Public Disclosure Authorized

9273

Joint UNDP/World Bank
Energy Sector Management Assistance Program

BASIS FOR FORMULATION OF A BOLIVIAN NATIONAL ENERGY PLAN

Public Disclosure Authorized

A REPORT BY CONSULTANTS
LA PAZ, BOLIVIA

NOVEMBER 1987

FILE COPY

Energy Strategy, Management & Assessment Division
Industry & Energy Department
The World Bank
Washington, D.C. 20433

BASIS FOR FORMULATION OF A BOLIVIAN

NATIONAL ENERGY PLAN

A Report by Consultants
La Paz, Bolivia

NOVEMBER 1987

The work underlying this report was undertaken at the request of the Bolivian Government. It was designed to assist the Government in formulating a strategy for the energy sector which would be appropriate in the context of the overall Bolivian economy. The work was carried out between November 1986 and June 1987; financed by the United Nations Development Program. The World Bank was the executing agency of which the supervision was carried out by Gabriel Sanchez-Sierra and Ignacio Rodriguez. The team consisted of Gustavo Rodriguez (Resident Project Director), Angel Zannier (Advisor to the RPD), Manuel Ignacio Dussan (Electric Power), Marc Heitner (Natural Gas), and Robert Gould (Rural Energy). In addition to Mr. Zannier, the following local consultants were used: Franz Lino (Hydrocarbons), Ricardo Quiroga (Macroeconomy), Eddy Iporre (Electric Power), Marcelo Valenzuela (Finance). The National Petroleum Company (YPFB) provided Max Perez, Guido Soliz, and Freddy Escobar. The National Electric Power Company (ENDE) provided Enrique Gomez. The Corporation for the Promotion of Rural Energy (COFER) provided Lucio Saal and Jorge Sarate. Secretarial support was provided by Yamila de Mattos.

ACRONYMS

ANICARVE	Asociacion Nacional de Industriales de Carbon Vegetal (National Association of Charcoal Industries)
CAF	Corporacion Andina de Fomento (Andean Development Fund)
CDF	Centro de Desarollo Forestal (Center for Forest Development)
CESSA	Cooperativa de Electrificación Sucre S.A. (Electrification Cooperative of Sucre S.A.)
CNECA	Comision Nacional de Estudio de la Cana y del Azucar (National Commission of the Study of Sugarcane and Sugar)
COBEE	Compañía Boliviana de Energía Eléctrica (Bolivian Power Company)
CODETAR	Corporacion de Desarollo Regional de Tarija (Regional Development Corporation of Tarija)
COFER	Corporacion de Fomento Energetico Rural (Corporation for the Promotion of Rural Energy)
COMIBOL	Corporación Minera de Bolivia (Bolivian Mining Corporation)
CONNAL	Consultura Nacional (National Consultants)
CORDEBENI	Corporacion de Desarrollo Regional de Beni (Regional Development Corporation of Beni)
CORDECH	Corporacion de Desarrollo Regional de Chuquisaca (Regional Development Corporation of Chuquisaca)
CORDECO	Corporacion de Desarrollo Regional de Cochabamba (Regional Development Corporation of Cochabamba)
CORDECRUZ	Corporacion de Desarrollo Regional de Santa Cruz (Regional Development Corporation of Santa Cruz)
CORDEOR	Corporacion de Desarrollo Regional de Oruro (Regional Development Corporation of Oruro)
CORDEPANDO	Corporacion de Desarrollo Regional de Pando (Regional Development Corporation of Pando)

CORDEPAZ	Corporacion de Desarrollo Regional de La Paz (Regional Development Corporation of La Paz)
CORDEPO	Corporacion de Desarrollo Regional de Potosi (Regional Development Corporation of Potosi)
COSELEREC	Cooperativa Servicios Electricos Trinidad (Cooperative of Electric Services Trinidad)
COSELCA	Cooperativa Servicios Electricos Camiri (Cooperative of Electric Services Camiri)
CRE	Cooperativa Rural de Electrificación (Rural Electrification Cooperative)
DGH	Dirección General de Hidrocarburos (General Hydrocarbons Directorate)
DINE	Dirección Nacional de Electricidad (National Electricity Directorate)
ELFEC	Empresa de Luz y Fuerza Eléctrica de Cochabamba (Electric Power Company of Cochabamba)
ELFEO	Empresa de Luz y Fuerza de Oruro (Electric Power Company of Oruro)
ENAF	Empresa Nacional de Fundicion (National Metal Smelting Company)
ENDE	Empresa Nacional de Electricidad (National Electric Power Company)
FAO	Food and Agriculture Organization
IMF	International Monetary Fund
INE	Instituto Nacional de Estadistica (National Statistical Institute)
INER	Instituto Nacional de Electrificacion Rural (National Institute for Rural Electrification)
INFOL	Instituto de Fomento Lanero (Institute for the Development of the Wool Industry)
INI	Instituto Nacional de Inversiones (National Institute of Investments)
JUNAC	Junta del Acuerdo de Cartagena (Cartagena Compact)

MACA	Ministerio de Asuntos Campesinos y Agropecuarios (Ministry of Rural and Agricultural Affairs)
MEH	Ministerio de Energia e Hidrocarburos (Ministry of Energy and Hydrocarbons)
NEP	National Energy Plan
OLADE	Organizacion Latinoamericana de Energia (Latin American Energy Organization)
PERTT	Programa Ejecutivo de Rehabilitacion de Terrenos de Tarija (Executive Program for the Rehabilitation of Land in Tarija)
SEPSA	Servicios Electricos Potosí S.A. (Electric Service of Potosí S.A.)
SETAR	Servicios Electricos de Taríja S.A. (Electric Service of Tarija S.A.)
TGN	Tesoro General de la Nación (General Treasury of the Nation)
UDAPE	Unidad de Políticas Economica (Economic Policies Unit)
USAID	United States Agency for International Development
YABOG	Yacibol Bogoc Transportadores, a subsidiary of YPFB involved in gas exports to Argentina and gas distribution in Eastern Bolivia
YPFB	Yacimientos Petroliferos Fiscales Bolivianos (Bolivian National Oil Company)

ABBREVIATIONS

bbl	Barrel
bd	Barrel per day
BTU	British thermal unit
CFD	Cubic feet per day
GWh	Gigawatt hour
ha	Hectare
kcal	Kilocalorie
kgoe	Kilograms of oil equivalent
ktoe	Kilo tons of oil equivalent
km	Kilometer
kW	Kilowatt
kWh	Kilowatt hour
bcf	billion cubic feet
bbl	barrel of oil (159 liters)
c.i.f.	cost, insurance, freight
CNG	compressed natural gas
f.o.b.	free on board
LPG	liquefied petroleum gas
MCF	thousand cubic feet
MMCF	million cubic feet
MMCFD	million cubic feet per day
MMBTU	million British Thermal unit
m^3	Cubic Meter
MM	Million
MT	Metric Ton
MW	Megawatt
MWh	Megawatt hour
toe	Tons of oil equivalent
TPD	Ton per day
GDP	Gross Domestic Product
PPF	Project Preparation Facility

Conversion Factors - Calorific

Product	Density	Cal.Equiv. (kcal/kg)
LPG	0.55	11,834
Kerosene	0.798	11,128
Diesel	0.800	10,972
Fuel Oil	0.850	11,050
Crude Oil	0.745	11,507
Ton of Oil Equivalent	-	10,000

Natural Gas (MCF)	263,356 kcal
1 kWh (generation)	2,867 kcal
1 kWh (consumption)	860 kcal

Conversion Factors - Natural Gas

Product (ton)	Number of MCF
LPG	44.94
Kerosene	42.25
Diesel	41.66
Fuel Oil	41.96
Crude Oil	43.69
Ton of Oil Equivalent	37.97
Biomass	
Fuelwood	300 toe = 1,000 ton
Charcoal	650 toe = 1,000 ton
Bagasse	209 toe = 1,000 ton
Electricity	86 toe/GWh

Currency Equivalents

Currency Unit:	Bolivian Peso (Bs)
Exchange Rate:	Bs2.10/US$

TABLE OF CONTENTS

TABLES

FIGURES

ANNEXES

EXECUTIVE SUMMARY

1. Bolivia is a net energy exporter and has a large energy resource base relative to its present internal needs. Proven natural gas reserves are about 4.1 x 10^{12} CF, equivalent to over 40 years at the current production level. However, liquid hydrocarbon proven reserves are limited by comparison, and reach approximately 124 million bbl plus 54 million bbl of probable reserve, with a possible imbalance between production and domestic demand in the next decade. Although Bolivia has an abundant economically exploitable hydropotential of nearly 18,000 MW, only a small fraction of less than 300 MW have already being exploited. Fuelwood resources are considerable with forests covering about half of the country, but mainly in the scarcely populated tropical lowlands, while the Altiplano inhabitants suffer from a century old shortage of fuelwood, which has contributed to the area's total deforestation and substantial degradation of its soil. Bolivia has also some minor coal and peat resources (which are limited to local markets).

2. Bolivia's short-to medium-term growth prospects will depend critically upon hydrocarbons exports. While mineral exports dropped from US$641 million (63% of total exports) to US$263.8 million (38% of total exports) in the period 1980-1986 as a consequence of the international tin prices crisis and internal administrative inefficiency plus social instability, hydrocarbons exports increased from US$245 million (24% of total exports) to US$371 million (60% of total exports) in the same period. Just about all of these hydrocarbons exports in 1986 are natural gas sales to Argentina. Hydrocarbons have become the main source of hard currency, contributing over 50% to the Government's treasury income in 1986. In 1987, the Government assigned about US$170 million for investments planned in the energy sector, which is almost 30% of the planned total public investment, in a period where the country is facing its worst economic crisis in the century. The public investment program is likely to be reduced by almost one-third, with energy, however, being the most resistant in the reduction. Per-capita GDP which is one of the lowest in Latin America, has fallen by about one-third since 1979 to US$560 in 1986. Inflation in the first half of 1985 was averaging 60% a month (equivalent to 28,000% a year), although in the last 18 months the current administration has taken strong measures to incentivate the economy and control successfully the inflation. In addition, Bolivia faces a difficult situation with its international debt, amounting to US$3.9 billion, over 5 times its exports of goods and services. Bolivian authorities have recently renegotiated its debt, and is paying about 60% of the service of the debt, or 35% of current total exports.

3. The major energy issues in Bolivia revolve around investment priorities, energy demand management and institutional problems. Although the country has a plentiful energy resource base, it has limited financial resources which must be allocated efficiently according to priorities. A list of technical assistance priorities is listed at the end of this summary.

Investment Priorities

Petroleum

4. Field Development. Field development is the key short term investment priority in Bolivia's energy sector. While the oil and condensates production peaked in 1973 at 47,400 bd, it declined steadily to 17,600 bd in 1986 as a result of the depletion of various fields and because no new fields came on stream due to a lack of investments reflecting the impact of foreign exchange shortages and insufficient exploration caused in particular by apparent lack of interest by the international petroleum industry. Liquid hydrocarbons exports, which reached 32,500 bd in 1973, were reduced to spot sales of naphtha and gasoline in 1980 and ceased altogether soon thereafter. Until now, Bolivia has been able to maintain an equilibrium in its internal supply/demand balance for petroleum products.

5. If the proposed field development investment program for the national petroleum company YPFB is carried out totalling US$245 million in a seven year period, Bolivia could be self-sufficient with respect to its domestic supply/demand balance until 1995 according to the current YPFB data and will have a surplus of liquids which could be exported providing an additional needed revenue of about US$32 million p.a. on average, 1/ excluding LPG exports estimated at another US$20 million p.a. However, because of the great inconsistencies that exist in YPFB data, an in-depth revision is warranted.

6. Exploration. At the same time that oilfield developments will be carried out, exploration needs to be accelerated to maintain an adequate reserve/demand ratio. An additional 120 million bbls are estimated to be required for the period 1989-1997 assuming the projected demand and production for the period, and a 15 year reserve/demand ratio. By way of illustration, if exploration costs were in the order of US$7.50/bbl for liquid hydrocarbons as calculated by a consultant in a hypothetical case to preserve self-sufficiency, the magnitude of exploration investments for the period 1987-1997 required is estimated in the order of US$900 million.

7. A World Bank private exploration promotion Project Preparation Facility (PPF) has recently been initiated to evaluate the hydrocarbons potential. Following the results obtained, YPFB exploration activities should focus on low risk areas, while the high risk areas should be offered to private investors. For the short term, the following measures should be implemented: the opening of new areas to private sector companies for exploration contracts on reasonable terms requiring (i) extension of the 1972 hydrocarbon Law to authorize joint ventures;

1/ At a crude oil price of US$20/bbl.

and (ii) agreement on payments due to private contractors (Occidental and Tesoro).

8. In the short term, exploration contracts with the private sector could reduce the investment outlays otherwise required by YPFB in exploration. Such savings could be used to increase the production activities.

9. YPFB's 1987 planned exploration program amounts to US$45 million. IDB has a strong participation in exploration activities in Bolivia, financing US$80 million for the period 1987-1989. An additional, IDB loan of US$31 million is being negotiated. However, the magnitude of the exploration program required and the critical economic situation in Bolivia, emphasizes the strong need of private participation in exploration activities.

Natural Gas

10. Natural gas is by far the most abundant energy resource in Bolivia and is a top priority in replacing the more scarce liquid hydrocarbons. YPFB has prepared a 5 year natural gas substitution plan (1987-1991) which aims for the replacement of 80% of the industrial consumption of liquid fuels in the main urban centers and a start in the conversion of commercial and residential consumers. The economics involved are discussed later in paras. 31-33.

11. For the time being, the only investment necessary concerns the development and expansion of natural gas transmission to major consuming areas estimated at US$16.8 million (US$6.4 million YPFB) for the period 1987-1991. 2/ To this one has to add the cost of converting to gas industrial consumers (about US$5 million for the three smelters plus US$2.5 million for the other industries), the cost of connections of industrial consumers (about US$2.5 million) and that of converting commercial and domestic users (about US$2 million). To attract private participation in natural gas distribution investments, a technical, financial, and economic evaluation is needed for each proposal, in addition to defining a plan for potential bidders. Contractual arrangements between YPFB and private firms also needs to be examined.

Electric Power

12. A tentative five-year investment program for the power subsector was prepared, for a long-term power expansion plan is not available. The total investment required is US$181 million for the period 1987-1991.

2/ If exports to Brazil do materialize, then major investments will be required for that purpose.

13. The required power generation investment amounts to US$76 million on the least cost expansion program prepared by the National Power Company (ENDE). The program is based on the addition of gas turbines in Santa Cruz. At a cost of gas of US$1/MCF at the plant, very few hydroelectric alternatives could compete with gas turbines. The most attractive hydroelectric alternative is the proposed expansion of the Zongo River plant. The power generation system should be expanded using plants for peak load operations. In this regard, the rehabilitation of small hydro-stations now on use may be attractive, and the large hydroelectric projects now under consideration can be improved by lowering their designed plant factor.

14. Regarding transmission investments (US$29 million), the only major project considered by ENDE is the Central-Eastern interconnection. It is important to commission the project by 1990 to reduce the need for expanding generation capacity and to allow the use of hydroelectric surplus, if any, in the Central-North-South interconnected system. The main benefits of the interconnection in the medium term would be to facilitate the development of additional thermal generation in the Santa Cruz area, where their performance is better, and avoid transporting natural gas to the Central Regions for power generation purposes.

15. Regarding substransmission, specific projects have been included to meet future demand with a total investment requirement of about US$8 million. An aggregate investment requirement for distribution was calculated at US$50 million for the 1987-1991 period taking into account the average cost per incremental peak demand at US$450/kW.

Rural Energy

16. LPG was found to be the most economic household cooking fuel which, however, requires an improvement in its marketing arrangements. The Ministry of Energy and Hydrocarbons (MEH) with the rural cooperatives and corporations, need to design a distribution network which will allow the transport of LPG to rural areas at the fixed national price as recommended in paras. 21-22.

17. Investments into fuelwood plantations can not be recommended at this time due to the very high economic costs. The very high cost of reforestation in the Altiplano is attributed to poor growth of currently identifiable species, attributable to the relatively poor-quality of soil and dry climate found at an altitude of about 4,000 m. above sea level. For the Valleys, only if about 10% of the reforestation costs would be assigned for fuelwood purposes, then it could be economically competitive with LPG and kerosene.

18. Investment in rural electrification is recommended only where there is a productive use for electricity. In addition, small hydroelectric plants are recommended only in areas where there is an advantage over diesel.

19. Unconventional technologies, such as biogas, windpower, and solar energy, are expensive relative to the income of the rural household based on subsistence farming, and requires a social and technical environment that can only be brought through continuous technical support. The energy problem of the rural areas should be treated as a part of integral rural development programs considering the resource endowments of the region in question.

Energy Demand Management

Energy Pricing

20. Petroleum Products. Except for LPG (domestic use) and diesel oil (for power generation) which are subsidized mainly for social reasons, petroleum product prices are either considerably above opportunity cost or close to it. On the whole, there is no subsidy of oil products, with a weighted price of the composite barrel to the consumer equivalent to about 160% of the opportunity cost.

21. With respect to LPG, the opportunity cost, including distribution, is of the order of US$17/bbl against a price of LPG for domestic use of US$12.5/bbl. This is critical because LPG represents about 25% of the petroleum products sold in Bolivia, and it is the only product whose consumption is rising rapidly. The price of LPG should therefore be increased at least to its opportunity cost (about 30%). Government policy has been to subsidize LPG for the low income rural population which may not have any other fuel alternative but animal dung or fuelwood. With that in mind, however, the rural population has actually been paying two or three times the price of LPG in the urban areas, due to high transport costs and an inefficient distribution system. A fixed national retail price at its economic cost should therefore be set, which would permit to subsidize the transport costs to the low income rural areas. The end result should be that the low income rural population will not be affected by the price increase.

22. By achieving a fixed national LPG retail price at its economic cost, the other domestic LPG prices for industrial purposes and vehicles should be eliminated. The existence of three simultaneous prices encourages fraud. Furthermore, in volume terms, more than 90% of LPG sold is for domestic use.

23. Regarding the subsidization of diesel oil used for power generation, this product represents only 0.[illegible]% of products sales in Bolivia. The number of beneficiaries is small so that they are well identified. The subsidization could be rationalized by the fact that the bulk of power generation in Bolivia is hydro and gas-based so that diesel oil is used in remote areas, without any other power alternative.

24. An important distortion exists regarding diesel and gasoline. While their retail prices are identical, the opportunity cost of diesel is about 35% higher than that of gasoline. Taking into account that about 60% of the diesel is used for transportation, measures should be considered to encourage, whenever feasible, the substitution of gasoline for diesel oil, including imposing special taxes and custom duties on diesel powered vehicles, trucks, and tractors (at present custom duties are identical at 20%). Increasing the price of diesel could have a negative effect for most of the food products are brought by road at already a high cost.

25. Natural Gas. The average incremental cost of gas (AIC) is considered low because most of the infrastructure for gas production and transport to the main markets already exists, and gas reserves are plentiful. The AIC is estimated in the order of US$0.65/MCF including exploration, operating costs, and minimal transport costs because most of the additional investments are required in more than 10 years' time. 3/ This is below the two current official prices for natural gas, for the power sector at US$0.88/MCF and one for the other consumers at US$1.76/MCF.

26. Oil and Gas Pricing Financial Viability. Oil and gas prices should also be sufficiently high to enable YPFB to recover costs. However, in financial terms, oil and gas prices are barely sufficient for YPFB to recover its costs. Following the fiscal measures taken in 1986, a 65% tax on petroleum products is collected from YPFB (in addition to an 11% royalty) which has resulted in a tight cash flow situation for the entity (paras. 43-44).

27. Although the current policy to maintain natural gas prices relatively low to encourage further use of this abundant resource is commendable, retail prices per kcal are well below other alternatives and need to cover all financial costs (paras. 31-32). The AIC, including the finan·ial cost of gas by taking into account past investments, is esti· ·d at US$1.50/MCF at city gate. In addition one would have to add a dis··ibution cost estimated at US$0.22/MCF for industrial consumers, and US$3.55/MCF for residential and commercial consumers. The tariff to be introduced depends on the density of consumers and the mix of industrial, commercial, and residential users.

28. Electric Power. The level and structure of electricity tariffs in Bolivia does not reflect the real cost of this public service. The current bulk electricity rates for sales from ENDE to the distribution companies are well below their marginal costs (e.g., bulk tariffs to ELFEC have a demand charge of US$2.5/kW per month and 12 mill/kWh of

---

3/ If exports to Brazil materialize in addition to Argentina, the AIC may reach US$1.15/MCF, because of production costs due to greater demand and additional transport costs.

energy charge, while the marginal costs were estimated at US$8.9/kW per month and 14 mills/kWh respectively). On the other hand the current bulk electricity rates for mining and industrial consumers are well above their marginal cost (e.g., bulk tariffs to COMIBOL--La Palca are US$13.5/kW per month as demand charge and 40 mills/kWh as energy charge, with the same marginal cost previously mentioned. In addition, with respect to the retail tariff structure, it is also inverted, since those consumers with higher marginal costs (residential) are paying much less than consumers with lower marginal costs (industrial). ELFEC, Cochabamba's distribution company, average residential tariff is about 20-25 mills/kWh while the average marginal cost is about 69 mills/kWh.

29. The following actions need to be taken in establishing an adequate power tariff structure: (i) first, carry out a reevaluation of assets for all the distribution and generation companies, in order to establish the real tariff base in each company; (ii) execute a detailed tariff study based on and consistent with the rate of return, cash flow, and marginal cost approaches for all generation and distribution companies; and (iii) implement the tariff structure based on actual marginal costs and taking into account the financial viability of the power companies.

Interfuel Substitution and Conservation

30. Natural Gas. The single most important measure oriented to substitute liquid fuels in Bolivia is the utilization of natural gas. However, under all circumstances and considering the structure of demand, the potential for substitution by natural gas remains small. YPFB's five year substitution plan (1987-1991) aims at substituting by the end of the decade 1,200 bd of liquid fuels and 112 tons of LPG through the conversion of 250 industries, 750 commercial and 15,000 residential users. Consumption of gas would thus increase from 22.6 MMCFD in 1986 to 38.6 MMCFD in 1990, an average annual growth rate of 15%. Should the smelter resume their operations, the market would be higher by about 9 MMCFD.

31. The conversion of industrial and commercial consumers appears highly economic whereas the use of natural gas in the residential sector needs to be evaluated in more detail before the viability of this option can be established. Private participation should ensure economic viability of projects.

32. For industrial and commercial consumers, the payback period ranges from 19 to 436 days 4/ justifying the conversion to natural gas. However, for the residential consumers, even with the recommended increase in the price of LPG, the high cost of supply does not justify their conversion. Nevertheless, on some circumstances with a cross-subsidy from industrial consumers, a tariff could be elaborated taking into consideration the anticipated mix of consumers.

4/ Assuming current prices.

33. Substitution of compressed natural gas (CNG) for gasoline and diesel oil is an interesting alternative. However, this is still in the study stage and would require many years to reach an impact at the national level.

34. Kerosene. In an economic comparison of household cooking fuels, kerosene was found to be an interesting alternative to LPG because of the lower former's transport and distribution costs to the rural areas. Currently, kerosene is almost only used for lighting purposes since the kerosene supply is restricted. However, kerosene seems to offer an interesting alternative which should be investigated further along with the program to improve the distribution of LPG in the rural areas.

35. Conservation. An audit of YPFB's internal consumption (10% of national petroleum product consumption) should be carried out. In the refineries alone, internal use and losses average 8% of the feedstock, notwithstanding the fact that they use increasing quantities of natural gas as fuel. A study to improve bagasse utilization should also be carried out, since the sugar mills require hydrocarbons for about 15% of their energy needs.

Institutional Problems

36. The Ministry of Energy and Hydrocarbons (MEH) is responsible for formulating energy policies and for regulating the activities of the sector, except forestry which is under the responsibility of Ministry of Agriculture. These functions are carried out by two main departments within the Ministry, one responsible for hydrocarbons (DGH), the other for electric power (DINE). Overall sector planning is limited within the Energy Planning Unit (DEP) of the MEH. The Rural Energy Corporation (COFER), funded through the MEH, is responsible for rural energy and alternative forms of energy. Power tariffs and petroleum product prices are set by the MEH.

37. MEH is insufficiently equipped to exercise its functions and to coordinate the efforts necessary to successfully meet Bolivia's future energy needs. The creation of the DEP was a first step but it must be strengthened. This unit must be staffed with highly qualified personnel, equipped with analytical tools, and advised by outside experts during its initial years. Free flow of information to and from the energy companies and with the other ministries of economy and planning must be established. DEP, working together with strengthened DGH and DINE, would be in charge of proposing and evaluating energy strategies, scheduling programs and monitoring those that are implemented. It would also make sure that a proper link is established between economic objectives and energy, and would coordinate with the Ministries of Planning, and Agriculture and Rural Affairs.

38. The current structure of DGH, DINE, COFER and DEP needs to be examined in detail. Most of these units are receiving enough funds to maintain basic office functions and nothing else. In the case of DINE, a political and legal solution should be worked out to give back DINE the responsibility for setting tariff rates.

39. Hydrocarbons. The national petroleum company YPFB is responsible for all phases of the hydrocarbons industry from exploration to drilling, production, refining, and marketing. YPFB has been engaging in operations contracts with foreign oil companies (Occidental and Tesoro).

40. YPFB's current situation is characterized by: (i) a high degree of centralization, featuring excessive concentration of decision-making authority to the top levels of management; (ii) overstaffing and duplication of functions; (iii) extremely slow and cumbersome administrative decision-making procedures; (iv) inadequate development and use of management information and other systems; and (v) poor coordinating and conflict resolution mechanisms between functions.

41. YPFB needs to be restructured to work under economic efficiency criteria. Five operational divisions (exploration and production; drilling and oilfields services; refinery; transport and marketing; and a new gas division (para. 42) should be set up along with four other general divisions (contracts, procurement, construction, and administration).

42. With respect to natural gas, there are three gas divisions: Yabog located at Santa Cruz (exports to Argentina, and transport and distribution in the eastern part of Bolivia), the Industrial Division located at Cochabamba (transport and distribution in the western part of Bolivia) and the Gas Division in Sucre (planning, tariffs, policy). There should be an attempt to unify those three divisions into one department in YPFB, to consolidate the functions presently fulfilled by the three groups at different locations.

43. The new tax structure (para. 26) appears to have had disastrous consequences for YPFB. The loss for 1986 was estimated at US$39 million, the investment program for that year was reduced to about US$50 million and it failed to comply with over US$18 million in debt service obligations. In addition, the accounting system is totally inadequate. YPFB's financial requirements need to be taken into consideration in the context of the ongoing review of the overall tax system.

44. An agreement between the Government and YPFB is urgent on realistic operating and capital budgets together with their corresponding financing plans. A reduction in YPFB's investment program will have adverse consequences. Development and enhanced oil recovery projects should ensure self sufficiency in petroleum products in the coming years and could provide a surplus for exports which is essential for Bolivia's economic recovery.

45. Electric Power. At the generation and transmission level, there are two companies responsible for the development and operation of generation and transmission projects. The National Electric Power Company (ENDE) is responsible for the programming, development, and transmission projects at the national level and for supplying energy to all distribution companies and some large mining and industrial consumers. The foreign owned private Bolivian Power Company (COBEE) is responsible for supplying energy to La Paz and Oruro markets, and for the operation of generation plants in that area, and is authorized to develop new generation projects at the Zongo River Basin.

46. In general, ENDE and COBEE are well organized and efficient. The deterioration of the financial situation and of their performance was due to external factors and not to inefficiencies in their operations. However, the lack of definition for the responsibility in the development of power generation projects at the national level has created problems for sector planning. The programming process needs to be strengthened and ENDE is the institution best qualified for directing this process and should be responsible for preparing the Power Development Program. Since COBEE's concession expires in 1990, a decision should be taken as soon as possible. The Government should evaluate carefully the alternatives before a decision is taken on not to extend the contract. Nevertheless, if the contract is not extended, COBEE's generation and transmission system should be transferred to ENDE. Regarding dist ibution, it should all be transferred to distribution companies. There is no need to burden ENDE with the sponsibility of developing part of their distribution system.

47. Rural Energy. There is virtually no coordination either on the national level or on the level of the regional development corporations with non-governmental organizations involved in rural development or with rural cooperatives. This lack of central government coordination has resulted in often sub-optimal investment decisions.

48. Inadequacies in the existing rural financing system for energy purposes should be investigated, and changes should be made to provide financing for small rural energy development projects, in line with priorities. Financing must be improved in the poorer regional areas which in fact may be in a much more critical fuel shortage situation.

Technical Assistance Priorities

49. The following technical assistance activities should be given high priority so that critical problems in the energy sector can be tackled.

[redacted]

Within the MEH: 5/

(a) evaluate options to strengthen the policy and institutional framework and market arrangements for LPG in the rural areas, and carry out an energy demand analysis focussing on the use of LPG (paras. 3.2-3.3 and 3.41, 3.47, and 3.50);

(b) establish an energy information system and develop and implement analytical tools to carry out energy planning, in particular, strengthen DINE's organization, methodologies and procedures regarding the setting of electricity rates and the development of data bases for power sector statistics (paras. 5.1-5.3 and 5.18);

(c) review the current electricity tariff structure both at bulk and retail level, and prepare specific proposals for setting electricity rates for 1987-1990 (paras. 3.21-3.28);

(d) carry out a study to improve bagasse utilization in the sugar mills (para. 3.56); and

(e) determine efficiency of current wood and dung stoves in the Altiplano, and carry out an analysis of the economics of its substitution by hydrocarbons including kerosene (paras. 1.42-1.43).

Within YPFB:

(a) develop and implement a petroleum supply management information system (MIS) optimizing the use of refineries and evaluating least cost supply options (para. 5.9);

(b) develop and introduce in YPFB modern integrated accounting, budgeting and control systems (paras. 5.33-5.38); and

(b) carry out an energy audit on YPFB's consumption of liquid fuels (para. 3.54).

Within ENDE:

(a) carry out a power system analysis of the interconnected system, including a stability analysis (paras. 4.32);

(b) Review electricity demand projections for the industrial, mining and residential sectors for the period 1987-1995 (paras. 1.39-1.41); and

---

5/ All of these activities could be carried out under the proposed technical assistance in strengthening energy planning at the MEH.

(c) Review procedures, methodologies, and organization in ENDE for project analysis (paras. 5.14-5.20).

I. THE ECONOMY AND ENERGY

Recent Economic Developments

Background

1.1 In the 1980's, Bolivia has been facing its worst economic crisis during the century, although in the last 18 months, the GOB has taken strong measures to reactivate the economy. Per capita GDP had fallen by one-third since 1979 reaching only about US$560 in 1986, which is one of the lowest in Latin America. GDP declined by 18% between 1980-1986. Inflation in the first half of 1985 was averaging 60% a month (equivalent to 28,000% a year), and the deficit of the consolidated non-financial public sector had reached 24% of GDP in 1984. As a result of recent measures by the current administration, inflation has been controlled to about 20% for 1986. The economy had appeared to have done well in the 1970s when GDP growth averaged 5.4% until 1978. However, this growth was based in large part of foreign borrowing, and debt built up rapidly from a level of US$500 million in 1970 to US$2,400 million by 1980. This borrowing was not, on the whole, used productively, and when external creditors reduced lending in 1979-1980 the economy did not have the resources to service this debt. With foreign debt greater than GDP (1.04 ratio in 1985) the debt service rose from US$ 208.5 million to US$349.5 million between 1980 and 1985, representing 56% of total exports in 1985. The economy embarked on a downward spiral of falling investment, savings, exports, consumption and GDP. Inflation grew to unprecedented levels in Latin America, and the public sector deficit widened. The exchange rate appreciated in real terms as the Government made futile attempts to maintain a fixed nominal rate system. Extreme price distortions opened up.

Exports & Foreign Debt

1.2 Bolivia faces two particularly important structural difficulties for its external accounts; one is the size of its current external debt obligations, and the other is the structure of its exports. Bolivia's total external debt at the end of 1985 was US$3.9 billion,over 5 times its exports of goods and services. These are among the highest such ratios for any country in Latin America, yet Bolivia is one of the poorest. The interest on this debt was accruing at almost 9% of GDP in 1985, although most of this interest was not paid. The current account balance in 1985 was in deficit at a level of 9.2% of GDP even though the trade balance (in goods and non-factor services) was in surplus of 1.3% of GDP.

1.3 In 1986, Bolivian authorities negotiated the reschedule of multilateral and some of the bilateral external debt. After the negotiation, Bolivia drawed on from the IMF a Compensatory Financing Facility of SDR 64 million on a Structural Adjustment Facility to be received in three installments. Bilateral creditors (including suppliers' credits, which are mostly from official sources) are assumed to continue to reschedule through the Paris Club. Presently, Bolivia is paying its debt service to multilateral organizations and to some bilateral sources. However, Bolivia has not paid interest nor principal to commercial banks since March 1984. Currently, Bolivia is paying 60% of its debt service which consists of 35% of total export earnings.

1.4 Bolivia's ability to service its debt depends on its exports performance, but exports prospects are currently poor. The structure of Bolivia's exports is highly concentrated in natural gas and minerals, which are vulnerable to exogenous factors. On the other hand, estimates of the value of exports as a result of the informal economy, range up to the equivalent of Bolivia's total legal exports or well above, when valued in terms of revenues brought back into the economy.

1.5 Considering gas and tin, both of these goods face problems brought on by external events over the recent past. First, the international market for tin collapsed in October 1985. Trading ceased on the London Metal Exchange after the International Tin Council, which had kept prices stable in the 1980s, announced it had run out of funds to cover purchases it had contracted for on margin. Effective tin prices as of August 1986 were less than half of what they had been a year earlier. Second, the reduction in the international price of petroleum from an average of US$28 per barrel in 1985 to a range of US$8-16 per barrel for most of 1986, reduced the value of Bolivia's natural gas exports to Argentina.

1.6 Bolivia's natural gas exports are exclusively to Argentina through a pipeline completed in 1972 and under terms of a 20-year contract covering the period to May 1992. The price for the gas has come to be negotiated on an annual or semi-annual basis, and these negotiations have become increasingly difficult for Bolivia. In addition to the problems created by the collapse in oil prices, Argentina has also in recent years developed its own supplies of gas and no longer has a global requirement for the Bolivian gas. Although it continues to import the volume of gas as specified under the terms of the 1972 contract, 1/ the level of imports likely from 1992 onwards is quite uncertain. Continuation of the purchases, and on what terms, will be based on more than purely economic considerations. In the short term, the price issue is likely to dominate. At the April 1986 negotiations, the price of the gas was reduced by 12% from its 1985 levels, with effect from January 1. The new price of US$4.22 per thousand cubic feet 2/ is, however, still equivalent to about US$22-US$23 per barrel of oil on

---

1/ As subsequently amended in the late 1970s, when the volume was increased.

2/ Includes dry gas and condensates.

energy equivalent terms. Partially offsetting the fact the current gas price is higher than the world price because of the recent decline in international prices, is the requirement that part of the gas in the order of 60% be paid by Argentina not in freely convertible foreign exchange, but in terms of Argentine goods on a counter-trade basis. Until Bolivia decides which Argentine goods to purchase, the gas receipts which must be dedicated to counter-trade accumulate without interest in a special account at the Argentine Central Bank. Because of these counter-trade restrictions, it cannot be said that Bolivia, in fact, receives a full US$1 of value for US$1 of recorded gas exports. The appropriate discount is not clear. However, even with this taken into account, it is likely Argentina will continue to push for lower gas prices. Given Bolivia's dependence on gas exports, with 60% of its merchandise exports being this one commodity to this one customer, Bolivia can ill afford a major reduction. Argentinean authorities are currently negotiating new volumes and gas prices.

1.7 Bolivia's exports suffered a third major shock in 1986 when a Government-sponsored effort led to the closure of some of Bolivia's clandestine cocaine processing laboratories. The long-term effectiveness of these interdictions is not yet clear, although the current government clearly intends to do whatever is possible to ensure their success. The extent of the illegal trade is also not clear, but estimates of its scale range to amounts of several times Bolivia's total legal exports.

<u>The Agricultural Sector</u>

1.8 Although contributing only in the order of 20% of Bolivia's GDP, and about 12% of the country's exports, the agricultural sector is of fundamental economic and social significance to the country. The 1976 census has demonstrated that about 55% of the country's total population live in rural areas and that 63% of the labor force are employed in the agricultural sector. The agriculture sector suffered a decline at the early 1980s which was worsened as consequence of the 1983 drought. In 1983, the agriculture sector output dropped by 26%.

1.9 With prospects of declining output in the mining sector and with not very clear potential external markets for hydrocarbons, the government is re-examining the role which agriculture may play in the country's foreign trade. In particular soybeans projects are in consideration as potential substitutes and complements to mineral and hydrocarbons export projects, in order to increase the foreign exchange.

1.10 The performance of the agricultural sector, however, is limited by a number of serious constraints and imbalances which are difficult to correct. The most serious of these are: (i) a concentration of population in areas of lowest productive potential; (ii) limited scale of national market; and (iii) high exporting costs.

The Industrial and Manufacturing Sector

1.11 The industrial and manufacturing sector had also a negative growth during the 1980-1985 period as reflected by an average decline rate of almost 10%. This sector in Bolivia has never being very important in GDP formation as reflected by its percent shares reaching the highest levels in the 1970s and early 1980s in the order of 15% of GDP, and 9% in 1985.

1.12 The industrial sector in Bolivia has a series of adverse factors among which the most important are: (i) reduced internal markets; (ii) technological dependence from abroad; (iii) high composition of imported inputs; (iv) high production costs which in turn makes the output uncompetitive with imported products; and (v) after the new economic policy implementation, all the industrial policy incentives have been abolished by uniform and reduced tariffs to imported products and with the abolishment of tax redemption on exported products.

The Mining Sector

1.13 During the 1980-1985 period, the mining industry has been affected not only by the international tin prices crisis but also by an inefficient administration, an artificially high local currency value plus social instability. During the 1980-1986 period, and as a consequence of the previously mentioned adverse situations, the mining sector's participation on GDP has been on average 8%. Mineral exports dropped from US$641.2 million (63% of total exports) in 1980 to US$263.8 million (38% of total exports) in 1986.

1.14 After the 1985 international tin prices collapse, several mines have turned to be marginal and uneconomic. As a result many mines have closed leaving a number of some 30,000 workers unemployed over a total mining force of about 70,000 workers. Government has created an Emergency Social Fund which will finance projects of high social content which should help to reduce unemployment.

Non-Factor Services

1.15 If growth was negative for the principal sectors of the economy, on the contrary, the non-factor services, commerce and financial sectors have incremented their share in GDP during the period. Whereas the tradeable sector of the economy (mining, hydrocarbons and industry) has declined its GDP share from 30% to 22%, the non-tradeable sector has incremented its participation from 70% to 78%.

Impact of the Energy Sector

1.16 The possible economic outcomes due to alternative energy development strategies depend on interactions between the sector and the rest of the economy. The relative importance and the impacts of the energy sector in the Bolivian economy have been estimated at two different levels: (i) fiscal policy; and (ii) foreign trade.

1.17 Fiscal Policy. As hydrocarbons became the main source of hard currency in a context of an overall production crisis, the sector has contributed to the Government's Treasury (TGN) with more than 50% of TGN's income in 1986. On the other hand regional governments, in oil producing regions, have received more than 90% of their income from royalties on hydrocarbons.

1.18 Until 1985, the National Petroleum Company (YPFB) was subject to the following system of taxes:

(a) For domestic sales:

(i) a 19% production tax for oil and gas;

(ii) a 15% tax on the sale of transportation fuels (that is gasoline, avgas, and diesel); and

(iii) a 12% tax on gasoline and diesel sales.

(b) For exports:

(i) a 15% export tax; and

(ii) a 19% tax on production.

In addition to the tax system above mentioned, YPFB pays an 11% royalty fee to regional governments of oil producing areas.

1.19 The above mentioned tax system to the hydrocarbons subsector, has been replaced on a temporary basis, by a 59% tax on exports and a 65% tax on domestic sales, in order to increase substantially the national fiscal income. This tax system has represented some US$365 million against US$165 million that would have been collected with the previous system (a net increment in taxes of more than 120%). On top of that, YPFB has paid some US$56 million to regional governments as royalties. Although those amounts have helped in a decisive manner in the economic stabilization program, they have also constrained the investment capability of the subsector.

1.20 Foreign Trade. The growing importance of the hydrocarbons subsector in the Bolivian economy may be reflected by pointing out that its participation in total exports has involved from 5.9% in 1970 to about 60% in 1986. Table 1.1 shows the increasing importance of natural gas in the total export market and the critical decline of oil production.

Table 1.1: HYDROCARBONS AND THE TRADE BALANCE
(US$ million)

	1975	1980	1985
- Petroleum Prod. Exports	111.4	24.2	1.9
- Natural Gas Exports	47.5	220.9	372.6
- Total Exports of Goods and NFS	505.0	1,023.6	712.9
- Total Imports of Goods and NFS 1/	641.0	795.4	664.4
- Hydrocarbons as % of total exports	31.5%	23.9%	52.5%
- Hydrocarbons as % of total imports	24.8%	30.8%	56.4%

1/ NFS-Non Factor Services.

Source: World Bank CEM of November 1986, and NEP estimates.

1.21 The hydrocarbons exports increased from US$158.9 million in 1975 to US$374.5 million in 1985. During the 1980-1985 period, YPFB generated almost 40% of the total foreign currency inflow to the country. In 1985, the current account balance deficit reached 9.2% of GDP, but excluding natural gas exports it would have reached 13.9% of GDP.

1.22 After the 1985 international tin prices crisis, the Bolivian trade balance is dramatically dependant on one product (natural gas) and on the willingness of one costumer (Argentina), which reveals the fundamental importance of the energy sector in the Bolivian economy.

1.23 The prospects for hydrocarbons exports are not so clear. Bolivia's export contract to Argentina will end in 1992 and it is expected that sales may not continue beyond that date. Although negotiations with Brazil are under way, prospects are not very clear and the failure to find a market for surplus gas may represent a major set-back.

Energy Supply and Demand

Hydrocarbons

1.24 Bolivia is more gas than oil-prone, and the largest liquids producer is a gas condensate field (Rio Grande). At present, about 62% of total liquids are produced from condensate, mostly by stripping gas of its liquid content at surface. The hydrocarbon developed rapidly in the 1960s and oil and condensates output continued to rise until it peaked in 1973 at 47,400 bd. and declined steadily to 17,700 bd in 1986 as a result of the depletion of various fields, and because no new fields came on stream due a lack of investments reflecting the impact of the foreign exchange shortage, and insufficient exploration caused in particular by apparent lack of interest by international oil industry. Oil exports, which reached 32,500 bd. in 1973, were reduced to spot sales of naphtha and gasoline in 1980, and have remained minimal thereafter.

1.25 Domestic demand for petroleum products in 1986 was about 21,300 bd. Demand grew during 1974-1978 at an average 11% p.a., grew at only 3.5% p.a. in 1979-1980, and declined by 9.4% p.a. in 1980-1986. Only LPG demand continues to grow at an average of 10% p.a. in 1980-1986, substituting for kerosene, electricity and to a minor extent fuelwood and dung. Gasoline (including avgas) now accounts for about 40% of total domestic consumption, diesel 20%, LPG 25%, fuel oil 4%, kerosene 4%, and jet fuel 7%.

1.26 The Bolivian market for petroleum products exhibits the following: (i) three products, gasoline, LPG and diesel oil account for more than 80% of products sales; (ii) the share of LPG--25% is probably one of the highest in the world; and (iii) the transportation sector (gasoline and 60% of the diesel) accounts for in excess of 50% of products sales. The overall decline in petroleum product consumption reflects the severe recession which has affected the economy since 1980.

1.27 Until now, Bolivia has been able to maintain an equilibrium in its domestic supply/demand balance for petroleum products. This can be attributed partly to the decline in the economy. Had the tin smelters continued to operate, a shortage of fuel oil would have been almost unavoidable.

Electric Power

1.28 In 1986, the installed generation capacity was about 553 MW, of which about 50% hydro and 50% thermal. The thermal capacity is composed of 134 MW (51%) in gas turbines, and 129 MW in diesel plants installed in small isolated systems and in self-producer plants. In terms of electricity production, in 1986, 75% was generated by hydro plants and 25% by thermal plants, of which, 91% in gas-fired thermal plants.

