	Lighting Efficiency Improvement Program Phase 1: Commercial Buildings Five Year Plan (English)	10/94	--
Sri Lanka	Energy Assessment (English)	05/82	3792-CE
	Power System Loss Reduction Study (English)	07/83	007/83
	Status Report (English)	01/84	010/84
	Industrial Energy Conservation Study (English)	03/86	054/86

EUROPE AND CENTRAL ASIA (ECA)

Bulgaria	Natural Gas Policies and Issues (English)	10/96	188/96
Central and Eastern Europe	Power Sector Reform in Selected Countries	07/97	196/97
Eastern Europe	The Future of Natural Gas in Eastern Europe (English)	08/92	149/92
Poland	Energy Sector Restructuring Program Vols. I-V (English)	01/93	153/93
Portugal	Energy Assessment (English)	04/84	4824-PO
Romania	Natural Gas Development Strategy (English)	12/96	192/96
Turkey	Energy Assessment (English)	03/83	3877-TU

MIDDLE EAST AND NORTH AFRICA (MNA)

Arab Republic of Egypt	Energy Assessment (English)	10/96	189/96
Morocco	Energy Assessment (English and French)	03/84	4157-MOR
	Status Report (English and French)	01/86	048/86
	Energy Sector Institutional Development Study (English and French)	05/95	173/95
Syria	Energy Assessment (English)	05/86	5822-SYR
	Electric Power Efficiency Study (English)	09/88	089/88
	Energy Efficiency Improvement in the Cement Sector (English)	04/89	099/89
	Energy Efficiency Improvement in the Fertilizer Sector (English)	06/90	115/90
Tunisia	Fuel Substitution (English and French)	03/90	--
	Power Efficiency Study (English and French)	02/92	136/91
	Energy Management Strategy in the Residential and Tertiary Sectors (English)	04/92	146/92
	Renewable Energy Strategy Study, Volume I (French)	11/96	190A/96
	Renewable Energy Strategy Study, Volume II (French)	11/96	190B/96

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Yemen	Energy Assessment (English)	12/84	4892-YAR
	Energy Investment Priorities (English)	02/87	6376-YAR
	Household Energy Strategy Study Phase I (English)	03/91	126/91

LATIN AMERICA AND THE CARIBBEAN (LAC)

LAC Regional	Regional Seminar on Electric Power System Loss Reduction in the Caribbean (English)	07/89	--
	Elimination of Lead in Gasoline in Latin America and the Caribbean (English and Spanish)	04/97	194/97
Bolivia	Energy Assessment (English)	04/83	4213-BO
	National Energy Plan (English)	12/87	--
	La Paz Private Power Technical Assistance (English)	11/90	111/90
	Prefeasibility Evaluation Rural Electrification and Demand Assessment (English and Spanish)	04/91	129/91
	National Energy Plan (Spanish)	08/91	131/91
	Private Power Generation and Transmission (English)	01/92	137/91
	Natural Gas Distribution: Economics and Regulation (English)	03/92	125/92
	Natural Gas Sector Policies and Issues (English and Spanish)	12/93	164/93
	Household Rural Energy Strategy (English and Spanish)	01/94	162/94
	Preparation of Capitalization of the Hydrocarbon Sector	12/96	191/96
Brazil	Energy Efficiency & Conservation: Strategic Partnership for Energy Efficiency in Brazil (English)	01/95	170/95
	Hydro and Thermal Power Sector Study	09/97	197/97
Chile	Energy Sector Review (English)	08/88	7129-CH
Colombia	Energy Strategy Paper (English)	12/86	--
	Power Sector Restructuring (English)	11/94	169/94
	Energy Efficiency Report for the Commercial and Public Sector (English)	06/96	184/96
Costa Rica	Energy Assessment (English and Spanish)	01/84	4655-CR
	Recommended Technical Assistance Projects (English)	11/84	027/84
	Forest Residues Utilization Study (English and Spanish)	02/90	108/90
Dominican Republic	Energy Assessment (English)	05/91	8234-DO
Ecuador	Energy Assessment (Spanish)	12/85	5865-EC
	Energy Strategy Phase I (Spanish)	07/88	--
	Energy Strategy (English)	04/91	--
	Private Minihydropower Development Study (English)	11/92	--
	Energy Pricing Subsidies and Interfuel Substitution (English)	08/94	11798-EC
	Energy Pricing, Poverty and Social Mitigation (English)	08/94	12831-EC
Guatemala	Issues and Options in the Energy Sector (English)	09/93	12160-GU
Haiti	Energy Assessment (English and French)	06/82	3672-HA
	Status Report (English and French)	08/85	041/85
	Household Energy Strategy (English and French)	12/91	143/91
Honduras	Energy Assessment (English)	08/87	6476-HO
	Petroleum Supply Management (English)	03/91	128/91
Jamaica	Energy Assessment (English)	04/85	5466-JM
	Petroleum Procurement, Refining, and Distribution Study (English)	11/86	061/86

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Jamaica	Energy Efficiency Building Code Phase I (English)	03/88	--
	Energy Efficiency Standards and Labels Phase I (English)	03/88	--
	Management Information System Phase I (English)	03/88	--
	Charcoal Production Project (English)	09/88	090/88
	FIDCO Sawmill Residues Utilization Study (English)	09/88	088/88
	Energy Sector Strategy and Investment Planning Study (English)	07/92	135/92
Mexico	Improved Charcoal Production Within Forest Management for the State of Veracruz (English and Spanish)	08/91	138/91
	Energy Efficiency Management Technical Assistance to the Comision Nacional para el Ahorro de Energia (CONAE) (English)	04/96	180/96
Panama	Power System Efficiency Study (English)	06/83	004/83
Paraguay	Energy Assessment (English)	10/84	5145-PA
	Recommended Technical Assistance Projects (English)	09/85	--
	Status Report (English and Spanish)	09/85	043/85
Peru	Energy Assessment (English)	01/84	4677-PE
	Status Report (English)	08/85	040/85
	Proposal for a Stove Dissemination Program in the Sierra (English and Spanish)	02/87	064/87
	Energy Strategy (English and Spanish)	12/90	--
	Study of Energy Taxation and Liberalization of the Hydrocarbons Sector (English and Spanish)	120/93	159/93
Saint Lucia	Energy Assessment (English)	09/84	5111-SLU
St. Vincent and the Grenadines	Energy Assessment (English)	09/84	5103-STV
Trinidad and Tobago	Energy Assessment (English)	12/85	5930-TR

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	Energy End Use Efficiency: Research and Strategy (English)	11/89	--
	Women and Energy--A Resource Guide The International Network: Policies and Experience (English)	04/90	--
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