1.29 Regionally, the market comprises four major load centers: the Northern system (La Paz), the Central system (Cochabamba and Oruro), the Southern system (Potosi and Sucre) and the Eastern system (Santa Cruz); and several small isolated systems (Trinidad, Tarija, Villamontes, etc). The Northern, Central and Southern systems are interconnected and represented in 1986 about 66% of total electricity consumption in the country; the Eastern system, with 20% of total consumption, would be interconnected in the late 1980s; the small isolated systems, with 14%, are far away from the interconnected system, and their interconnection would not be justifiable in the short to medium term.

1.30 Regionally, the Central-North-South (C-N-S) interconnected system has an installed capacity of 342 MW of which only 50 MW in thermal plants; the Eastern system, 118 MW all in gas turbines; and about 3 other isolated systems, and microsystems (small communities with diesel engines) have and installed capacity of 112 MW, mostly in small diesel plants.

1.31 In 1987, the C-N-S system can meet its demand with hydroelectric generation, using only the gas turbines in emergency situation. The Central-South system is in a balanced situation and the transmission line which link La Paz with the rest of the interconnected system serves as a reserve support for the Northern system. On the other hand, the Eastern, Trinidad, and Tarija isolated systems are operating with a very small capacity reserve and require further expansion of their generation capacity.

Biomass

1.32 Biomass consumption in 1985 totalled 921,000 toe (45% of total national energy consumption), which is an increase from 838,000 toe (10%) from 1980. Most of the biomass in Bolivia is consumed in the rural areas, where introduction of commercial fuels has been restricted because of the subsistence family income levels, poor road system, and scattered nature of communities.

1.33 For the purpose of the National Energy Plan, Bolivia was divided into three climatological and geographical regions--Altiplano, Valleys, Tropics. Most of the dung consumed in Bolivia (160,000 toe) originates in the Altiplano, because of the lack of fuelwood and prohibitive costs of reforestation as a consequence of the poor terrain and climate at an altitude of about 4,000 m. For the Valleys, deforestation problems exist only in Tarija and the Province of Yamparaez, and for those specific areas, as in the Altiplano, the most cost-efficient policy choice for the short term would be to improve the delivery of LPG to those areas. In the Tropics, there is an abundance of fuelwood, although care should be taken with the expansion of the agricultural frontier and large amount of wood waste.

1.34 The Altiplano is the only region in Bolivia, where there is an overall critical imbalance between fuel supply and demand. In the Altiplano, the major household cooking fuels are dung and fuelwood with the supply of fuelwood decreasing. Approximately 210,808 toe of fuelwood 3/ and 152,058 toe of dried animal dung were consumed as household

3/ No breakdown of fuelwood resources between trees and shrubs was possible.

cooking fuels in 1985. Both are consumed in the two-pot "kery" stove (9-14% thermal efficiency), unique to the Altiplano. These estimations were based .n an average fuelwood equivalent daily consumption per inhabitant in rural households of 2.05 kgs/person/day and the total rural population in the region. 4/ Much of the fuelwood used in the Altiplano is the shrub-thola, which burns very quickly and is slow growing although it is a hardy species which has grown relatively well in the Altiplano. However, because of the great demand, its supply in many parts is inadequate.

Energy Demand Projections

Hydrocarbons

1.35 Oil. Forecasting the supply/demand balance for petroleum products becomes a difficult task because of the lack of refining model and the blending of heavier cuts with gasoline. With the recently discovered oil fields Santa Cruz and Villamontes, Bolivia may be self-sufficient with respect to the internal demand of petroleum products until 1995 if the proposed YPFB investment program (paras. 4.2-4.4) is carried out. Table 1.2 below shows YPFB and the private contractors (Tesoro and Occidental) projected production curve in relation to the estimated domestic demand. Caution must be taken with these estimates, however, since large inconsistencies in data still exist in YPFB. Since negotiations are still underway between YPFB and the private contractors on payments due to the private contractors, it is assumed that the production of the latter will eventually phase out because of the end of the life of the reservoir. For 1987 and 1988, the Peña and Rio Grande oil fields, followed by Villamontes and Santa Cruz, will provide about 56% of the national production. The production curve shown has two peaks, in 1989 at 11 MMbbl and in 1993 at 10.5 MMbbl. Annex 1 shows the projected production by field.

1.36 Projected increases in domestic petroleum consumption would largely depend on the strength of the economic recovery in Bolivia following several years of severe recession. It is anticipated that a modest economic recovery will take place beginning in 1987, and petroleum product domestic prices will be maintained in real terms reducing unauthorized exports of hydrocarbons and encouraging energy conservation. In addition, by increasing the supply of gas and improving the infrastructure for its transportation, the substitution of petroleum products should keep increasing by 1,200 bd by 1990. Under these

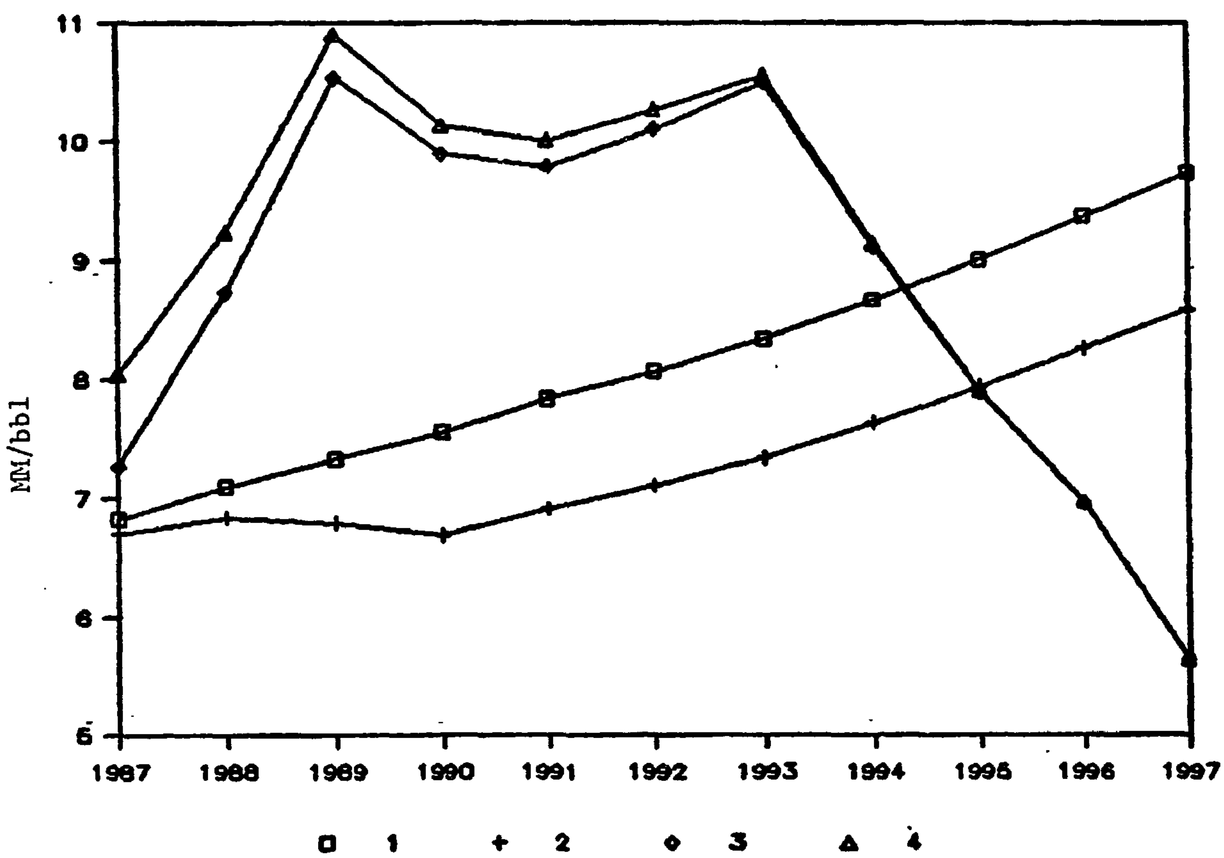
---

4/ Approximately 45% of the rural population in the Altiplano was assumed to consume primarily fuelwood (tree species and shrubs) for cooking, 35% dried dung, and 20% hydrocarbons (mostly LPG). Consumption estimates include fuelwood equivalent of all fuels.

assumptions, projected domestic demand for petroleum products by around 1990 would be about 24,000 bd, representing an annual growth of about 3.6%. By 1997, petroleum product consumption is estimated at about 32,000 bd, following the same assumptions.

1.37 Natural Gas. A 20 year YPFB gas demand forecast prepared on a sectoral basis indicates that by 2005, the main uses of gas would be for power generation (about 45%), industry (about 30%) and YPFB (about 15%). The share of the commercial and domestic sectors would therefore remain small. Overall consumption is estimated at 265 MMCFD.

Figure 1: SUPPLY/DEMAND BALANCE OF LIQUID HYDROCARBON



1/ Domestic petroleum product demand without YPFB's 5 year gas substitution plan.
2/ Domestic petroleum product demand considering YPFB's 5 year gas substitution plan.
3/ YPFB's production according to the investment program, and including transfer of Escondido field from Tesoro to YPFB.
4/ YPFB's production without Escondido.
5/ Total production including Tesoro and Occidental.
6/ Because of large inconsistencies in YPFB data, a further in-depth review of data is needed.

Source: YPFB and NEP estimates.

1.38 Over 1986-2005, one can anticipate the cumulated domestic demand for gas to be of the order of 0.9-1.3 TCF depending on developments in the economy. This represents about 25% of Bolivia's proven reserves of 4 TCF. Should Bolivia continue to export about 215 MMCFD (to Argentina and/or Brazil) during the same period, that consumption would represent about 1.6 TCF. Thus it would use about 75% of its proven reserves in the next 20 years. It is only if potential exports beyond 1991 exceed 300 MMCFD that there would be grounds for concern regarding Bolivia's reserves. But since Bolivia's gas reserves are thought by all to exceed 4 TCF by a considerable margin, higher exports would only entail an effort to confirm probable reserves, and possibly undertake more exploration in gas prone areas.

Electric Power

1.39 There are major uncertainties related to the projection of electricity demand, mainly the future of the mining sector and the impact of gas substitution and electricity rate increases on industrial and residential consumption. ENDE is now projecting a rate of growth of 5.8% p.a. for total electricity consumption for the period 1985-1991 based on the assumption of a 9.5% annual rate of growth for the residential sector and a drop in the consumption of the mining sector. The rate of growth projected for the Eastern system is about 12.5% p.a. The projected rates of growth are considered reasonable and adequate for planning the expansion of the power system at this time. However, further studies are necessary to analyze the case of the mining sector and the potential impact on residential and industrial demand of substitution of natural gas for electricity, and the impact on residential demand of the projected increases in electricity rates. The rate of growth for total consumption projected by ENDE is estimated at 6.3% for 1990-1995.

1.40 There are three factors related to electricity demand that should be analyzed further and monitored closely in the future. First, electricity demand in the mining sector should be studied based on the end use of electricity in this sector and on specific plans for the operation of existing mines. This is important, for a major portion of electricity consumption in this sector is related to support services (camps, etc). Second, substitution of natural gas for electricity at smelters (ENAF) and residential (water heating and cooking) should be assessed. Third, the rate of growth of demand in the Eastern system, now projected at 13% p.a. for 1986-1990, should be studied further based on realistic plans for connection of new consumers, an analysis of annual consumption for new consumers, an assessment of the price elasticity of demand in light of projected electricity rate increases, and an analysis of saturation of demand in existing high-income residential consumers demand. Furthermore, it would be important to analyze the economic potential for load management programs in order to shave the peak load.

1.41 As long as the opportunity cost of gas keeps around US$1/MCF, the power sector would have a lot of flexibility to adjust power supply to changes in demand at a reasonable cost, and the demand projection would not be so critical to take generation expansion decisions. In effect, under these conditions, the least cost solution would be gas turbines, which require a short lead time (one to two years), have a low capital cost, and can be developed in modules adapted perfectly to demand growth. Furthermore, in case of emergency, jet type turbines could be installed in short notice. This does not imply that medium and long term growth of demand would not affect major strategic decisions like the expansion of gas transport capacity, the strengthening of the transmission system, or the sizing of new generating units.

Biomass

1.42 In general, the Altiplano is the only critical region in fuel supply and demand. Only specific cases in the Valleys exists (paras. 3.44-3.46). Estimates of fuelwood supply in the Altiplano show that given projections of fuelwood consumption and estimated growth rates, there will be roughly a 6% decrease in 1992 from the estimated total supply of fuelwood in 1987. 5/ Dung supply is assumed to grow with projected demand, although shortfalls in fuelwood supply could put pressure on the portion of dung used as fertilizer. Fuelwood supply is most critical in the department of Oruro. Some areas of Oruro near Lake Poopo use dung alone as household cooking fuel, and there is some evidence that cultivated land is being deprived of natural fertilizer as a result.

1.43 Projections for dung consumption in the Altiplano through 1992, based on expected population growth, showed a demand in 1992 of 169,640 toe, an increase of almost 8% over the expected demand for 1987. There have been no studies in the Altiplano relating the consumption for dung as cooking fuel to nutrient (fertilizer) deprivation of farmland. Such deprivation could result in restrains on additional production of agricultural products, or, if fuelwood supplies are very low, insufficient fertilizer for present production. For the purposes of the current study, it has been assumed that the supply of dung exactly meets demands for cooking and fertilizer, and that projected increases in dung demand will be met by increases in animal stock. This must be confirmed through further study. If there are deficits in fuelwood supply, the subsequent need for additional cooking fuel could come from dung currently used for fertilizer in the Altiplano. This relationship requires further evaluation before definitive conclusions can be reached on the impacts of fuelwood shortages in the Altiplano. There is reason to believe, however, that in areas where there is a deficit of fuelwood, and where dung is used as a substitute cooking fuel, agricultural productivity will eventually suffer from deficits in supplies of natural fertilizer.

5/ Using an average growth rate for tree species in the Altiplano assuming thola supply constant.

II. MACRO-ECONOMIC PROSPECTS AND THE ENERGY SECTOR

Economic Development Alternatives

2.1 One of the most important bottlenecks for economic development in Bolivia is its ability to generate hard currency in order to import capital and intermediate goods necessary to pursue economic growth. In this respect, it is important to allocate resources to those sectors that will expand the country's export horizon.

2.2 The hydrocarbons subsector is one with good possibilities in helping Bolivia's economy in a decisive manner through exports of crude oil, LPG, and natural gas. Therefore, well planned actions should be conceived in order to exploit this subsector in the best possible way, taking into account both external and internal constraints.

2.3 It is highly probable that economic development in Bolivia will be, at least in part, based in hydrocarbons into the 1990s. Means of transferring economic surpluses from this sector to allow other sectors' development should be planned in such a careful way that the hydrocarbons development itself may be assured. Other important sectors in future exports performance may be agriculture and mining.

2.4 Considering Bolivia's future in the present decade, the agriculture sector may probably play an important role. It is expected that agricultural products such as soybeans, tea, coffee, nuts, and wood will grow rapidly, generating export surpluses. In terms of hard currency generation, however, these products may have limited possibilities as compared with those of present natural gas exports.

2.5 With respect to the mining industry, which has been the traditional hard currency generator in Bolivia's economy, its future role may not be as important as in the past, due to external factors. This fact is reflected by the change in its relative importance in foreign trade as compared with the hydrocarbons subsector in the recent past. Its future export possibilities are presently limited and major changes, both externally and internally, must occur before the mining industry recovers a prominent role in Bolivia's economy.

2.6 Predicting future economic performance in a context in which several unpredictable non-economic variables (as in the case of possible natural gas export agreements), or some economic non-quantifiable variables (as the case of the presumably large Bolivian informal economy), may take place, makes it extremely difficult.

2.7 Nevertheless, a macro-economic model developed by the Unidad de Analisis de Politicas Economicas (UDAPE) has been utilized. Using various energy investments, production, export, and import levels, if any, the model is capable of demonstrating the impact of the energy sector in the Bolivian economy. Although the model does not include the effects of the informal economy, the obtained results may indicate what strategies should be encouraged within the energy sector in order to obtain the best possible macro-economic outcomes.

General Assumptions

2.8 The main assumption of the macro-economic model, for sectors other than energy, are those of the IMF's Structural Adjustments Facilities (SAF) document prepared for Bolivia. A major assumption is a slowly but steady recovery of international mineral prices, i.e., for tin concentrates, an evolution from US$2.55/pound in 1987 to US$4.77/pound in 1992, has been considered, while export volumes change from 3,352 MT to 4,072 MT during the same period.

2.9 The energy sector is considered in the macro-economic model through hydrocarbons investment and production scenarios, and through planned electric power investment levels which are those necessary to implement the power expansion program discussed in Chapter V. The investment figures do consider expansions on the generation, transmission, subtransmission, and distribution systems, sufficient to match the forecasted demand with adequate reliability levels. Although an in-depth revision of the power expansion program will be carried out in the near future, the investment requirements probably will not differ substantially with those considered in the present analysis, which are summarized in Annex 1. With respect to electric power production levels, they are not considered explicitly in the macro-economic model, although they could be assumed as those sufficient to match the forecasted demand estimated elsewhere in the present document. Energy for the rural areas is considered implicitly within the model. Therefore, no investment levels, nor production patterns, are needed as assumptions for the analysis.

2.10 General assumptions for the hydrocarbons subsector, which are common for the four scenarios considered below, are as follows:

(a) Hydrocarbons Internal Demand. The demand for internal petroleum products has been considered as that with no natural gas substitution. The effect of an aggressive natural gas substitution program will lead to lower petroleum demand levels, but the effect of a possible economic reactivation performance in the Bolivian economy will probably compensate that demand reduction and, therefore, no further adjustments have been done for the present analysis.

(b) Hydrocarbons Foreign Trade. Concerning export markets for hydrocarbon surpluses, only natural gas, LPG, and crude have been considered. Although negotiations regarding natural gas volumes and export prices to Argentina are already in progress, some assumptions have been made. Those estimates should not be considered as the recommended levels, nor as the most likely outcomes of the negotiations between Bolivian and Argentinean authorities, and were taken only for analysis purposes. The main assumption concerning natural gas exports to Argentina is that the combined effect of volumes and prices will represent to the Bolivian economy a stream of foreign currency inflows of US$244 million p.a. between 1988 and 1991, decreasing to US$128 million p.a. in 1992, to be continued by a constant level of US$73 million p.a. from 1993 to 1995. No natural gas exports to Brazil have been included in the model.

2.11 LPG marginal surpluses, until 1989, are assumed to be exported to the Brazilian border as normally happens. After the commission of the Vuelta Grande recycling plant project in 1989, and after new LPG production and transport facilities are completed, net surpluses are also assumed to be exported to Brazil. In all cases, the considered border price has taken to be of US$21.9/barrel, which is the present price for Bolivian exports. Although the Santos c.i.f. price of LPG is in the order of US$13/barrel due to high transportation costs to the Mato Grosso area, it is worthwhile for the Brazilian economy to buy Bolivian LPG at the above-mentioned price. Crude surpluses have been considered to be exported at a border price of US$20/barrel. If crude imports would take place, the border import price assumed for those cases is of US$30/barrel.

Hydrocarbons Subsector Investment and Production Scenarios

2.12 Four different scenarios have been considered for the present analysis. The two first cases may be seen as production targets which, if feasible, will allow the country exportable crude oil surpluses. In both cases, a high private participation is anticipated. A third case is considered, in which no private participation occurs and where no investment for exploration activities take place. In the fourth case, investments in developing existing fields are curtailed because of financial constraints.

2.13 The aim of considering those cases is to analyze the macro-economic impacts of different investment and production patterns in the oil subsector. There is no intention to point out any of the considered cases as the most likely, nor as the recommended one.

(a) Case 1. A public investment level of US$1.35 million is considered for the period 1987-1995, while private participation during the period is assumed to be of US$983 million. This includes an exploration program (around US$900 million) to be shared in equal terms by YPFB and private companies, which would allow a constant reserves to demand ratio of 15 years. Investment on field development in YPFB is divided in US$274 million for existing fields plus US$334 million for developing new fields. For private companies, investment in field development is set at US$334 million.

The expected production level estimated for YPFB amounts to 92.2 million bbl for the period 1987-1995, which is divided in 73.1 million bbl corresponding to the production of already existing fields while the balance corresponds to new discoveries. This YPFB production forecast has its peak at 13 million bbl in 1993. Private companies are assumed to reach a peak of 5 million bbl in 1994, and a total production of 29 million bbl for the 1987-1995 period.

The production estimates, both for YPFB as well as for private companies, have been calculated taking into account known technical characteristics of existing fields, and considering a high probability of finding oil fields with low associated natural gas. Due to the gas prone nature of Bolivian oil fields, this production forecasts may be considered as an upper bound.

(b) Case 2. This scenario considers the same investment pattern of the previous case 1, but assumes a different production level. The production estimates, both for YPFB as well as for private companies, have been calculated taking into account known technical characteristics of existing fields, and considering that new discoveries may have high associated natural gas contents which may not allow an optimum oil production program due to limited natural gas markets.

The estimated production level for YPFB amounts to 84.4 million bbl for the period 1987-1995, which is divided in 73.1 million bbl corresponding to the production of already existing fields while the balance corresponds to new discoveries. This YPFB production forecast has its peak at 11.8 million barrels in 1993. Private companies are assumed to reach 3.6 million bbl in 1994, and a cumulative production of some 22.6 million bbl during the 1987-1995 period.

(c) Case 3. A reduced public investment level of US$465 million is used for the period 1987-1995, while new private participation during the period is considered to be non-existent. In this case, no exploration activities are assumed while investment for field development at YPFB (US$274 million) are exclusively for already existing fields.

The estimated production level for YPFB amounts to 73.1 million bbl for the period 1987-1995. Private companies are assumed to reach a peak in 1987 with 1.7 million bbl, and will have a total production of 5.4 million bbl in the 1987-1995 period.

The production estimates, both for YPFB as well as for private companies, have been calculated taking into account known technical characteristics of existing fields. No new discoveries have been considered.

(d) Case 4. A further reduced public investment level of US$256 million is considered for the period 1987-1995, while new private participation during the period is considered to be non-existent. In this case, no exploration activities are considered while investment for field development at YPFB (US$161 million) is not sufficient to exploit even already existing fields.

The expected production levels estimated for YPFB amounting to 62.9 million bbl for the period 1987-1995. Private companies are assumed to have a production level that will reach a peak of 1.7 million bbl in 1987, and a total production of some 5.4 million bbl in the 1987-1995 period.

The production estimates, both for YPFB as well as for private companies have been calculated taking into account the investment curtailments considered.

2.14 Figure 2 below summarizes the liquid hydrocarbons production patterns for the four scenarios.

Macro-Economic Analysis

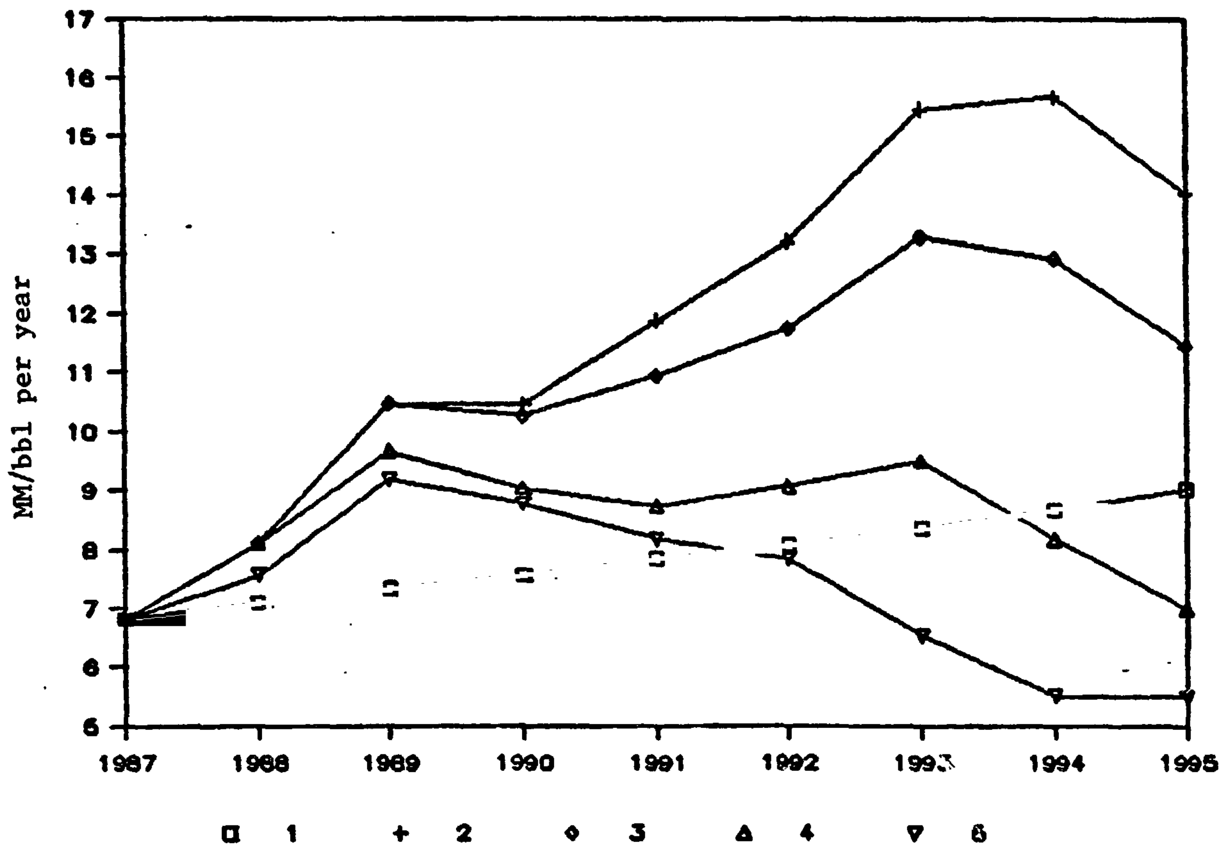
2.15 A comparative analysis of the macro-economic implications that result from the four scenarios is presented in order to help decision-makers find the best energy sector alternatives, towards obtaining the best possible national economic performance.

2.16 The macro-economic impacts of energy sector growth alternatives have been measured using the following indicators: impact on GDP, final demand evolution, impact on exports, and impact on balance of payments.

Impact on GDP

2.17 The hydrocarbons sector may have an important effect on the economy through public and private investment depending upon the success of these investments in reaching significant levels of production.

Figure 2: BALANCE BETWEEN LIQUID HCU SUPPLY AND DEMAND 6/



1/ Domestic Demand.
2/ Case 1 - Production.
3/ Case 2 - Production.
4/ Case 3 - Production.
5/ Case 4 - Production.
6/ Because of large inconsistencies in YPFB data, a further in-depth review of data is needed.

Source: YPFB and NEP estimates.

2.18 It is important to note that YPFB investment is fixed within the public investment ceiling specified in SAF's forecast. According to it, Bolivia's public investment would grow from US$259 million in 1987 to US$440 million in 1995. In cases 1 and 2, in which YPFB is assumed to invest US$150 million per year in real terms, hydrocarbons would be the sector with the highest priority within the national public investment plan given its investment share. On the other hand, if YPFB investments are those of cases 3 and 4, then hydrocarbons would rank below agriculture, mining, and transportation in the national investment plan.

Table 2.1: YPFB'S PROPOSED INVESTMENT LEVELS AS A SHARE OF TOTAL PUBLIC INVESTMENTS FORECASTS

	1987	1989	1991	1993	1995
Total Public Investment (in US$ million)	259	308	362	399	440
YPFB Share case 1	58%	48%	41%	38%	34%
YPFB Share case 2	58%	48%	41%	38%	34%
YPFB Share case 3	58%	23%	6%	6%	5%
YPFB Share case 4	58%	11%	2%	0%	0%

Source: NEP estimates.

2.19 In cases 1 and 2, high public and private investments in hydrocarbons, associated with high production levels, lead to higher economic growth rates than in cases 3 and 4, in which YPFB's investments are set to a minimum level and no private investments are required.

Table 2.2: REAL GDP GROWTH RATES
(%)

	1987	1988	1989	1990	1991	1992	1993	1994	1995
Case 1	3.3	3.6	5.8	4.0	5.0	4.5	5.5	3.9	2.4
Case 2	3.3	3.6	5.8	3.8	4.4	3.9	4.9	3.9	2.2
Case 3	3.3	3.6	4.9	3.5	3.6	3.2	3.9	2.9	3.1
Case 4	3.3	3.3	4.9	3.6	3.5	2.7	2.6	3.2	3.2

Source: NEP estimates.

2.20 Real GDP grows faster between 1990-1993 in case 1, as compared with the other three cases, showing the impact of higher investment levels on production. These growth rates are significant, given that they respond to changes in only one sector of the economy. However, even with the expected GDP's high growth rates of case 1, the living standard of the country's population is not expected to improve significantly, as measured by GDP per capita, which grows from US$520 in 1987 to US$652 in 1995.

Hydrocarbon's Participation in GDP

2.21 The results reflect the expected differences on hydrocarbons economic importance, due to different sectoral investment strategies. Those cases in which reduced oil subsector investment are considered not only may lead to minor participation in GDP's formation, but also may burden national finances through the need of importing crude and condensates, which in some cases may represent amounts as high as US$100 million per year.

Table 2.3: HYDROCARBON'S PARTICIPATION IN GDP
(%)

	1987	1989	1991	1993	1995
Case 1	6.97	8.79	9.37	11.52	10.05
Case 2	6.97	8.79	8.66	9.90	8.26
Case 3	6.97	8.03	7.06	6.78	4.91
Case 4	6.97	7.77	6.79	4.88	3.71

Source: NEP estimates.

Final Demand Evolution

2.22 As explained before, the assumptions of national public and private investments are considered constant according to SAF's forecasts. Investments in the energy sector were modified within the overall public investment target. Also, public consumption forecast is not modified from SAF's results. Three important components of the final aggregate demand are changed in every case, as a result of the scenarios presented: real exports, imports, and private consumption.

Table 2.4: AVERAGE ANNUAL REAL GROWTH RATES FOR FINAL AGGREGATE DEMAND VARIABLES DURING THE 1987-1995 PERIOD
(%)

	Case 1	Case 2	Case 3	Case 4
Public Consumption	3.5	3.5	3.5	3.5
Private Consumption	4.2	3.7	2.8	2.8
Public Investment	6.8	6.8	6.8	6.8
Private Investment	7.2	7.2	7.2	7.2
Exports	4.3	4.2	4.0	3.8
Imports	6.0	5.5	4.7	4.5

Source: NEP estimates.

2.23 Estimated economic growth for the considered cases, as measured by their GDP growth rates, imply that, on average, import annual growth rates may have to be greater in cases 1 and 2 than in cases 3 and 4. In turn, that implies that private consumption for the first two cases is higher than for the last two, taking also into account that aggregate investments and savings are greater for cases 1 and 2 than for cases 3 and 4. Also, real exports growth rates are greater for those cases with higher investment levels in hydrocarbons (private and public) than for the other two with small investment. On the other hand, better GDP growth rates and export performance for cases 1 and 2 may lead to smaller fiscal deficits in those cases, as compared to scenarios 3 and 4.

Table 2.5: GOVERNMENT DEFICIT AS A PERCENTAGE OF GDP

	1987	1989	1991	1993	1995
Case 1	3.52	2.96	1.56	0.74	1.11
Case 2	3.52	2.96	1.72	1.12	1.53
Case 3	3.52	2.99	2.10	1.84	2.31
Case 4	3.52	2.99	2.16	2.26	2.60

Source: NEP estimates.

Impact on Exports

2.24 Different investment scenarios have important effects on crude and condensates production levels, thus on export possibilities of this product during the following years as can be seen in Table 2.6.

Table 2.6: EXPORTS OF LPG AND CRUDE OIL
(In Current US$ Millions)

	1987	1989	1991	1993	1995
Case 1	14	116	138	190	135
Case 2	11	113	115	142	80
Case 3	11	96	71	66	(21)*
Case 4	7	79	51	(13)*	(100)*

* Imports.

Source: NEP estimates.

2.25 Case 1 presents important export revenues for the country, as compared to the other three cases. In cases 3 and 4, in which no private investment is assumed, imports of crude oil may begin in 1995. The contribution of exports revenues in cases 1 and 2 is important, particularly in the context of decreasing natural gas exports as it was assumed earlier. The expected shares of LPG and crude oil in total hydrocarbon's exports are presented in Table 2.7.

Table 2.7: LPG AND CRUDE OIL EXPORTS AS A PERCENTAGE OF TOTAL HYDROCARBON'S EXPORTS

	1987	1989	1991	1993	1995
Case 1	6	34	38	72	75
Case 2	4	34	34	66	52
Case 3	4	30	24	47	0
Case 4	3	26	18	0	0

Source: NEP estimates.

2.26 As expected, the negative effect of decreasing natural gas exports is reduced in cases 1 and 2 because of the export surpluses of LPG and crude oil generated by higher production levels. Nevertheless, hydrocarbon's share in total Bolivian exports after 1992 would, in any case, considerably be reduced. That means that even under the most optimistic crude export scenario, not finding new natural gas export markets may represent a major setback to the Bolivian foreign trade.

2.27 Hydrocarbons total exports decrease in every case, starting in the early 1990s, and lose relative importance against non-traditional and mineral exports.

Table 2.8: HYDROCARBONS EXPORTS AS A PERCENTAGE OF TOTAL EXPORTS

	1987	1989	1991	1993	1995
Case 1	43	45	39	25	17
Case 2	43	44	38	21	14
Case 3	43	43	35	15	5
Case 4	42	42	33	7	0

Source: NEP estimates.

Table 2.9: BOLIVIA'S TOTAL GOODS AND SERVICES EXPORTS (US$ million--c.i.f values)

	1987	1989	1991	1993	1995
Case 1	583	760	928	1,058	1,229
Case 2	580	756	901	1,003	1,116
Case 3	580	740	851	917	1,051
Case 4	576	723	828	826	960

Source: NEP estimates.

Impact on Balance of Payments

2.28 The Trade Balance and Current Account Situation. The trade balance situation is clearly more favorable for cases 1 and 2 than for the other two cases. This is the result of a less depressed export performance in the first two cases, even though these two cases have greater import growth rates, which are in accordance with their GDP growth rates.

Table 2.10: TRADE BALANCE (US$ millions f.o.b.)

	1987	1989	1991	1993	1995
Case 1	(146)	(57)	(45)	(136)	(158)
Case 2	(148)	(61)	(57)	(152)	(174)
Case 3	(148)	(67)	(75)	(169)	(203)
Case 4	(153)	(80)	(91)	(217)	(258)

Source: NEP estimates.

2.29 The most favorable export situation of cases 1 and 2, in relation to the last two cases, contributes to improve the current balance situation in spite of growing debt services obligations in every case. Debt service to exports ratio for all cases is as follows in Table 2.11.

Table 2.11: DEBT SERVICE AS PERCENTAGE OF EXPORTS

	1987	1989	1991	1993	1995
Case 1	44.95	42.50	60.05	71.39	68.49
Case 2	50.15	42.71	61.82	75.84	72.22
Case 3	50.15	43.65	65.47	83.02	80.14
Case 4	50.54	44.68	67.27	92.13	87.69

Source: NEP estimates.

2.30 The current account balance as percentage of GDP is an important indicator to evaluate the balance of payments performance. In the obtained results, the deficit in the current account is lower for those cases wit higher private and public investment (case 1 and 2) than for the other two, as may be expected, given the better exports and better debt service situation in the first two cases.

Table 2.12: CURRENT ACCOUNT DEFICIT AS A PERCENTAGE OF GDP

	1987	1989	1991	1993	1995
Case 1	9.17	8.51	8.34	8.90	8.29
Case 2	9.23	8.59	8.65	9.34	8.09
Case 3	9.23	8.75	9.19	9.98	9.49
Case 4	9.34	9.05	9.57	11.09	10.55

Source: NEP estimates.

2.31 Capital Account. The direct impact of foreign investment is reflected in the capital account balance. Thus, case 1 and 2, for which private investment of foreign companies have been specified, present a far better position than cases 3 and 4, in which no private foreign investment is assumed. The assumption of foreign lending does not change, in any scenario and are those of SAF's forecast.

Table 2.13: CAPITAL ACCOUNT BALANCE SURPLUS
(Deficit--US$ Million)

	1987	1989	1991	1993	1995
Cases 1 and 2	272	581	336	142	79
Cases 3 and 4	215	491	203	9	(55)

Source: NEP estimates.

2.32 The lower capital account balance for cases 3 and 4 make the balance of payment situation critical, making it necessary to resort to exceptional financing, which includes exceptional borrowing and/or non-paying the debt service. From 1991 to 1995, exceptional financing for cases 3 and 4 exceeds the first two cases by approximately US$200 million annually. Of course, this situation will induce the country's foreign debt to grow annually and to be capitalized at the model's assumed interest rates.

Table 2.14: BALANCE OF PAYMENTS EXCEPTIONAL
FINANCING REQUIREMENTS
(US$ Million)

	1987	1989*	1991	1993	1995
Case 1	88	(178)	131	436	528
Case 2	88	(175)	144	452	543
Case 3	147	(81)	297	603	708
Case 4	151	(68)	315	656	770

* During 1989, there is no need of exceptional financing in any of the cases due to improved export situation.

Source: NEP estimates.

Table 2.15: OUTSTANDING FOREIGN DEBT EVOLUTION
THROUGH DECEMBER OF EACH YEAR
(US$ Million)

	1987	1989	1991	1993	1995
Case 1	4,589	5,239	5,933	6,810	7,741
Case 2	4,585	5,248	5,959	6,867	7,831
Case 3	4,644	5,468	6,553	7,655	8,935
Case 4	4,648	5,498	6,512	7,792	9,199

Source: NEP estimates.

Conclusions

2.33 Investments in the development of already existing fields should be considered as a high priority. In fact, the economic analysis carried out on a field-by-field basis (Chapter IV) has demonstrated the convenience of pursuing those investments. These results are reinforced from a macro-economic point of view as demonstrated in the present comparative analysis. Investing in developing YPFB's existing fields will lead to a production pattern that could allow not only self-sufficiency in crude and condensates, but may also lead to exportable surpluses that can help the already constrained Bolivian economy. 6/

2.34 Although not considered in the present analysis, it is obvious that efforts should be placed in finding natural gas export markets. That would help the economy in two ways. The first obvious one is that of providing significant amounts of revenues from natural gas sales, which could be the main source of foreign trade as presently happens. The second is that the existence of new natural gas markets will allow the oil sector an optimum exploitation, reaching to production patterns that will allow important crude and condensates exportable surpluses. This, on the other hand, may represent the best economic growth feasible alternatives, as demonstrated in cases 1 and 2.

2.35 Exploration investments should be encouraged. Although the internal demand could be met by YPFB's existing fields development in the short term, the possibility of having a constant 15 year reserves to demand ratio, may enable the Bolivian oil sector to export surpluses. Given the amounts needed for a successful exploration program, efforts should be shared between YPFB and private initiatives.

2.36 Success in public investment within the hydrocarbons subsector should be closely monitored. As demonstrated on the analysis, public investments in the oil subsector may be bigger than in any other sector, and therefore its use should be absolutely justified.

6/ An in-depth review of YPFB data is warranted.

III. ENERGY DEMAND MANAGEMENT

Energy Pricing

Hydrocarbons

3.1 Petroleum Products. Except for LPG (domestic use) and diesel oil (for power generation) which are subsidized mainly for social reasons, oil products prices are either considerably above opportunity costs or close to it. On the whole, there is no subsidy of oil products with a weighted price of the composite barrel to the consumer equivalent to about 160% of the opportunity cost. In Bolivia's case, transport to and from the international markets could make a considerable difference as the cost of shipping to and from Santos, Brazil, the nearest international port 7/ is estimated at US$85/ton of which US$50/ton is within Bolivia and the balance in Brazil. 8/ The prices of products as of February 1987 and the estimated opportunity costs appear below in Table 3.1.

3.2 A major issue arises with LPG prices where the real opportunity cost, including distribution, is of the order US$17/bbl against a price of LPG for domestic use of US$12.5/bbl (volume-wise, more than 90% of the LPG sold is for domestic use). This is particularly serious since LPG represents about 25% of the products sold in Bolivia, and it is the only product whose consumption is rising rapidly. The existence of three simultaneous prices for the one product is likely to encourage fraud--YPFB is not in position to ensure that for each bottle purchased, the end-use corresponds to the price paid by the consumer especially since

---

7/ Arica, a Chilean port, is connected to Bolivia by a crude oil pipeline which was designed for Bolivia's crude exports in the 1970's. Importing from Africa would be prohibitively expensive because of the altitude difference. The crude line to Argentinean ports is presently used to meet Argentina's internal requirements, and could not be used, according to specialists, to import products.

8/ For the evaluation to be fully valid, a provision for domestic transport and distribution has to be added. In the case of liquid fuels, the provision is relatively small US$1-3/bbl. In the case of LPG, however, it is much higher, approximately US$45/ton or US$4/bbl.

LPG distribution is in private hands. 9/ If such pricing policies are maintained, considerable damage could be made to the natural gas distribution program with respect to both commercial and domestic customers. The price of LPG should therefore be increased by about 30%, to its opportunity cost.

Table 3.1: DOMESTIC PRICES OF OIL PRODUCTS AND OPPORTUNITY COSTS d/

	Domestic	Opportunity	% of Opportunity Cost
	------(US$/bbl)-------		
Opportunity Cost			
Special Gasoline a/	37.9	16.9	224
Premium Gasoline a/	43.9	16.9	260
Avgas b/	68.0	26.4	258
Avgas (Meat) b/	54.0	26.4	205
LPG - Domestic use a/	12.5	13.1	95
LPG - Industrial use a/	17.9	13.1	137
LPG - Vehicles a/	37.9	13.1	289
Kerosene b/	31.8	28.2	113
Jet Fuel b/	48.0	28.2	170
Diesel Oil b/	37.9	26.1	145
Diesel Oil - Power b/	18.9	26.1	72
Fuel Oil b/	32.6	22.0	148
Weighted Average	32.0	19.5	164

a/ Estimated at CIF Santos Brazil due to close balance between domestic supply and demand.
b/ Product anticipated to be imported at the margin, estimated at CIF Santos plus transport to Santa Cruz Bolivia.
c/ Exchange Rate: Bs2.10 = US$1,00.
d/ February 1987.

Source: NEP estimates.

3.3 Government policy has been to subsidize LPG for the low income rural population which may not have any other fuel alternative but animal dung or fuelwood. With that in mind, however, the rural population has actually been paying two or three times the prices of LPG in the urban

---

9/ To emphasize this point further, YPFB's Commercial Department records the industrial consumption of LPG in La Paz in 1985 to be about 30,000 bbl. The Gas Division, on the basis of market surveys estimates it to exceed 50,000 bbl.

areas, due to high transport costs and an inefficient distribution system. A fixed national retail price covering its opportunity cost should therefore be set, which would subsidize the transport costs to the low income rural areas. The end result should be that the low income rural population will not be affected by the price increase.

3.4 By achieving a fixed national LPG retail price at its economic cost, the LPG prices for industrial purposes and vehicles should be eliminated. The existence of three simultaneous prices encourages fraud. Furthermore, in volume terms, more than 90% of LPG sold is for domestic use.

3.5 Regarding the subsidization of diesel oil used for power generation, this product represents only 0.5% of products sales in Bolivia. The number of beneficiaries is small so that they are well identified. The subsidization could be rationalized by the fact that the bulk of power generation in Bolivia is hydro and gas-based so that this diesel oil is used in remote areas, without any other power alternative.

3.6 An important distortion exists regarding diesel and gasoline (para. 3.60). While their prices are identical, the opportunity cost of diesel is about 35% higher than that of gasoline. Taking into account that about 60% of the diesel is used for transportation, measures should be considered to encourage, whenever feasible, the replacement of diesel by gasoline imposing special taxes and custom duties on diesel-powered vehicles, trucks and tractors (at present customs duties are identical at 20%). Increasing the price of diesel could have a negative effect for most of the food products are brought by road at already high costs.

3.7 Natural Gas. The average incremental cost (AIC) of gas is estimated in the order of US$0.65/MCF including exploration, operating, and a minimal transport cost because most of additional investments are required in more than 10 years time. 10/ This is below the two current official prices for natural gas, for the power sector at US$0.88/MCF and one for the one other consumers at US$ 1.76/MCF.

3.8 The AIC is considered low because most of the infrastructure for gas production and transport to the main markets already exists. Furthermore, reserves should suffice to meet the demand in the next 20 years, even under the most optimistic scenarios.

3.9 Oil and Gas Pricing Financial Viability. Oil and gas prices should also be sufficiently high to enable YPFB to recover costs. The present fiscal regime for hydrocarbons is a provisional introduced in 1986. YPFB is subject essentially to a flat tax of 65% on all products. Furthermore, YPFB pays on 11% royalty. Taking into

---

10/ If exports to Brazil materialize in addition to Argentina, the AIC may reach US$1.15/MCF.

consideration the fiscal deficit, YPFB's tax structure needs to be reviewed to ensure a sound financial position for YPFB.

3.10 Regarding oil, with an average selling price of the barrel of the order of US$32/bbl, YPFB is left with less than US$10/bbl to cover its exploration, production, transport, refining, distribution, depreciation and debt service obligations.

3.11 On natural gas, the AIC has to take into consideration past investments, resulting in a financial cost of gas estimated at US$1.50/MCF at city gate. In addition one would have to add a distribution cost estimated at US$0.22/MCF for industrial consumers, and US$3.35/MCF for domestic and commercial consumers. Instead, because also of the present fiscal regime, YPFB collects on average less than US$0.30/MCF, i.e. less than 15% of its financial cost. In addition, the industrial park of Santa Cruz is only charged 36% of the official price. Although the current policy to maintain natural gas prices relatively low to encourage further use of this abundant resource is commendable, retail prices per kcal are well below other alternatives (para. 3.67) and need to cover all financial costs.

3.12 It is intended to award citywide concession to private distributors in early 1988. Subject to a detailed financial analysis of YPFB's domestic gas operations, YPFB's bulk gas tariff should be of the order of US$1.90-2.50/MCF (net of taxes); this would cause financial losses in the early years because of low pipeline utilization to be made up in subsequent years as consumption rises. But this level is close to YPFB's financial cost of supply.

3.13 Regarding the different concessions, the tariff to be introduced in each will depend inter alia on the density of consumers and the mix of industrial, commercial and domestic users. The first priority will be to complete the conversion of fuel oil and then diesel consumers. Subject to detailed financial analyses, the concessionaires could charge industrial users US$2.50-3.00/MCF, and commercial users US$3.00-4.00/MCF; this would still be well below the price of diesel (US$7.2/MCF), kerosene (US$5.93/MCF) and fuel oil (US$4.88/MCF). Regarding LPG replacement, as explained above if (i) the domestic LPG price (US$3.2/MCF) is increased by some 30% to reach its opportunity cost level; and (ii) the price of gas is increased to reach the cost of supply, conversion to natural gas would be still unattractive. For large commercial users presently using LPG, conversion to natural gas would remain an attractive proposition. Obviously, should the present tax regime continue to apply to gas, the prices above would have to be adjusted accordingly.

3.14 Regarding the power subsector (63% of domestic gas sales in 1986), from which YPFB collects net of taxes US$0.21/MCF, even the US$0.88/MCF price of natural gas is very low in relation to any other energy source: fuel oil is priced at about US$5.75/MCF and diesel oil for power generation at about US$3.60/MCF. The netback of natural gas against hydroelectric projects is about US$1.70/MCF. There is therefore little rationale for such a low price for the power sector.

Electricity Tariffs

3.15 The level and structure of electricity tariffs in Bolivia do not reflect the real cost of this public service. The current bulk electricity rates for sales from ENDE to the distribution companies are well below their marginal costs (e.g. bulk tariffs to ELFEO have a demand charge of US$2.5/kW per month and 12 mill/kWh of energy charge, while the marginal costs were estimated at US$8.9/kW per month and 14 mills/kWh respectively). On the other hand the current bulk electricity rates for mining and industrial consumers are well above their marginal cost (e.g. bulk tariffs to COMIBOL-La Palca are US$13.5/kW-month as demand charge and 40 mills/kWh as energy charge, with the same marginal costs previously mentioned). In addition, with respect to the retail tariff structure at the distribution level, it is also inverted, since those consumers with higher marginal costs (residential) are paying much less than consumers with lower marginal costs (industrial). ELFEC's average residential tariff is about 20-25 mills/kWh while the average marginal cost is about 69 mills/kWh.

Marginal Cost Analysis

3.16 Generation and Transmission. The marginal capacity and energy costs for generation and transmission in the interconnected system were analyzed on the basis of tentative generation and transmission expansion programs for the period 1980-1995. Table 3.2. summarizes the marginal costs estimation:

Table 3.2: MARGINAL COST ESTIMATES FOR 1990-1995

	Generation	Transmission
Energy Cost (mills/kwh)	13.5	13.9
Capacity Cost (US$/kw-m)	5.8	9.1

Source: NEP estimates.

3.17 The value for the marginal capacity and energy costs was determined, by and large, by the capital and production costs of a gas turbine, which is the marginal unit. The energy cost in this case depends directly on the cost of gas at the plant (assumed at US$1/MCF) and any change in this cost would affect directly this estimate. The capacity cost for the transmission system was estimated on the basis of the average incremental cost of the proposed transmission expansion, mainly the Central-East interconnection. The seasonal variations (wet and dry periods) of marginal costs were not significant, and therefore, were not considered. For the period 1987-1989, before the interconnection is commissioned, the marginal cost for the Central and Northern systems would be nil for they have hydro surpluses.

3.18 Based on this results, one can estimate the marginal cost of supplying a consumer connected at the transmission level. This is the case of the bulk supply by ENDE to the distribution companies and the large industrial consumers like COMIBOL and ENAF. However, the capacity costs estimated above refer to the coincidental peak demand; to determine the costs for these consumers one should take into account the peak demand diversity, which is estimated, in this case at 2.5%. The marginal costs for these consumers would be at an energy cost of US$13.9 mills/kWh and a capacity cost of US$8.9/kW/month.

3.19 Distribution. For the distribution system, the case of ELFEC which is the distribution company in Cochabamba, has been selected taking into account that it had the required information for this analysis. The analysis and its results can only be applied to this company. In the future, when the other distribution companies prepare complete investment programs and collect additional data, the analysis can be extended to them. The cost calculation for the distribution system was based on the average incremental costs related to the proposed 1987-1995 expansion program for ELFEC's distribution system. The results are summarized below in Table 3.3.

Table 3.3: ELFEC DISTRIBUTION MARGINAL COST STRUCTURE

	Voltage Level	
	Medium - 10kV	Low - 380-220 V
Energy cost (mills/kWh)	14.2	15.0
Capacity costs (US$/kW-m)	12.6	19.8

Source: NEP estimates.

3.20 The calculation of the marginal cost for different consumers is much more complex than for the HV consumers. It requires an evaluation of the load curves for individual consumers and of the coincidence factors. Unfortunately, this detailed information was not available, and "typical" values and aggregate demand by feeders have been utilized, as shown in Table 3.4.

Table 3.4: ELFEC RETAIL MARGINAL COST STRUCTURE FOR AVERAGE CONSUMERS

	Industrial	Commercial	Residential
Average Cost (mills/kWh) a/	41	55	69

a/ Calculated on the basis of the capacity and energy costs, and a typical load factor for the consumer. These results are tentative, they are based on non-supported assumptions about coincidence and load factors.

Source: NEP estimates.

Tariff Structure and Levels

3.21 Legal Framework. The National Electricity Code of 1968 established that electricity rates should be set at a level sufficient to achieve an average rate of return of 9% on the rate base, composed of net revalued asset, and a provision for working capital. Until the late 1970s the power utilities reached this rate of return; however, during the period 1981-1985 of economic recession and hyperinflation, the rates did not keep pace with inflation. In fact, from 1981 to 1984 the average rates dropped about 80% in real terms, to levels of less than 10 mills/kWh. In 1985, the new administration made substantial tariff increases and changed also the ground rules to set electricity rates. Decree 21060 established that bulk and retail tariffs should be negotiated between the concerned parties and set a ceiling of 45 mills/kWh for sales to mining and industrial consumers (later increased to 75 mills/kWh by Decree 21072) without any consideration of marginal cost levels. Recently, the Government has approved a Decree which would allow the distributors monthly tariff increases of 1.5% until tariffs would average 50 mills/kWh. Distributors at such rate increased would reach this tariff level in 4 years time.

3.22 Average Retail Tariffs. The current average electricity retail rates charged by the power companies to specific consumer categories are, in general, consistent within each other. The major exceptions are the isolated systems and the subsidiaries of the Bolivian Power Company (COBEE and ELFEC) as shown below in Table 3.5. The first, with a higher average rate and the latter with a lower average rate. This fact reflects basically differences in the "accounting" cost of service for these systems. The average rates for 1986 are summarized in Table 3.5.

Table 3.5: RANGE OF RETAIL TARIFFS IN MILLS/KWH

	Average	Residential	Industrial
COBEE and ELFEC	29-34	20-25	25-29
Small Isolated (diesel)	62-96	40-64	70-150
Other distribution	42-46	21-29	50- 62
ENDE's bulk to distribution Companies	23-25	-	-

Source: NEP estimates.

3.23 The average rates are not sufficient, in most cases, to achieve a 9% return on the rate base. In fact, the projected rate of return in 1987 for the largest generation and distribution companies (with the exception of COBEE) are below 4%. The results of the rate of return calculation are summarized below in Table 3.6, while a detailed firm financial description is provided in Chapter V.

Table 3.6: POWER COMPANIES TARIFFS AND RATES OF RETURN (mills/kWh)

	Actual Average Tariff	Tariff Required for 9%	Rate of of Return
ENDE	36	62	1.3%
ENDE S.Cruz	23	35	- 3.2%
ENDE Tarija	41	116	- 28.6%
ENDE Trinidad	53	132	- 34.2%
ELFEC	49	54	3.4%
CRE	46	54	1.8%
COBEE	27	27	9.1%

Source: NEP estimates.

3.24 From the Table 3.6, the following can be concluded:

(a) The distribution companies require a margin of about 30 mills/kWh to achieve a 9% rate of return (difference between the required tariff and the actual bulk energy purchase tariff).

(b) The distribution companies are in a better shape than the generation company and apparently would require a mcdest tariff increase to obtain a 9% return. However, this is deceiving, as their operating expenses would increase as a result of the increases in bulk energy purchase price necessary to meet the generation company's requirements.

(c) ENDE is operating at a loss in all the isolated systems. The case is specially dramatic in the Tarija and Trinidad thermal systems where in spite of a subsidized diesel oil price, sales revenues cover just 50% of fuel costs.

3.25 The retail tariff structures for the major distribution companies are similar regarding the application of demand and energy charges to large commercial and industrial consumers, and differential energy charges according to the consumption level to residential and small commercial consumers. In most of the distribution companies, in contradiction with the cost of service, the average tariff for a residential consumer is substantially lower (about 50%) than for an industrial consumer. The only exception are the COBEE companies where the average residential rate is only 15% lower.

3.26 This distortion in average rates for industrial, commercial and residential consumers can be explained by comparing ELFEC's current structure in terms of relativity with the marginal costs estimated previously for this company. In broad terms, the current ELFEC retail tariff structure as shown in Table 3.7 is inverted.

Table 3.7: RELATIVITY OF ELFEC'S RETAIL TARIFFS a/

	Retail tariffs	Marginal Cost Structure
Residential	1	1
Small commercial	2.8	.8
Medium industrial	1.8	.6

a/ Taking the residential rates to be 1.

Source: NEP estimates.

3.27 HV Level Tariff Structure. The bulk tariff structure includes bulk sales to distribution companies and large mining and industrial consumers. Table 3.8. summarizes the tariff structures and compares them with the HV marginal costs obtained above.

Table 3.8: COMPARISON OF TARIFF STRUCTURE AND HV MARGINAL COSTS

	Demand Charge	Energy Charge
	(US$/kW/month)	(mills/kWh)
Marginal Cost	8.9	14
Bulk sale to CRE and ELFEC	3.5	17
Bulk sale to ELFEC	2.5	12
COMIBOL/Central	13.5 a/	40
COMIBOL/La Palca	10.9	48
Private Mining	6.7	44
Matilde Mine	6.1	50
COBEE Interconnection	13.5	10

a/ Refers to contracted peak demand. Additional at US$7.6/kW per month.

Source: NEP estimates.

3.28 The following conclusions are evident:

(a) The tariffs for the distribution companies are well below marginal costs, for the energy charge is about the same, and the demand charge is less than half. For example in the case of the distribution companies (CRE or ELFEC), typically with a load factor of about 50%, the average rates would be:

Actual: 27 mills/kWh
Marginal: 38.3 mills/kWh

(b) The energy charge for the mining industry is well above the marginal energy costs, while the capacity charge is in the same range of the marginal capacity costs.

Pricing Strategy

Petroleum Products

(a) Increase the price of LPG about 30% to its economic cost, but consider this to be the only national retail price for all LPG, which would already consider transport costs to the rural areas.

Natural Gas

(a) Charge a natural gas retail price to consumers which is sufficient to cover its average incremental cost plus whatever financial costs that may occur.

(b) Natural gas conversion for the residential/commercial sector should only be encouraged where the gas line passes and covers a minimal consumption level.

(c) All taxes should be removed from domestic gas sales in order to encourage substitution. The revenue loss to the State would be small (less than US$8 million per annum).

Electric Power

(a) Carry out a reevaluation of assets for all the distribution and generation companies, in order to establish the real tariff base in each company.

(b) After completing the previous recommendation, carry out a detailed tariff study based on and consistent with the rate of return, cash flow and marginal cost approaches for all generation and distribution companies.

(c) At the bulk level, attempt to reduce the gap between actual electricity rates and marginal costs for large industrial and mining consumers supplied at the transmission level.

(d) Implement the tariff structure based on actual marginal cost and taking into account the financial viability of the power companies.

Interfuel Substitution and Conservation

The Structure of Energy Demand

3.29 In 1985, Bolivia consumed 2.011 million toe of energy. Per capita energy consumption was 313 kgoe, compared with a world average of 1,500 kgoe and an average for Latin America of 1,000 kgoe. Petroleum products met 48% of total demand, electricity 7%, natural gas 3%, and biomass 11/ the remaining 42%.

3.30 Commercial energy consumption amounted to 1.167 million toe in 1985, represented by: gasoline 30%, other petroleum products 53%, electricity 11%, and natural gas 6%. The transport sector is the most

---

11/ Fuelwood, animal dung, bagasse, and charcoal.

important consumer of commercial energy 51%, followed by household/ commercial 25%, industry 21%, and agriculture 3%.

3.31 Biomass energy consumption in Bolivia totaled 0.847 million toe in 1985, represented by fuelwood 67% (including a minimal amount of charcoal), animal dung 19%, and bagasse 14%. Fuelwood accounted for 56% of the energy consumption in the household sector, animal dung accounted for 34% of the household energy consumption in the rural Altiplano, and bagasse supplied 34% of the energy consumption in the industrial sector.

The Household/Commercial Sector

3.32 The household/commercial sector consumes 25% of all the energy consumed in Bolivia in 1985, LPG is an important source of energy, increasing by 25% between 1980 and 1985. For all practical purposes, the sector is not using natural gas. For analytical purposes and to point out the most critical issues in the sector, it has been divided into urban and rural areas.

Urban Areas

3.33 The urban areas have to a great extent switched over to modern fuels; LPG is the most common urban household cooking fuel although supply shortages have occurred recently which may lead to increasing use of fuelwood or dung if available. Fuelwood and dung is not common in the urban areas except for the very low income population that may have access to those fuels. For lighting purposes, electricity is well spread in the urban areas although the marginal income areas continue to use kerosene.

Rural Areas

3.34 For the purpose of the National Energy Plan, the rural areas of Bolivia were divided into three physical areas that share climatological and geographical attributes--the Altiplano, the Valleys, and the Tropics.

3.35 Altiplano. With over half of the total rural population and at an altitude of about 4,000 m, the cumulative effects of deforestation and high levels of current consumption have forced much of the population to rely on dung and small shrubs for household cooking and heating needs. The inadequacies of the present transportation networks and scattered nature of communities is a major impediment to development and distribution of commercial energy.

3.36 Unconventional technologies, such as biogas, windpower and solar energy, are expensive relative to the income of the rural household based on subsistence farming and require a social and technical environment that can only be brought about through continuous technical support. The energy problem of the Altiplano should be treated as a part of integral rural development programs considering the resource endowments of the region in question.

3.37 With the short supply of fuelwood in many parts of the Altiplano, dried dung is commonly used as the primary cooking fuel. In fuelwood-poor areas in Oruro, there are indications that the need for dung as a cooking fuel is restricting its use as natural fertilizer, although no such tendency for the Altiplano as a whole is quantifiable.

3.38 The supply of LPG, the principal supplement to biomass as a cooking fuel is poor. Where it is available, the price is more than double the price at YPFB distribution centers, depending on the distance from those centers. Kerosene is delivered to rural areas and its use for household cooking should be investigated. Currently it is only used for household lighting.

3.39 Charcoal is not consumed as a cooking fuel in rural households in the Altiplano. No biogas plants have succeeded in the Altiplano, nor have pilot programs been coordinated on a national level. A pilot program might be justified in rural areas where other fuels have higher opportunity costs than biogas. The high capital cost would be a barrier to implementation on small farms.

3.40 Economic Comparison of Energy Alternatives. According to the opportunity cost analysis shown below, LPG is the best short-term alternative for household cooking in the rural Altiplano. Oruro should be a priority for improving the distribution of LPG because of the severe shortage of fuelwood and subsequent increasing use of dung. Relative costs of actual and potential cooking fuels for the Altiplano were estimated and are summarized below in Table 3.9.

Table 3.9: ALTIPLANO ECONOMIC COMPARISON OF HOUSEHOLD COOKING FUELS
(Cost of Useful Energy)

Fuel	Average Market Price	Opportunity Cost	Opportunity Cost Relative to LPG	Efficiency Used a/
	(mills/'000 kcal)	(mills/'000 kcal)		
LPG	30-43	35-49	1.0-1.4	59%
Kerosene	48	35	1.0	56%
Fuelwood	349	930	26.6	9-14%

a/ Although some of these efficiencies may be considered high, they are the result of a JUNAC study and are commonly used in Bolivia.

Source: NEP estimates.

3.41 LPG and kerosene are clearly the most economic fuels for cooking in rural areas in terms of useful energy. LPG has the disadvantage that under the current distribution system, its costs rise substantially in rural areas (para. 3.2-3.3).

3.42 Kerosene would seem to be the ideal household cooking fuel for rural areas in the Altiplano. Its price does not seem to vary with distance from YPFB distribution centers, but its delivery under the current distribution system in Bolivia is expected to decrease in the early 1990s and is restricted. Nevertheless its use for household cooking purposes in the Altiplano should be investigated.

3.43 The marginal costs of rural electricity was estimated between 120 and 370 mills/kWh. However, for most homes in rural areas, electricity is simply not available, and for the few rural areas where there is a power line, connection costs are prohibitive. The opportunity cost of electricity for rural households indicates that it may be more costly than kerosene. Furthermore, expansion of electric grids to rural areas, or installation of local diesel electric generators or hydro-electric plants, is not recommended if there are no productive end uses for the power. Household illumination is not considered sufficient reason for the introduction of electric power.

3.44 Valleys. Only two areas in the Valleys have shortage of fuelwood supplies--the historically deforested and eroded Valley of Tarija and the province of Yamparaez in the Department of Chuquisaca. The Valleys have a greater resource basis than the Altiplano, due to the more temperate climate.

3.45 Most households in rural areas in the Valleys use three-stone stoves to burn fuelwood for cooking. A negligible quantity of dung is used for fuel in the Valleys. An estimated 199, 464 TOE of fuelwood (35% of national fuelwood consumption), was consumed in 1985 in rural households for cooking purposes.

3.46 The UNDP is financing a joint Bolivian-Brazilian program to improve the efficiency of wood-burning household stoves and foster the development of fuelwood plantations. The project is a demonstration program for both stove improvement and fuelwood plantations. In the town of Lavadero, in the province of Yamparaez 132 families have been chosen for installation of efficient stoves developed in Brazil, and to be constructed entirely from local material.

3.47 Economic Comparison of Energy Alternatives. Economic costs indicate that for Yamparaez and Tarija, the most cost-efficient policy choice would be also to improve the delivery of LPG to those areas. For other areas in the Valleys, there appears to be sufficient fuelwood supplies to warrant its continued use. Therefore, investment in reforestation in most areas in the Valleys cannot be recommended. Table 3.10 below shows the economic comparison of household cooking fuels in the Valleys.

Table 3.10: VALLEYS ECONOMIC COMPARISON OF HOUSEHOLD COOKING FUELS
(Cost of Useful Energy)

Fuel	Average market Price	Opportunity Cost	Opportunity Cost Relative to LPG	Thermal Efficiency a/
	(mills/'000 kcal)	(mills/'000 kcal)		(%)
LPG	27-34	28-35	1.0-1.2	59
Kerosene	38-42	34-37	1.2-1.3	56
Fuelwood b/	172-196	270-349	9.6-12.5	9-14

a/ JUNAC study.
b/ Fuelwood deficit area, total reforestation cost.

Source: NEP estimates.

3.48 If only 10% of reforestation costs are assigned for energy purposes in Tarija, the economic cost of fuelwood would be comparable to LPG. However, in general, the above data favors LPG as a fuel supply for the Valleys. As in the Altiplano, the distribution of LPG is poor to areas just outside of the city of Tarija with prices similarly dependent on distances from distribution centers. The use of kerosene which has been restricted for lighting purposes should be examined toward cooking purposes. In relation to lighting purposes, the same conditions as in the Altiplano hold for the Valleys making rural electrification viable only if it is marketed to productive end uses.

3.49 Tropics. The tropics with 17% of the country's population, occupies 69% of the total land mass. The tropics have by far the greatest per capita supply of fuelwood in Bolivia. Rough estimates indicate 40 to 50% losses in cutting, and 40 to 60% losses in processing by the forest industry, all of which could be used as fuelwood.

Table 3.11: TROPICS ECONOMIC COMPARISON OF HOUSEHOLD COOKING FUELS
(Cost of Useful Energy)

Fuel	Average Market Price	Opportunity Cost	Opportunity Cost Relative to LPG	Thermal Efficiency a/
	(mills/'000 kcal)	(mills/'000 kcal)		(%)
LPG	30-41	35-50	1.0-1.4	59
Kerosene	48	35	1.0	56
Fuelwood b/	53-71	233	6.7	6

a/ JUNAC study.
b/ . Fuelwood deficit area.

Source: NEP estimates.

3.50 The above table indicates a close alignment of economic costs of fuelwood energy for cooking fuel, reflecting the relative abundance of fuelwood. LPG and fuelwood in the surplus areas have the lowest opportunity cost for cooking fuels. In the fuelwood deficit areas, the cost of fuelwood is higher. Although LPG is the primary cooking fuel in the city of Trinidad, LPG is apparently used very little outside of a 100 kilometer radius from trinidad, probably due to higher costs and poor delivery. In the short term, continued use of fuelwood is the best option. 12/ However, efforts should be made to control and slow down the rate of deforestation, if not maintain sustainable yields. Rural electrification in the Tropics holds the same constraints as in the Valleys and Tropics, indicating a viable option only if it is has productive end uses.

The Industrial/Mining Sector

3.51 The Bolivian industrial sector is concentrated in the cities of Cochabamba, Santa Cruz, and La Paz. Moreoever, the mineral industries have their major installations in the cities of Oruro and Potosi. The mines are mainly disseminated along the Andean Range.

3.52 Energy Consumption. In 1985, the industrial mining sector was the third largest consumer of energy in Bolivia, after the transport and household/commercial sectors, accounting for 50% of the total electric power demand and 12% of oil consumption. Major consumers of energy are the agroindustries and the mineral industries.

3.53 Because of the collapse of the economy, the share of petroleum products in industry decreased from 154,000 toe in 1983, to 100,000 toe in 1985. 13/ Paralleling this evolution, the share of non-commercial energy in industry remained fairly constant at 120,000 toe in the same period.

3.54 YPFB's internal consumption of oil products represents, at 2,000 bd, about 10% of the national consumption in Bolivia. In the refineries alone, internal use and loss average 8% of the feedstock, notwithstanding the fact that they use increasing quantities of natural gas as fuel. An energy audit focussing on YPFB's consumption of liquid fuels should be carried out.

3.55 The industrial sector, for gas market analysis purposes, comprises a diversified range of users which individually use in excess of US$0.50 MCF/hr at peak. The main representative industries are

---

12/ The region of the Tropics is diverse, and further study is warranted on an area-by-area basis to ascertain comparative costs of cooking fuels for implementation of the appropriate energy strategy.

13/ Excluding YPFB's internal consumption.

breweries, ceramics, detergents, edible oils and other food related industries, glass, sawmills and textile; they are mostly located at Cochabamba, La Paz and Santa Cruz. In the first two cities, gas became available in 1984, and the conversion effort is under way. On the other hand, in Santa Cruz, the more important users have already converted to natural gas, particularly those located in an industrial park sponsored by the regional development corporation (CORDECRUZ). On the whole, the industrial market will include both growth and conversion. A market analysis of the gas potential for industrial purposes is presented in Annex 2.

3.56 Bagasse, most of which is produced by the sugar industry in the department of Santa Cruz, is approximately 32% of the total quantity of sugarcane processed. The average bagasse production is 3.32 MT per ton of sugar product. All of the bagasse is consumed internally (that is, in the production of sugar). The bagasse contributes approximately 84% of the total calorific requirements of sugar processing. Of the rest, 14% is provided by hydrocarbons, and about 1% by fuelwood. Because of the relatively high hydrocarbon consumption, an improved bagasse utilization study should be carried out.

3.57 For the Valleys, agricultural product drying is one of the major agro-industrial needs, particularly for the aji. Because of the time required for drying in the sun, large losses (30 to 40%) often occur. During humid weather, losses can reach 70%. Based on the very limited data available, pilot studies could be initiated for small-scale solar drier which has been used with some success in Perú, and the continued use of LPG driers for larger-scales operations.

The Transport Sector

3.58 The transport sector is the single most important user of energy in Bolivia over half all the energy consumed in Bolivia, and 60% of the diesel. Bolivia's internal transportation needs are largely met by road vehicles which carry about 93% of the freight (mostly agricultural products) and 96% of the passengers. Most of the freight and passengers move along a main transportation axis linking the Altiplano cities of La Paz and Oruro, with the Valley of Cochabamba and the lowland city of Santa Cruz. Foreign trade depends more on the railroads, which carry largely mineral products exports and 81% of the imports. The principal flows are from the mines in the Altiplano towards Chilean and Peruvian ports along the Pacific. In terms of energy, road vehicles consumed 80% of the total, railroads 3% and airplanes 17%. Of additional importance in the qualitative balance is the fact about 85% of all diesel sale are to the transport sector. Both the high energy consumption of the sector and its exclusive reliance on liquid fuels suggest that transport should have a high priority for improving energy efficiency and interfuel substitution, especially among road vehicles.

3.59 Substitution of Gasoline for Diesel Oil. Since the opportunity cost of diesel is about 35% higher than that of gasoline while their retail prices are identical (para. 3.6) measures should be considered to encourage, whenever feasible the substitution of gasoline for diesel. Substitution could be brought about by imposing special taxes and custom duties on diesel-powered vehicles.

3.60 Substitution of CNG for Gasoline and Diesel Oil. Compressed natural gas could pay a small but important role in gasoline and diesel oil conservation in Bolivia in the future. Consultants are currently in the field to examine interfuel substitution possibilities. Substitution by CNG appears economical, but it would take many years to have an impact at the national level.

3.61 Energy Efficiency in Transport. An important way in which fuel savings can be achieved is through improving traffic flow in urban areas. The most immediate results could probably be achieved by introducing and enforcing parking and stopping regulations along the main urban arteries, staggering work hours to spread out the commuter rush over a longer period and reduce average commuting time. In the longer run, priority lanes for bus services could be introduced in high density routes and some underpasses built in main intersections. Considering that these measures involve new investments in traffic control and road improvement, more information is needed before a decision can be made. Thus, it is recommended that the Government undertake an urban transportation study, including a review of energy saving possibilities, particularly for La Paz.

3.62 Recent studies indicate that changes in the driving behavior of vehicle operators can reduce fuel consumption per vehicle by about 10-15%. These savings have been achieved through training drivers in fuel saving techniques and motivating them to use those techniques. The achievement of those savings do not require any capital expenditure, and basically require the vehicle operators to reduce idling time, maintain proper tire pressure, accelerate more gently, perform periodic maintenance, etc. These techniques are timed-tested and generally known, but the problem is to motivate the drivers. It is recommended that the Government establish a driver training and motivation program that would enable Bolivia to take advantage of these very economical energy saving opportunities.

3.63 Another source of energy savings can be a sustained effort to rehabilitate the existing road infrastructure and improve road maintenance. Much of the network is in poor condition as a result of light construction and deferred maintenance, and the fact that about a third of the trucks exceed the legal axle load limit. A truck consumes about 5% more fuel on a gravelled road than on a paved road and that a similar savings occurs between paved roads in poor and in good conditions. Thus, while fuel savings constitute only a fraction of the major (50%-80%) savings in transport costs that can be obtained through road rehabilitation and improvement, these savings are nonetheless important when considering the large volume of fuel consumed in road transport.

Natural Gas Substitution Potential

3.64 Because of the relatively large domestic supply of natural gas available, substitution of gas for other products is a top priority. However, under all circumstances, considering the structure of demand, the potential for substitution by natural gas remains small. The combined consumption of fuel oil and diesel oil (other than transportation) accounted for only 12% of the consumption of petroleum products in 1986. This market, on a calorific equivalent basis represents about 14 MMCFD of gas (or twice the present gas market other than power generation). However, all this demand cannot be connected economically, so that the above estimate represents an upper ceiling for the replacement of fuel oil and diesel oil (other than transportation). Regarding kerosene and LPG replacement, even in areas close to the gas network, connecting potential consumers would not be economical most of the time, unless the specific consumption is relatively high. In conclusion, the potential for substitution by natural gas, in a five year perspective, is small and cannot be anticipated to cause a significant shift in consumption patterns. On the other hand, gas will have a major impact on the development of the power sector, where it represents the most attractive energy source; furthermore, once the economy picks up, sectors which are already gas users such as the cement industry would represent a growth market. Lastly, the tin smelters could become, once they reopen, important consumers. 14/

3.65 During 1986, the average consumption of gas amounted to 22.6 MMCFD, equivalent to nearly 200 thousands of ton of fuel oil on an annual basis, which represents, in turn, approximately 20% of Bolivia's consumption of liquid fuels.

3.66 YPFB's Gas Division has prepared a 5-year liquid fuels substitution program (dated April 1986) as well as a 20-year gas demand forecast (February 1987). The 5-year program aims in particular for the replacement of 80% of the industrial consumption of liquid fuels in the main urban centers and a start in the conversion of commercial and domestic consumers. The program qims at substituting by the end of the decade 1,200 bd of liquid fuels 15/ and 112 tons/day of LPG through the conversion of 250 industries, 770 commercial and 15,000 domestic users. Consumption of gas would thus increase from 22.6 MMCFD in 1986 to 38.6 MMCFD in 1990, an average annual growth rate of 15%. Should the smelter resume their operations, the market would be higher by abgut 9 MMCFD. A detailed regional analysis of gas market is provided in Annex 2.

14/ They are already connected to the gas network, but have yet to make the investment in conversion.

15/ 1,200 bd represents approximately 45% of the consumption of liquid fuels by the industrial sector nationwide in 1986.

3.67 Since virtually all the gas in Bolivia is used as fuel, as opposed to feedstock, the price of gas in relation to other fuels can be evaluated on a calorific equivalent basis as shown below in Table 3.12.

Table 3.12: COST OF FUEL PER KCAL

	Unit	Price per Unit b$	Price per Unit US$	kcal/unit	US$/MM kcal
Domestic LPG	liter	0.17	0.08	6,509	12
Kerosene	liter	0.42	0.20	8,880	23
Diesel Oil	liter	0.50	0.24	8,778	27
Fuel Oil	liter	0.43	0.20	9,393	22
kWh (ind.)	kWh	0.10	0.05	860	58
kWh (dom.)	kWh	0.05	0.03	860	29
Natural Gas (ind)	MCF	3.70	1.76	263,356	7
Natural Gas (elec)	MCF	1.85	0.88	263,356	3

Source: NEP estimates.

3.68 On a purely calorific equivalent basis, the present price of gas is considerably lower than that of other energy sources. However, this is somehow theoretical because few consumers have a choice to make between the different fuels at any point in time. The real option is often between a liquid fuel, and conversion to natural gas, where the consumer has to pay the connection, metering and conversion cost (industrial consumers) or for the conversion cost only (residential and commercial consumers).

3.69 For industrial commercial consumers, the payback period ranges from 19 to 436 days. Unquestionably, with the present prices, conversion to natural gas for such consumers pays off. On the other hand, for residential consumers, the difference between the official price of LPG (US$3.2/MCF) and that of gas (US$1.8/MCF) is not sufficiently attractive to cover the estimated conversion cost (US$100) for an household using 40 kg of LPG (1.8 MCF of gas equivalent) per month. The impact of the price difference on the payback period is shown in Table 3.13.

Table 3.13: IMPACT OF PRICE DIFFERENCE BETWEEN LPG AND NATURAL GAS ON PAYBACK PERIOD FOR COMMERCIAL AND DOMESTIC CONSUMERS

Price of LPG	Price Difference	Payback
(US$/MCF)	(US$/MCF)	(months)
3.0	1.2	46
4.0	2.2	25
5.0	3.2	17
6.0	4.2	13

Source: NEP estimates.

3.70 Thus to reduce the payback period to two years (which can be taken to be the maximum period acceptable to domestic households), the price of LPG would have to be increased by 25% over its present level. However, the approach followed so far does not take into account the cost of supply; as will be seen, the present price of gas for domestic consumers does not cover the cost of supply, so that conversion of such consumers does not represent an economically attractive proposition. With a cost of supply of the order of US$4.85/MCF. the price of LPG would have to be increased to a minimum of about US$6.85/MCF or in excess of 200% in order to make it attractive for them to convert to natural gas. Taking into account the additional benefits associated with the substitution of liquid fuels and electricity, on some circumstances, with a cross subsidy from industrial consumers, a tariff could be elaborated which would take into account the cost of supply in each system and the present anticipated mix of consumers. However, the conclusions depend on the specific circumstances in each case.

3.71 Technical, financial, and economic evaluation for each proposal should be carried out, along with a well-defined plan for bidders to attract private investors. The contractual arrangements between YPFB and private investors need to be examined in detail. The economic viability and financial incentives may attract private investors in the distribution phase.

Interfuel Substitution and Conservation Strategy

(a) Improve LPG distribution in the rural areas, particularly in the Altiplano.

(b) Incentivate natural gas substitution in industry where economic and analyze in detail case-by-case the conversion of household/ commercial consumers. Private participation in gas distribution is encouraged.

(c) Carry out an energy audit of YPFB's consumption of liquid fuels.

(d) As a medium term strategy, control the growth of the diesel fleet taking into account the yield of the refinery.

(e) Investigate the use of kerosene in rural areas, particularly in the Altiplano.

(f) Investigate possibilities for improving traffic flow in urban areas, particularly in La Paz.

(g) Rural electrification needs to be examined in detail for its viable only if it is marketed for productive end uses.

(h) Investigate, on a site-specific basis, the needs for irrigations and the economics involved.

(i) Carry out an analysis of the trade-off between dung burning and its substitution by hydrocarbons.

(j) Determine efficiency of current wood and dung stoves in the Altiplano, and analyze the possibility for an efficient woodstove program.

(k) Carry out an improved bagasse utilization study.

(l) Initiate pilot studies for small-scale solar drier which have been used with some success in Perú, and the continued use of LPG driers for larger-scale operations.

(m) Examine biogas, windpower, small hydro, and solar energy in detail on a case by case basis only taking into account the conditions of each location. The energy problem needs to be treated as a part of integral rural development programs.

IV. INVESTMENT AND TECHNICAL ASSISTANCE PRIORITIES

Investment Priorities

Petroleum

4.1 There is an urgent priority in identifying ways of increasing Bolivia's oil supply without increasing the country's overall budget deficit. Several types of measures seems appropriate and possible to be implemented in the short term, particularly the following:

(a) The reorientation of YPFB's short run investment program from exploration to production, to defer the decline in production. In the short and medium term exploration contracts with the private sector would reduce the investment outlays otherwise required by YPFB in exploration.

(b) The opening of new areas to private sector companies for exploration contracts on reasonable terms. This would require: (i) extension of the 1972 hydrocarbon law to authorize joint ventures; (ii) agreement on payments due to the private contractors; and (iii) revision of the current fiscal regime to attract private risk capital while ensuring a reasonable profit share for YPFB. The feasibility study for private exploration promotion funded under the World Bank Project Preparation Facility (PPF) was recently initiated.

4.2 Field Development. The critical financial situation of YPFB makes it particularly necessary to focus on a well defined investment program oriented to: (i) invest in currently producing oil fields, (ii) assure an adequate period in supplying its internal demand; (iii) prioritize investment opportunities in field development for those fields that have an ERR greater than 20%.

4.3 Under that criteria, except for Sirari and Naranjillos, there are eight fields (Cascabel, Escondido, HSR-Yapacani, La Peña, San Roque, Santa Cruz, Villamontes, and Vuelta Grande) wich should proceed with their scheduled program and the other two (Camiri and Monteagudo) require reservoir injection studies before any investment is undertaken. Table 4.1 below shows YPFB's investment program. 16/

16/ Because of great inconsistencies in YPFB data, an in-depth examination is warranted.

Table 4.1: YPFB CURRENT FIELDS DEVELOPMENT INVESTMENT PROGRAM a/

Fields	1987	1988	1989	1990	1991	1992	1993
South District							
Camiri				3.5	3.0	1.0	
Monteagudo			3.0	2.0			
San Roque		12.00	25.0	9.5			
Vuelta Grande	16.25	15.85					
Escondido			13.5	8.5			
Villamontes	7.10	12.00					
Subtotal	23.35	39.85	41.5	23.5	3.0	1.0	0
Central District							
HSR/Yapacani	15.0	9.0					
Santa Cruz	17.5						
Naranjillos	0.6	6.0					
Sirari					5.5	15.5	13.0
Cascabel			6.6	9.6	5.3		
Subtotal	33.1	15.0	6.6	9.6	10.8	15.5	13.0
Santa Cruz Division							
La peña	8.0						
Subtotal	8.0						
TOTAL	64.45	54.85	48.1	33.1	13.8	16.5	13.0

a/ Pending results of World Bank PPF, confirmation of data, and completion of studies mentioned below.

Source: YPFB.

4.4 For the period after 1993, no further investment opportunities in currently producing oil fields is foreseen, emphasizing the need to accelerate exploration immediately. Based on the production forecast, the economic evaluation of each field is as follows, choosing a 12% discount rate and a base price of US$15/bbl, and taking into account the year in which investments should start considering the "future investment criteria":

INVESTMENT PROGRAM STARTING IN 1987

4.5 Vuelta Grande. This is one of the largest retrograde gas condensate fields in Bolivia. The proposed investment program consists in the drilling of remaining wells and installation of a gas processing plant to recycle gas at 90 MMCFD. This project is partially financed by the World Bank, and the development program is based on sound reservoir engineering studies. The pilot plant which has been in operation since

June 1983 is recycling gas at about 20 MMCFD and recovering over 1,000 bd of condensates. The actual production data indicates that the reservoir is behaving as it was predicted by the simulation study. When the project is fully completed early in 1989, a substantial amount of liquids (average of 6,289 bd in 1989) would result. The ERR is estimated at more than 100%.

4.6 La Peña. This field, discovered in 1965, has an investment program that consists in drilling 10 in-fill wells to optimize field production and to prove the additional recoverable reserves, estimated at 1.1 million barrels. The actual proven reserves as of December 1986 are calculated at 8.3 million barrels. The cumulative production from 1987 to 1997 is estimated at 9.3 million barrels. This field development project is financed by the IDB (US$33.6 million) and is expected to be completed in 1987 with the perforation of 8 shallow wells. La Peña will become the main oil producer field for the next two years. The ERR is estimated at more than 100%.

4.7 Villamontes. Field discovered by YPFB in April 1987. Its preliminary proven reserves are estimated at 7.5 million bbl, adding 3.0 million as probable reserves. According to the development program, between 1987 and 1988, the total perforation of 8 wells is expected, including two structure probatory wells, which together with other investments for production infrastructure, will require a total of US$19 million. The economic evaluation of this field, in view of the preliminary existing data, renders the highest ERR well above 100%.

4.8 Santa Cruz. The development of this field constitutes a technical and economical priority. It has two producing horizons: Chorro and Tupambi. The final investment required for its development will be made in 1987, US$17.5 million, covering two producing wells, four injection wells, plus recycling and duct injection systems. By December 1986, US$24 million were invested. The ERR is estimated at more than 100%, which reflects the projects earning power. Besides, it's a field located along the limits of the city of Santa Cruz, which minimizes its production costs with regards to other fields.

4.9 HSR-Yapacani. Due to the physical and chemical characteristics of HSR crude (paraffinic), it should be mixed with the condensates of the Yapacani field for its transportation. The ERR is about the lowest among those development projects analyzed, around 24%. However taking into consideration the project has already ensured international financing (IDB) for US$27.8 million and that the HSR crude is 35 degrees API, the continuation of its development is recommended. These fields are expected to enter into production by 1989.

4.10 Naranjillos. A predominantly gas producing field. Its development is programmed so as to assure the supply of dry gas to the industrial sector of Santa Cruz, which is now consuming wet gas from Caranda and Colpa fields, at highly subsidized prices. This project should be seen from the gas supply strategy point of view, and should be evaluated only from the perspective as a marginal condensates producer. This field is included in the production investment program but should nevertheless be analyzed in detail for it may have negative repercussions on liquid production associated with gas. Its ERR is very low, between 11-21%, compared to other projects.

INVESTMENT PROGRAM STARTING IN 1988

4.11 San Roque. Taking into consideration the last YPFB revision carried out in may 1987, this field enters the development program in 1988 with the perforation of 6 wells and the extension of gas processing plant plus the necessary infrastructure. YPFB has secured financing for the gas plant (US$8.7 million) from the Corporación Andina de Fomento. As the Santa Cruz field, this is also a retrograde gas condensate reservoir, with a yield of 2.7 tons of LPG and 7.5 bbl of natural gasolines per million processed cubic feet of gas. By 1991, it would reach a peak condensate production of 3,000 bd. Its estimated recycling life is 6 years with a probable additional reserve of 2.8 million barrels. The maximum recycling flow will be of 87 MMCFD. Its ERR is more than 50%.

INVESTMENT PROGRAM STARTING IN 1989

4.12 Escondido. Originally a property of Tesoro, it is legally in a position to be reverted to YPFB (as occurred with Villamontes). Still there is no decision in this regard since it is a fundamental aspect of the Government-Tesoro negotiations, and could become, if Bolivian legislation foresees, the first "joint venture" field between YPFB and a private company. It is an ideal field for a recycling project (Vuelta Grande type), since it is a gas field rich in liquids, and although it is not as large (its reserves are estimated at 10 million bbl), it is a highly productive field, specially if it is possible to optimize investments by taking advantage of Occidental's Tita Camp recycling plant, which is being passed on to YPFB's hands, upon this years closure of the camp. It is estimated that with about a US$22 million investment, the perforation of five wells (three producers and two injectors) could be covered, along with the purchase and installation of recollection and injection systems, the pipelines (gas and oil) and the overhaul of the Tita Plant. Its ERR is estimated at 53% and the initiation of production is scheduled for 1991, helping substantially the supply/demand balance.

4.13 Cascabel. Field discovered in 1985, with a primary gas dome reservoir and 35 degree API oil. Recent data indicates proven reserves at 1 MMbbl and 3.4 MMbbl as probable. At least perforation of two new wells is required to define the field more precisely. According to the priorities given by the forecast production, its development may be deferred until 1989. A total investment in the order of US$21.5 million is required for the perforation of nine wells, recollection and injection systems, separation battery and pipeline to connect with the HSR-Yapacani. The oil production peak is estimated at 3,000 bd, producing 4.4 million bbl in 11 years. The ERR is estimated at 32%. Nevertheless, this scheme should be confirmed by the feasibility study to be financed by the World Bank, under PPF-1.

4.14 Monteagudo. Together with Camiri, Monteagudo is one of the two water injection programmes which YPFB has scheduled. This project was originally financed by IDA under Cr. S-25-BO. The investment should be deferred until a more detailed study is carried out, including an evaluation of the reservoir to define its water injection behavior and reserves, proven as well as probable. If the studies suggested are carried through, the field could peak with a secondary production by 1993 of some 4,400 bd. The estimated ERR is over 100%.

INVESTMENT PROGRAM STARTING IN 1990

4.15 Camiri. Field discovered in 1927, its primary reserves are practically depleted. According to a recent YPFB revision, the field contains probable reserves of about 7.5 million bbl, which could be recovered by means of water injection. Water injection is foreseen for Sararenda, although pilot trials would not be very reliable due to the variability of physical properties. The Sararenda formation reached a primary recovery at above 45% and an additional recovery around 24% is expected. The water injection project requires a more detailed study of the reservoir injection behavior, so as to define an optimum design of the project. Upon the revised data, the estimated ERR for the project is over 100%, although concrete evidence that the water injection would be effective still needs to be confirmed.

POTENTIAL INVESTMENT PROGRAM STARTING IN 1991

4.16 Sirari. Field which should be put into production only if the export of gas to Brazil is realized or, if there is a critical shortfall in future supply of liquid hydrocarbons. In any case, due to the fact that no step wells were drilled after the discovery well to define the reservoir limits and hydrocarbon potential, investment in this field seems unrealistic. Its ERR is estimated at about 10%. This picture could change once the World Bank's PPF-1 is completed.

Exploration

4.17 According to the production schedule, and to keep a reserve/demand ratio of 15 years, there will be a need to replenish cumulative reserves by 120 million bbl by 1997. By way of illustration, if exploration costs were in the order of US$7.50/bbl as calculated by the consultant for liquid hydrocarbons in a hypothetical case to preserve self-sufficiency, the magnitude of exploration investments for the period 1987-1998 required is calculated in the order of US$900 million. The size of the investment program required and the critical economic situation in Bolivia highlights the need of private participation in exploration activities. Table 4.2. shows the required annual increment of reserves, maintaining a 15 years reserve/demand ratio.

Table 4.2: ADDITIONAL RESERVES REQUIRED
(15 year reserve/demand ratio)
('000 bbl)

Year	Proven Reserves	Additional Reserves	Total Additional Reserves
1987	116,386	0	0
1988	107,260	0	0
1989	109,984	13,444	1,344
1990	113,361	13,406	26,850
1991	117,549	14,105	40,955
1992	121,003	13,717	54,673
1993	125,146	14,689	69,363
1994	130,081	14,086	83,449
1995	135,172	12,993	96,443
1996	140,649	12,445	108,889
1997	146,124	11,120	120,009

Source: NEP estimates.

4.18 Following the results obtained from the PPF for private exploration promotion, YPFB exploration activities should focus on low risk areas while the high risk areas should be offered to private investors. Nevertheless, the 1987 YPFB exploration investment program consist of US$45 million which will cover activities (exploration and drilling) in traditional areas and new stratigraphic traps zone. IDB is financing US$80 million in exploration activities for the next three years and is considering a new project to finance up to US$30 million for exploration activities (including 4 exploratory wells) in the Altiplano.

4.19 The Altiplano and the Northwest (including the North Sub-Andean and part of the Llanuras Benianas) present favorable geological conditions according to preliminary studies carried out by YPFB and private companies. However, further prospecting is needed before the liquid hydrocarbon potential could be determined.

Natural Gas

4.20 For the purpose of the NEP, the YPFB five year natural gas substitution plan, has been taken as an indicative one. In general, the development and expansion of natural gas transmission to major consuming areas for industrial purposes is an economic option, however, for the residential/commercial sector, a more detailed analysis needs to be carried out. To attract private participation in gas distribution investments, a technical, financial, and economic valuation is needed for each proposal in addition to defining a plan for bidders. Contractual arrangements between YPFB and private firms also need to be examined. The plan aims for the replacement of 80% of the industrial consumption of liquid fuels in the main urban centers and a start in the conversion of commercial and domestic consumers (paras. 3.64-3.70). If exports to Brazil materialize, then further investments will be necessary.

4.21 The investment necessary for the development and expansion is US$16.8 million of which US$6.4 million is YPFB and the remainder is private. To this, one has to add the cost of converting to gas industrial customers (about US$5 million for the three smelters plus US$2.5 million for the other industries), the cost of connections of industrial consumers (about US$2.5 million) and that of converting commercial and domestic users (about US$2 million).

4.22 Nearly 30% of the investments would be in the La Paz area, where the potential for industrial substitution of liquid fuels is the highest. By end-1988, some 50 industries would be converted, representing altogether nearly 450 bd of liquid fuels and 20 tons/day of LPG. If the program at the industrial level is successfully implemented, in the last two years of the plan, small industries, commercial and domestic consumers could be connected. A similar approach is proposed for Cochabamba (20% of the proposed investments) where about 40 industries could be connected by end-1987 representing about 320 bd of liquid fuels and 18 tons/day of LPG. In subsequent years, the small industries, commercial and domestic users would be connected.

4.23 In Santa Cruz (24% of the proposed investments), unlike the first two cities, emphasis is to be given already now to the conversion of small industries, commercial and domestic users, essentially because the larger industrial consumers are virtually all connected.

4.24 In Sucre and Tarija (altogether 24% of proposed investments) major and medium industries are to be connected in the early years of the program, followed by commercial and domestic users. In Oruro and Potosi (altogether 2% of the proposed investments), as long as the smelters remain closed, implementation of the gas network will be slowed down in view of the major impact of the smelters on the local economy.

4.25 Financing. The lack of credit could be an impediment for certain industries to convert to gas despite the financial benefits. Therefore, consideration ought to be given to setting up credit lines for such conversions. A detailed market survey should be made to evaluate the potential demand for such credits.

4.26 The cost of gas equipment (pipe, valves, meters) is said to be considerably higher than in other countries in Latin America. At the minimum, a feasibility study ought to be carried out to assess the merits of creating a domestic gas equipment industry including in particular polyethylene pipes and the assembly of meters.

Electric Power

4.27 Currently there is not available a long term (10 years) investment program for the power subsector. The Ministry of Energy and Hydrocarbons has collected a list of specific projects in the power subsector for future financing, but their timing and justification is yet to be determined. The only investment programs, that were based on an expansion plan, were the programs for ENDE and ELFEC. Therefore a tentative five-year investment program for the subsector based on this information, has been prepared, in order to estimate a preliminary figure for the required investment.

4.28 The tentative investment program for the electric power subsector is summarized as follows in Table 4.3.

Table 4.3: INVESTMENT REQUIREMENTS FOR 1987-1991

Type	US$million
Generation	76
Transmission & Subtransmission	37
Substations	8
Distribution	60
TOTAL	181

Source: NEP estimates.

4.29 Generation. The required generation investment amount considers an expansion program prepared by ENDE which is based in the least cost criteria. The program considers that the construction of the 6th and 7th gas turbines at Santa Cruz, is necessary to meet projected increases in electricity demand at the Eastern system. By 1990, and assuming that the Central-East interconnection system will be commissioned, the best alternative would be to continue expanding the gas turbine plant at Santa Cruz and such expansion should be carried out with gas turbines rather than combined cycle plants. This can be explained by the fact that the improvement in efficiency does not compensate the high investment associated with a combined cycle plant. At a cost of gas at the plant of US$1/MCF, very few hydroelectric alternatives could compete with gas turbines. At this moment, the most attractive hydroelectric alternative is the proposed expansion of the Zongo River plant. The power generation system should be expanded, at least in the period 1990-1995, using plants suitable for peak load operation. In this regard, the rehabilitation of small hydro-stations now on use may be attractive, and the large hydroelectric projects now under consideration can be improved by lowering their designed plant factor.

4.30 The generation expansion program, for the interconnected system is as shown in Table 4.4.

Table 4.4: GENERATION EXPANSION PROGRAM

Year	Project	Capacity (MW)
1987	6th Turbine at Santa Cruz	22
1988	7th Turbine at Santa Cruz	22
1990	8th Turbine at Santa Cruz	22
1991	9th Turbine at Santa Cruz	22
1992	10th Turbine at Santa Cruz	22
1993	Zongo River Expansion	61
1994	11th Turbine at Santa Cruz	22
1995	12th Turbine at Santa Cruz	22

Source: NEP estimates.

4.31 Although the above generation expansion program may be subject to further changes during the power system expansion revision to be carried out by ENDE during this year, it has been considered as adequate for estimating investment requirements in generation.

4.32 Transmission. Regarding transmission investment, the only major project considered by ENDE is the Central-Eastern interconnection project. It has been found that it is important to commission this project by 1990, in order to reduce the need for expanding generation capacity and to allow the use of hydroelectric surplus, if any, in the C-N-S interconnected system. The interconnection will perform a role in the system completely different to that envisaged when it was planned in the late 70's due to major changes in the cost of gas, in the demand of the Eastern system and the availability of hydro surplus. Initially it was intended for the use of hydroelectric resources which were the least cost alternative; now, gas turbines are the most attractive development and there may not be significant hydro surpluses in the C-N-S system when the interconnection is commissioned. The main benefits of the interconnection in the medium term would be, therefore, to facilitate the development of additional thermal generation in the Santa Cruz area, where their performance is better, and to facilitate the need of gas transport to the central regions.

4.33 Subtransmission and Distribution. Regarding subtransmission and substation investment, specific projects suitable to meet future demand in Santa Cruz, Cochabamba and La Paz systems have been included (i.e. subtransmission lines to Chapare, Yacuiba and Trinidad) with a total investment required of about US$8 million.

4.34 Due to the absence of detailed information at the national level on distribution, an aggregate investment requirement has been estimated taking into account the average cost per incremental peak demand (US$450/kW derived from ELFEC's records) and the increase in peak demand for the whole system. Using this assumption an estimated investment of about US$50 million is required for the 1987-1991 period.

4.35 Impact of Reduced Investment Levels. Although the estimated investment in the power sector represents only a small fraction (about 5%) of the public sector investment, it is important to analyze the impact of a reduction in this investment program caused by financial constraints. A reduction in generation would affect in the short term the electricity supply to Santa Cruz; if total investment in generation is reduced in, say 10%, this would be equivalent to cancel the 7th turbine in Santa Cruz. In this case, the margin of generation in 1989 would be 4.3 MW which is completely inadequate. This margin means that whenever one of the generation units at Santa Cruz is taken out of service for maintenance or there is a forced outage, it would be necessary to ration about 15 MW, equivalent to 12% of the peak demand in Santa Cruz. Expressing it in probabilistic terms, it means that there would be about 330 hours per year with power rationing at peak.

4.36 A reduction in transmission investment in 1987 or 1988 would mean a postponement of the construction of the Central-East interconnection. A postponement of one year would result in: (i) need to install two additional turbines in 1990 (investment of US$17 million) in order to meet the projected demand in the C-N-S and the Eastern systems operating in isolation; and (ii) an increase in fuel costs in 1990 of about US$1.3 million.

4.37 Investment in distribution is not as lumpy as investment in generation and transmission, and, therefore, gives more flexibility to reduce it gradually. The implications of a reduction in this investment are much more difficult to analyze for it depends on the distribution company and the component that is affected by the reduction. It is not worthwhile to analyze these implications, for a reduction of 20% in the investment estimated for distribution represents only about US$2 million per year.

Technical Assistance Priorities

4.38 The following technical assistance activities should be given high priority so that critical problems in the energy sector can be tacked.

Within the MEH:

(a) Evaluate options to strengthen the policy and institutional framework, and market arrangements for LPG in the rural areas and carry out an energy demand analysis focussing on the use of LPG (paras. 3.2-3.3 and 3.41, 3.47, and 3.50).

(b) Establish an energy information system and develop and implement analytical tools to carry out energy planning, in particular, strengthen DINE's organization, methodologies, and procedures regarding the setting of electricity rates and the development of data bases for power sector statistics (paras. 5.1-5.3 and 5.18).

(c) Review the current electricity tariff structure both at bulk and retail level, and prepare specific proposals for setting electricity rates for 1987-1990 (paras. 3.21-3.28).

(d) Carry out a study to improve bagasse utilization in the sugar mills (para. 3.5).

(e) Determine the efficiency of current wood and dung stoves in the Altiplano, and analyze the economics of dung burning and its substitution by hydrocarbons, including kerosene (paras. 3.37-3.38).

(f) Evaluate the current organizational structure of the rural energy sector(paras. 5.30-5.32 and 5.42-5.44).

Within YPFB:

(a) Develop and implement a petroleum supply management information system (MIS) optimizing the use of refineries and evaluating least cost supply options (para. 5.9).

(b) Develop and introduce in YPFB modern integrated accounting, budgeting and control systems (paras. 5.33-5.38).

(c) Carry out an energy audit on YPFB's consumption of liquid fuels (para. 3.54).

Within ENDE:

(a) Carry out a power system analysis of the interconnected system, including a stability analysis (paras. 4.32).

(b) Review electricity demand projections for the industrial, mining and residential sectors for the period 1987-1995 (paras. 1.39-1.41).

(c) Review procedures, methodologies, and organization in ENDE for project analysis (paras. 5.14-5.20).

V. INSTITUTIONAL AND FINANCIAL ISSUES

Organization Structure

Institutional Problems

5.1 The Ministry of Energy and Hydrocarbons (MEH) is responsible for formulating energy policies and for regulating the activities of the sector, except forestry which is under the responsibility of the Ministry of Agriculture. These functions are carried out by two main departments within the Ministry, one responsible for hydrocarbons (DGH), and the other for electric power (DINE). Overall sector planning is limited within the Energy Planning Unit (DEP) of the MEH. The Rural Energy Corporation (COFER), funded through the MEH, is responsible for rural energy and alternative forms of energy. Power tariffs and petroleum product prices are set by the MEH.

5.2 MEH is insufficiently equipped to exercise its functions and to coordinate the efforts necessary to successfully meet Bolivia's future energy needs. The recent creation of the DEP was a first step but it must be strengthened. This unit must be staffed with highly qualified personnel, equipped with analytical tools, and advised by outside experts during its initial years. Free flow of information to and from the energy companies and with the other ministries must be established. DEP, working together with strengthened DGH and DINE, would be in charge of proposing and evaluating energy strategies, scheduling programs and monitoring those that are implemented. It would also make sure that a proper link is established between economic objectives and energy, and would coordinate with the Ministries of Agriculture and Rural Affairs, and Planning.

5.3 The current structure of DGH, DINE, COFER and DEP needs to be examined in detail. Most of these units are receiving enough funds to maintain basic office functions and nothing else. In the case of DINE, a political and legal solution should be worked out to give back DINE the responsibility for setting rates at all levels.

Hydrocarbons

5.4 Petroleum. YPFB was incorporated in December 1936 as a state oil company to take over the nationalized Bolivian assets of Standard Oil of New Jersey, Inc. (now Exxon). On September 1969, the Bolivian subsidiary of Gulf Oil Co. was nationalized and YPFB assumed the administration, production, transportation, pipeline construction and operation, refining and distribution as well as imports and exports. YPFB has been engaging in operations contract with foreign oil companies. YPFB is experienced in all phases of the oil industry from exploration to drilling, production, refining, and marketing.

5.5 A previous diagnosis of YPFB's operations carried out by independent consultants in December 1985 is still true today, and includes the following:

(a) A high degree of centralization, featuring excessive concentration of decision-making authority to the top levels of management.

(b) Duplication of functions, overstaffing.

(c) Extremely slow and cumbersome administrative decision-making procedures.

(d) Inadequate development and use of management information and other systems.

(e) Poor coordinating and conflict resolution mechanisms between functions.

(f) Excessive specialization; no cross-functional career paths.

(g) Excessive centralization of administrative staff functions in La Paz.

5.6 In line with the above issues, YPFB's organizational structure should include corporate restructuring to gear YPFB to work under economic efficiency criteria. At present investment decisions are based on physical targets of production and supply with little economic priority consideration. The present organizational structure and accounting system of YPFB does not permit a realistic evaluation of economic performance since revenues and costs cannot be attributed to the underlying lines of activity and transfer prices used among the company's operating unit do not have a solid economic foundation.

5.7 Since the role of YPFB is an integral part of the Government policies for the oil and gas subsector, it is important to assess the competitiveness of its operations and activities on the basis of international standards. This would determine which of its operations and activities are economically justified, which are not, and what opportunities exist for increasing their efficiency. One w. to do so would be to reorganize YPFB into a set of independent, commercially oriented divisions--each specializing in a particular field of activities--and by using proper transfer prices between them.

5.8 The operational divisions could be responsible, respectively, for exploration and production; drilling and oil-field services; refining; transport and marketing. In addition, the restructuring should start with (i) defining clear objectives commensurate with the human, technical and financial resources of the division, integrated in a long-term investment strategy for the sector; (ii) establishing control mechanism over operations without interfering with managerial responsibilities and the financial autonomy of the company; (iii) making the divisions cost-conscious, and self reliant; (iv) holding managers accountable for results by means of performance evaluation and introducing managerial incentives linked to result; and (v) opening up the industry to outside competitors toward maximizing the efficiency of operations, encourage entrepreneurship and innovations and bring in latest technologies and knowhow. This will help optimize the potential of each division and ease their adjustment to an increasingly competitive environment.

5.9 With respect to refinery operations, a computerized refinery model should be set up to take into account the specific circumstances of the Bolivian environment. Bolivia's three refineries (Cochabamba, Santa Cruz, Sucre) represent twice the demand and operate considerably below capacity. A petroleum supply management information system should be set up optimizing the use of refineries and evaluating least cost supply options.

5.10 As a result of a current situation where salaries are very low and the lack of a career development perspective, the morale in YPFB is very low. With the government freeze on salaries, the ratio of the private oil companies salaries to YPFB is substantially different. This is critical, for YPFB best staff is leaving in a period where the oil sector is the backbone of the Bolivian economy. A revision of YPFB's salary structure is urgent.

5.11 The regional difficulties should also be resolved. A constraint on drilling activities is that the three petroleum producing provinces jealously watch over exploration and production activities and have been able to stop the movement of rigs and other equipments out of their respective provinces. For example, about one third of the time the rigs are in waiting; costing YPFB about US$ 12 million per year.

5.12 Natural Gas. At present, responsibility for natural gas is under Yabog located at Santa Cruz (exports to Argentina, and transport and distribution in eastern part of Bolivia), the Industrial Division located at Cochabamba (transport and distribution in western part of Bolivia) and the Gas Division located at Sucre (planning, tariffs, policy). In addition, YPFB centralized services (personnel, accounts, commercial, etc.) provide support to the different groups involved with natural gas. It is intended that gas distribution in the main towns be awarded to concessionaires in early 1988 who will get the concession at no cost, but will be required to invest part of their income in the expansion of the network, and the connection of new consumers. YPFB would supervise the concessionaires, and ensure that they comply with their obligations, including the one to invest. The Gas Division is presently preparing bid documents that will serve for the selection of concessionaires. The selection is expected during the second half of 1987.

5.13 While the gas activity of YPFB is small, it is likely to play an increasingly important role in the future; the problems of gas are very specific (load management, transport, distribution, metering, safety etc.) and demand in general a different expertise than that of oil. That is why many countries have opted for separate gas companies which essentially buy the gas from the producers in the producing areas, and are responsible for transport and sometimes distribution. In the case of Bolivia, some consideration ought to be given to consolidate the functions presently fulfilled by the three groups at different locations. 17/

5.14 The concessionaire system for gas appears prima facie reasonable under the Bolivian circumstances, in particular the wide geographical dispersion of the consumption centers, and the need to raise private capital for the distribution systems. However, these concessionaires will have virtually no past records in the operation of gas networks. It is therefore intended that they be closely monitored by the present Gas Division. In addition, and taking in particular into account the safety aspects, consideration ought to be given to securing the service of experts from an operating gas utility to ensure that the systems being introduced are up to standards. This could avoid costly mistakes, and spare the need for introducing modifications at a later stage, after expenditures have already been incurred.

Electric Power

5.15 ENDE's responsibilities on planning of the expansion system at the national level (generation and transmission) should continue, while the coordination of operational activities should be strengthened. Construction of new plants, included in the least cost expansion program prepared by ENDE, could be developed by ENDE or private or regional entities, as long as the operation will be closely coordinated with ENDE. At the distribution level the responsibility of construction of new facilities should be transferred to the distributors companies.

5.16 At the regulatory level the Ministry of Energy and Hydrocarbons is responsible for formulating the policies for the sector and regulating power sector operations. Its regulatory function is carried out by DINE in accordance with the National Electric Code (NEC) of 1986.

5.17 At the generation and transmission level, there are two companies responsible for the development and operation. On the one hand, ENDE is responsible for the planning, development, and operation of generation and transmission projects at the national level, and for supplying energy to all distribution companies and some large mining and industrial consumers. On the other hand, the private Bolivian Power

17/ An immediate benefit will be that a true costing system for gas would be rapidly developed.

Company (COBEE) is responsible for supplying energy to La Paz and Oruro markets, and for the operation of generation plants in that area, and is authorized to develop new generation projects at the Zongo River Basin. Additionally, there are several regional development coorporations (CORDECRUZ, CORDECH, etc) which pursue the development and operation of multi-purpose projects (irrigation and power). The organization at the generation and transmission level raises some queries and creates some problems for sector planning discussed below.

5.18 In the early sixties, with the support of the international financing institutions, the Government introduced major reforms in the regulation and organization of the power subsector that contributed to its rapid development in the 1960s and 1970s. The most important actions in this period were: (i) in 1962, the creation of ENDE, as responsible for the planning, construction and operation of generation and transmission systems, for the interconnection of isolated systems, and for assisting in the creation and development of distribution companies; (ii) in 1962, the creation of the Direccion Nacional de Electricidad (DINE) responsible for the regulation and coordination of the power subsector; and (iii) the enactment by the Government in 1968 of the National Electricity Code (NEC) which regulates the operations of power electric utilities and establishes technical criteria to set electricity rates. In the 1980s, however, the regulatory action weakened, mainly as a result of the economic crisis and new legislation enacted by the Government.

5.19 First, the provisions of the NEC for setting electricity rates based on a 9% rate of return were not applied during the economic recession and electricity rates deteriorated rapidly. Second, DINE's technical capability weakened as its budget was reduced and salaries were kept too low. And third, the Decrees 21060 and 21072, and the Law of Municipalities enacted in 1985 weakened the application of the NEC and role of DINE in regulating the power subsector. Other problems, like lack of definition of responsibilities in developing new generation projects and the expiration of the concession in 1990 of the largest distribution company (COBEE), contributed to create institutional problems in the power subsector.

5.20 Generation. The lack of definition for the responsibility in the development of power generation projects at the national level has created problems for sector planning. On the one hand, COBEE is pursuing the development of very attractive generation projects in the Zongo River with little coordination with ENDE, which is responsible for the preparation of national power development plans. On the other hand, the regional development corporations are promoting vigorously multipurpose projects with substantial electric power components. To alleviate these problems, the planning process should be strengthened so there is a procedure for ranking generation alternatives at the early stages of preparation and for taking only the most attractive projects to the feasibility and design stages. In the case of multipurpose projects, the contribution of the project to power generation can be easily assessed and valued at the equivalent cost of the best electric power alternative.

In that way, one can estimate the cost assigned to other purposes and assess the merits of the project for non-electric uses. ENDE is the institution best qualified for directing this process and should be responsible for preparing the Power Development Program. In order to reduce tensions with other institutions and get their support, the criteria to be used in preparing the plan should be widely discussed and should be evident to the interested parties.

5.21 Although generation and transmission planning should be centralized, the construction and operation of all the generation projects do not necessarily have to be centralized. In the case of electric power generation projects, only ENDE and COBEE have the experience and the infrastructure necessary to undertake their construction. The future development of the power system with few hydroelectric projects does not justify that other power companies enter into this activity. On the contrary, only one company could have the responsibility for the construction of all new generation projects. Taking into account that COBEE's concession expires in 1990, and provided that a local company would be created, this is a good opportunity to make ENDE responsible for the construction and operation of all generation projects. However, there are two exceptions. If a new large multipurpose project is developed, it would be advisable to create a special executing agency for its construction; and second, the operation of small (say, less than 5 MW) thermal systems in isolated areas is burdening ENDE's administration and can be transferred to local distribution companies.

5.22 Subtransmission and Distribution. At the subtransmission and distribution level there are about 8 distribution companies responsible for power distribution to the major urban centers, which purchase energy from the two generation companies. By tradition ENDE has developed the major distribution substations at Cochabamba, Santa Cruz, Sucre, and Potosi. As the distribution systems have grown and the distribution companies as well, there is no need to burden ENDE with the responsibility of developing part of their distribution system. This responsibility should be transferred to the distribution companies.

5.23 At the distribution level, the concession for the largest distribution company, COBEE, would expire in 1990, and a decision should be taken about the extension, modification or expiration of the concession contract. This has created a lot of controversy and political turmoil, with advocates for about every possible course of action. The problem should be put in perspective, by distinguishing between political and technical considerations. The technical considerations refer to the supply to the consumers at La Paz of a reliable electricity service at a reasonable cost. In this regard, COBEE has done a good job. It is a well organized, efficient, and responsible company who has managed to provide a low cost service with a reasonable reliability in spite of major external financial constraints. However, the uncertainty about the future of the contract has affected negatively electricity service for, of course, COBEE is not eager to make major investments in the development of the power system. The major preoccupation at this point would be to take, as soon as possible, a decision on the future of the contract. The Government should evaluate carefully the alternatives before a decision is taken not to extend the contract. Nevertheless, if the concession contract is not extended, a solution would be to transfer the generation and transmission system to ENDE and to have a local company responsible for power distribution.

5.24 Legal Aspects. Regarding sector regulation, the application of the NEC and the role of DINE weakened with the approval in 1985 of the Law of Municipalities, and by the Decrees 21060 and 21072 of 1985. Article 9 of the Law of Municipalities establishes that the municipal governments are responsible for the regulation of public services in their jurisdiction. There would be a conflict, therefore, between the application of the provisions in the NEC and this law. Decree 21060 contributed to the confusion by establishing that electricity rates should be negotiated between the producers and the consumers, and that, in the case of the distribution companies, the municipal governments would represent the consumers. Decree 21072 of August, 1985, was more precise by establishing that as of January, 1986, the municipal governments would set electricity rates for the urban areas, according to the corresponding provisions of the NEC; that the Regional Development Corporations should set electricity rates for rural consumers in accordance with the NEC; and that the Ministry of Energy and Hydrocarbons, through DINE, should set bulk electricity rates.

5.25 After the change in regulations, the actual setting of electricity rates was erratic: tariff increases at retail level have been set by negotiations or by default in a few cases (no comments from the municipal government), and in other cases tariff increases have not been approved; at the bulk level, tariff increases have been approved by DINE, creating in some cases conflicts for the distribution companies when DINE authorized a tariff increase for bulk rates and the corresponding increases at the retail level were not authorized by the municipal government.

5.26 The provisions of Decree 21072 did not weaken the application of the NEC. It only weakened the role of DINE. The provisions of the Law of Municipalities, on the contrary, are vague and may be in conflict with the application of the NEC. There are political, legal and technical issues involved in this problem. The political issue is the power struggle between the national government and the municipal and regional governments. The legal issue is whether the municipal governments can regulate public services. The technical issue is what rules should be applied to set tariffs. The first two issues are out of the scope of this analysis. Regarding the technical issue, in our opinion, the provisions of the NEC for setting electricity rates are appropriate as long as there is supervision by a qualified group to ensure that the cost of service has been correctly evaluated and that it is reasonable. There are practical advantages to have a centralized group to perform this function in a relatively small power subsector like this, and the best suited would be DINE.

5.27 Therefore, a political and a legal solution should be worked out to give back to DINE the responsibility for setting electricity rates at all levels. This would require strengthening DINE's organization and establishing higher salaries to attract qualified personnel.

5.28 Performance Indicators. In general, ENDE, COBEE, and ELFEC are well organized and efficient. The deterioration of the financial situation and of their performance was due to external factors and not to inefficiencies in their operations. Regarding generation, the thermal power plants show an availability over 80%, which is adequate considering that they are diesel engines and gas turbines; their efficiencies in the range of 25% to 33% are also adequate. These results are very good, specially considering that there were difficulties to purchase spare parts, and the maintenance of thermal plants fell behind schedule as a result of the critical financial situation in the 1980s.

5.29 Regarding management efficiency indicators, the number of customers per employee for the distribution companies is in the range of 200 to 400. The lowest value corresponds to COBEE which operates several hydroelectric plants, and therefore, this figure can be considered very good. The highest value corresponds to ELFEC and is excellent for a distribution company of its size. The collection period for 1986 was in the range of 70 to 160 days. ENDE and COBEE show collection periods below 80 days which are reasonable, while ELFEC and CRE have collection periods of 120 and 160 days which are too high and should be improved.

Rural Energy

5.30 The MEH is the main organization dealing with energy issues, however there is apparently no department devoted to rural energy or alternative energy resources on a national level. COFER, funded through the MEH, is nominally the public organization that is involved with rural energy and alternative forms of energy. Its predecessor, INER, was involved in the original biogas program in Bolivia. COFER is now mainly involved with rural electrification and the organization currently receives only enough funds to maintain basic office functions and nothing else. There is similarly no coordination, or, evidently, cooperation, among the three government ministries pertinent to energy development, MACA, MEH, and the Ministry of Planning. The ties indicated between the Ministry of Planning and the regional development corporations is nominal.

5.31 There is virtually no coordination either on the national level or on the level of the regional development corporations with non-governmental organizations involved in rural development or with rural cooperatives. Ties should be established among the Ministry of Planning, MACA and MEH for the purpose of coordinating national energy policy. COFER should be streamlined and provided with a reasonable budget to allow promotion of alternative and other energy resources in rural areas, under the guidance of the National Energy Plan.

5.32 Although the regional development corporations must submit yearly plans to the Regional Directorate in the Ministry of Planning in La Paz, which technically has jurisdiction over the corporations, there is virtually no control over their activities, nor is financial support channeled through the national government. More involvement with small rural projects should be promoted, and funds should be channeled to those regional development corporations that are short of funds due to depressed levels of departmental productivity. A detailed description of the rural organizations per region is included in Annex 4.

5.33 A number of international organizations participate in reforestation and alternative energy projects in rural Bolivia. However, the lack of central government coordination has resulted in often sub-optimal investment decisions.

Financial Situation

Hydrocarbons

5.34 The evaluation of YPFB's financial position and prospects constitutes a unique challenge in view of the highly inflationary environment in recent years, the delays in closing the books, and the application of certain financial procedures which are at variance with generally accepted accounting principles. Furthermore, on certain items, there does not seem to be a consensus within YPFB's financial staff, possibly because the corporation has yet to adjust to the fiscal regime introduced in early 1986.

5.35 Weaknesses in YPFB's accounting, budgeting, and management information systems have been documented by Arthur D. Little, Booz Allen & Hamilton, and others. In summary: (i) YPFB experiences considerable delays in the submission of financial information and the accounting information is said to be inaccurate at times; (ii) the costing system is slow, and needs to be indexed to a hard currency or standard costing system in order to become meaningful; (iii) YPFB's accounting and costing systems need to be integrated; (iv) inventory costing, which is still on an historical cost basis, needs to be upgraded; and (v) internal audit has to be reorganized along functional lines. Furthermore, the geographical dispersion of YPFB's activities, and the insufficient availability of modern computers in the accounting department renders any analysis difficult.

5.36 The tax mechanisms in place have a determinant impact on YPFB's financial performance. Taxes are essentially levied on YPFB's production and sales. In 1985, these taxes were equivalent to about 40% of its gross sales; with the tax increase of early 1986, the ratio increased to about 70% of sales proceeds. 18/ The new taxes have had disastrous implications for YPFB--the loss for FY1986 can be estimated at US$39 million; in order to meet its financial obligations, its indebtedness to foreign oil companies increased by US$50 million and it failed to comply with over US$18 million in debt service obligations. 19/ The investment program in 1986 was reduced to about US$50 million, which compares to an average US$88 million per annum over 1979-83 and an anticipated average of US$125 million annually over 1985-88. 20/ YPFB's balance sheet at end-1986 shows considerable liquidity, taking into account the general state of affairs, US$78 million, but these funds are largely impounded by the Central Bank, and cannot be used by the company.

5.37 A continued reduction in YPFB's investment program will have adverse consequences. In particular, development and enhanced oil recovery projects which could ensure self sufficiency in oil products in the coming years will have to be deferred until YPFB's internal cash generation increases.

5.38 The main financial issue regarding YPFB's investment program is not foreign financing (YPFB has large unused credits from CAF, IDB and the World Bank) but the financing of local costs. The method used thus far to generate local financing (non-compliance with financial obligations to foreign oil companies, lenders, Government, etc.) is financially unsound. A preliminary analysis for FY1987 shows that even if its investment program was reduced to nil (and disbursements of foreign credits were therefore halted), YPFB would still nave a cash deficit in excess of US$50 million during the year (including compliance with its short term liabilities). As a result, the solutions to be considered include an increase in the prices of oil products (with inflationary consequences) and a reduction in taxes (with adverse repercussions on general budget revenues); regarding operating expenses, these are relatively small and cannot contribute much to a solution of

---

18/ The new taxes were initially interpreted as an advance against future taxes, but it now seems that they have to be charged to the current year, and that they will remain in effect until the Government can mobilize revenues at a similar level from new sources.

19/ Payments overdue are to Arlabank (US$4.7 million), Texas Commerce Bank (US$5.1 million), World Bank S-25-BO (between 6/20/84 and 12/20/86), for US$6.8 million, and Bancomer (US$1.5 million).

20/ Source: Vuelta Grande Gas Recycling Project, Staff Appraisal Report of June 4, 1986 (pages 20-22).

the fundamental problems. 21/ YPFB's financial requirements need to be taken into consideration in the context of the ongoing review of the overall tax system.

5.39 Regarding YPFB's anticipated performance beyond 1987, unless there is a major reform in taxation, or an increase in dollar terms in the prices of oil products, one can anticipate rising deficits, declining production, and an increasingly difficult situation for the petroleum sector as a whole, including foreign oil companies. What is required as a matter of urgency is an agreement between the Government and YPFB on realistic operating and capital budgets together with their corresponding financing plans. Unless such an agreement is reached, the situation is likely to deteriorate further.

Electric Power

5.40 The financial position of ENDE and the power distribution companies was strong in the late 1970s and they achieved, in general, a rate of return of about 9%. However, from 1980 to 1985 their financial position deteriorated rapidly as the result of the decline in sales, substantial reduction in real terms of electricity rates during the hyperinflation period, and increase in receivables resulting in a loss of revenues because the amount in arrears was not revalued during the hyperinflation period. In general the distribution companies could face better this situation than ENDE for, among other things, they could adapt their investment programs to the drop in the rate of growth in demand. ENDE, on the other hand, could not reduce its generation and transmission investment program at the same pace, and as a result of the substantial increase in receivables for sales to the distribution companies, and a substantial reduction in net income, it accumulated overdue debt for about US$50 million, of which about US$28 million was owed to Government (including YPFB and CBF). ENDE's income statements, and sources and uses of funds (expressed in current US$), tell part of the story. However, they should be read with caution for the financial results during this period of hyperinflation are severely distorted.

5.41 The reduction in the pace of inflation by late 1985 and the implementation of substantial increases in electricity rates reversed the trend and now most of the power companies are in a recovery path. As it was explained above, ENDE has continued to carry most of the financial burden by having average rates still at a low level. To ensure ENDE's financial recovery, the Government recently issued an Executive Decree approving the capitalization of ENDE's debt to the Government and an increase of 1.5% per month in real terms of ENDE's rates to distribution

---

21/ YPFB's management, for all practical purposes, has control over operating expenses which amounted in 1986 (excluding purchases from oil companies, taxes and depreciation) to US$75 million, i.e., 12% of total cost of goods sold.

companies, until they reach a value of 50 mills/kWh. Starting from the current levels of about 25 mills/kWh, it would take about 4 years to reach that ceiling (para. 3.23). Table 5.1 shows ENDE's average tariff and financial key indicators.

Table 5.1: ENDE'S FORECASTED FINANCIAL PERFORMANCE

	1987	1988	1989	1990
Average Tariff (mills/kwh)	3.6	3.9	4.4	4.9
Rate of Return (%)	1.2	2.4	4.7	7.0
Net Int. Cash Gener.(MMUS$)	(001)	2.5	13.1	25.1

Source: ENDE and NEP estimates.

Rural Energy

5.42 There is an almost total unavailability of agrarian or other rural financing for energy purposes. Small rural electric cooperatives must, in general, pool financial resources to purchase equipment at the full cost upfront. In Tarija, the Banco de Argentina, which formerly financed small rural projects, closed, leaving a vacuum in the availability of rural loans in Tarija. The Caja Central de Ahorros y Prestamos in La Paz maintains branches in each department and a number of local offices, and finances rural projects in electricity and potable water supply. Loans can be obtained through them by individuals, cooperatives and private entities. The rural loan program is financed under the USAID PL-480 program, which annually lends US$1 million to the Caja at 3% interest. The central office of the Caja re-lends to local offices at 4% interest, and the local offices lend to rural loan recipients at 6% interest (this compares to the private bank lending rate of approximately 25% in La Paz). The principle drawback of this rural lending program appears to be the lack of bank offices in most rural areas.

5.43 Inadequacies in the existing rural financing system should be investigated, and changes should be made to provide financing for small rural energy development projects, in line with priorities. Furthermore, the system by which SEMTA finances rural development projects in the department of La Paz should be evaluated, with possible applications in all three regions.

5.44 Great differences in the financial situation of the rural corporations exists because most of the financing for the corporations, as mandated by National Law, consists of a percentage of corporate profits from major departmental industries. For the Altiplano, CORDEOR, receives financing from the Vinto smelter. However, the downturn in smelter operations has resulted in loss of financing for CORDEOR, and other business interests dedicated to departmental development. Meanwhile, the regional Corporations in the Valleys and Tropics are financially well-off relative to the Altiplano corporations. Both regions are gas and oil producing, and so receive substantial contributions to finance regional projects. The national government must act to improve financing for the poorer regional corporations (a national issue currently subject to great controversy vis-à-vis the natural gas royalties).

Institutional Strategy

Petroleum

(a) Restructure YPFB under economic efficiency criteria by considering a set of independent, commercially oriented divisions. The operational divisions could be responsible for exploration and production; drilling and oil-field services; refining; transport and marketing.

(b) Continue in resolving the regional difficulties, between the Departments, that have negative implications for all activities of the oil subsector.

(c) Develop and introduce in YPFB modern integrated accounting, budgeting, and control systems.

(d) Review the tax structure on YPFB to assure its financial viability.

(e) To satisfy the increase in domestic demand of oil products (30,000 to 35,000 bd), an average of 45 exploration wells each year for the period 1987-1992 are needed to increase reserves to about 250 million bbl and maintain a reserve/production ratio of 15 years. If about 10,000 bd were to be exported, 60 wells each year would be needed. This should be carried out in conjunction with a revision of operation contracts to increase all activities in the subsector.

Natural Gas

(a) Since gas distribution in the main towns is expected to be awarded to concessionaires in early 1988, ensure they comply with their obligations, particularly in investments.

(b) Consider a separate gas utility which will consolidate the functions presently fulfilled by the three groups.

(c) Because of the importance of gas exports to the Bolivian economy and the fact that the current gas export agreement with Argentina is expiring in 1992, alternative arrangements need to be investigated.

Electric Power

(a) Work out a political and a legal solution to give back to DINE the responsibility for setting electricity rates at all levels, in accordance with the provisions of the National Electricity Code.

(b) Confirm ENDE as the institution responsible for preparing the National Power Sector Development Plan.

(c) Take a decision as soon as possible on the future of COBEE's concession contract, and if the contract is not extended, to transfer COBEE's generation and transmission system to ENDE once the contract expires. The distribution system should then be transferred to the municipalities or regional activities.

(d) Prepare a plan to transfer the operation of ENDE's generation plants at the small isolated systems to the distribution companies/cooperatives in these areas.

(e) Transfer the responsibility in developing distribution substations in Cochabamba and Santa Cruz from ENDE to the distribution companies in those cities.

Rural Energy

(a) Improve the coordination among the Ministry of Planning, MACA, and MEH toward coordinating national energy policy in the rural sector and breakthroughs in the development of alternative energy resources such as biomass, geothermal, and others.

(b) Investigate existing inadequacies in the rural financing system.

PETROLEUM

Structure of Petroleum Demand

The share of gasoline has slightly increased from 61% of the combined consumption of gasoline and diesel in 1980 to 65% in 1985. Such an increase would have been higher had more energetic measures been taken to encourage the use of gasoline as opposed to diesel in view of the relative scarcity of diesel in Bolivia.

Table 1: DEMAND FOR PETROLEUM PRODUCTS, 1980-86

	1980		1986		1980-86 Avg. Annual Growth Rate
	('000 bbl)	(%)	('000 bbl)	(%)	(%)
Gasoline	2,903	33.8	2,952	38.0	0.3
Avgas	112	1.3	76	1.0	- 6.3
LPG	1,107	12.9	1,966	25.3	10.0
Kerosene	947	11.0	331	4.3	- 16.1
Jet Fuel	673	7.8	570	7.3	- 2.7
Diesel Oil	1,881	29.1	1,563	20.1	- 3.0
Fuel Oil	958	11.2	319	4.1	- 16.7
Total	8,581	100.0	7,777	100.0	- 1.6

Source: YPFB.

The commercial and domestic sector has seen its share increase from 19% of the consumption of oil products in 1980 to 28% in 1985. The absolute growth rate, however, was of approximately 3.5% per annum, slightly higher than population growth. Thus the relative increase in the share of this group is probably due more to the decline in the industrial and mining sectors than any other factor. However, a structural shift has happened in consumption patterns with kerosene consumption declining by 35% and LPG increasing by 55% over their 1980 levels. On a calorific equivalent basis, LPG's share has increased from 56% to 75% of the total requirements of this sector. This is certainly due to a deliberate pricing policy promoting LPG use, as well as the relative advantages of LPG over kerosene as a cooking fuel. The decline in the share of the "other" sectors (i.e., industry, mining, agriculture, etc.) from 28% in 1980 to 18% in 1985 can only be explained by the economic recession in Bolivia.

Regarding gasoline and diesel oil, the virtual stagnation in their consumption reflects the recession. The decline in the consumption of kerosene by 616,000 bbl annually is equivalent from a calorific standpoint to 840,000 bbl of LPG which is within 2% of the increase in LPG use (850,000 bbl).

The huge decline of 67% or 639,000 bbl in the consumption of fuel oil can be explained by:

(a) the more widespread use of natural gas; 1/

(b) the closure of the tin smelters at Potosi and Oruro (which used to consume 320,000-380,000 bbl of fuel oil per annum; and

(c) the recession.

As a result, the Bolivia market for fuel oil has almost disappeared. Table 2 shows the consumption of oil products by sector for 1985.

Table 2: CONSUMPTION OF OIL PRODUCTS BY SECTOR, 1985
('000 bbl)

Sector	Gasoline	LPG	Kerosene/ Jet Fuel	Diesel Oil	Fuel Oil	Total ('000 bbl)	Total (%)
Transport	2,863	--	586	950	--	4,399	58.6
Industry	--	75	53	101	503	732	9.9
Agriculture	--	--	143	58	35	236	3.1
Household/Commercial	--	1,710	429	--	--	2,139	28.5
Total	2,863	1,785	1,211	1,109	538	7,506	100.00

Source: YPFB.

Reserves

Proven reserves of liquid hydrocarbons (crude and condensates) are estimated at 138 million bbl, equivalent to a reserve/production ratio of approximately 21 years based on current production although many of these fields are in their decline. Probable reserves as of

1/ Natural gas sales, other than for power generation, increased from [illegible] MMCFD in 1980 to 8.2 MMCFD in 1986. The increase is equivalent [illegible] annual consumption of 270,000 bbl of oil.

January 1, 1987 amount to 31.7 million bbl. Only about 20% of the hydrocarbon potential has been explored. Bolivia covers about 1 MM km^2 of which 41% are sedimentary basins. The sedimentary basins are divided into the Llanura Chaco Beniana, Faja Subandina, and the Altiplano. About 75% of crude oil fields discovered so far are in the Faja Subandina.

A very recent discovery in the Villamontes field may increase significantly the reserve by 30 MM bbl, pending confirmation of these reserves. However, caution must be taken with these figures since they are still very preliminary.

Exploration

Petroleum exploration in Bolivia started in the 1920s, carried out mostly by large international companies, and led to the first discovery in 1927 in Camiri. A total of 323 exploration wells were drilled in Bolivia through 1986 with a discovery rate per exploration well of 1.3 million bbl of oil and condensates, and 17.2 billion cu. feet of gas. Exploration in Bolivia has been restricted to known basins which are gas prone. The National Petroleum Company (YPFB) and Occidental, indicate that there is a possibility to find large liquid reserves in the north western and south eastern regions of the Chaco Beniano basin although a greater risk is involved.

Bolivia is a country which is relatively unexplored with only 0.6 wells per 1,000 km^2 of sedimentary basins, while the United States has 380 and Canada 47 for the same area.

Of the 28 fields discovered in the period 1976-1985, only five (Cambeiti, Espejos, Cascabel, H. Suarez, and Techi) were crude, while the others were gas or gas condensates. As a result of that exploration activity, YPFB's reserves of crude oil and condensates were increased by 53 million bbl and the private companies by 23 million bbl. In natural gas, YPFB's reserves were increased by 3.3×10^9 CF.

Unless new fields are found, there will be a decline in liquids production resulting from the fact that many of Bolivia's fields are past their peak. To stimulate exploration, the GOB is reviewing the legal framework for private sector activities, and intends to soon promote areas for exploration by private sector companies. The GOB in assistance with the World Bank has recently initiated a study of the hydrocarbon potential in Bolivia with a selection of areas for petroleum exploration.

The hydrocarbon law sets the principle of state sovereignty over petroleum resources and assigns all direct responsibility to YPFB which may enter into operation contracts with private oil companies to carryout exploration and production activities. Contracts are of the production sharing type and may not exceed 30 years. The contractor receives in cases of discovery 40-50% of production. However, the GOB authorizes exports of hydrocarbons only after internal demand has been satisfied. The price paid to the private sector by YPFB is pegged to the Government selling price of Arab light crude. This has not been carried out in practice; there is an outstanding debt to Occidental and Tesoro. The Bolivian debt to Occidental is expected to be paid in a counter trade basis, with Argentinean goods and services, to be commercialized by Occidental. The product, to be kept in a trust fund in a U.S. bank, shall be used in investments by Occidental in Bolivia. Debts to Occidental as related to internal oil sales will be paid by the same mechanism but with no restrictions as in the case of the gas. Tesoro is waiting for an agreement to be reached between Occidental and the GOB. This is a critical issue which needs to be resolved if the government wants to attract private investors in Bolivia. Exploration in Bolivia needs to be accelerated because of the high potential and the critical balance between domestic supply and demand.

Refineries

Bolivia's three refineries, which are located at Cochabamba (27,300 bd), Santa Cruz (15,000 bd), and Sucre (3,000 bd), represent twice the demand and operate considerably below capacity. They are all of the simple hydroskimming type which is suitable for local crude. Bolivia's crude are particularly light with densities of the order of 47-50° API (oil fields) and 57-70° API (condensate fields) so that they yield a relatively high proportion of light products (LPG, gasoline), and a low one of heavy products (diesel, fuel oil).

A computerized refinery model should be set up to take into account the specific circumstances of the Bolivian environment. The optimum use of the refineries needs to be determined, and consider the moment when Bolivia may be an importer to determine importing refined products or crude (if so, at what quality). A reliable refining model would help optimize for a given level of demand for oil products, and of crude oil supply, the output of the refineries.

An energy audit in the refineries is also recommended, in unison with an audit of YPFB's internal consumption which is about 10% of the national consumption. In the refineries alone, internal use and losses average 8% of the feedstock (against 45% usually), notwithstanding the fact that they use increasing quantities of natural gas as fuel. The potential for energy savings at the refineries needs to be determined.

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PRODUCCION HISTORICA Y PROYECCION
PETROLEO Y CONDENSADO

(miles de barriles)

CAMPOS	RESERVAS Probadas 31/12/86	Probables 01/01/87	Remanentes 31/12/97	PRODUCCION 1980	1981	1982	1983	1984	1985	1986	PROYECCION 1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Distrito Sur																					
Bermejo	3,128.5	1,390.0	4,122.5	43.8	36.6	31.6	39.5	33.1	38.4	40.4	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0	36.0
Buena Vista	10.6		7.0	10.4	13.9	12.5	10.2	11.4	11.3	9.8	3.6										
Caigua	3.8		3.8	90.6	34.4	25.8	31.3	17.6	0.3	4.0											
Camatindi	50.1		1.1	25.5	27.7	32.3	24.0	25.7	13.3	20.5	18.0	14.0	11.0	6.0							
Cambeiti	140.0	1,103.8	1,111.1	95.8	78.3	48.7	45.0	39.5	30.1	26.7	26.6	22.2	18.2	15.3	12.8	10.6	8.8	7.3	6.0	4.9	
Camiri	1,077.4	7,548.0	4,895.7	373.2	323.2	287.5	252.0	213.6	170.0	159.2	157.0	140.0	125.0	111.2	100.0	225.0	766.5	766.5	730.0	715.0	693.5
Guairuy	39.1		17.2	42.6	33.0	23.8	14.0	17.8	9.9	11.3	11.0	7.3	3.6								
Monteagudo	13,870.9	1,239.0	6,203.7	1,077.2	892.8	797.0	819.5	734.2	689.2	616.4	548.9	491.3	440.2	391.8	348.7	307.6	1606.0	1421.0	1250.7	1113.0	925.0
San Alberto	53.5		2.6	23.5	25.2	21.3	7.9	9.8			7.3	11.0	14.6	11.0	7.0						
Tatarenda	79.3		4.3	96.0	89.9	92.4	74.8	67.6	53.9	61.5	30.0	20.0	15.0	10.0							
Toro	73.6		3.5	41.2	40.6	35.1	44.0	40.6	45.3	40.6	25.0	20.0	15.0	10.0							
Espino	47.6		4.0	106.0	241.0	223.0	208.0	90.0	50.0	17.0	14.5	11.0	9.0	5.5	3.6						
San Roque	3,023.8	2,861.0	181.3		1.0	2.0	2.0			148.9	339.0	365.0	365.0	730.0	905.5	789.4	630.7	504.8	401.7	323.0	260.4
Vuelta Grande	32,920.1	17,385.0	34,390.5	4.3	2.4	0.7	140.0	467.8	424.1	337.1	350.0	400.0	2295.5	2540.4	2762.2	1972.8	1610.0	1309.0	1191.2	1000.0	851.0
Escondido	10,016.0		3,876.0												730.0	1374.0	1095.0	890.6	711.7	671.6	664.3
Villamontes	7,500.0	3,900.0	1,232.3								324.2	1036.7	2171.7	1629.0	1222.7	916.1	687.3	515.4	386.9	290.2	217.5
Sub Total	72,842.0	35,346.8	56,037.2	2,031.9	1,840.9	1,633.8	1,716.2	1,768.9	1,543.9	1,521.4	1,891.1	3,344.5	5,519.8	5,496.2	5,708.5	5,384.5	6,464.3	5,530.6	4,716.7	4,157.7	3,717.7
Distrito Centro																					
Espejos	15.6		15.6						2.0												
H. Suarez R.	1,101.9		164.9						102.5				95.0	109.0	117.0	116.0	112.0	105.0	99.0	95.0	89.0
Montecristo	405.9	1,441.4	1,736.2	0.1			2.0	11.2	10.5	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1	10.1
Palmar	562.8		317.0	289.2	294.5	247.7	190.1	114.9	65.4	44.3	40.0	35.0	31.0	27.0	23.8	20.7	17.6	15.5	13.2	11.7	10.3
Yapacani	2,710.2	401.0	1,436.1				2.0	1.0					114.0	182.5	226.0	226.0	219.0	211.7	197.1	193.5	186.1
Santa Cruz	4,286.6	4,373.6	2,236.3					34.0	190.5	318.3	525.9	761.0	761.0	761.0	733.6	655.1	573.0	498.2	436.1	381.4	337.6
Warnes	82.7	95.2	177.9						1.0												
Naranjillos	895.8		178.6									47.0	116.8	102.9	90.8	89.3	70.8	62.0	55.1	48.5	43.0
Palacios	957.4		513.4														50.0	102.0	102.0	97.0	93.0
*Enconada	258.1		61.1														40.0	45.0	42.0	38.0	32.0
Sirari	1,348.0	1,822.6	2,365.1														135.0	164.0	182.5	180.0	164.0
Cascabel	997.8	3,415.0	846.3													981.8	778.9	617.9	490.1	389.0	308.8
Sub Total	13,642.8	11,629.6	10,040.5	289.3	294.5	247.7	194.9	161.1	452.0	372.7	576.0	853.1	1,127.9	1,192.5	1,201.3	2,070.0	2,006.4	1,831.4	1,627.2	1,444.2	1,273.9
Division Santa Cruz																					
Caranda	3,181.5	2,248.5	4,488.9	454.4	419.9	404.6	411.8	318.1	205.2	137.4	196.2	153.3	129.4	96.7	80.3	71.2	56.6	49.3	43.8	36.5	32.8
La Peña	8,281.8	1,100.0	50.8	633.9	477.4	370.2	746.5	870.8	1,302.3	1,272.4	1,971.0	2,099.1	1,532.3	1,124.5	824.9	605.9	444.2	325.9	239.0	175.2	
Colpa	1,624.6	656.1	1,623.3	461.4	365.3	290.3	130.0	184.0	148.2	129.4	112.0	94.9	82.1	71.2	62.0	54.7	45.6	41.9	34.6	31.0	27.4
Rio Grande	18,004.0		12,017.5	3,757.3	3,257.7	2,559.8	1,953.6	1,572.7	1,383.4	1,054.5	1,106.7	949.0	806.6	722.7	580.3	492.7	419.7	354.0	299.3	255.5	•
Sub Total	31,091.9	4,008.6	18,180.5	5,307.0	4,520.2	3,912.9	3,241.8	2,945.6	3,044.0	2,633.7	3,355.9	3,255.3	2,541.4	2,015.1	1,547.5	1,224.5	966.1	771.1	616.7	478.2	60.2
Otros Campos				0.7	1.4	40.6	76.1	128.5	1.2	0.7											
TOTAL YPFB	117,576.7	50,977.0	84,286.2	7,629.0	6,657.0	5,835.0	5,227.0	5,098.0	5,061.0	4,336.5	5,853.0	7,482.9	9,189.1	8,703.8	8,457.3	8,819.0	9,436.8	8,133.1	6,960.6	6,100.1	5,051.8
Occidental																					
Tita	160.3		110.3	730.0	501.0	367.4	281.5	186.0	159.3	93.0	50.0										
Porvenir	4,566.0		686.3		361.0	2,102.0	2,021.0	1,911.0	1,561.3	1,322.3	1,160.7	833.0	584.0	383.0	365.0	328.5	109.5	73.0	36.5	25.5	11.0
Sub Total	4,726.3	0.0	796.6	730.0	862.0	2,469.4	2,302.5	2,097.0	1,711.6	1,415.3	1,210.7	833.0	584.0	383.0	365.0	328.5	109.5	73.0	36.5	25.5	11.0
Tesoro																					
La Vertiente	602.0		(450.4)	345.0	572.5	613.9	571.3	520.3	471.6	472.1	418.4	265.0	173.0	105.0	91.0						
Taiguati	859.0	1,187	2,046.0																		
Los Suris	464.0	1,539	2,003.0																		
Sub Total	1,925.0	2,726.0	3,598.6	345.0	572.5	613.9	571.3	520.3	471.6	472.1	418.4	265.0	173.0	105.0	91.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Compañias	6,651.3	2,726.0	4,395.2	1,075.0	1,434.5	3,083.3	2,873.8	2,617.3	2,183.2	1,887.4	1,629.1	1,098.0	757.0	488.0	456.0	328.5	109.5	73.0	36.5	25.5	11.0
TOTAL Cdo. Y Con	124,228.0	53,703.0	88,681.4	8,703.9	8,091.5	8,918.3	8,100.8	7,621.3	7,244.2	6,423.9	7,482.1	8,580.9	9,946.1	9,191.8	8,913.3	9,227.5	9,546.3	8,206.1	6,997.1	6,125.6	5,062.8
Gasolina Natural																					
Division Santa Cruz*				896.0	877.6	794.5	727.8	518.2	593.4	539.9	559.3	527.2	485.4	447.1	410.6	375.9	363.1	319.3	293.8	248.2	
Otros																					
Santa Cruz												164.2	155.1	146.0	113.1	109.5	107.6	107.6	105.8	102.2	98.5
Vuelta Grande													306.6	350.4	333.9	331.0	329.2	326.6	323.7	329.1	315.7
San Roque															237.2	219.0	200.7	191.6	182.5	173.3	164.2
Total Gasolina Natural				896.0	877.6	794.5	727.8	518.2	593.4	539.9	559.3	693.4	947.1	943.5	1,074.8	1,035.4	1,000.6	945.1	905.8	843.8	578.4
Total Hidrocarburos Liquidos				9,599.9	8,969.1	9,712.8	8,828.6	8,219.5	7,837.6	6,963.8	8,041.4	9,244.3	10,893.2	10,135.3	10,008.1	10,262.9	10,546.9	9,151.2	7,902.9	6,969.4	5,641.2

NOTAS: 1) Las "Reservas Probadas", al 31/12/86, incluyen el campo Villamontes.
2) YPFB cuantifica 916,800 barriles de "Reserva Probada", no incluida en este cuadro por tratarse de campos de gas que a la fecha se considera antieconomico su explotacion, dichos campos son: Boqueron, Bulo Bulo, Huayco, Los Monos, Madrejones, Ñupuco, Palometas, Rio Seco, Sararenda, Santa Rosa, Tacobo y Tigre.

29-Jun-97

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PRODUCCION Y RESERVAS DE PETROLEO Y CONDENSADOS

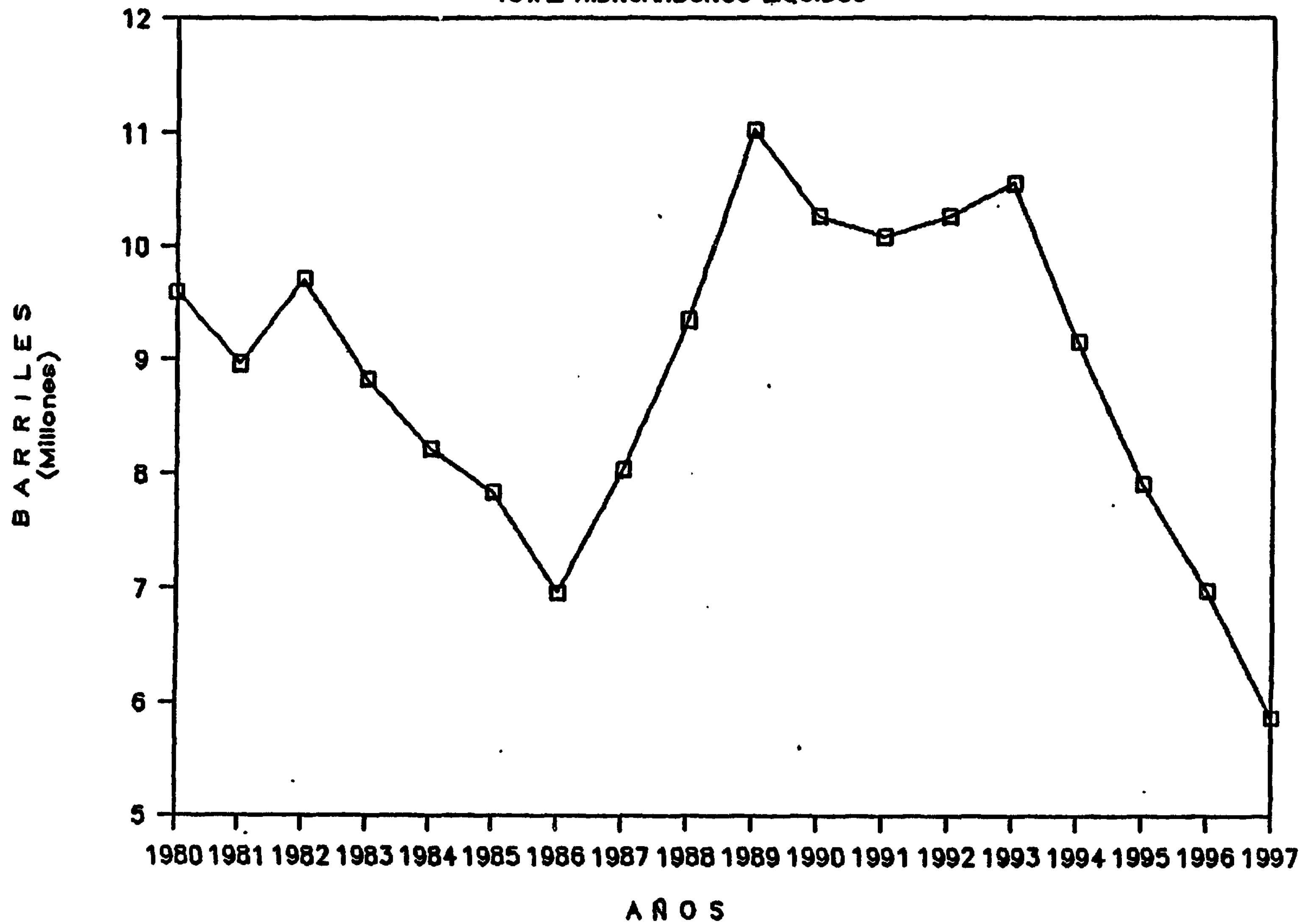
Campos	Volumen Original In Situ	Probadas Originales	Probadas al 31-12-86	Relacion Res/Prod (anos) 31-12-86	% de Declin. Anual 1980-86	Año desc. o Inicio Prod.	Acum. (Dic. 86) 000's bls		PRODUCCION (miles de barriles)													
									1980		1981		1982		1983		1984		1985		1986	
	000's Bbl						Pet.	Cond.	Pet.	Cond.	Pet.	Cond.	Pet.	Cond.	Pet.	Cond.	Pet.	Cond.	Pet.	Cond.	Pet.	Cond.
Distrito Sur																						
Bermejo	16,611.4	7,234.0	3,128.5	77	1.34%	1924	4,167.6		43.0		36.6		31.6		39.5		33.1		38.4		40.4	
Buena Vista	1,262.4	270.5	10.6	1	0.98%	1956	259.9		18.0		13.9		12.5		10.2		11.4		11.3		9.8	
Caigua	15,674.2	6,251.6	3.8	1	40.31%	1973	6,247.8		90.6		34.0		25.0		31.3		17.6		8.3		4.6	
Camatindi	6,113.5	946.0	50.1	2	3.55%	1929	895.9		23.5		27.7		32.3		24.0		25.7		13.5		20.5	
Cambeiti	6,565.9	1,054.2	140.0	5	19.10%	1976	914.2		93.0		78.3		48.7		43.0		39.3		30.1		26.7	
Camiri	150,051.4	57,745.5	1,877.4	12	13.24%	1927	40,310.1		371.2		323.2		287.5		252.0		213.0		170.0		159.2	
Espino	4,011.1	990.0	47.6	3	26.29%	1979		942.4		106.0		241.0		223.0		200.0		90.0		50.0		17.0
Guairuy	9,509.6	3,299.7	39.6	3	19.03%	1967	3,260.0		42.0		33.0		25.0		14.0		17.0		9.9		11.5	
Huayco	83.0	66.7	66.5	-		1982	0.2															
Los Monos	3,633.0	382.1	5.6	-		1956	376.5															
Monteagudo	107,007.1	44,066.0	13,870.9	23	6.00%	1967	30,189.9		1,017.2		672.0		797.0		819.5		734.2		689.2		616.4	
San Roque	8,630.0	3,180.0	3,023.8	30		1981		156.2				1.0		2.0		2.0						148.9
San Alberto	3,621.0	657.8	52.5	-	100.00%	1966	605.3		25.5		25.2		21.5		7.9		9.0					
Sanandita	5,495.6	2,273.8	69.4	-		1926	2,204															
Tatarenda	11,055.6	7,386.1	79.2	6	7.15%	1964	7,306.9		96.0		84.9		92.4		70.8		67.6		53.9		61.5	
Tigre	400.7	100.6	10.6	-		1967	90.0															
Toro	16,290.6	3,087.7	72.5	2	-2.00%	1954	3,015.2		41.2		46.6		33.1		44.0		40.6		45.3		40.6	
Vuelta Grande	69,112.3	34,352.4	32,928.1	92	-109.17%	1978		1,424.3		4.3		2.4		0.7		194.0		467.0		424.1		337.1
Escondido		10,016.0	10,016.0	-		1980																
Ñupuco	287.0	291.0	290.9	-		1977/85		0.1														
Barredero	3.5	1.2	0.0			1950	1.2															
Madrejones	4,813.6	1,203.4	0.2				1,203.2															
Villamontes	38,000.0	7,550.0				1987																
Sub Total	400,645.3	192,841.1	65,495.2	12.2			109,575.5	2,523.0	1,951.7	110.3	1,596.6	244.4	1,408.1	225.7	1,362.2	334.0	1,211.0	557.0	1,069.7	474.1	998.6	523.0
Distrito Centro																						
Cascabel	16,000.0	1,000.0	997.8	-		1985	2.2															
Espejos	625.0	123.0	15.6	-		1976	107.4												2.0			
H. Suarez R.	5,543.3	1,526.1	1,101.9	-		1982	424.1	0.1											182.5			
Montecristo	3,095.0	440.0	405.9	40	-133.14%	1976	64.6	1.5		0.1						2.0		11.2		10.5		10.1
Palmar	7,328.9	2,221.0	562.0	-	26.05%	1984	727.4	931.6		289.2		294.5		247.7		190.1		114.9		65.4		44.3
Sirari	4,705.0	1,370.0	1,368.0	-		1985		2.0														
Tacobo	916.0	84.9	84.9	-		1982																
Yapacani	7,109.5	2,710.2	2,710.2	-		1968/82		0.0								2.0		1.0				
Santa Cruz	13,840.5	4,634.9	4,294.6	13		1964/84		340.3										34.0		190.5		310.3
Warnes	304.1	83.6	82.7	-		1985		0.9												1.0		
Naranjillos	1,042.6	695.0	695.0	-		1964																
Palometas	204.3	199.0	199.0	-		1973																
Palacios	1,001.0	987.4	987.4	-		1970																
Santa Rosa	131.4	83.7	83.7	-		1973																
Enconada	380.0	258.1	258.1	-		1972																
Boquerón	140.1	78.8	78.4	-		1985		0.4														
Rio Seco	131.5	58.9	58.9	-		1970																
Bulo Bulo	75.7	53.0	53.0	-		1966																
Sub Total	62,929.1	17,018.0	14,200.7	38			1,326.7	1,484.6	0.0	289.5	0.0	294.5	0.0	247.7	0.0	194.9	0.0	161.1	184.5	267.5	0.0	372.7
Division Santa Cruz																						
Caranda	189,331.0	57,231.6	3,181.5	23	10.07%	1960	53,832.7	217.4	454.4		619.9		494.6		367.9	43.9	295.3	22.8	192.1	12.1	70.0	66.6
Colpa	60,939.0	19,636.0	1,624.6	13	19.10%	1961	8,371.9	9,639.5		461.6	34.5	221.3	52.6	162.3	33.6	96.4	15.1	170.9	60.2	107.9	69.0	60.4
Rio Grande	116,726.0	77,019.7	18,004.0	16	10.58%	1962		59,015.7		3,757.3		3,257.9		2,560.0		1,953.7		1,372.0		1,388.5		1,094.5
La Peña	76,336.7	32,338.1	8,281.0	7	-12.32%	1965	23,082.0	244.3	603.9		380.7	89.0	445.7	120.5	735.5	11.0	860.7	10.2	1,293.0	7.3	1,199.0	72.6
Sub Total	451,332.7	186,415.4	31,091.9	12			85,286.6	69,116.9	1,058.3	4,218.7	802.9	3,568.2	982.9	2,880.8	1,137.0	2,105.0	1,169.1	1,778.7	1,545.3	1,515.0	1,339.6	1,294.1
Otros Campos	60,233.1	12,407.2	5.7					4,272	0.0	0.7	0.0	56.2	0.0	51.9	0.0	52.7	0.0	107.5	0.0	42.0	0.0	0.0
TOTAL YPFB	1,053,337.2	400,753.7	110,993.5	25			196,106.8	77,396.9	3,010.0	4,619.0	2,037.5	4,163.2	2,391.0	3,372.1	2,499.2	2,706.6	2,380.1	2,603.1	2,802.5	2,299.4	2,338.0	2,187.8
Occidental																						
Tita		4,185.1	160.3	2	29.07%	1976		4,029.0		730.0		501.0		367.4		231.5		186.0		120.3		93.0
Porvenir		13,859.0	4,566.0	3		1976		9,279.3				341.0		2,102.0		2,021.0		1,911.0		1,561.3		1,322.3
Techi		268.5	5.7	-		1977	262.0															
Sub Total		18,312.6	4,732.0	3				13,304.3	0.0	730.0	0.0	842.0	0.0	2,469.4	0.0	2,252.5	0.0	2,097.0	0.0	1,711.6	0.0	1,415.3
Tesoro																						
La Vertiente		4,284.0	602.0	1	-5.37%	1977	157.0	3,523.0		345.0		372.5		613.9		371.3		320.3		471.6		472.1
Taiguati		839.0	839.0	-		1981																
Los Suris		464.0	464.0	-		1981																
Sub Total		5,607.0	1,925.0	4				3,523.0	0.0	345.0	0.0	372.5	0.0	613.9	0.0	371.3	0.0	320.3	0.0	471.6	0.0	472.1
Total Consócios		23,919.6	6,657.0	4			157.0	16,827.3	0.0	1,075.0	0.0	1,414.5	0.0	3,083.3	0.0	2,873.8	0.0	2,617.3	0.0	2,183.2	0.0	1,937.4
TOTAL PARCIAL		432,673.3	117,650.5	18					3,010.0	5,694.0	2,037.5	5,577.7	2,391.0	6,455.4	2,499.2	5,580.4	2,380.1	5,220.4	2,802.5	4,482.6	2,338.0	4,077.2
TOTAL CDB Y CCVO		432,673.3	117,650.5	18				270,490.0	8,703.9		8,037.1		8,846.4		8,079.5		7,600.5		7,285.1		6,415.2	
Gasolina Natural									896.0		877.6		798.5		727.8		598.2		593.4		539.9	
TOTAL CDB, CCVO Y GAS NAT									9,600		8,915		9,648		8,807		8,199		7,879		6,955	

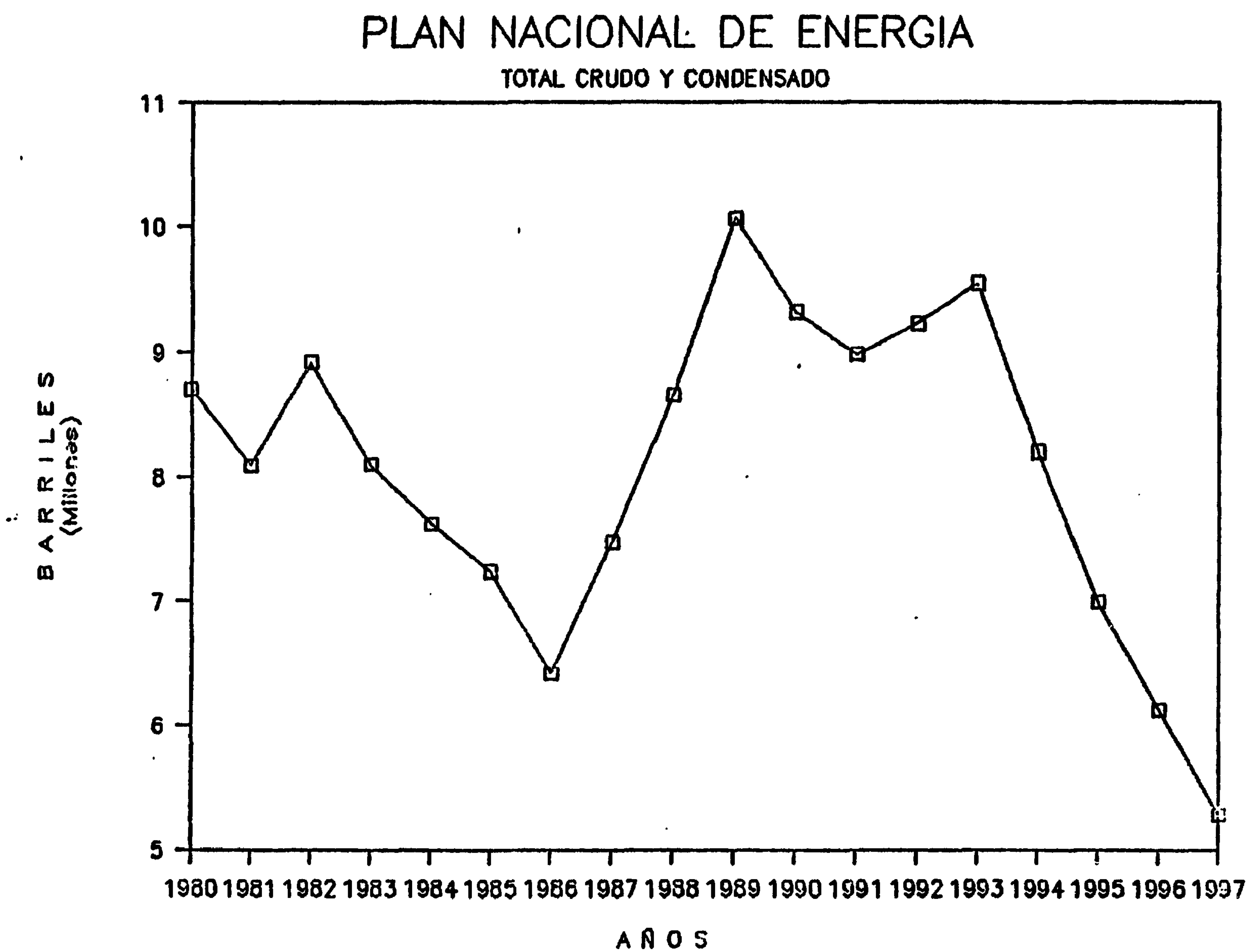
NOTA: Los valores correspondientes a "Otros Campos", son la diferencia entre la produccion total de YPFB y los subtotales de cada uno de los distritos y divisiones y se asignan arbitrariamente a la columna "Condensado".

29-Jun-87

PLAN NACIONAL DE ENERGIA

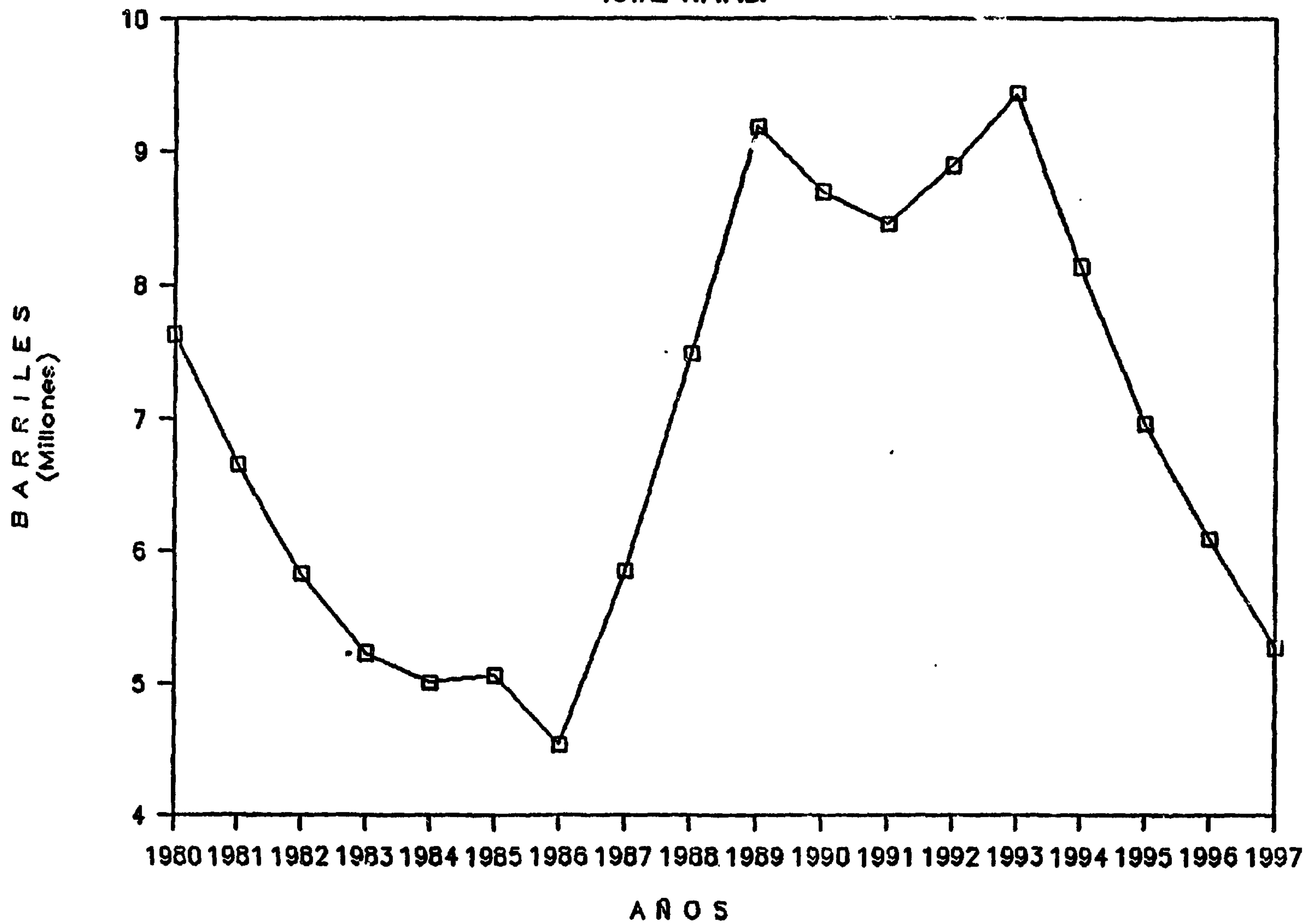
TOTAL HIDRCARBUROS LIQUIDOS




PLAN NACIONAL DE ENERGIA
TOTAL CRUDO Y CONDENSADO
BARRILES (Millones)
11
10
9
8
7
6
5
1980 1981 1982 1983 1984 1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997
AÑOS

PLAN NACIONAL DE ENERGIA

TOTAL Y.P.F.B.



B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

VENTAS HISTORICAS DE PRODUCTOS Y PROYECCION DE DEMANDA

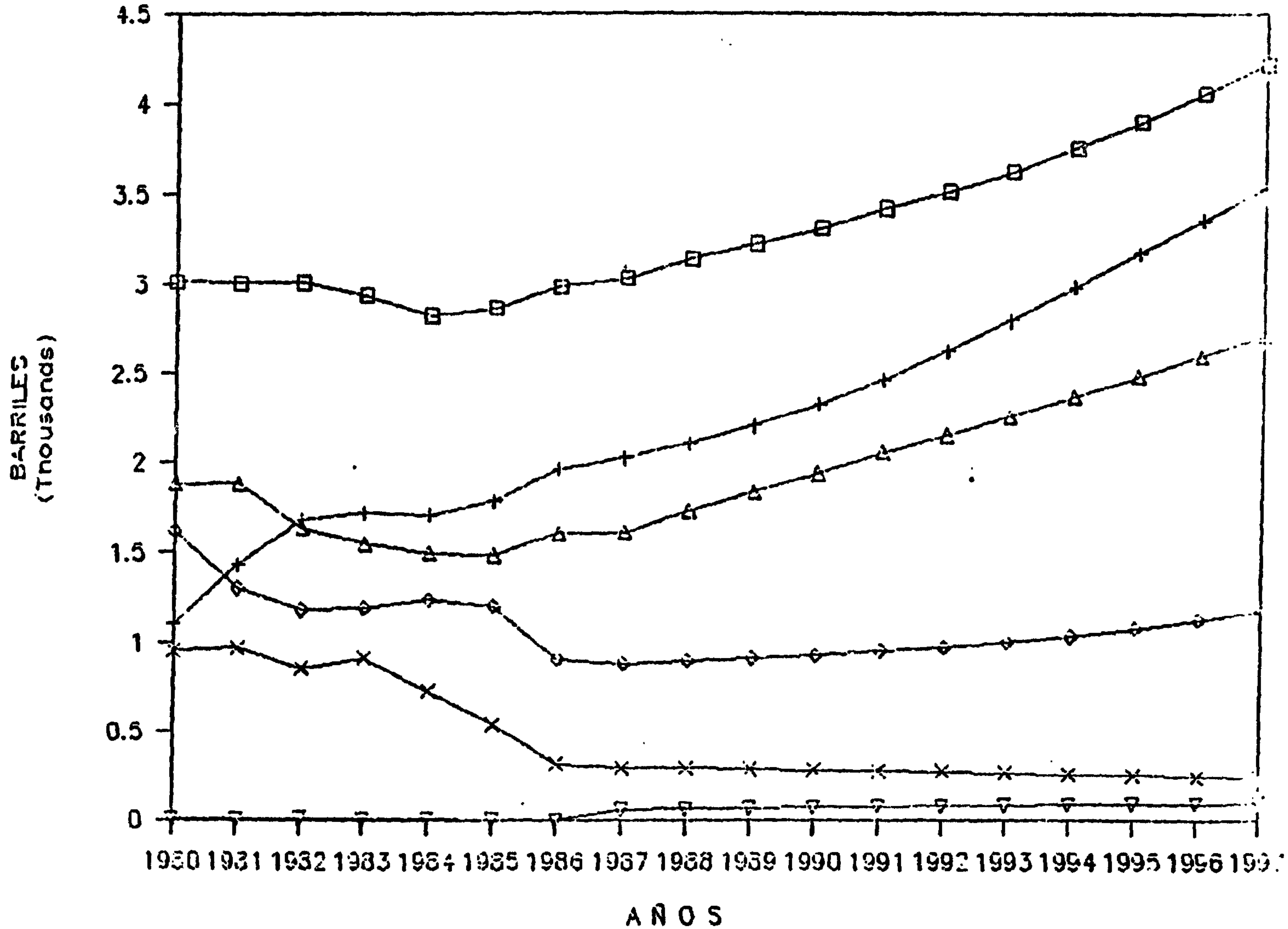
(MBBL)

	HISTORICAS							PROYECCION										
Año	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
A. Internas																		
Gasolina	2,903	2,900	2,919	2,849	2,728	2,784	2,908	2,955	3,063	3,146	3,226	3,330	3,428	3,534	3,667	3,808	3,968	4,129
Avgas	112	109	91	90	94	80	76	74	77	79	81	83	84	86	88	90	92	93
GLP	1,107	1,435	1,687	1,721	1,712	1,788	1,964	2,026	2,105	2,204	2,324	2,464	2,622	2,796	2,981	3,171	3,358	3.533
Kerosene	947	662	669	633	661	627	331	328	324	320	316	312	309	306	303	300	298	295
Jet Fuel	673	644	514	559	576	575	576	555	574	592	612	640	665	696	735	778	829	864
Diesel Oil	1,881	1,885	1,636	1,551	1,496	1,487	1,606	1,613	1,732	1,836	1,936	2,052	2,150	2,252	2,367	2,460	2,598	2,705
Fuel Oil	958	975	857	915	727	541	319	277	296	292	286	282	275	268	262	255	248	241
Otros	9	9	12	11	10	5	0	61	65	69	74	79	83	87	91	94	97	100
Tot. Ventas Internas	8,590	8,618	8,386	8,329	8,005	7,888	7,780	7,909	8,235	8,538	8,854	9,248	9,616	10,025	10,494	10,976	10,891	11,984
B. Exportaciones																		
Gasolinas	647	63	35	327	9													
GLP	76	223	428	261	173	86	24	113	138	1,465	1,557	1,482	1,290	1,102	872	630	493	369
Diesel		(278)																
Tot. Exportaciones	723	9	463	588	182	86	24	113	138	1,465	1,557	1,482	1,290	1,102	872	630		

29-Jun-97

PLAN NACIONAL DE ENERGIA

DEMANDA DE PRODUCTOS



□ 1 + 2 ◇ 3 △ 4 × 5 ▽ 6

1.- Gasolina
2.- G.L.P.
3 K
4.- Diesel Oil
5.- Fuel Oil

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM FAUD BM

BALANCE OFERTA DEMANDA DE HIDROCARBUROS LIQUIDOS

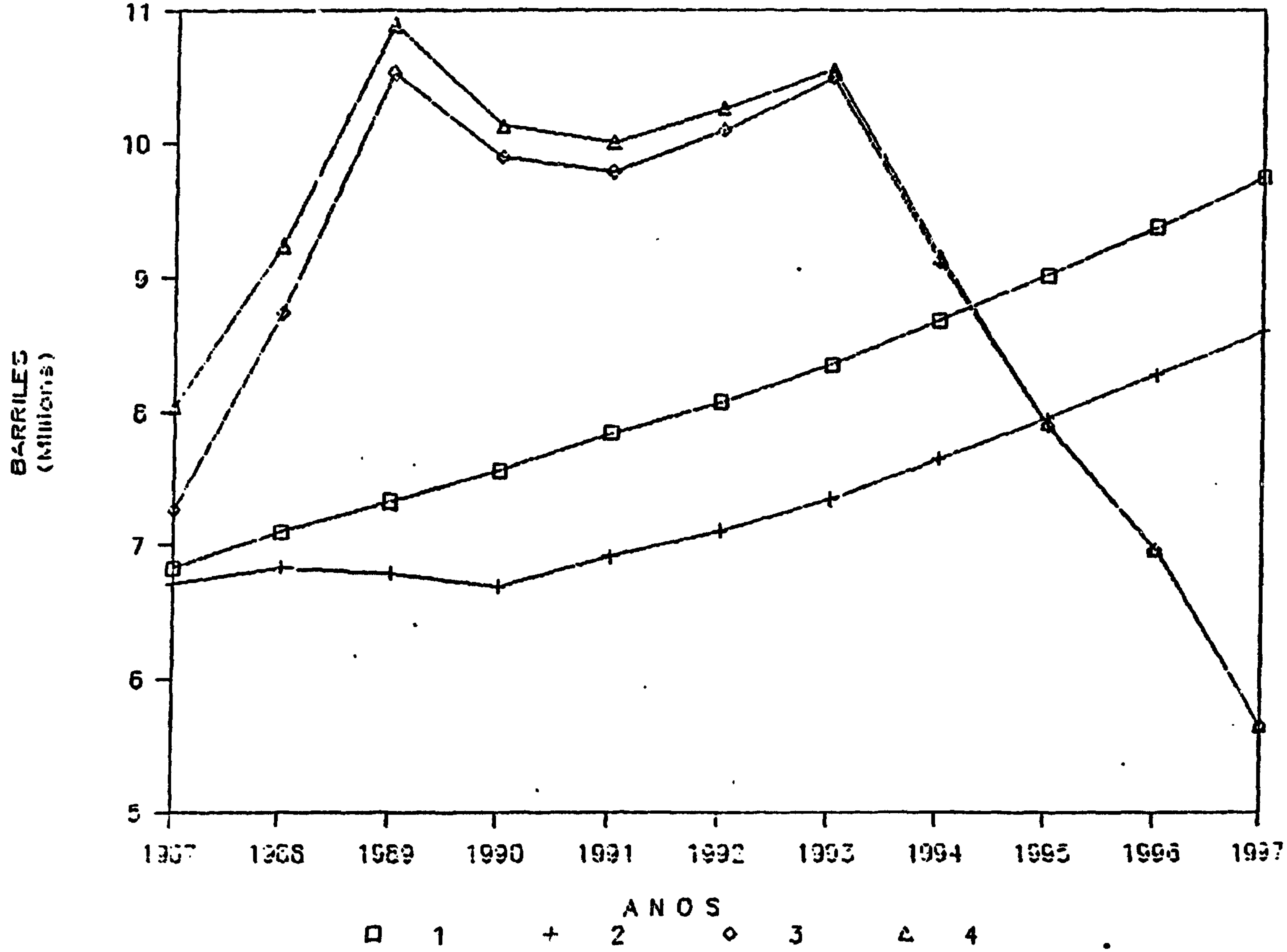
(MBBL)

	DEMANDA							OFERTA						
Años	Productos de Petroleo	Consumo Propio y Perdidas	Carga Ref. Crudo y Con Estimada	--- Sustitucion Liquidos y GLP --- por Gas Natural HCU Liquid	GLP	Total	Productos Petroleo con Sust.	Proyeccion Produccion Crudo y Con	Proyeccion Produccion Gasolina	Proyeccion Produccion Crudo, Con Gasolina Nat	Proyeccion Produccion Crudo y Con Y.P.F.B.	Alicuota Companias	Total Crudo,Cond Disponibles Y.P.F.B.	Total HCB Liquidos Disponibles Y.P.F.B.
1987	6,318	505	6,824	70	49	119	6,704	7,482	559	8,041	5,853	856	6,709	7,269
1988	6,573	526	7,099	141	125	266	6,833	8,551	693	9,244	7,463	581	6,043	6,737
1989	6,769	543	7,332	284	256	541	6,791	9,946	947	10,893	9,189	396	9,585	10,532
1990	6,998	560	7,557	451	418	867	6,689	9,192	944	10,135	8,704	255	8,958	9,902
1991	7,256	580	7,837	470	457	926	6,910	8,913	1,095	10,008	8,457	237	8,654	9,759
1992	7,469	598	8,067	489	472	961	7,106	9,228	1,035	10,263	8,899	164	9,043	10,079
1993	7,725	618	8,343	508	483	996	7,347	9,546	1,001	10,547	9,437	55	9,492	10,492
1994	8,030	642	8,672	528	505	1,034	7,639	8,206	945	9,151	8,133	37	8,170	9,115
1995	8,344	668	9,012	549	523	1,072	7,940	6,997	906	7,903	6,961	18	6,379	7,285
1996	8,682	695	9,377	571	541	1,112	8,265	6,126	844	6,969	6,100	13	6,113	6,957
1997	9,020	722	9,742	594	559	1,153	8,588	5,063	578	5,641	5,052	6	5,057	5,636

29-Jun-97

PLAN NACIONAL DE ENERGIA

BALANCE OFERTA-DEMANDA HCU LIQUIDOS



1.- Demanda
2.- Demanda con Sust.
3.- Total HCU líquidos disponibles YPFB
4.- Producción de Crudo Condensado y Gasolina Natural.

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

G A S O L I N A S

(Metros Cubicos)

REFINERIA	(1) DE: Gasolina Blanca	(2) DE: Produccion Intermedia	(3) DE: Gasolinas Elaboradas	(4) DE: Butano	(5) A: Pet.Crudo Slop	(6) A: Otros prod. Elaborados	
Sucre	46.3				626.2		(a)
	17,256.9		13,003.4		342.8	13,003.4	(b)
Subtotal	17,303.2	0.0	13,003.4	0.0	969.0	13,003.4	
Santa Cruz		12,527.5	260.0		50.1	38.5	(a)
		702.9	38.5	1,946.4	72.6	260.0	(b)
		63,408.0					(b)
		64,935.0					(b)
		679.9		29.8			(c)
		171.5					(c)
		882.9					(c)
		25,001.1					
		29.2					
	0.0	168,338.0	298.5	1,976.2	122.7	298.5	
Cochabamba		36.6			6.0		(b)
		93,522.7					(b)
		135,542.1					(b)
		549.1	22.0	51.6		22.0	(c)
		1,124.5		5,060.3			(c)
		38,633.8					(c)
	0.0	269,408.8	22.0	5,111.9	6.0	22.0	
T O T A L E S	17,303.2	437,746.8	13,323.9	7,088.1	1,097.7	13,323.9	

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)+(2)+(4)-(5)	461,040.4	2,899.9
- Otros productos = (3) - (6)	0.0	0.0
TOTAL PRODUCCION BRUTA	461,040.4	2,899.9
- Perdidas en Refinerias .	4,193.0	26.4
- Demasias en Refinerias .	1,310.6	8.2
- Saldo en tanques-Refinerias al 1/1/85.	24,688.9	155.3
- Saldo en tanques-Refinerias al 31/12/85.	22,782.6	143.3
TOTAL PRODUCCION NETA DISPONIBLE	460,064.3	2,893.9

REFERENCIAS

(a) Gasolina 92 Octanos.
(b) Gasolina Especial.
(c) Gasolina Premium.
(2) Productos intermedios:
Platformado,
Platformado redestilado,
Gasolinas media y liviana

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1985"

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

K E R O S E N E

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Productos Elaborados	(3) A: Fuel Oil	(4) A: Petroleo Crudo	(5) A: Diesel Oil	(6) A: Slop	(7) A: Jet Fuel
Sucre	9,043.7	0.0 0.0	0.0	0.0	733.5	8.3	0.0
Subtotal	9,043.7	0.0	0.0	0.0	733.5	8.3	0.0
Santa Cruz	24,658.6	0.0	2,069.7	10,471.4	199.2	43.0	0.0
Subtotal	24,658.6	0.0	2,069.7	10,471.4	199.2	43.0	0.0
Cochabamba	89,109.4	0.0	0.0	0.0	0.0	0.0	130.6
Subtotal	89,109.4	0.0	0.0	0.0	0.0	0.0	130.6
T O T A L	122,811.7	0.0	2,069.7	10,471.4	932.7	51.3	130.6

R E S U M E N

	(M3)	(MBBL)
- Produccion = (1)-(3)-(4)-(5)-(6)-(7)	109,156.0	686.6
- Otros productos = (2)	0.0	0.0
TOTAL PRODUCCION BRUTA	109,156.0	686.6
- Perdidas en Refinerias .	76.2	0.5
- Demasias en Refinerias .	37.9	0.2
- Saldo en tanques-Refinerias al 1/1/85.	4,952.3	31.1
- Saldo en tanques-Refinerias al 31/12/85.	14,646.7	92.1
TOTAL PRODUCCION DISPONIBLE	99,423.3	625.4

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1985"

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

G. L. P.

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: C4/C3	(3) A: Petroleo Crudo	(4) A: G.C.M. Export.	(5) A: Slop	
Sucre	2,069.1	0.0	1,200.3	0.0	0.0	
Subtotal	2,069.1	0.0	1,200.3	0.0	0.0	
Santa Cruz	218,820.0					(a)
	413.0					(b)
	12,957.0					(c)
		27,601.0	0.0	13,283.6	0.0	
Subtotal	232,190.0	27,601.0	0.0	13,283.6	0.0	
Cochabamba	0.0	53,290.6	0.0	0.0	4,056.0	
Subtotal	0.0	53,290.6	0.0	0.0	4,056.0	
T O T A L E S	234,259.1	82,891.6	1,200.3	13,283.6	4,056.0	

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)-(3)-(5)	229,002.8	1,440.4
- Otros productos = (2)	82,891.6	521.4
TOTAL PRODUCCION BRUTA	311,894.4	1,961.8
- Perdidas en Refinerias .	3,075.0	19.3
- Demasias en Refinerias .	2,927.0	18.4
- Saldo en tanques-Refinerias al 1/1/85.	1,545.7	9.7
- Saldo en tanques-Refinerias al 31/12/85.	1,380.4	8.7
TOTAL PRODUCCION NETA DISPONIBLE	311,911.7	1,961.9

REFERENCIAS

Produccion de planta

(a) Rio Grande segun GID
(b) Camiri segun DPL
(c) Colpa segun DPL

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1985"

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

D I E S E L O I L

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Gasolina Blanca	(3) DE: Kerosene	(4) DE: Productos Elaborados	(5) A: Petroleo Crudo	(6) A: Combustible	(7) A: Fuel Oil	(8) A: Slop	(9) A: Combustible Liquido
Sucre	12,613.4	81.2	733.5	19.4	861.5	60.4	0.0	14.1	0.0 (a
Subtotal	12,613.4	81.2	733.5	19.4	861.5	60.4	0.0	14.1	0.0
Santa Cruz	132,055.1	1,280.2 332.8	199.2	0.0	65.7	0.0	0.0	73.8	0.0 (
Subtotal	132,055.1	1,613.0	199.2	0.0	65.7	0.0	0.0	73.8	0.0
Cochabamba	95,317.7	32,112.8	0.0	0.0	19.2	0.0	10,715.2	192.0	981.9
Subtotal	95,317.7	32,112.8	0.0	0.0	19.2	0.0	10,715.2	192.0	981.9
T O T A L	239,986.2	33,807.0	932.7	19.4	946.4	60.4	10,715.2	279.9	981.9

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)-(5)-(6)-(7)-(8)-(9)	227,002.4	1,427.8
- Otros productos =(2)+(3)+(4)	34,759.1	218.6
TOTAL PRODUCCION BRUTA	261,761.5	1,646.5
- Perdidas en Refinerias .	174.9	1.1
- Demasias en Refinerias .	172.1	1.1
- Saldo en tanques-Refinerias al 1/1/85.	23,339.4	146.8
- Saldo en tanques-Refinerias al 31/12/85.	34,372.7	216.2
TOTAL PRODUCCION NETA DISPONIBLE	250,725.4	1,577.1

REFERENCIAS

+ Est.No. 1.
(a) Fuel Oil
(b) Gasolina Media

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1985"

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

F U E L O I L

REFINERIA	(1) DE: Diesel Oil	(2) DE: Gasolina Blanca	(3) DE: Kerosene	(4) DE: Crudo Reducido	(5) DE: Petroleo Crudo	(6) A: Petroleo Crudo	(7) A: Combustible	
Sucre	0.0	5,440.6	0.0	9,945.7	0.0	35.6	682.9	
Subtotal	0.0	5,440.6	0.0	9,945.7	0.0	35.6	682.9	
Santa Cruz	0.0	4,305.4 0.0	2,069.7	12,331.3	0.0	16,019.6	0.0	(c)
Subtotal	0.0	4,305.4	2,069.7	12,331.3	0.0	16,019.6	0.0	
Cochabamba	10,715.2	17,498.8 29,354.8	0.0	8,350.4	0.0	0.0	557.0	(c) (d)
Subtotal	10,715.2	46,853.6	0.0	8,350.4	0.0	0.0	557.0	
T O T A L	10,715.2	56,599.6	2,069.7	30,627.4	0.0	16,055.2	1,239.9	

R E S U M E N

	(M3)	(MBBL)
- Produccion = (4)-(6)-(7)	13,332.3	83.9
- Otros productos = (1)+(2)+(3)+(5)	69,384.5	436.4
TOTAL PRODUCCION BRUTA	82,716.8	520.3
- Perdidas en Refinerias .	312.9	2.0
- Demasias en Refinerias .	383.3	2.4
- Saldo en tanques-Refinerias al 1/1/85.	8,374.2	52.7
- Saldo en tanques-Refinerias al 31/12/85.	11,126.7	70.0
TOTAL PRODUCCION NETA DISPONIBLE	80,034.7	503.4

REFERENCIAS

(c) Gasolina Liviana
(d) Gasolina Media

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1985"

29-Jun-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

J E T F U E L

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Kerosene	(3) A: Solvente	(4) A: Slop
Sucre	3,376.0	0.0	0.0	0.0
	0.0			
Subtotal	3,376.0	0.0	0.0	0.0
Santa Cruz	53,282.2	0.0	20.6	64.8
Subtotal	53,282.2	0.0	20.6	64.8
Cochabamba	44,488.7	0.0	0.0	5.8
Subtotal	44,488.7	0.0	0.0	5.8
T O T A L	101,146.9	0.0	20.6	70.6

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)-(3)-(4)	101,055.7	635.6
- Otros productos = (2)	0.0	0.0
TOTAL PRODUCCION BRUTA	101,055.7	635.6
- Perdidas en Refinerias .	151.0	0.9
- Demasias en Refinerias .	112.4	0.7
- Saldo en tanques-Refinerias al 1/1/85.	5,530.1	34.8
- Saldo en tanques-Refinerias al 31/12/85.	8,700.9	54.7
TOTAL PRODUCCION NETA DISPONIBLE	101,017.1	635.4

FUENTE: Elaborado con informacion extractada del "Movimiento de produccion de G.I.D. Año 1985"

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

A V G A S

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Isopentano	(3) A: Slop
Santa Cruz	4,414.0	553.8	27.0
Subtotal	4,414.0	553.8	27.0
Cochabamba	6,448.9	2,531.5	11.8
Subtotal	6,448.9	2,531.5	11.8
T O T A L	10,862.9	3,085.3	38.8

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)-(3)	10,824.1	68.1
- Otros productos = (2)	3,085.3	19.4
TOTAL PRODUCION BRUTA	13,909.4	87.5
- Perdidas en Refinerias .	570.5	3.6
- Demasias en Refinerias .	159.7	1.0
- Saldo en tanques-Refinerias al 1/1/85.	1,892.6	11.9
- Saldo en tanques-Refinerias al 31/12/85.	709.1	4.5
TOTAL PRODUCCION NETA DISPONIBLE	14,682.1	92.4

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1985"

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

G A S O L I N A B L A N C A

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Gasolinas liv y med	(3) A: Petroleo Crudo	(4) A: Fuel Oil	(5) A: Gasolina Especial	(6) A: Diesel Oil
Sucre	22,406.7	0.0	2,719.8	5,440.6	17,256.9 46.3	81.2
Subtotal	22,406.7	0.0	2,719.8	5,440.6	17,303.2	81.2
Santa Cruz		14,070.8	9,031.5	0.0	0.0 0.0 0.0	5.6
Subtotal	0.0	14,070.8	9,031.5	0.0	0.0	5.6
Cochabamba	0.0 0.0	197.0	0.0	0.0	0.0 0.0	0.0
Subtotal	0.0	197.0	0.0	0.0	0.0	0.0
T O T A L	22,406.7	14,267.8	11,751.3	5,440.6	17,303.2	86.8

R E S U M E N

	(M3)	(MBBL)
- Produccion = (1)+(2)-(3)-(4)-(5)-(6)	2,092.6	13.2
- Otros productos *	0.0	0.0
TOTAL PRODUCCION BRUTA	2,092.6	13.2
- Perdidas en Refinerias .	39.3	0.2
- Demasias en Refinerias .	39.4	0.2
- Saldo en tanques-Refinerias al 1/1/85.	1,248.2	7.9
- Saldo en tanques-Refinerias al 31/12/85.	1,021.9	6.4
TOTAL PRODUCCION NETA DISPONIBLE	2,319.0	14.6

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1985"

29-Jun-87

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

S O L V E N T E

(Metros Cubicos)

REFINERIA	(1) DE: Gasolina Liviana	(2) DE: Jet Fuel	(3) A: G.C.M.
Santa Cruz	489.1	20.6	505.8
Subtotal	489.1	20.6	505.8
Cochabamba	45.4 0.0	0.0	45.4
Subtotal	45.4	0.0	45.4
T O T A L	534.5	20.6	551.2

R E S U M E N

	(M3)	(MBBL)
- Produccion = (1)+(2)	555.1	3.5
- Otros Productos	0.0	0.0
TOTAL PRODUCCION BRUTA	555.1	3.5
- Perdidas en Refinerias	1.4	0.0
- Demasias en Refinerias	0.2	0.0
- Saldo en tanques-Refinerias al 1/1/85	13.2	0.1
- Saldo en tanques-Refinerias al 31/12/85	15.9	0.1
TOTAL PRODUCCION NETA	551.2	3.5

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Ano 1985."

29-Jun-97

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

C O M B U S T I B L E L I Q U I D O

(Metros Cubicos)

REFINERIA	(1) DE: Diesel Oil	(2) DE: Fuel Oil	(3) DE: Slop	(4) DE: Lubricantes	(5) DE: Gasolinas Liv y Med	(6) DE: Crudo Reducido	(7) A: Consumo	(8) A: Lubricantes	(9) A: Seguridad Industrial	(10) A: Slop
Sucre	60.4	682.9	0.0	0.0	0.0	0.0	759.1 0.0	0.0	0.0	0.0
Subtotal	60.4	682.9	0.0	0.0	0.0	0.0	759.1	0.0	0.0	0.0
Cochabamba	981.9	557.0	3,363.6	18,412.4 0.0	10,524.2	1,070.1	34,931.9 0.0 0.0	28.5	11.0	41.5
Subtotal	981.9	557.0	3,363.6	18,412.4	10,524.2	1,070.1	34,931.9	28.5	11.0	41.5
T O T A L	1,042.3	1,239.9	3,363.6	18,412.4	10,524.2	1,070.1	35,691.0	28.5	11.0	41.5

R E S U M E N

	(M3)	(MBBL)
- Produccion=(1)+(2)+(3)+(4)+(5)+(6)	35,652.5	224.3
- Otros productos	0.0	0.0
TOTAL PRODUCCION BRUTA	35.652.5	224.3

- Perdidas en Refinerias .	23.9	0.2
- Demasias en Refinerias .	135.5	0.9
- Saldo en tanques-Refinerias al 1/1/85.	1,306.6	8.2
- Saldo en tanques-Refinerias al 31/12/85.	1,298.7	8.2
TOTAL PRODUCCION NETA DISPONIBLE	35,772.0	225.0

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1985"

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1985

C O M B U S T I B L E G A S E O S O

(Metros Cubicos)

REFINERIA	(1) DE: Nafta	(2) DE: Produccion	(3) A: Consumo	(4) A: Lubricantes
Santa Cruz	24,492.8	0.0	24,492.8	0.0
				0.0
Subtotal	24,492.8	0.0	24,492.8	0.0
Cochabamba	24,201.2	4,890.4	27,089.2	2,002.4
	0.0			0.0
Subtotal	24,201.2	4,890.4	27,089.2	2,002.4
T O T A L	48,694.0	4,890.4	51,582.0	2,002.4

R E S U M E N

	(M3)	(MBBL)
- Produccion = (2)-(4)	2,888.0	18.2
- Otros productos = (1)	48,694.0	306.3
TOTAL PRODUCCION BRUTA	51,582.0	324.5
- Perdidas en Refinerias .	0.0	0.0
- Demasias en Refinerias .	0.0	0.0
- Saldo en tanques-Refinerias al 1/1/85.	0.0	0.0
- Saldo en tanques-Refinerias al 31/12/85.	0.0	0.0
TOTAL PRODUCCION NETA	51,582.0	324.5

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de S.I.D. Año 1985"

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

G A S O L I N A S

(Metros Cubicos)

REFINERIA	(1) DE: Gasolina Blanca	(2) Produccion Intermedia	(3) DE: Gasolinas Elaboradas	(4) DE: Butano Pet.	(5) A: Crudo Slop	(6) A: Otros prod. Elaborados	(7) A: Diesel Oil	(8) A: Fuel Oil	(9) A: Kerosene	
Sucre	0.0	0.0			821.2		13.8			(a)
	11,924.4		13,102.1		82.7	13,102.1		21.1	8.8	(b
Subtotal	11,924.4	0.0	13,102.1	0.0	903.9	13,102.1	13.8	21.1	8.8	
Santa Cruz		13,886.2			63.2					(a)
		58,253.0		949.4	91.9					(b)
		64,322.1								(b)
		15,523.4								(b)
		3,175.9		407.3						(c
		1,197.0								(c
		8,278.9								(c
Subtotal	0.0	164,636.5	0.0	1,356.7	155.1	0.0	0.0	0.0	0.0	
Cochabamba		30,535.5	1,355.0			1,355.0				(b
		92,124.6								(b
		147,824.2								(b
		1,915.7	658.8	150.0		658.8				(c
		3,104.3		4,779.3						(c
		141.6								(c
	1,748.1									(d
Subtotal	1,748.1	275,645.9	2,013.8	4,929.3	0.0	2,013.8	0.0	0.0	0.0	
T O T A L E S	13,672.5	440,282.4	15,115.9	6,286.0	1,059.0	15,115.9	13.8	21.1	8.8	

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)+(2)+(4)-(5)-(7)-(8)-(9)	459,138.2	2,888.0
- Otros productos = (3) - (6)	0.0	0.0
TOTAL PRODUCCION BRUTA	459,138.2	2,888.0
- Perdidas en Refinerias .	2,557.6	16.1
- Demasias en Refinerias .	1,764.9	11.1
- Saldo en tanques-Refinerias al 1/1/86.	22,782.6	143.3
- Saldo en tanques-Refinerias al 31/12/86.	13,622.1	85.7
TOTAL PRODUCCION NETA DISPONIBLE	467,506.0	2,940.6

REFERENCIAS

(a) Gasolina 92 Octanos.
(b) Gasolina Especial.
(c) Gasolina Premium.
(d) Isopentano.
(2) Productos intermedios: Platformado, Platformado redestilado, Gasolinas media y liviana

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

[illegible]-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEN PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

K E R O S E N E

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Productos Elaborados	(3) A: Fuel Oil	(4) A: Petroleo Crudo	(5) A: Diesel Oil	(6) A: Slop	(7) A: Jet Fuel	
Sucre		8.8						(a)
		20.8						(b)
	5,112.1		0.0	197.8	2,087.0	6.0	0.0	
Subtotal	5,112.1	29.6	0.0	197.8	2,087.0	6.0	0.0	
Santa Cruz	17,495.2	0.0	1,445.5	10,059.5	51.3	69.5	0.0	
Subtotal	17,495.2	0.0	1,445.5	10,059.5	51.3	69.5	0.0	
Cochabamba	56,681.4	0.0	0.0	0.0	8,111.6	170.2	130.6	
Subtotal	56,681.4	0.0	0.0	0.0	8,111.6	170.2	130.6	
T O T A L E S	79,288.7	29.6	1,443.5	10,257.3	10,249.9	245.7	130.6	

R E S U M E N

	(M3)	(MBBL)
- Produccion = (1)-(3)-(4)-(5)-(6)-(7)	56,959.7	358.3
- Otros productos = (2)	29.6	0.2
TOTAL PRODUCCION BRUTA	56,989.3	358.5
- Perdidas en Refinerias .	276.7	1.7
- Demasias en Refinerias .	76.0	0.5
- Saldo en tanques-Refinerias al 1/1/86.	14,646.7	92.1
- Saldo en tanques-Refinerias al 31/12/86.	4,335.5	27.3
TOTAL PRODUCCION DISPONIBLE	67,099.8	422.1

REFERENCIAS

(a) Gasolina Especial
(b) Jet Fuel.

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

G. L. P.

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: C4/C3	(3) A: Petroleo Crudo	(4) A: G.C.N. Export.	(5) A: Slop	
Sucre	1,088.1	14.4	931.3	0.0	0.0	
Subtotal	1,088.1	14.4	931.3	0.0	0.0	
Santa Cruz	212,612.7					(a)
	315.7					(b)
	10,844.6					(c)
		28,966.0	0.0	4,000.6	0.0	
Subtotal	223,773.0	28,966.0	0.0	4,000.6	0.0	
Cochabamba	0.0	65,903.2	0.0	0.0	2,992.7	
Subtotal	0.0	65,903.2	0.0	0.0	2,992.7	
T O T A L E S	224,861.1	94,883.6	931.3	4,000.6	2,992.7	

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)-(3)-(5)	220,937.1	1,389.7
- Otros productos = (2)	94,883.6	596.8
TOTAL PRODUCCION BRUTA	315,820.7	1,986.5
- Perdidas en Refinerias .	6,169.6	38.8
- Demasias en Refinerias .	4,966.9	31.2
- Saldo en tanques-Refinerias al 1/1/86.	1,380.4	8.7
- Saldo en tanques-Refinerias al 31/12/86.	7,403.1	46.6
TOTAL PRODUCCION NETA DISPONIBLE	308,595.3	1,941.1

REFERENCIAS

Produccion de plantas:

(a) Rio Grande segun GID
(b) Camiri segun DPL
(c) Colpa segun DPL

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

D I E S E L O I L

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Gasolina Blanca	(3) DE: Kerosene	(4) DE: Productos Elaborados	(5) A: Petroleo Crudo	(6) A: Combustible	(7) A: Fuel Oil	(8) A: Slop	(9) A: Combustible Liquido	
Sucre				10.1						(a)
		13.8								(b)
	12,507.7	84.4	2,087.0		367.0	61.6	26.8	9.2	0.0	
Subtotal	12,507.7	98.2	2,087.0	10.1	367.0	61.6	26.8	9.2	0.0	
Santa Cruz				675.5						(c)
				307.5						(d)
		6.1								(e)
	128 675.8	0.0	51.3		100.5			93.2		
Subtotal	128,675.8	6.1	51.3	983.0	100.5	0.0	0.0	93.2	0.0	
Cochabamba				19,081.2						(f)
	120,829.0	0.0	8,111.6		0.0	505.6	15,664.8	217.3	8.3	
Subtotal	120,829.0	0.0	8,111.6	19,081.2	0.0	505.6	15,664.8	217.3	8.3	
T O T A L E S	262,012.5	104.3	10,249.9	20,074.3	467.5	567.2	15,691.6	319.7	8.3	

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)-(5)-(6)-(7)-(8)-(9)	244,?58.2	1,540.8
- Otros productos =(2)+(3)+(4)	30,428.5	191.4
TOTAL PRODUCCION BRUTA	275,386.7	1,732.2
- Perdidas en Refinerias .	139.6	0.9
- Demasias en Refinerias .	69.7	0.4
- Saldo en tanques-Refinerias al 1/1/86.	34,372.7	216.2
- Saldo en tanques-Refinerias al 31/12/86.	16,697.5	105.0
TOTAL PRODUCCION NETA DISPONIBLE	292,992.0	1,842.9

REFERENCIAS

+ Est.No. 1.
(a) Fuel Oil
(b) Gasolina 90 octanos
(c) Jet Fuel
(d) Platformado
(e) Gasolina Media
(f) Lubricantes

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

F U E L O I L

(Metros Cubicos)

REFINERIA	(1) DE: Diesel Oil	(2) DE: Gasolina Blanca	(3) DE: Kerosene	(4) DE: Crudo Reducido	(5) DE: Petroleo Crudo	(6) A: Petroleo Crudo	(7) A: Combustible	(8) A: Diesel Oil	(Slo
Sucre		21.1							
					1.3				
	26.8	8,141.2	0.0	8,693.1	2,582.5	11,964.4	324.1	10.1	0.
Subtotal	26.8	8,162.3	0.0	8,693.1	2,583.8	11,964.4	324.1	10.1	0.
Santa Cruz		659.7							
	0.0		1,445.5	10,577.9	0.0	14,930.2	0.0	0.0	188.
Subtotal	0.0	659.7	1,445.5	10,577.9	0.0	14,930.2	0.0	0.0	188.
Cochabamba		5,288.8							
		13,056.4							
	15,664.8		0.0	7,529.5	0.0	0.0	0.0	0.0	506.
Subtotal	15,664.8	18,345.2	0.0	7,529.5	0.0	0.0	0.0	0.0	506.1
T O T A L E S	15,691.6	27,167.2	1,445.5	26,800.5	.,583.8	26,894.6	324.1	10.1	694.7

R E S U M E N

	(M3)	(MBBL)
- Produccion = (2)+(4)-(6)-(7)-(8)-(9)	26,044.2	163.8
- Otros productos = (1)+(3)+(5)	19,720.9	124.0
TOTAL PRODUCCION BRUTA	45,765.1	287.9
- Perdidas en Refinerias	223.8	1.4
- Demasias en Refinerias	171.0	1.1
- Saldo en tanques-Refinerias al 1/1/86	11,126.7	70.0
- Saldo en tanques-Refinerias al 31/12/86	9,454.2	59.5
TOTAL PRODUCCION NETA DISPONIBLE	47,384.8	298.1

REFERENCIAS

(a) Gasolina Especial
(b) Slop
(c) Gasolina Liviana
(d) Gasolina Media

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

J E T F U E L

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Kerosene	(3) A: Solvente	(4) A: Slop	(5) A: Kerosene	(6) A: Diesel Oil
Sucre	4,439.5 0.0	0.0	0.0	0.0	20.8	0.0
Subtotal	4,439.5	0.0	0.0	0.0	20.8	0.0
Santa Cruz	45,150.5	0.0	12.8	107.4	0.0	675.5
Subtotal	45,150.5	0.0	12.8	107.4	0.0	675.5
Cochabamba	44,442.4	130.6	0.0	6.2	0.0	0.0
Subtotal	44,442.4	130.6	0.0	6.2	0.0	0.0
T O T A L E S	94,032.4	130.6	12.8	113.6	20.8	675.5

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)-(3)-(4)-(5)-(6)	93,209.7	586.3
- Otros productos = (2)	130.6	0.8
TOTAL PRODUCCION BRUTA	93,340.3	587.1
- Perdidas en Refinerias .	103.1	0.6
- Demasias en Refinerias .	207.2	1.3
- Saldo en tanques-Refinerias al 1/1/86.	8,700.9	54.7
- Saldo en tanques-Refinerias al 31/12/86.	7,347.8	46.2
TOTAL PRODUCCION NETA DISPONIBLE	93,444.4	587.8

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

AVGAS

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Isopentano	(3) A: Slop
Santa Cruz	2,678.4	456.5	0.0
Subtotal	2,678.4	456.5	0.0
Cochabamba	6,783.7	2,611.7	11.2
Subtotal	6,783.7	2,611.7	11.2
TOTALES	9,462.1	3,068.2	11.2

RESUMEN

	(M3)	(MBBL)
- Produccion =(1)-(3)	9,450.9	59.4
- Otros productos = (2)	3,068.2	19.3
TOTAL PRODUCION BRUTA	12,519.1	78.7
- Perdidas en Refinerias .	164.5	1.0
- Demasias en Refinerias .	206.5	1.3
- Saldo en tanques-Refinerias al 1/1/86.	709.1	4.5
- Saldo en tanques-Refinerias al 31/12/86.	850.6	5.4
TOTAL PRODUCCION NETA DISPONIBLE	12,419.6	78.1

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH FNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

GASOLINA BLANCA

(Metros Cubicos)

REFINERIA	(1) DE: Produccion	(2) DE: Gasolinas liv y med	(3) A: Petroleo Crudo	(4) A: Fuel Oil	(5) A: Gasolina Especial	(6) A: Diesel Oil	(7) A: Slop
Sucre	22,818.9	0.0	6,043.4	8,141.2	11,924.4 0.0	84.4	0.0
Subtotal	22,818.9	0.0	6,043.4	8,141.2	11,924.4	84.4	0.0
Santa Cruz		15,089.3	8,492.2	0.0	0.0 0.0 0.0	0.0	42.5
Subtotal	0.0	15,089.3	8,492.2	0.0	0.0	0.0	42.5
Cochabamba	0.0 0.0	144.3	0.0	0.0	0.0 0.0	0.0	0.0
Subtotal	0.0	144.3	0.0	0.0	0.0	0.0	0.0
TOTALES	22,818.9	15,233.6	14,535.6	8,141.2	11,924.4	84.4	42.5

RESUMEN

	(M3)	(MBBL)
- Produccion = (1)+(2)-(3)-(4)-(5)-(6)-(7)	3,324.4	20.9
- Otros productos =	0.0	0.0
TOTAL PRODUCCION BRUTA	3,324.4	20.9
- Perdidas en Refinerias .	8.2	0.1
- Demasias en Refinerias .	89.3	0.6
- Saldo en tanques-Refinerias al 1/1/86.	1,021.9	6.4
- Saldo en tanques-Refinerias al 31/12/86.	729.0	4.6
TOTAL PRODUCCION NETA DISPONIBLE	3,698.4	23.3

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

SOLVENTE

(Metros Cubicos)

REFINERIA	(1) DE: Gasolina Liviana	(2) DE: Jet Fuel	(3) A: G.C.M.
Santa Cruz	424.5	12.8	427.2
Subtotal	424.5	12.8	427.2
Cochabamba	13.1 0.0	0.0	13.1
Subtotal	13.1	0.0	13.1
TOTALES	437.6	12.8	440.3

RESUMEN

	(M3)	(MBBL)
- Produccion = (1)+(2)	450.4	2.8
- Otros productos	0.0	0.0
TOTAL PRODUCCION BRUTA	450.4	2.8
- Perdidas en Refinerias .	0.0	0.0
- Demasias en Refinerias .	0.0	0.0
- Saldo en tanques-Refinerias al 1/1/86.	15.9	0.1
- Saldo en tanques-Refinerias al 31/12/86.	26.0	0.2
TOTAL PRODUCCION NETA DISPONIBLE	440.3	2.8

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AñO 1986

C O M B U S T I B L E L I Q U I D O

(Metros Cubicos)

REFINERIA	(1) DE: Diesel Oil	(2) DE: Fuel Oil	(3) DE: Slop	(4) DE: Lubricantes	(5) DE: Gasolinas Liv y Med	(6) DE: Crudo Reducido	(7) A: Consumo	(8) A: Lubricantes	(9) A: Seguridad Industrial	(10) A: Slop
Sucre	61.6	324.1	0.0	0.0	0.0	0.0	380.9 0.0	0.0	0.0	0.0
Subtotal	61.6	324.1	0.0	0.0	0.0	0.0	380.9	0.0	0.0	0.0
Cochabamba	503.6	0.0	1,264.1	6,814.7 0.0	274.9	18,710.4	27,482.5 v.0 0.0	0.0	11.0	0.0
Subtotal	503.6	0.0	1,264.1	6,814.7	274.9	18,710.4	27,482.5	0.0	11.0	0.0
T O T A L E S	567.2	324.1	1,264.1	6,814.7	274.9	18,710.4	27,863.4	0.0	11.0	0.0

R E S U M E N

	(M3)	(MBBL)
- Produccion=(1)+(2)+(3)+(4)+(5)+(6)	27,955.4	175.8
- Otros productos	0.0	0.0
TOTAL PRODUCCION BRUTA	27,955.4	175.8

- Perdidas en Refinerias .	311.1	2.0
- Demasias en Refinerias .	338.7	2.1
- Saldo en tanques-Refinerias al 1/1/86.	1,298.7	8.2
- Saldo en tanques-Refinerias al 31/12/86.	1,418.3	8.9
TOTAL PRODUCCION NETA DISPONIBLE	27,863.4	175.3

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

BALANCE PRODUCCION DE PRODUCTOS REFINADOS

AÑO 1986

C O M B U S T I B L E G A S E O S O

(Metros Cubicos)

REFINERIA	(1) DE: Nafta	(2) DE: Produccion	(3) A: Consumo	(4) A: Lubricantes
Santa Cruz	25,211.2	0.0	24,211.2	0.0
				0.0
Subtotal	25,211.2	0.0	24,211.2	0.0
Cochabamba	22,493.9	616.7	23,965.9	1,125.5
	1,980.8			0.0
Subtotal	24,474.7	616.7	23,965.9	1,125.5
T O T A L E S	49,685.9	616.7	48,177.1	1,125.5

R E S U M E N

	(M3)	(MBBL)
- Produccion =(1)+(2)-(4)	49,177.1	309.3
- Otros productos = (1)	0.0	0.0
TOTAL PRODUCCION BRUTA	49,177.1	309.3
- Perdidas en Refinerias .	0.0	0.0
- Demasias en Refinerias .	0.0	0.0
- Saldo en tanques-Refinerias al 1/1/86.	0.0	0.0
- Saldo en tanques-Refinerias al 31/12/86.	0.0	0.0
TOTAL PRODUCCION NETA DISPONIBLE	49,177.1	309.3

FUENTE: Elaborado con informacion extractada del "Movimiento de productos de G.I.D. Año 1986."

29-Jun-97

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEN FNUD BM

CARACTERISTICAS GENERALES DE OLEODUCTOS, POLIDUCTOS Y PROPANODUCTOS DE Y.P.F.B.

DATOS	OCC CMR-CBB	OCC RAMAL SRC	OCY	OCOLP+OCOLP CBB-OR	OCOLP OR-LPZ	OCSZ	OSSA	OCCH	OPSC	OCT	EST.1 REF.SCZ	PCBY	OSP
Año Iniciacion Operacion	1950	1950	1954	1956	.1956	1957	1966	1969	1971	1973	1967	1969	1975
Producto	CRUDO	CRUDO	CRUDO	PROD	PROD	CRUDO	CRUDO	CRUDO	CRUDO	CRUDO	CRUDO	GLP	PROD
Longitud (Km)	522.59	71.24	257.14	164.10	208.40	271.70	971.00	59.69	39.00	29.59	9.71	50.00	104.62
Contenido (Barriles)	60,304.00	4,127.00	39,046.00	19,625.00	24,923.00	14,118.00	369,129.00	5,602.00	3,564.65	3,536.00	505.07	830.00 (MPCSD)	3,388.00
Diametro (Pulgadas)	6.5/8	4.1/2	6.5/8	6.5/8	6.5/8	4.1/2	12.3/4 10.3/4 8.5/8	6.5/8 5.5/16 4.1/2	4.1/2 6.5/8	6./58	4.1/2	2.3/8	3.1/2
Especificacion Cañeria	SLX-42	SLX-42	SLX-42	SLX-42	SLX-42	SLB	SLX-52 SLX-42	SLX-42	SLA SLX-42	SLX	SLB	SL	SL GRD B
Tipo de Cañeria	Sin Cost.	Sin Cost.	Sin Cost.	Sin Cost.	Sin Cost.	Sin Cost.	Sin Cost.	Sin Cost.	Sin Cost.	Sin Cost.	Sin Cost.	Sin Cost.	E.R.W.
Peso (lbs/pie)	17.02	10.79	17.02	17.02	17.02	10.79	37.45 33.60 28.04 31.20 22.36	17.02 14.62 10.79	10.79 17.02	16.97 17.02 12.89	10.79	3.65	5.55
Capacidad Instalada BPD	7,800.00	3,120.00	15,000.00	12,000.00	12,000.00	5,000.00	30,000.00	11,000.00	8,000.00	9,000.00	7,000.00	95 Tn/D	3,700.00
Cap. Potenc. increm. BPD				20,000.00	2,000.00	6,000.00	50,000.00						
Numero de Estaciones	5	0	3	2	0	4	6	1	1	1	1	1	1
Potencia Instalada HP	25,522.00	12.00	2,866.00	1,290.50	0.00	1,434.00	12,725.00	706.00	560.00	S/I	120.00	50.00	340.00
Pot.real util.actual.HP	2,071.00	10.00	2,044.00				12,725.00	600.00	560.00	S/I	120.00	50.00	340.00

DESCRIPCION DE SIGLAS:

OCC = Oleoducto Camiri - Cochabamba
OCY = Oleoducto Camiri - Yacuiba
OCOLP = Oleoducto Cochabamba - Oruro - La Paz
OCSZ = Oleoducto Camiri - Santa Cruz
OSSA = Oleoducto Santa Cruz - Sica Sica - Arica
OCCH = Oleoducto /cerrillos Chorety
OPSC = Oleoducto La Peña - Santa Cruz
OCT = Oleoducto Caigua - Tiguipa
PCBY = Propanoducto Camiri - Boyuibe
OSP = Poliducto Sucre - Potosi

S/I = Sin Informacion

Total Longitud Oleoductos: 277.67 Km
Total Longitud Propanoductos: 50.00 km

01-Jul-87

[illegible]

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: Caairi	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)					3,500	3,000	1,000						
COSTOS DE O.& M. (en M US$)								767	767	730	715	694	4,800
					3,500	3,000	1,000	767	767	730	715	5,494	4,800
PRODUCCION (en MBA)					111	100	225	767	767	730	715	694	4,800
INGRESOS (en M US$)					1,890	1,700	3,825	13,031	13,031	12,410	12,155	11,790	81,600
FLUJO NETO (en M US$)					(1,610)	(1,300)	2,825	12,264	12,264	11,680	11,440	87,696	76,800

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento		
		12%	14%	16%
Precio por Barril	$15.00	6.22	5.91	5.61
	$17.00	7.05	6.70	6.36
	$19.00	7.88	7.48	7.11
	$21.00	8.71	8.27	7.86

b) Tasa Interna de Retorno (TIR):

		T.I.R.
Precio por Barril	$15.00	121%
	$17.00	140%
	$19.00	162%
	$21.00	188%

c) Valor Actual Neto (VAN) (en Miles de US$)

		Tasa de Descuento		
		12%	14%	16%
Precio por Barril	$15.00	52,536	46,386	41,059
	$17.00	60,882	53,831	47,721
	$19.00	69,229	61,276	54,383
	$21.00	77,575	68,721	61,044

01-Jul-87

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: Cascabel	Hasta 1986	1987	1988	1989	1990	[illegible]	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)				6,600	9,600	5,300							
COSTOS DE O.& M. (en M US$)							982	779	618	490	389	309	846
				6,600	9,600	5,300	982	779	618	490	389	1,155	846
PRODUCCION (en MBA)							982	779	618	490	389	309	846
INGRESOS (en M US$)				0	0	0	16,691	13,241	10,504	8,332	6,613	5,250	14,382
FLUJO NETO (en M US$)				(6,600)	(9,600)	(5,300)	15,709	12,462	9,886	7,842	6,224	4,941	13,536

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento 12%	14%	16%
	$15.00	1.91	1.78	1.66
Precio	$17.00	2.16	2.01	1.88
por	$19.00	2.42	2.25	2.10
Barril	$21.00	2.67	2.49	2.32

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	32%
Precio	$17.00	37%
por	$19.00	41%
Barril	$21.00	45%

c) Valor Actual Neto (VAN) (en Miles de US$)

		Tasa de Descuento 12%	14%	16%
	$15.00	14,108	11,168	8,763
Precio	$17.00	18,061	14,577	11,713
por	$19.00	22,014	17,985	14,663
Barril	$21.00	25,967	21,394	17,613

01-Jul-87

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: Escondido	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)				13,500	8,500								
COSTOS DE O.& M. (en M US$)				0	0	730	1,376	1,095	891	712	672	664	3,800
				13,500	8,500	730	1,376	1,095	891	712	672	4,464	3,800
PRODUCCION (en MBA)						730	1,376	1,095	891	712	672	664	3,800
INGRESOS (en M US$)				0	0	12,410	23,392	18,615	15,140	12,099	11,417	11,293	64,600
FLUJO NETO (en M US$)				(13,500)	(8,500)	11,680	22,016	17,520	14,250	11,387	10,746	10,629	60,800

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento 12%	14%	16%
	$15.00	3.86	3.55	3.28
Precio	$17.00	4.37	4.03	3.72
por	$19.00	4.88	4.50	4.15
Barril	$21.00	5.40	4.97	4.59

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	53%
Precio	$17.00	59%
por	$19.00	64%
Barril	$21.00	68%

c) Valor Actual Neto (VAN) (en Miles de US$)

		Tasa de Descuento 12%	14%	16%
	$15.00	53,492	44,313	36,760
Precio	$17.00	63,122	52,536	43,812
por	$19.00	72,752	60,758	50,664
Barril	$21.00	82,382	68,981	57,915

01-Jul-87

CAMPO: HSR-Yapacani	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)		15,000	9,000										
COSTOS DE O.& M. (en M US$)		0	0			343	342	331	317	296	289	275	3,172
		15,000	9,000	0	0	343	342	331	317	296	289	3,447	3,172
PRODUCCION (en MBA)				209	292	343	342	331	317	296	289	275	3,172
INGRESOS (en M US$)		0	0	3,553	4,956	5,831	5,814	5,627	5,384	5,034	4,905	4,677	53,924
FLUJO NETO (en M US$)		(15,000)	(9,000)	3,553	4,956	5,488	5,472	5,296	5,067	4,738	4,616	4,402	50,752

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento		
		12%	14%	16%
	$15.00	2.06	1.82	1.61
Precio	$17.00	2.34	2.06	1.82
por	$19.00	2.61	2.31	2.04
Barril	$21.00	2.89	2.55	2.25

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	24%
Precio	$17.00	27%
por	$19.00	29%
Barril	$21.00	31%

c) Valor Actual Neto (VAN)
(en Miles de US$)

		Tasa de Descuento		
		12%	14%	16%
	$15.00	23,827	17,745	12,762
Precio	$17.00	29,991	22,997	17,280
por	$19.00	36,155	28,249	21,778
Barril	$21.00	42,319	33,501	26,276

01-Jul-87

- 113 -

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: La Peña	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)		8,000											
COSTOS DE O.& M. (en M US$)		0	2,088				606	444	326	239	175	0	0
		8,000	2,088	0	0	0	606	444	326	239	175	0	0
PRODUCCION (en MBA)		0	2,088	1,532	1,125	825	606	444	326	239	175		
INGRESOS (en M US$)		0	35,498	26,049	19,117	14,023	10,300	7,551	5,540	4,063	2,978		
FLUJO NETO (en M US$)		(8,000)	33,410	26,049	19,117	14,023	9,694	7,107	5,214	3,824	2,803	0	0

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento		
		12%	14%	16%
	$15.00	7.38	7.13	6.88
Precio	$17.00	8.37	8.08	7.80
por	$19.00	9.35	9.03	8.72
Barril	$21.00	10.34	9.98	9.64

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	343%
Precio	$17.00	395%
por	$19.00	447%
Barril	$21.00	499%

c) Valor Actual Neto (VAN)
(en Miles de US$)

		Tasa de Descuento		
		12%	14%	16%
	$15.00	61,212	57,044	53,270
Precio	$17.00	70,652	65,891	61,581
por	$19.00	80,093	74,739	69,891
Barril	$21.00	89,533	83,586	78,201

01-Jul-87

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: Monteagudo	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)				3,000	2,000								
COSTOS DE O.& M. (en M US$)						1,606	1,421	1,251	1,113	985	873	772	5,000
				3,000	2,000	1,606	1,421	1,251	1,113	985	873	5,772	5,000
PRODUCCION (en MBA)				0	0	1,606	1,421	1,251	1,113	985	873	772	5,000
INGRESOS (en M US$)				0	0	27,302	24,157	21,262	18,921	16,745	14,838	13,124	85,000
FLUJO NETO (en M US$)				(3,000)	(2,000)	25,696	22,736	20,011	17,808	15,760	13,965	92,352	80,000

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento 12%	14%	16%
	$15.00	11.46	10.94	10.44
Precio	$17.00	12.99	12.40	11.83
por	$19.00	14.52	13.86	13.22
Barril	$21.00	16.05	15.32	14.62

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	196%
Precio	$17.00	214%
por	$19.00	231%
Barril	$21.00	248%

c) Valor Actual Neto (VAN)
(en Miles de US$)

		Tasa de Descuento 12%	14%	16%
	$15.00	109,563	96,684	85,628
Precio	$17.00	125,567	110,872	98,255
por	$19.00	141,572	125,060	110,881
Barril	$21.00	157,576	139,249	123,508

01-Jul-87

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: Naranjillos	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)		600	6,000										
COSTOS DE O.& M. (en M US$)				117	103	91	80	71	62	55	49	43	177
		600	6,000	117	103	91	80	71	62	55	49	220	177
PRODUCCION (en MBA)			47	117	103	91	80	71	62	55	49	43	177
INGRESOS (en M US$)			799	1,986	1,749	1,544	1,365	1,204	1,054	937	825	731	3,009
FLUJO NETO (en M US$)		(600)	(5,201)	1,869	1,646	1,453	1,285	1,133	992	882	776	688	2,832

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento		
		12%	14%	16%
	$15.00	1.28	1.22	1.17
Precio	$17.00	1.45	1.38	1.32
por	$19.00	1.62	1.54	1.48
Barril	$21.00	1.79	1.71	1.63

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	11%
Precio	$17.00	16%
por	$19.00	21%
Barril	$21.00	26%

c) Valor Actual Neto (VAN)
(en Miles de US$)

		Tasa de Descuento		
		12%	14%	16%
	$15.00	795	378	32
Precio	$17.00	1,663	1,162	742
por	$19.00	2,531	1,945	1,453
Barril	$21.00	3,399	2,729	2,163

01-Jul-87

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: San Roque	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)			12,000	25,000	9,500								
COSTES DE O.& M. (en M US$)		339				1,223	1,007	831	696	586	496	433	181
		339	12,000	25,000	9,500	1,223	1,007	831	696	586	496	614	181
PRODUCCION (en MBA)		339	365	365	730	1,223	1,007	831	696	586	496	433	181
INGRESOS (en M US$)		5,763	6,205	6,205	12,410	20,786	17,126	14,134	11,839	9,965	8,437	7,354	3,077
FLUJO NETO (en M US$)		5,424	(5,795)	(18,795)	2,910	19,563	16,118	13,302	11,142	9,379	7,941	6,922	2,896

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento		
		12%	14%	16%
	$15.00	1.57	1.51	1.45
Precio	$17.00	1.78	1.71	1.64
por	$19.00	1.99	1.91	1.83
Barril	$21.00	2.20	2.11	2.03

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	48%
Precio	$17.00	57%
por	$19.00	68%
Barril	$21.00	80%

c) Valor Actual Neto (VAN)
(en Miles de US$)

		Tasa de Descuento		
		12%	14%	16%
	$15.00	20,528	17,260	14,508
Precio	$17.00	28,125	24,139	20,757
por	$19.00	35,682	30,998	27,006
Barril	$21.00	43,239	37,856	33,255

01-Jul-87

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: Sirari	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)						5,500	15,500	13,000					
COSTOS DE O.& M. (en M US$)								135	164	183	180	164	2,365
		0	0	0	0	5,500	15,500	13,135	164	183	180	2,529	2,365
PRODUCCION (en MBA)								135	164	183	180	164	2,365
INGRESOS (en M US$)								2,295	2,788	3,103	3,060	2,788	40,205
FLUJO NETO (en M US$)						(5,500)	(15,500)	(10,840)	2,624	2,920	2,880	2,624	37,840

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento 12%	14%	16%
	$15.00	1.03	1.00	0.96
Precio	$17.00	1.17	1.13	1.09
por	$19.00	1.31	1.26	1.22
Barril	$21.00	1.44	1.40	1.35

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	7%
Precio	$17.00	10%
por	$19.00	13%
Barril	$21.00	16%

c) Valor Actual Neto (VAN) (en Miles de US$)

		Tasa de Descuento 12%	14%	16%
	$15.00	(4,974)	(6,266)	(7,332)
Precio	$17.00	(1,895)	(3,515)	(4,866)
por	$19.00	1,183	(763)	(2,401)
Barril	$21.00	4,261	1,988	64

01-Jul-87

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: Santa Cruz	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:												
INV. EN DESARROLLO (en M US$)	17,500											
COSTOS DE O.& M. (en M US$)	0	925	916	907	847	765	681	606	542	484	436	2,000
	17,500	925	916	907	847	765	681	606	542	484	2,436	2,000
PRODUCCION (en MBA)	526	925	916	907	847	765	681	606	542	484	436	2,000
INGRESOS (en M US$)	8,940	15,728	15,574	15,419	14,394	12,998	11,570	10,299	9,212	8,221	7,414	34,000
FLUJO NETO (en M US$)	(8,560)	14,803	14,658	14,512	13,547	12,234	10,690	9,693	8,670	7,736	6,978	32,000

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento		
		12%	14%	16%
	$15.00	4.00	3.75	3.53
Precio	$17.00	4.53	4.25	4.00
por	$19.00	5.06	4.75	4.47
Barril	$21.00	5.60	5.25	4.94

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	133%
Precio	$17.00	171%
por	$19.00	220%
Barril	$21.00	285%

c) Valor Actual Neto (VAN) (en Miles de US$)

		Tasa de Descuento		
		12%	14%	16%
	$15.00	62,172	54,653	48,623
Precio	$17.00	73,137	64,748	57,603
por	$19.00	84,102	74,644	66,584
Barril	$21.00	107,978	98,723	90,665

01-Jul-87

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: Villamontes	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)		7,100											
COSTOS DE O.& M. (en M US$)			1,807	2,172	1,629	1,228	916	687	515	387	290	218	1,232
		7,100	1,807	2,172	1,629	1,229	916	687	515	387	290	1,450	1,232
PRODUCCION (en MBA)		324	1,807	2,172	1,629	1,228	916	687	515	387	290	218	1,232
INGRESOS (en M US$)		5,511	30,714	36,919	27,693	20,871	15,574	11,684	8,762	6,577	4,933	3,698	20,944
FLUJO NETO (en M US$)		(1,569)	28,907	34,747	26,064	19,643	14,658	10,997	8,246	6,190	4,643	3,480	19,712

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento		
		12%	14%	16%
	$15.00	8.27	7.99	7.74
Precio	$17.00	9.37	9.06	8.77
por	$19.00	10.47	10.12	9.80
Barril	$21.00	11.57	11.19	10.83

b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	1147%
Precio	$17.00	1837%
por	$19.00	3478%
Barril	$21.00	12403%

c) Valor Actual Neto (VAN)
(en Miles de US$)

		Tasa de Descuento		
		12%	14%	16%
	$15.00	92,226	84,606	77,918
Precio	$17.00	106,215	97,500	89,849
por	$19.00	120,204	110,394	101,781
Barril	$21.00	134,193	123,288	113,712

01-Jul-87

EVALUACION ECONOMICA DE CAMPOS PRODUCTORES DE HIDROCARBUROS LIQUIDOS

CAMPO: Vuelta Grande	Hasta 1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	VALOR RESIDUAL
FLUJOS:													
INV. EN DESARROLLO (en M US$)		16250	15850										
COSTOS DE O.& M. (en M US$)			400	2,602	2,891	2,596	2,254	1,963	1,716	1,515	1,324	1,169	25,000
PRODUCCION (en MBA)		350	400	2602.1	2890.8	2596.1	2253.8	1963.2	1715.6	1515.4	1324.1	1168.7	25000
INGRESOS (en M US$)		5,950	6,800	44,236	49,144	44,134	38,315	33,374	29,165	25,762	22,510	19,868	425,000
FLUJO NETO (en M US$)		(10,300)	(9,450)	41,634	46,253	41,538	36,061	31,411	27,450	24,246	21,186	18,699	400,000

SUPUESTO:

Precio de un barril en US$ 17

INDICADORES ECONOMICOS:

a) Relacion B/C

		Tasa de Descuento		
		12%	14%	16%
	$15.00	8.28	7.60	6.98
Precio	$17.00	9.38	8.61	7.91
por	$19.00	10.49	9.63	8.84
Barril	$21.00	11.59	10.64	9.77

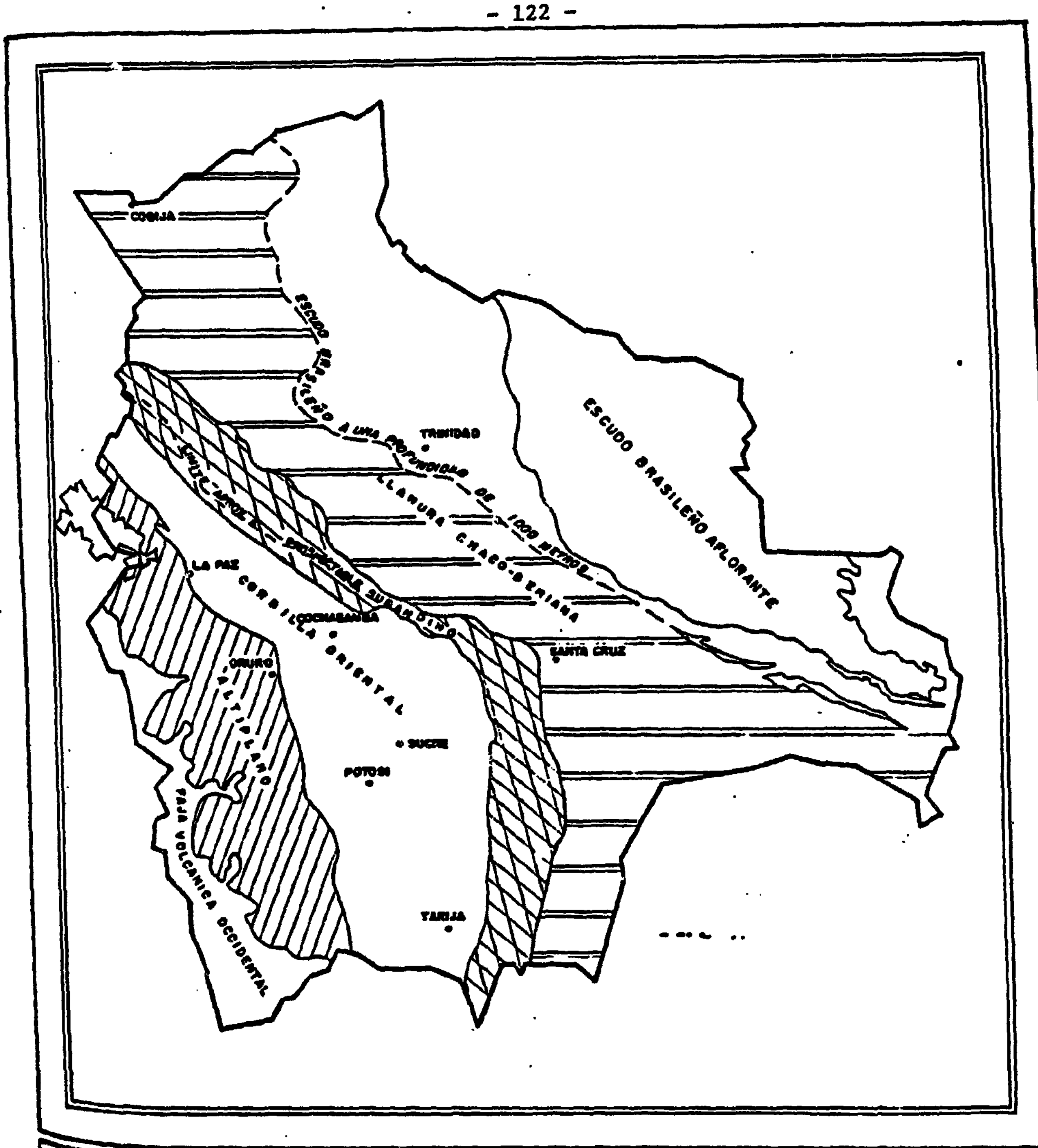
b) Tasa Interna de Retorno (TIR):

		T.I.R.
	$15.00	112%
Precio	$17.00	129%
por	$19.00	148%
Barril	$21.00	168%

c) Valor Actual Neto (VAN)
(en Miles de US$)

		Tasa de Descuento		
		12%	14%	16%
	$15.00	319,143	270,614	230,552
Precio	$17.00	367,541	312,163	266,431
por	$19.00	415,939	353,712	302,310
Barril	$21.00	464,337	395,260	338,189

01-Jul-87

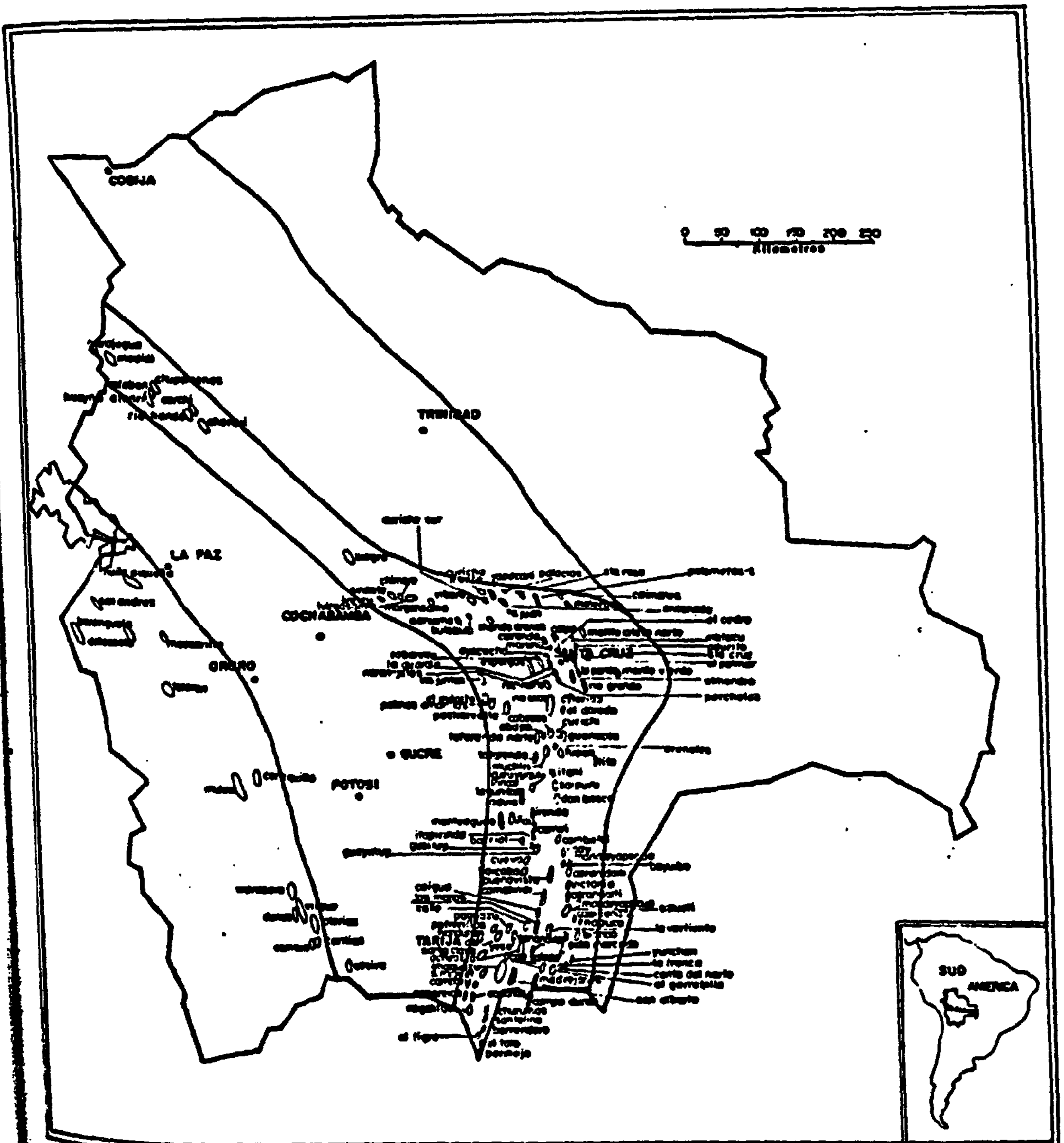


BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH - PNUD - BM

UNIDADES MORFOESTRUCTURALES CAMPOS DE HIDROCABUROS

AREAS DE INTERES PETROLERO

- Llanura Chaco - Beniana
- Faja Subandina
- Altiplano



BOLIVIA
PLAN NACIONAL DE ENERGIA
REN - PNUD - BM

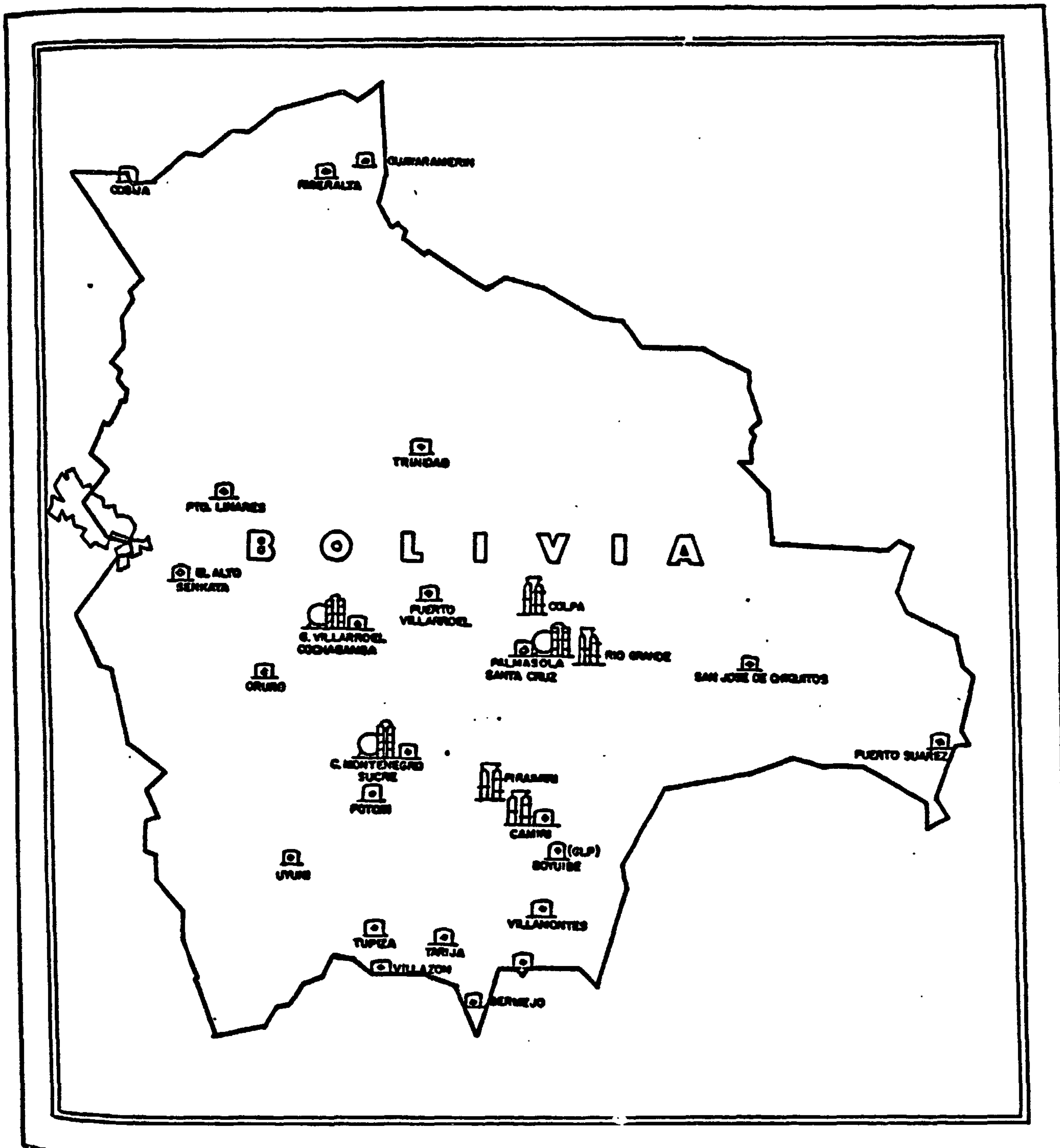
CAMPOS DE PETROLEO Y GAS NATURAL

Petroleo — Gas — Gas Condensado — Estructuras Geológicas — Limites Morfoestructurales

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEN - PNUD - BM

MAPA DE UBICACION DE CAMPOS NUEVOS

Ciudad o Pueblo   Campo de Gas condensado   Campo Petrolifero



BOLIVIA
PLAN NACIONAL DE ENERGIA
MEM - PNUD - BM

UBICACION DE REFINERIAS, PLANTAS DE GAS Y PLANTAS DE ALMACENAJE

Refineria — Planta de Gas — Planta de Almacenaje

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEN - PNUD - BM

RED DE OLEODUCTOS Y POLIDUCTOS

———	Oleoducto	OCSZ	Oleoducto Camiri - Santa Cruz
- - - -	Proyecto oleoducto	PSCV	Poliducto Santa Cruz - Villamontes
———	Poliducto	OCCH	Oleoducto Cerrillos - Charoti
- - - -	Proyecto poliducto	OCS	Oleoducto Camiri - Sucre
OCOLP	Poliducto Cochabamba - Oruro - La Paz	OSP	Poliducto Sucre - Potosi
OSSA	Oleoducto Santa Cruz - Sica Sica - Arica	OCY	Oleoducto Camiri - Yacuiba (invertido)

NATURAL GAS

Overview

Over 1986-2005, one can anticipate the cumulated domestic demand for gas to be of the order of 0.9-1.3 TCF depending on developments in the economy. This represents about 25% of Bolivia's proven reserves of 4 TCF. Should Bolivia continue to export about 215 MMCFD (to Argentina and/or Brazil) during the same period, that consumption would represent about 1.6 TCF. Thus it would use about 75% of its proven reserves in the next 20 years. It is only if potential exports beyond 1991 exceed about 300 MMCFD that there would be grounds for concern regarding Bolivia's reserves. But since Bolivia's gas reserves are thought by all to exceed 4 TCF by a considerable margin, higher exports would only entail an effort to confirm probable reserves, and possibly undertake more exploration in gas prone areas. One can therefore anticipate that the major challenge for Bolivia's gas sector will remain on the demand side, i.e., the identification of economic outlets for the gas, rather than on the supply side.

Gas Domestic Market Regional Analysis

For the purpose of regional analysis, Bolivia has been divided into five main regions. For each, the present utilization of petroleum products is examined, together with the potential for substitution by natural gas. Gas can be mainly used to replace fuel oil, diesel oil, kerosene, and LPG. 1/

La Paz, Oruro

This region in 1986 accounted for about 40% of the national consumption of oil products replaceable by natural gas, but less than 8% of the natural gas consumption. The main reasons are that: (a) gas only reached that market in 1984, with the conversion of the Cochabamba-La Paz products pipeline to natural gas; (b) there is only one major gas consumer, the SOBOCE cement plant; and (c) the mining industry which accounts for about 60% of fuel oil use in the region has yet to convert.

1/ The consumption of these four products in 1987 at 4.2 million bbl represented about 55% of the consumption of oil products in 1986--the balance consisted mainly of gasoline (37%) and aviation fuels (5%).

At present there are only four users of gas in La Paz, all in the El Alto area. 2/ In Oruro, gas is not being used for the time being and the potential market outside the mining industry is not significant. YPFB's Gas division, the Ministry of Energy and Hydrocarbons (MEH) with the external support of the Organization of American States (OAS) have made a particularly important effort to identify the market of the La Paz region 3/ and define priorities for conversion to gas. Three major industrial areas were targeted (El Alto, La Paz proper, and the vicinity); in each, the industrial and commercial users of replaceable liquid fuels were identified (down to hundreds of small businesses such as bakeries) and the potential for substitution of each quantified. El Alto is by far the largest potential market for gas, with its concentration of industries, followed by the city of La Paz and the region. 4/ In all, the potential replacement market (which is not necessarily economic) for La Paz can be estimated at 17.6 MMCFD and of Oruro, excluding the smelters, at 3.7 MMCFD.

Cochabamba and Beni Pendo

This region represents about 22% of the market of fuels replaceable by natural gas and presently accounts for about 8% of national gas sales. In this region, only the city of Cochabamba presently receives gas; the present consumers comprise eight industries including one cement plant. 5/ All the present users of liquid fuels replaceable by natural gas are located in the city and not in the region, which ought to facilitate the substitution program. Among the industries slated for conversion are ceramics, canning, dairy, glass, textile, and shoes. The oil refinery is also expected to pursue its conversion from oil to gas (as main fuel). The potential industrial market for gas in Cochabamba is estimated at 5.2 MMCFD.

2/ These are the CBN brewery, the Fanviplan glass factory, the Patria detergents factory, and the SOBOCE cement plant.

3/ Guillermo Léon and Ricardo Bilboa La Vieja: Proyecto de Utilizacion de Gas Natural en El Alto de La Paz, Bolivia (January 1987); Franz Lino Alurralde: Sustitucion de Hidrocarburos Liquidos por Gas Natural El Alto de La Paz (February 1987); and YPFB's Gas Division: Market Survey for Depto. La Paz (1984-85).

4/ It is interesting to note that in El Alto and La Paz proper, consumption of fuel oil and LPG is particularly high while in the vicinity of La Paz, diesel oil becomes the dominant industrial fuel.

5/ These are as follows: Ceramil, Faboce, Ibocal: ceramics; Coboce: cement; Iasa: vegetable oils; Quimbol: detergents; and Vidriolux: glass.

Santa Cruz-Camiri

This region accounted for about 25% of the national consumption of replaceable liquid fuels and over 75% of natural gas sales in 1986. The ENDE power plant represented over 80% of gas sales in the region during 1986; industrial sales, however, still represented nearly 90% of the sales in that category during the year. This situation is explained by the following factors: (a) Santa Cruz is located near the gas fields and has been one of the first markets for gas; (b) the regional development corporation CORDECRUZ has encouraged the use of natural gas in the Santa Cruz industrial park; and (c) the region has enjoyed relative prosperity in recent years. In all, approximately 20 industries are presently using natural gas. In addition to the typical industries of La Paz and Cochabamba, the three sugar mills in the vicinity of the city and a number of farms are also gas users. As a result, consumption of fuel oil has now become negligible but there remains a market for diesel substitution estimated at 5.5 MMCFD.

Sucre-Potosi

Sucre was the first city in Bolivia to use natural gas; the main user is a cement plant. The gas-fueled thermal power plant is no longer in use since the city has been interconnected to the hydro-based western grid in 1984. At present, there are three industrial consumers in Sucre 6/ and two smelters at Potosi who use minor quantities of gas for maintenance purposes. There remains a small potential for diesel replacement in the industrial sector estimated at 5 MMCFD.

Bermejo-Tarija-Villamontes-Yacuiba

This predominantly agricultural area is located in the vicinity of the gas pipeline to Argentina, and next to what could be a major gas find. Gas is used mostly for power generation (Villamontes) and two industries. 7/ A pipeline is under construction from Tarija to Puente, site of a cement plant--commissioning is expected at end-1987. Altogether, the potential for gas substitution in the industrial sector is estimated at 2 MMCFD.

6/ These are two ceramics plants (Elvia and Mabe) and one cement plant (Fancesa).

7/ At Bermejo, the sugar mill (Ing Azucarero Bermejo). At Villamontes, an oil press (Fca. de Aceites).

Market Development Strategy

With respect to exports to Argentina and Brazil, the outcome of the negotiations is virtually impossible to predict. Both economic and geo-political considerations will influence the decision of those countries to import Bolivian gas. Until a decision is reached, it would be wiser for Bolivia to avoid any large investments linked to export projects and concentrate on the development of the domestic gas market.

The strategy in place until now has been to develop the main gas grid from the producing areas to the main markets and to connect the larger users to the gas network. By the end of 1987, all the major plants will use gas as a fuel. Furthermore, 11 urban centers in Bolivia 8/ have access to gas through the main gas pipelines and capacity use at present is below 30% and will only reach 50% around 1990. The major task ahead is therefore, wherever economical, to build the distribution networks and connect the remaining industrial, commercial, and domestic consumers. However, it is essential to establish first the economic cost of gas. Since the cost of gas in turn depends on the demand, this becomes usually an iterative process. 9/ As long as the netback of gas exceeds its cost of supply, conversion to gas deserves to be pursued.

Average Incremental Cost of Supply

The cost of gas can be broken down into exploration, production, and transport. One way to evaluate the cost of exploration (or the cost of replacing gas reserves) is to assess the historical investments in exploration and the corresponding discoveries. Over 1976-85, YPFB invested US$357 million in exploration and discovered gas reserves equivalent to 2,409 BCF. 10/ Assuming that the gas reserves are produced from the fourth year after discovery, over a 20-year period, the cost of exploration can be estimated, at a 12% discount rate, at US$0.35/MCF.

8/ Bermejo, Camiri, Cochabamba, La Paz, Oruro, Potosi, Santa Cruz, Sucre, Tarija, Villamontes, and Yacuiba altogether account for about 95% of the urban population and 35% of Bolivia's total population.

9/ Afsaneh Mashayekhi: Marginal Cost of Natural Gas in Developing Countries (World Bank-Energy Department).

10/ In fact, 83% of the reserves were natural gas, and the balance, crude oil and condensate. The gas reserves are expressed on a calorific equivalent basis.

The cost of production includes the capital costs of field development and the operating costs. In connection with the preparation of export projects, YPFB has investigated five scenarios, each providing for a different volume of exports, from 200 MMCFD to 400 MMCFD. 11/ At a 12% discount rate, the production cost remains in the range of US$0.23-42. As there is a degree of uncertainty about the optimal order in which the fields ought to be developed for each scenario, and the estimated cost of field development, the production cost can roughly be estimated at US$0.30/MCF. In the event that no exports materialize, the incremental cost of production is virtually nil, as the domestic market can be supplied without further investments. The operating cost (excluding depreciation) was derived from YPFB's accounts and estimated at US$0.20/MCF. 12/

Regarding the incremental cost of domestic transport, three scenarios were investigated, corresponding to the possibility of installing the new power station in Cochabamba, Santa Cruz or Sucre. 13/ In the first instance, the incremental cost of transport turned out to be US$0.09/MCF, while in the other two it was US$0.06/MCF and US$0.07/MCF. They are low because most of the additional investments in pipelines are required in more than 10-years' time. For the time being, it can be therefore assumed that the incremental cost of transport is US$0.10/MCF. In the case of exports to Brazil, the cost of the Santa Cruz-Puerto Suarez (border town) pipeline has been estimated by YPFB at US$216 million (200 MMCFD, 24", without compression) so that the transport cost in

---

11/ In view of the range of quantities for exports selected, and taking into account that a provision was made for the domestic market, this calculation in effect covers all reasonably conceivable production levels. YPFB has appointed a firm of consultants, International Petroleum Engineering Consultants (U.K.), to optimize the sequence of fields development and gas transport. The study is funded by IDB.

12/ YPFB estimated the 1986 cost of gas production at US$175.8 million, less US$4.4 million for depreciation, US$59.6 million for purchases from oil companies, less US$98.0 million for royalties and taxes, which leaves US$13.9 million. The net production was 78.2 BCF less 13.2 BCF of purchases, or 65.0 BCF. The production cost was therefore US$0.21/MCF.

13/ The calculation is necessarily very tentative and does not make an allowance for load factors. Therefore, before the final decision is made on the location of the next power plant, this analysis will have to be made in detail.

Bolivia will be of the order of US$0.30/MCF. 14/ In summary, the average incremental cost of gas can be estimated as follows:

Table 1: AVERAGE INCREMENTAL COST OF GAS
(US$/MCF)

	With Exports	Without Exports
Exploration	0.35	0.35
Production	0.30	--
Operating Costs	0.20	0.20
Transport	0.10-0.30	0.10
	0.95-1.15	0.65

Source: NEP estimates.

These low prices reflect: (a) the relative abundance of gas in Bolivia; (b) the adequacy of the infrastructure of gas gathering systems and pipelines in the producing areas, in relation to future needs; and (c) the interconnection in place of all the consumption centers to the pipeline network. The above calculation does not include the cost of distribution mains and connection to consumers.

The average incremental cost of supply up to the city gate calculated above confirms that natural gas is a far cheaper source of energy to Bolivia 15/ than crude oil and oil products so that all efforts should be made, whenever economic, to accelerate the replacement of liquid fuels by natural gas, particularly since, even under the most optimistic scenario, Bolivia would not exhaust its proven gas reserves of 4 TCF in the next 20 years.

For gas pricing purposes, however, the incremental cost of supply constitutes only one input. In order to build up the price of gas, the following elements need also to be taken into account: (a) all customer duties and taxes on equipment and materials from exploration down to distribution; (b) royalties and other taxes on production; (c) the cost of transportation in Bolivia; (d) the cost of distribution; and (e) the prices of alternative fuels.

14/ Clearly, if the quantity transported were to increase significantly beyond 200 MMCFD, the cost of transport could decrease to US20-25¢/MCF.

15/ US$0.65/MCF is equivalent to crude oil at about US$3.40/bbl.

Priorities in Gas Use

Gas is not a freely-traded commodity so that its opportunity cost to the economy (netback) can only be measured against that of fuels it can replace. In the case of Bolivia, gas can essentially replace fuel oil and diesel oil in the manufacturing sector, hydroelectric generation in the power sector, and LPG and kerosene in the commercial and domestic sectors. 16/ The opportunity value will necessarily depend on whether Bolivia has a surplus or deficit in a particular fuel in a given year. One can reasonably anticipate that supplies of gasoline and LPG will match the demands, but deficits should be expected in diesel oil, kerosene, and fuel oil. The relative ranking of fuels can thus be estimated as follows:

Table 2: RELATIVE RANKING OF OPPORTUNITY COSTS

Fuel	c.i.f. Santos	Transportation a/	c.i.f. Santa Cruz	Distribution	Total	Equivalent
	----------	----------	US$/ton	----------	----------	(US$/MCF)
LPG	150		150	45 b/	195	4.34
Kerosene	137	85	222	20	242	5.73
Diesel	120	85	205	20	225	5.40
Fuel Oil	78	85	163	20	183	4.36

a/ Taken to be US$35/ton for transport in Brazil and US$50/ton for transport in Bolivia, in line with recent quotes.

b/ The cost of LPG bottling and transport to distributors has been estimated by YPFB at US$16.70/ton, and the cost of distribution at about B$0.06/kg (equivalent to US$28.6/ton).

Source: NEP estimates.

As Table 2 above indicates, the netback of gas is highest when it is used for kerosene and diesel replacement and lowest when it replaces fuel oil. In allocating gas, as long as the cost of supply (including distribution) is below the netback, substitution by gas will remain advantageous to the economy.

In order to evaluate the opportunity cost of gas to the power sector, three scenarios of future development plants were investigated, including an all-hydro sequence, an all thermal sequence, and a mixed

16/ Replacement of wood and charcoal in the rural areas by natural gas is not considered a realistic option in the foreseeable future.

one. The netback of gas turned out to be US$1.7/MCF for the all thermal sequence, and US$2.2/MCF for the mixed one.

Taking into account: (a) a marginal cost of gas to the economy of the order of US$0.65/MCF; and (b) the large size of the gas reserves, together with the high netbacks attained through the substitution of liquid fuels, the construction of gas distribution networks is of the highest priority. A key consideration is, everything else being equal, to connect first the larger users in order to ensure early revenues, and then gradually the smaller ones. This is the strategy YPFB's gas division will pursue in the coming years, with support from the private sector.

YPFB 5-Year Gas Substitution Program

YPFB's Gas Division is presently involved in the preparation of Master Plans and specifications for the gas distribution networks of the different cities. For certain cities these have already been completed (La Paz, Sucre, Tarija) while for others, they are at the basic design stage (Cochabamba, Santa Cruz). It is anticipated that the plans will all be completed by end-1987.

In order to ascertain the economic viability of the gas distribution project, preliminary calculations were performed for La Paz (El Alto Project), Tarija and the five-year plan as a whole. For this calculation, it was assumed that the city gate cost of gas was US$0.65/MCF; capital costs included the distribution mains, connection, meters, as well as conversion on consumer premises. The result can be summarized as follows:

Table 3: ECONOMIC RATE OF RETURN-DISTRIBUTION PROJECTS

	Industrial	Commercial and Residential	Combined
La Paz (El Alto)	>100%	7%	77%
Tarija	>100%	11%	80%
5-year Plan	>100%	26%	>100%

Source: NEP estimates.

The economic rates of return (ERR) of the distribution/conversion projects of industrial consumers exceed 100% but this is explained by their high levels of consumption together with the fact that only the incremental costs (thereby excluding the gas pipelines) are taken into account. Furthermore, they indicate that without the industrial consumers, the commercial and domestic sectors cannot support a gas distribution project even on a marginal basis--this is because their consumptions are low, and connection/conversion costs relatively high. Therefore, provided that industrial consumers are integrated in a distribution project, the ERR is adequate.

In all, the program appears to have been well designed and reflects realistically the implementation capabilities of YPFB, and the availability of financing (CAF has indicated its interest in providing US$10-12 million for the program). The main constraints are likely to be: (a) difficulties in YPFB in securing budget approvals for the gas network in 1987; (b) delays in implementing the new institutional framework for gas distribution; and (c) lack of financing for industrial consumers for conversion and metering facilities. 17/ Lastly, the present pricing framework may act as a disincentive to the commercial and domestic sectors in converting to gas.

Long-Term Gas Demand Forecast

YPFB's Gas Division released, in September 1986, a 20-year gas demand forecast, which, after review and updating, is presented here. The approach is sector-wise, which is appropriate considering the small size of Bolivia's market for liquid fuels and the considerable impact of relatively small number of consumers can have on overall demand.

Regarding the industrial sector, an overall growth rate of 8.5% was adopted, which is considered reasonable, taking into account that between 1980-86, GNP declined, while industrial consumption at Santa Cruz and Sucre (the only cities with long enough records) grew annually by 11% and 32% respectively.

With respect to the domestic and commercial sectors, the program is ambitious, with the target of connecting 100,000 consumers by 1995, and 300,000 by 2005. This would still represent only 30% of the domestic and commercial market in that year, and, on the basis of experience elsewhere, the target should be achievable provided that pricing incentives are in place, and the institutional framework is responsive to the requirements.

Regarding the cement industry, the growth of its demand for gas will essentially depend on development in the economy. An 8% growth rate is anticipated, on the assumption that the economy recovers.

17/ This is reported to be the reason why a bottling plant in the industrial park of Santa Cruz has not converted to gas.

Regarding the power sector, the forecast reflects the WASP III analysis of the least-cost solution to expand the power sector, which has concluded that the all-gas sequence was more attractive than installing hydroelectric schemes. The forecast is based on two major components, i.e., the continuation of the growth load at Santa Cruz, and the commissioning of a new gas-based power plant at Cochabamba, Santa Cruz or Sucre. The optimal solution will depend on the incremental cost of gas transport for each location, as well as purely technical consideration (stability of load, reliability of supply, impact of altitude on gas turbine efficiency, etc.).

Regarding the smelters, the forecast assumes that they will be converted to gas and in operation by 1988, and that their demand will grow by 3.5% from 1990, which should be achievable if the tin industry recovers.

YPFB is presently initiating a CNG program, whose first step is the preparation of a detailed master plan. 18/ YPFB anticipates that by 2005, this market could reach 9 MMCFD representing 1,600 bbl/day of gasoline.

Regarding fertilization, such a project today would, if anything, be even less viable than it was at the time of the energy assessment 19/ considering the drastic fall in international prices. An economic analysis should be carried out if a concrete proposal is advanced. YPFB's forecast thus anticipates a demand from that sector of 6 MMCFD by 1991, which seems early, but could be justified by 1995 if the economic environment warrants it.

A high and low density polyethylene plant is under study by YPFB which could use 15.5 MMCFD by 1992. Again this does not appear realistic, so early, but could be in place by the mid-1990s, if the circumstances are right.

The long-term gas demand forecast can thus be summarized as follows:

18/ Preparation of the master plan is to be financed under a World Bank Project Preparation Facility (PPF).

19/ Bolivia, Issues, and Options in the Energy Sector, April 1983.

Table 4: LONG-TERM GAS DEMAND FORECAST
(MMCFD)

	1985	1990	1995	2000	2005
Industrial	4.0	12.5	18.0	22.7	28.3
Com/Dom	--	1.6	6.0	13.9	24.0
Cement	3.1	6.3	9.4	13.8	20.3
Power	11.8	18.2	44.8	84.8	113.4
Smelters	--	4.8	6.8	9.7	10.3
CNG	--	0.8	2.5	4.7	9.0
Petrochem.	--	--	18.4	21.5	21.5
YPFB	22.3	27.6	33.9	34.5	36.6
Sub-total	41.2	71.8	139.8	205.6	263.4
Losses, Flares	21.3	23.0	31.4	27.8	22.6
TOTAL	62.5	94.9	171.2	233.4	286.0

Source: YPFB and NEP estimates.

As a result, by the year 2005, the power sector will still be the main user of gas accounting for nearly 45% of total gas use. In addition, should the gas export project to Brazil materialize, an additional demand of 14 MMCFD could be anticipated from a steel mill located near the Brazilian border (which is not included in the above forecast).

A regional breakdown of the anticipated gas demand indicates that Santa Cruz will remain the main market for gas, accounting for 60% of the total consumption if the new power station is located there, or 45% otherwise. La Paz would represent about 8% of the total market and Cochabamba another 10%.

A number of gas consumption forecasts have been made in recent years. The Energy Assessment report 20/ anticipated a 1990 demand between 82 MMCFD ("baseline") and 136 MMCFD. This now appears on the high side. GDC's forecast (1982) anticipated a 1991 demand of 69.8 MMCFD to which the above forecast seems closer. By the year 2005, the above forecast is higher than GDC's and YPFB's (because of a higher anticipated demand from the power sector) and at the same level as the Energy Assessment's (about 280 MMCFD by 2005).

20/ Bolivia, Issues and Options in the Energy Sector, April 1983.

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PRODUCCION HISTORICA DE GAS NATURAL

(MPCD)

Campos	Reservas Probadas al 31-12-86 MMMPC	PRODUCCION 1980	1981	1982	1983	1984	1985	1986
Distrito Sur								
Barredero			405					
Bermejo	232.63	25	25	16	22	3		502
Buena Vista								
Caiqua	27.54	403	88	104	164	36	22	•
Cambeiti	4.36	1,445	1,159	934	811	712	586	575
Camiri	2.09	10,400	9,677	9,737	9,140	8,058	5,019	956
Espino	26.39	5,567	13,682	15,211	16,603	9,164	6,677	2,640
Escondido	281.10							
Huayco	17.72			156				
Los Monos	9.30							
Monteagudo	44.67	5,553	5,252	5,537	5,534	3,534	3,940	6,039
Nupuco	24.26							
San Roque	69.33		110	145	134			12,804
Toro								
Vuelta Grande	639.19	279	124	44	8,622	27,948	26,230	21,489
SUBTOTAL	1,477.57	23,676.71	30,690.41	31,884.93	41,030.14	49,454.79	42,473.97	45,005.77
Distrito Centro								
Boqueron	1.75							
Bulo Bulo	2.51							
Cascabel	16.10							
Enconada	23.50							
H. Suarez R.	9.40			170	277	214	463	
Montecristo	7.44	5			115	471	430	
Naranjillos	[illegible]							
Palacios	[illegible]							
Palmar	11.75	[illegible]	[illegible]	[illegible]	16,037	[illegible]	5,230	2,808
Paloametas	79.51							
Rio Seco	9.42							
Santa Cruz	173.91					2,122	12,932	19,980
Santa Rosa	29.64							
Sirari	53.52							
Taccoo	7.65			16				
Warnes	5.10							
Yapacani	278.92							
SUBTOTAL	1,019.49	20,597.26	[illegible]	[illegible]	16,424.66	12,915.07	13,054.73	22,768.01
Division Santa Cruz								
Caranda	113.19	11,792	[illegible]	15,511	16,382	16,333	12,444	9,925
Colpa	224.59	55,405	48,633	[illegible]	[illegible]	32,035	26,425	18,154
Rio Grande	835.82	264,545	[illegible]	[illegible]	211,723	132,573	177,562	159,324
La Peña	21.77					4,701	7,466	10,035
SUBTOTAL	1,195.37	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	223,895.89	197,437.53
TOTAL YPFB	3,692.43	[illegible]	[illegible]	[illegible]	318,652.05	298,432.19	285,424.66	265,231.32
Occidental								
Tita	1.50	53,652	45,614	35,638	23,973	16,888	12,019	8,919
Porvenir	102.13		13,838	79,373	95,597	112,655	108,992	120,809
SUBTOTAL	104.63	53,652	59,452	115,011	119,570	129,542	121,011	129,728
Tesoro								
La Vertiente	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	43,203	41,975
Total Compañias	[illegible]	[illegible]	[illegible]	[illegible]	165,805	176,055	164,214	171,703
TOTAL	[illegible]	456,[illegible]	[illegible]	511,[illegible]	484,477	474,537	447,638	[illegible]

[illegible]

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH FNUD BM

VENTAS INTERNAS DE GAS NATURAL
HISTORICAS Y PROYECCION

(MMPCD)

	HISTORICA							PLAN QUINQUENAL					
	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	%	%
I. La Paz													
Cemento					194	555	1.149	1,490	1,610	1,740	1,880		13%
Industria						251	523	798	2,778	2.998	3,598		62%
Electricidad													
Com. y Dom									200	300	400		
Total	0	0	0	0	194	207	1,672	2,288	4,588	5,033	5,878		37%
II. Cochabamba													
Cemento					794	1.102	1,116	1,400	1.510	1,620	1.740		12%
Industria					326	539	701	1,664	2.154	2,401	2.731		40%
Electricidad													
Com. y Dom									100	150	200		
Total	0	0	0	0	1,120	1,641	1,817	3,064	3,764	4,171	4,671		27%
III. Santa Cruz													
Cemento													
Industria	2,905	3,909	4,307	2,876	3,613	3,147	3,174	3,600	4,000	4,200	4,300	1%	8%
Electricidad	7,609	8,517	9,400	9,372	10,187	11,709	14,309	14,600	16,470	18,510	16,920	11%	4%
Com. y Dom	9	14	16	24	26	37	51	160	260	350	450	34%	72%
Total	10,523	12,440	13,723	12,272	13,826	14.893	17,534	18,360	20,730	23,060	21,670	9%	5%
IV. Sucre													
Cemento	1,027	1,392	1,924	1.302	717	1.419	1.376	1.920	2,000	2,100	2,150	5%	12%
Industria	8	29	33	39	33	35	42	100	450	670	750	32%	106%
Electricidad	1.680	1,708	447	1,061	0	2	1	50	100	200	300	-71%	316%
Com. y Dom									100	150	200		
Total	2,715	3,129	2,404	2,402	750	1,456	1,419	2,070	2.650	3,120	3,400	-10%	24%
V. Tarija/Villamontes													
Cemento									130	290	480		
Industria		7	21	30	36	30	31	300	760	920	1,130		146%
Electricidad		30	79	113	139	111	108	120	530	640	850		67%
Com. y Dom									150	220	320		
Total	0	37	100	143	175	141	139	420	1,570	2,070	2,780		111%
Total													
Cemento	1,027	1,392	1,924	1,302	1,705	3.077	3.641	4.810	5,250	5,750	6.250	23%	14%
Industria	2,913	3.945	4,361	2,945	4,008	4,002	4,471	6.462	10,142	11.197	12.509	7%	29%
Electricidad	9,289	10,255	9,926	10,546	10,326	11,822	14,418	14,770	17,100	19,350	18.070	8%	6%
Com. y Dom	9	14	16	24	26	37	51	160	810	1.170	1,570	34%	136%
	13,238	15,606	16,227	14,817	16.065	18,938	22,581	26,202	33,302	37,459	38,399	9%	14%

Excluye consumo interno de YPFB y fundiciones

FUENTE: YPFB - Division de Gas Natural

29-Jun-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH FNUD BM

PROGRAMA DE SUSTITUCION DE GAS NATURAL

FLAN QUINQUENAL

	Sector Industrial					Sector Domestico-Comercial			Total				
	Gas natural	Eq. en Comb. Liquidos				Gas natural	Eq. en Comb. Liquidos		Gas natural	Eq. en Comb. Liquidos			
	Sustituible	D.O	F.O	KER	GLP	Sustituible	KER	GLP	Sustituible	D.O	F.O	KER	GLP
AñO	MPCD	Bbl/año	Bbl/año	Bbl/año	Ton/año	MFCD	Bbl/año	Ton/año	MPCD	Bbl/año	Bbl/año	Bbl/año	Ton/año
1	925.89	1776.97	28536.44	4764.60	2152.37	0.00	0.00	0.00	925.89	1776.97	28536.44	4764.60	2152.37
2	1851.78	3553.94	57072.89	9529.20	4304.75	0.00	0.00	0.00	1851.78	3553.94	57072.99	9529.20	4304.75
3	3703.56	7107.89	114145.78	19058.40	8609.50	300.00	1007.18	2283.04	4003.56	7107.89	114145.78	20065.59	10692.54
4	7407.12	14215.77	226291.56	38116.80	17219.00	700.00	2350.10	5327.10	8107.12	14215.77	226291.56	40466.99	22546.10
5	11799.00	22644.69	363651.74	60717.27	27428.61	1200.00	4028.74	9132.18	12999.00	22644.69	363651.74	64746.01	[illegible]
6	12270.00	23550.48	378197.81	63145.96	28525.75	1500.00	5035.92	11415.22	13770.00	23550.48	378197.81	65161.83	39940.97
7	12761.60	24492.50	393325.72	65671.80	29600.76	1530.00	5136.64	11643.52	14291.80	24492.50	393325.72	70806.44	41310.30
8	13272.27	25472.20	409058.75	66298.67	30853.45	1560.00	5239.37	11876.40	14832.27	25472.20	409058.75	73538.04	42729.85
9	13803.16	26491.08	425421.10	71030.61	32087.59	1591.81	5344.16	12113.92	15394.97	26491.08	425421.10	76374.77	[illegible]
10	14355.29	27550.73	442437.94	73871.84	33371.09	1623.65	5451.04	12356.20	15978.94	27550.73	442437.94	79322.85	[illegible]
11	14929.50	28652.76	460135.46	76826.71	34705.94	1656.12	5560.07	12603.33	16585.62	28652.76	460135.46	82386.76	[illegible]
12	15526.68	29798.87	478540.88	79899.78	36094.17	1689.24	5671.27	12855.39	17215.92	29798.87	478540.88	85571.05	[illegible]
13	16147.75	30990.82	497662.51	83095.77	37537.94	1723.03	5784.69	13112.50	17870.78	30990.82	497662.51	88880.46	[illegible]
14	16793.66	32230.45	517589.82	86419.60	39039.46	1757.49	5900.39	13374.75	18551.15	32230.45	517589.82	92319.99	52414.21
15	17465.40	33519.67	538293.41	89876.39	40601.04	1792.64	6018.39	13642.24	19258.04	33519.67	538293.41	95894.78	54243.26
16	18164.02	34860.46	559825.14	93471.44	42225.08	1028.49	6138.76	13915.09	19992.51	34860.46	559825.14	99610.20	56149.17
17	18890.58	36254.88	582218.15	97210.30	43914.08	1865.06	6261.54	14193.39	20755.64	36254.88	582218.15	103471.84	58107.47
18	19646.20	37705.07	605506.88	101098.71	45670.64	1902.36	6386.77	14477.26	21548.56	37705.07	605506.88	107485.48	60147.90
19	20432.05	39213.27	629727.15	105142.66	47497.47	1940.41	6514.50	14766.80	22372.46	39213.27	629727.15	111657.16	62264.27
20	21249.33	40781.81	654916.24	109348.37	49397.37	1979.22	6644.79	15062.14	23228.55	40781.81	654916.24	115993.16	64459.51

FUENTE: YPFB - Division de Gas Natural

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH FNUD BM

PROYECCION DE LA DEMANDA A LARGO PLAZO - POR CIUDAD

(MMPCD)

	La Paz	Oruro			Cochabamba				Cocha.	Sucre				Fotosi			Camiri		
	Ind.	Ind.	Net	Total	Ind.	Elec.	YPFB	Total	COBOCE	Ind.	Elec.	YPFB	Total	Ind.	Net	Total	Ind.	Elec.	Total
1966	1.67				0.70	0.00	3.25	3.95	1.12	1.42	0.05	0.61	2.08	0.00		0.00		0.45	0.45
1987	2.09	0.20		0.20	1.66	0.00	3.53	5.19	1.40	1.97	0.10	0.62	2.69	0.10	1.35	1.45		0.46	0.46
1988	4.34	0.25	2.70	2.95	2.25	0.00	3.83	6.08	1.51	2.50	0.20	0.63	3.33	0.15	1.47	1.62		0.47	0.47
1989	4.69	0.35	2.87	3.22	2.55	0.00	4.15	6.70	1.62	2.94	0.30	0.64	3.88	0.18	1.60	1.78	0.02	0.48	0.50
1990	5.40	0.48	3.05	3.53	2.93	0.00	4.50	7.43	1.74	3.11	0.40	0.65	4.16	0.29	1.74	2.03	0.06	0.49	0.55
1991	6.72	0.55	3.24	3.79	3.63	0.00	4.60	8.23	2.00	3.08	0.50	0.66	4.24	0.34	1.90	2.24	0.07	0.50	0.57
1992	7.35	0.68	3.44	4.12	3.98	0.00	4.69	8.67	2.15	3.26	0.56	0.67	4.49	0.42	2.07	2.49	0.09	0.52	0.61
1993	8.04	0.84	3.65	4.50	4.36	0.00	4.79	9.15	2.32	3.44	3.07	0.68	7.19	0.52	2.25	2.78	0.11	0.55	0.66
1994	8.80	1.04	3.68	4.92	4.77	0.00	4.90	9.67	2.49	3.64	5.91	0.69	10.24	0.65	2.45	3.10	0.14	0.57	0.71
1995	9.63	1.29	4.12	5.41	5.23	0.00	5.00	10.23	2.68	3.85	8.91	0.70	13.46	0.81	2.67	3.48	0.17	0.60	0.77
1996	10.38	1.57	4.37	5.94	5.73	0.00	5.05	10.78	2.75	4.09	12.05	0.71	16.85	0.90	2.91	3.81	0.19	0.60	0.79
1997	11.19	1.90	4.64	6.55	6.28	0.00	5.09	11.37	2.83	4.34	15.37	0.72	20.44	1.00	3.17	4.17	0.22	0.60	0.82
1998	12.06	2.31	4.93	7.24	6.88	0.00	5.14	12.02	2.91	4.61	18.89	0.73	24.23	1.12	3.45	4.57	0.25	0.60	0.85
1999	13.00	2.81	5.24	8.04	7.53	0.00	5.19	12.72	2.99	4.90	22.60	0.74	26.24	1.24	3.76	5.00	0.29	0.60	0.69
2000	14.01	3.41	5.56	8.97	8.25	0.00	5.24	13.49	3.07	5.20	26.52	0.75	32.47	1.38	4.10	5.48	0.33	0.60	[illegible]
2001	14.90	3.93	5.68	[illegible]	8.98	0.00	5.24	14.22	3.24	5.64	28.11	0.76	34.51	1.55	4.10	5.65	0.36	0.66	[illegible]
2002	15.85	4.53	5.79	10.32	9.78	0.00	5.24	15.02	3.41	6.11	29.80	0.77	36.68	1.73	4.10	5.83	0.39	0.74	1.13
2003	16.86	5.21	5.91	11.13	10.64	0.00	5.24	15.88	3.60	6.62	31.59	0.78	38.99	1.94	4.10	6.04	0.42	0.82	1.24
2004	17.94	6.01	6.04	12.04	11.58	0.00	5.24	16.82	3.79	7.18	33.48	0.79	41.45	2.18	4.10	6.28	0.46	0.90	1.36
2005	19.08	6.92	6.16	13.08	12.61	0.00	5.24	17.85	4.00	7.78	35.49	0.80	44.07	2.44	4.10	6.54	0.50	1.00	1.50

	El Fuente	Tarija			Villamontes			Berm-Yac	Santa Cruz				YPFB (Campos)	Total por Sector				Total Demanda	
	Ind.	Ind.	Elec	Total	Ind.	Elec	Total	Ind.	Ind.	Elec.	YPFB	Total		Ind	Net	Elec.	YPFB	Incl. YPFB	Excl. YPFB
1966					0.10	0.11	0.21	0.00	3.23	13.86	2.51	19.59	16.11	8.23	0.00	14.47	22.48	45.18	22.70
1987		0.27		0.27	0.11	0.12	0.23	0.00	3.76	14.14	2.62	20.52	19.91	11.56	1.35	14.82	26.68	54.41	27.73
1988	0.13	0.45	0.40	0.85	0.12	0.13	0.25	0.34	4.26	16.00	2.74	23.00	19.48	16.30	4.17	17.20	26.68	64.35	37.67
1989	0.29	0.62	0.50	1.12	0.13	0.14	0.27	0.39	4.53	18.03	2.87	25.43	18.91	18.31	4.47	19.45	26.57	68.80	42.23
1990	0.48	0.82	0.70	1.52	0.16	0.15	0.31	0.47	4.69	16.43	3.00	24.12	19.46	20.63	4.79	18.17	27.61	71.20	43.59
1991	0.67	1.30	0.60	2.10	0.19	0.20	0.39	0.85	7.30	20.05	3.74	31.09	21.23	26.70	5.14	22.05	30.22	84.11	53.69
1992	0.81	1.29	0.82	2.12	0.20	0.22	0.42	1.69	8.64	24.66	4.66	37.96	22.41	30.56	5.51	26.79	32.43	95.29	62.86
1993	0.97	1.29	0.85	2.14	0.21	0.24	0.45	3.38	10.23	27.65	5.80	43.68	21.70	35.71	5.91	32.36	32.97	106.95	73.98
1994	1.16	1.28	0.87	2.16	0.22	0.27	0.49	6.73	12.11	30.73	7.22	50.07	21.05	43.05	6.33	38.36	33.86	121.60	87.74
1995	1.40	1.28	0.90	2.18	0.23	0.30	0.53	13.41	14.34	34.10	9.00	57.44	19.21	54.32	6.79	44.81	33.91	139.83	105.92
1996	1.40	1.39	0.92	2.30	0.26	0.32	0.58	14.08	15.35	37.79	9.10	62.24	19.41	58.10	7.28	51.68	34.26	151.32	117.06
1997	1.40	1.50	0.94	2.44	0.30	0.34	0.64	14.79	16.44	41.81	9.20	67.45	19.31	62.19	7.81	59.06	34.32	163.38	129.06
1998	1.40	1.62	0.96	2.58	0.34	0.36	0.70	15.53	17.60	46.21	9.30	73.11	19.22	66.63	8.39	67.01	34.39	176.41	142.02
1999	1.40	1.76	0.98	2.73	0.39	0.38	0.77	16.30	18.85	51.01	9.40	79.25	19.11	71.45	9.00	75.57	34.44	190.46	156.02
2000	1.40	1.90	1.00	2.90	0.45	0.40	0.85	17.12	20.18	56.25	9.50	85.93	19.01	76.70	9.66	84.77	34.50	205.63	171.13
2001	1.40	2.05	1.02	3.07	0.49	0.42	0.91	17.24	21.42	59.62	9.60	90.64	19.30	81.19	9.79	89.84	34.90	215.70	180.80
2002	1.40	2.21	1.04	3.25	0.53	0.44	0.97	17.37	22.74	63.20	9.70	95.64	19.59	86.05	9.89	95.21	35.30	226.46	191.16
2003	1.40	2.39	1.06	3.45	0.58	0.46	1.03	17.49	24.14	66.99	9.80	100.93	19.91	91.30	10.01	100.71	35.73	237.96	202.23
2004	1.40	2.58	1.08	3.66	0.63	0.48	1.10	17.61	25.63	71.01	9.90	106.54	20.22	96.98	10.14	106.95	36.15	250.22	214.07
2005	1.40	2.78	1.10	3.68	0.68	0.50	1.18	17.74	27.21	75.27	10.00	112.48	20.55	103.14	10.26	113.36	36.59	263.35	226.76

29-Jun-97

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

RECUPERACION DEL COSTO DE CONVERSION DESDE EL PUNTO DE VISTA DEL USUARIO

Usuarios Tipicos		Consumo F.O.	Consumo G.O.	Consumo GLP	Costo (US$)	Eq.Gas (MPCD)	Gas Costo (US$)	Ahorro (US$)	Conexion Costo (US$)	Conversion Costo (US$)	Tiempo de Retorno 1/ (Dias)
		(litros/dia)			---------- por dia ----------						
Industrial	Grande	13,000			2,662	444.0	793	1,869	15,000	20,000	19
Industrial	Pequeño	1,450			297	49.5	88	208	7,000	3,000	48
Comercial	Grande			200	16	4.9	9	7	300	1,000	145
Comercial	Pequeño			20	2	0.5	1	1	200	300	436
		(kg/mes)			---------- por mes ----------						-- mes --
Domestico				40	6	1.8	3	3	160	100	40

Precios (b$)

G.O. (por litro)	0.50
F.O. (por litro)	0.43
LPG (por kg)	0.30
Gas Natural (por MPC)	3.75

Tasa de Cambio (b$/US$) 5.10

1/ Para los usuarios Comerciales y Domesticos, el costo de la conexion es pagado por el Distribuidor.

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH FNUD BM

CAPACIDAD ACTUAL Y PREVISTA DE GASODUCTOS

(MMPCD)

	Oruro - La Paz		Parot-Oruro		Parot-COBOCE		Coch - Parot		Huayn-Parot		Huay-Coch	Tap.-Hua	Rio-Huayn		Tarab-Tap
	Instal	Adicc.	Insta	Adicc.	Insta	Adicc.	Insta	Adicc.	Insta	Adicc.	Insta	Insta	Insta	Adicc.	Instal
Capacidad	14.80	4.28	24.40	7.76	4.20	0.00	7.00	0.00	29.00	13.51	11.50	11.50	31.40	11.11	11.50
1986	1.67	0.00	1.67	0.00	1.12	0.00	2.79	0.00	0.00	0.00	6.74	6.74	0.00	0.00	6.74
1987	2.09	0.00	2.29	0.00	1.40	0.00	3.69	0.00	0.00	0.00	8.88	8.88	0.00	0.00	8.88
1988	4.34	0.00	7.29	0.00	1.51	0.00	5.42	0.00	3.38	0.00	11.50	11.50	3.38	0.00	11.50
1989	4.69	0.00	7.91	0.00	1.62	0.00	4.80	0.00	4.73	0.00	11.50	11.50	4.73	0.00	11.50
1990	5.40	0.00	8.93	0.00	1.74	0.00	4.07	0.00	6.60	0.00	11.50	11.50	6.60	0.00	11.50
1991	6.72	0.00	10.51	0.00	2.00	0.00	3.27	0.00	9.24	0.00	11.50	11.50	9.24	0.00	11.50
1992	7.35	0.00	11.47	0.00	2.15	0.00	2.83	0.00	10.80	0.00	11.50	11.50	10.80	0.00	11.50
1993	8.04	0.00	12.54	0.00	2.32	0.00	2.35	0.00	12.51	0.00	11.50	11.50	12.51	0.00	11.50
1994	8.80	0.00	13.72	0.00	2.49	0.00	1.83	0.00	14.38	0.00	11.50	11.50	14.38	0.00	11.50
1995	9.63	0.00	15.04	0.00	2.68	0.00	1.27	0.00	16.45	0.00	11.50	11.50	16.45	0.00	11.50
1996	10.38	0.00	16.32	0.00	2.75	0.00	0.72	0.00	16.35	0.00	11.50	11.50	18.35	0.00	11.50
1997	11.19	0.00	17.74	0.00	2.83	0.00	0.13	0.00	20.44	0.00	11.50	11.50	20.44	0.00	11.50
1998	12.06	0.00	19.30	0.00	2.91	0.00	0.52	0.00	22.73	0.00	11.50	11.50	22.73	0.00	11.50
1999	13.00	0.00	21.04	0.00	2.99	0.00	1.22	0.00	25.25	0.00	11.50	11.50	25.25	0.00	11.50
2000	14.01	0.00	22.98	0.00	3.07	0.00	1.99	0.00	28.04	0.00	11.50	11.50	28.04	0.00	11.50
2001	14.80	0.10	24.40	0.11	3.24	0.00	2.72	0.00	29.00	1.46	11.50	11.50	30.46	0.00	11.50
2002	14.80	1.05	24.40	1.77	3.41	0.00	3.52	0.00	29.00	4.10	11.50	11.50	31.40	1.70	11.50
2003	14.80	2.06	24.40	3.59	3.60	0.00	4.38	0.00	29.00	6.97	11.50	11.50	31.40	4.57	11.50
2004	14.80	3.14	24.40	5.58	3.79	0.00	5.32	0.00	29.00	10.10	11.50	11.50	31.40	7.70	11.50
2005	14.80	4.28	24.40	7.76	4.00	0.00	6.35	0.00	29.00	13.51	11.50	11.50	31.40	11.11	11.50

	Sucre-Pot		Tarab-Sucre		Cerr- Tarab		Mont - Cerr		Camiri - Cerr		Taquip - Camir		Tar-ElPu	Villamontes-Tarij		Cap. Promedio Utilizada
	Instal	Adicc.	Insta	Adicc.	Insta	Adicc.	Insta	Adicc.	Insta	Adicc.	Insta	Adicc.	Instal.	Insta	Adicc.	
Capacidad	7.30	0.00	14.20	36.41	25.70	36.41	6.00	0.00	22.00	0.00	22.00	0.00	2.00	4.60	0.68	
1986	0.00	0.00	2.08	0.00	8.82	0.00	6.00	0.00	2.82	0.00	3.27	0.00	0.00	0.00	0.00	27%
1987	1.45	0.00	4.14	0.00	13.02	0.00	6.00	0.00	7.02	0.00	7.48	0.00	0.00	0.27	0.00	40%
1988	1.62	0.00	4.95	0.00	16.45	0.00	6.00	0.00	10.45	0.00	10.92	0.00	0.13	0.98	0.00	45%
1989	1.78	0.00	5.66	0.00	17.16	0.00	6.00	0.00	11.16	0.00	11.66	0.00	0.29	1.41	0.00	47%
1990	2.03	0.00	6.19	0.00	17.69	0.00	6.00	0.00	11.69	0.00	12.24	0.00	0.48	2.00	0.00	51%
1991	2.24	0.00	6.48	0.00	17.98	0.00	6.00	0.00	11.98	0.00	12.55	0.00	0.67	2.77	0.00	55%
1992	2.49	0.00	6.98	0.00	18.48	0.00	6.00	0.00	12.48	0.00	13.09	0.00	0.81	2.92	0.00	57%
1993	2.78	0.00	9.97	0.00	21.47	0.00	6.00	0.00	15.47	0.00	16.12	0.00	0.97	3.11	0.00	64%
1994	3.10	0.00	13.34	0.00	24.84	0.00	6.00	0.00	18.84	0.00	19.55	0.00	1.16	3.32	0.00	72%
1995	3.48	0.00	14.20	6.97	25.70	6.97	6.00	0.00	22.00	0.00	22.00	0.00	1.40	3.58	0.00	78%
1996	3.81	0.00	14.20	7.32	25.70	7.32	6.00	0.00	22.00	0.00	22.00	0.00	1.40	3.70	0.00	80%
1997	4.17	0.00	14.20	10.41	25.70	10.41	6.00	0.00	27.00	0.00	22.00	0.00	1.40	3.84	0.00	83%
1998	4.57	0.00	14.20	14.60	25.70	14.60	6.00	0.00	22.00	0.00	22.00	0.00	1.40	3.98	0.00	86%
1999	5.00	0.00	14.20	19.04	25.70	19.04	6.00	0.00	22.00	0.00	22.00	0.00	1.40	4.13	0.00	90%
2000	5.48	0.00	14.20	23.75	25.70	23.75	6.00	0.00	22.00	0.00	22.00	0.00	1.40	4.30	0.00	94%
2001	5.65	0.00	14.20	25.95	25.70	25.95	6.00	0.00	22.00	0.00	22.00	0.00	1.40	4.47	0.00	97%
2002	5.83	0.00	14.20	28.31	25.70	28.31	6.00	0.00	22.00	0.00	22.00	0.00	1.40	4.60	0.05	97%
2003	6.04	0.00	14.20	30.83	25.70	30.83	6.00	0.00	22.00	0.00	22.00	0.00	1.40	4.60	0.25	98%
2004	6.28	0.00	14.20	33.52	25.70	33.52	6.00	0.00	22.00	0.00	22.00	0.00	1.40	4.60	0.46	99%
2005	6.54	0.00	14.20	36.41	25.70	36.41	6.00	0.00	22.00	0.00	22.00	0.00	1.40	4.60	0.68	99%

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

COSTO DE TRANSPORTE DE GAS NATURAL

(US$/MPC)

RUTA	Orur-LPaz	Par-Orur.	Par.-COB	CBB-Par.	Hua-Par	Hua-CBB	Tap-Hua	Rio-Hu	Tarb-Tap	Sucre-Pot	Tarb-Suc	Cerr-Tara	Mont-Cerr	Cami-Cerr	Taq-Cami	Tar-Elfue	Vil-Tar	Total
Longitud (Km)	200	128	27	34	253	12	249	434	13	114	44	180	65	62	55	80	190	2139.84
Capacidad (MMFCD)	14.80	24.40	4.20	7.00	29.00	11.50	11.50	31.40	11.50	7.30	14.20	25.70	6.00	22.00	22.00	2.00	4.60	
Costo de Inversion	8.38	5.37	0.67	1.44	30.00	0.39	8.35	52.00	1.24	2.02	2.56	9.10	3.63	2.58	1.91	1.48	3.52	134.64
Costo Anual	1.16	0.74	0.09	0.20	4.14	0.05	1.15	7.17	0.17	0.28	0.35	1.25	0.50	0.36	0.26	0.20	0.49	18.57
Costo/MPC Anual	0.44	0.18	0.02	0.17	1.04	0.01	0.29	1.76	0.04	0.29	0.11	0.18	0.22	0.07	0.05	0.80	0.57	0.65
Año de Expansion	2000	2000	2005	2005	2000			2001		2005	1994	1994	2005	2005	2005		2001	

RUTA	Orur-LPaz	Par-Orur.	Par.-COB	CBB-Par.	Hua-Par	Hua-CBB	Tap-Hua	Rio-Hu	Tarb-Tap	Sucre-Pot	Tarb-Suc	Cerr-Tara	Mont-Cerr	Cami-Cerr	Taq-Cami	Tar-Elfue	Vil-Tar	Total
1986	1.89	1.21	0.2[illegible]	0.20	0.00	0.02	0.47	0.00	0.07	0.00	0.47	0.39	0.23	0.35	0.22	0.00		2.24
1987	1.52	0.89	0.18	0.15	0.00	0.02	0.36	0.00	0.05	0.53	0.23	0.26	0.23	0.14	0.10	0.00	4.93	1.83
1988	0.73	0.28	0.[illegible]7	0.10	3.35	0.01	0.27	5.82	0.04	0.47	0.20	0.21	0.23	0.09	0.07	4.30	1.36	1.35
1989	0.68	0.26	0.16	0.11	2.40	0.01	0.27	4.15	0.04	0.43	0.17	0.20	0.23	0.09	0.06	1.93	0.94	1.20
1990	0.59	0.23	0.15	0.13	1.72	0.01	0.27	2.98	0.04	0.38	0.16	0.19	0.23	0.08	0.06	1.16	0.66	1.17
1991	0.47	0.19	0.13	0.17	1.23	0.01	0.27	2.13	0.04	0.34	0.15	0.19	0.23	0.08	0.06	0.83	0.48	0.94
992	0.43	0.18	0.12	0.19	1.05	0.01	0.27	1.82	0.04	0.31	0.14	0.19	0.23	0.08	0.06	0.69	0.45	0.81
1993	0.39	0.16	0.11	0.23	0.91	0.01	0.27	1.57	0.04	0.27	0.10	0.16	0.23	0.06	0.04	0.58	0.43	0.69
1994	0.36	0.15	0.10	0.30	0.79	0.01	0.27	1.37	0.04	0.25	0.07	0.14	0.23	0.05	0.04	0.48	0.40	0.56
1995	0.33	0.13	0.09	0.43	0.69	0.01	0.27	1.19	0.04	0.22	0.07	0.13	0.23	0.04	0.03	0.40	0.37	0.48
1996	0.31	0.12	0.09	0.75	0.62	0.01	0.27	1.07	0.04	0.20	0.07	0.13	0.23	0.04	0.03	0.40	0.36	0.43
1997	0.28	0.11	0.09	4.21	0.55	0.01	0.27	0.96	0.04	0.18	0.07	0.13	0.23	0.04	0.03	0.40	0.35	0.39
1998	0.26	0.11	0.09	1.05	0.50	0.01	0.27	0.86	0.04	0.17	0.07	0.13	0.23	0.04	0.03	0.40	0.33	0.36
1999	0.24	0.10	0.08	0.45	0.45	0.01	0.27	0.78	0.04	0.15	0.07	0.13	0.23	0.04	0.03	0.40	0.32	0.33
2000	0.23	0.09	0.08	0.27	0.40	0.01	0.27	0.70	0.04	0.14	0.07	0.13	0.23	0.04	0.03	0.40	0.31	0.30
2001	0.21	0.08	0.08	0.20	0.39	0.01	0.27	0.64	0.04	0.14	0.07	0.13	0.23	0.04	0.03	0.40	0.30	0.28
2002	0.21	0.08	0.07	0.15	0.39	0.01	0.27	0.63	0.04	0.13	0.07	0.13	0.23	0.04	0.03	0.40	0.29	0.27
2003	0.21	0.08	0.47	0.12	0.39	0.01	0.27	0.63	0.04	0.13	0.07	0.13	0.23	0.04	0.03	0.40	0.29	0.25
2004	0.21	0.08	0.07	0.10	0.39	0.01	0.27	0.63	0.04	0.12	0.07	0.13	0.23	0.04	0.03	0.40	0.29	0.24
2005	0.21	0.08	0.06	0.09	0.39	0.01	0.27	0.63	0.04	0.12	0.07	0.13	0.23	0.04	0.03	0.40	0.29	0.22

29-Jun-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

REQUERIMIENTOS DE EXPANSION DE GASODUCTOS

Nueva Planta de Energia Electrica en Sucre

Ruta	Orur - La Paz Caudal Ad. (MMPCD)	Orur - La Paz Inv. (MM$us)	Farot-Oruro. Caudal Ad (MMPCD)	Farot-Oruro. Inv. (MM$us)	Parot.-COBOCE Caudal Ad (MMPCD)	Parot.-COBOCE Inv. (MM$us)	CBB-Parot Caudal Ad (MMPCD)	CBB-Parot Inv. (MM$us)	Huay-Parot Caudal Ad (MMPCD)	Huay-Parot Inv. (MM$us)	Rio-Huayn Caudal Ad (MMPCD)	Rio-Huayn Inv. (MM$us)	Sucre-Pot Caudal Ad (MMPCD)	Sucre-Pot Inv. (MM$us)	Tarab-Sucre Caudal Ad (MMPCD)	Tarab-Sucre Inv. (MM$us)	Cerr- Torre Caudal Ad (MMPCD)	Cerr- Torre Inv. (MM$us)	Mont - Cerr Caudal Ad (MMPCD)	Mont - Cerr Inv. (MM$us)	Camiri - Cerr Caudal Ad (MMPCD)	Camiri - Cerr Inv. (MM$us)	Taquip - Camiri Caudal Ad (MMPCD)	Taquip - Camiri Inv. (MM$us)	TOTAL Caudal (MMPCD)	TOTAL Inv. (MM$us)
1986	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00	0.00
1987	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		25.62	0.00
1988	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		60.84	0.00
1989	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		67.62	0.00
1990	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		75.69	0.00
1991	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		85.68	0.00
1992	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		92.67	0.00
1993	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00	1.21	0.00	3.91	0.00		0.00		0.00		110.18	5.12
1994	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00	1.21	0.00	3.91	0.00		0.00		0.00		129.81	5.12
1995	0.00		0.00		0.00		0.00		0.00		0.00		0.00		6.97	1.21	6.97	3.91	0.00		0.00		0.00		157.85	5.12
1996	0.00		0.00		0.00		0.00		0.00		0.00		0.00		7.32		7.32		0.00		0.00		0.00		164.37	0.00
1997	0.00		0.00		0.00		0.00		0.00		0.00		0.00		10.41		10.41		0.00		0.00		0.00		176.91	0.00
1998	0.00		0.00		0.00		0.00		0.00		0.00		0.00		14.60		14.60		0.00		0.00		0.00		193.32	0.00
1999	0.00	5.72	0.00	3.78	0.00		0.00		0.00	5.37	0.00		0.00		19.04		19.04		0.00		0.00		0.00		211.31	14.87
2000	0.00	5.72	0.00	3.78	0.00		0.00		0.00	5.37	0.00	8.93	0.00		23.75		23.75		0.00		0.00		0.00		230.75	23.80
2001	0.10	5.72	0.11	3.78	0.00		0.00		1.46	5.37	0.00	8.93	0.00		25.95		25.95		0.00		0.00		0.00		243.65	23.80
2002	1.05		1.77		0.00		0.00		4.10		1.70	8.93	0.00		28.31		28.31		0.00		0.00		0.00		257.60	8.93
2003	2.06		3.59		0.00		0.00		6.97		4.57		0.00		30.83		30.83		0.00		0.00		0.00		272.66	0.00
2004	3.14		5.58		0.00		0.00		10.10		7.70		0.00		33.52		33.52		0.00		0.00		0.00		286.94	0.00
2005	4.28		7.76		0.00		0.00		13.51		11.11		0.00		36.41		36.41		0.00		0.00		0.00		306.58	0.00

Costo Incremental Promedio de Transportes $0.07 por MPC

29-Jun-97

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

REQUERIMIENTOS DE EXPANSION DE GASODUCTOS

Nueva Planta de Energia Electrica en Cochabamba

Ruta	Orur - La Paz		Parot-Oruro.		Parot.-COBOCE		CBB-Parot		Huay-Parot		Rio-Huayn		Sucre-Pot		Tarab-Sucre		Cerr- Torre		Mont - Cerr		Camiri - Cerr		Taquip - Camiri		TOTAL Caudal	TOTAL Inv.
	Caudal Ad. (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	Caudal Ad (MMPCD)	Inv. (MM$us)	(MMPCD)	(MM$us)
1986	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00	0.00
1987	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		25.02	0.00
1988	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		60.84	0.00
1989	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		67.62	0.00
1990	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		75.69	0. .0
1991	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		85.68	0.00
1992	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		92.67	0.00
1993	0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		0.00		103.04	0.00
1994	0.00		0.00		0.00		0.00	1.01	0.00	7.14	0.00		0.00		0.00		0.00		0.00		0.00		0.00		120.95	8.15
1995	0.00		0.00		0.00		0.00	1.01	0.00	7.14	0.00	12.01	0.00		0.00		0.00		0.00		0.00		0.00		140.39	20.16
1996	0.00		0.00		0.00		3.46	1.01	0.54	7.14	0.00	12.01	0.00		0.00		0.00		0.00		0.00		0.00		159.14	20.16
1997	0.00		0.00		0.00		7.30		5.87		3.47	12.01	0.00		0.00		0.00		0.00		0.00		0.00		179.26	12.01
1998	0.00		0.00		0.00		11.38		11.59		9.19		0.00		0.00		0.00		0.00		0.00		0.00		200.89	0.00
1999	0.00	5.72	0.00	3.78	0.00		15.71		17.74		15.34		0.00		0.00		0.00		0.00		0.00		0.00		224.19	9.50
2000	0.00	5.72	0.00	3.78	0.00		20.31		24.36		21.96		0.00		0.00		0.00		0.00		0.00		0.00		249.26	9.50
2001	0.10	5.72	0.11	3.78	0.00		22.56		28.31		25.91		0.00		0.00	0.70	0.00	1.82	0.00		0.00		0.00		265.14	12.02
2002	1.05		1.77		0.00		24.97		32.55		30.15		0.00		0.00	0.70	0.00	1.82	0.00		0.00		0.00		282.30	2.52
2003	2.06		3.59		0.00		27.54		37.13		34.73		0.00		1.56	0.70	1.56	1.82	0.00		0.00		0.00		303.85	2.52
2004	3.14		5.58		0.00		30.29		42.07		39.67		0.00		1.69		1.69		0.00		0.00		0.00		320.57	0.00
2005	4.28		7.76		0.00		33.24		47.40		43.00		0.00		2.52		2.52		0.00		0.00		0.00		340.46	0.00

Costo Incremental Promedio de Transporte: $0.09 por MPC

29-Jun-97

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

REQUERIMIENTOS DE EXPANSION DE GASODUCTOS

Nueva Planta de Energia Electrica en Santa Cruz

Ruta	Orur - La Paz Caudal Ad. (MMPCD)	Orur - La Paz Inv. (MM$us)	Parot-Oruro. Caudal Ad (MMPCD)	Parot-Oruro. Inv. (MM$us)	Parot.-COBOCE Caudal Ad (MMPCD)	Parot.-COBOCE Inv. (MM$us)	CBB-Parot Caudal Ad (MMPCD)	CBB-Parot Inv. (MM$us)	Huay-Parot Caudal Ad (MMPCD)	Huay-Parot Inv. (MM$us)	Rio-Huaya Caudal Ad (MMPCD)	Rio-Huaya Inv. (MM$us)
1986	0.00		0.00		0.00		0.00		0.00		0.00	
1987	0.00		0.00		0.00		0.00		0.00		0.00	
1988	0.00		0.00		0.00		0.00		0.00		0.00	
1989	0.00		0.00		0.00		0.00		0.00		0.00	
1990	0.00		0.00		0.00		0.00		0.00		0.00	
1991	0.00		0.00		0.00		0.00		0.00		0.00	
1992	0.00		0.00		0.00		0.00		0.00		0.00	
1993	0.00		0.00		0.00		0.00		0.00		0.00	
1994	0.00		0.00		0.00		0.00		0.00		0.00	
1995	0.00		0.00		0.00		0.00		0.00		0.00	
1996	0.00		0.00		0.00		0.00		0.00		0.00	
1997	0.00		0.00		0.00		0.00		0.00		0.00	
1998	0.00		0.00		0.00		0.00		0.00		0.00	
1999	0.00	5.72	0.00	3.78	0.00		0.00		0.00	5.37	0.00	
2000	0.00	5.72	0.00	3.78	0.00		0.00		0.00	5.37	0.00	8.96
2001	0.10	5.72	0.11	3.78	0.00		0.00		1.46	5.37	0.00	8.96
2002	1.05		1.77		0.00		0.00		4.10		1.70	8.96
2003	2.06		3.59		0.00		0.00		6.97		4.57	
2004	3.14		5.58		0.00		0.00		10.10		7.70	
2005	4.28		7.76		0.00		0.00		13.51		11.11	

Ruta	Sucre-Pot Caudal Ad (MMPCD)	Sucre-Pot Inv. (MM$us)	Tarab-Sucre Caudal Ad (MMPCD)	Tarab-Sucre Inv. (MM$us)	Cerr- Torre Caudal Ad (MMPCD)	Cerr- Torre Inv. (MM$us)	Mont - Cerr Caudal Ad (MMPCD)	Mont - Cerr Inv. (MM$us)	Camiri - Cerr Caudal Ad (MMPCD)	Camiri - Cerr Inv. (MM$us)	Taquip - Camiri Caudal Ad (MMPCD)	Taquip - Camiri Inv. (MM$us)	TOTAL Caudal (MMPCD)	TOTAL Inv. (MM$us)
1986	0.00		0.00		0.00		0.00		0.00		0.00		0.00	0.00
1987	0.00		0.00		0.00		0.00		0.00		0.00		25.02	0.00
1988	0.00		0.00		0.00		0.00		0.00		0.00		60.84	0.00
1989	0.00		0.00		0.00		0.00		0.00		0.00		67.62	0.00
1990	0.00		0.00		0.00		0.00		0.00		0.00		75.69	0.00
1991	0.00		0.00		0.00		0.00		0.00		0.00		85.68	0.00
1992	0.00		0.00		0.00		0.00		0.00		0.00		92.67	0.00
1993	0.00		0.00		0.00		0.00		0.00		0.00		100.43	0.00
1994	0.00		0.00		0.00		0.00		0.00		0.00		109.03	0.00
1995	0.00		0.00		0.00		0.00		0.00		0.00		118.60	0.00
1996	0.00		0.00		0.00		0.00		0.00		0.00		127.04	0.00
1997	0.00		0.00		0.00		0.00		0.00		0.00		136.21	0.00
1998	0.00		0.00		0.00		0.00		0.00		0.00		147.29	0.00
1999	0.00		0.00		0.00		0.00		0.00		0.00		159.71	14.87
2000	0.00		0.00		0.00		0.00		0.00		0.00		173.29	23.83
2001	0.00		0.00	0.70	0.00	1.82	0.00		0.00		0.00		184.62	26.35
2002	0.00		0.00	0.70	0.00	1.82	0.00		0.00		0.00		196.94	11.48
2003	0.00		1.56	0.70	1.56	1.82	0.00		0.00		0.00		213.38	2.52
2004	0.00		1.69		1.69		0.00		0.00		0.00		224.67	0.00
2005	0.00		2.52		2.52		0.00		0.00		0.00		236.80	0.00

Costo Incremental Promedio de Transporte: $0.06 por MPC

29-Jun-93

EXPORTACION DE GAS NATURAL

Alternativa - 200 MMPCD
(MMPCD)

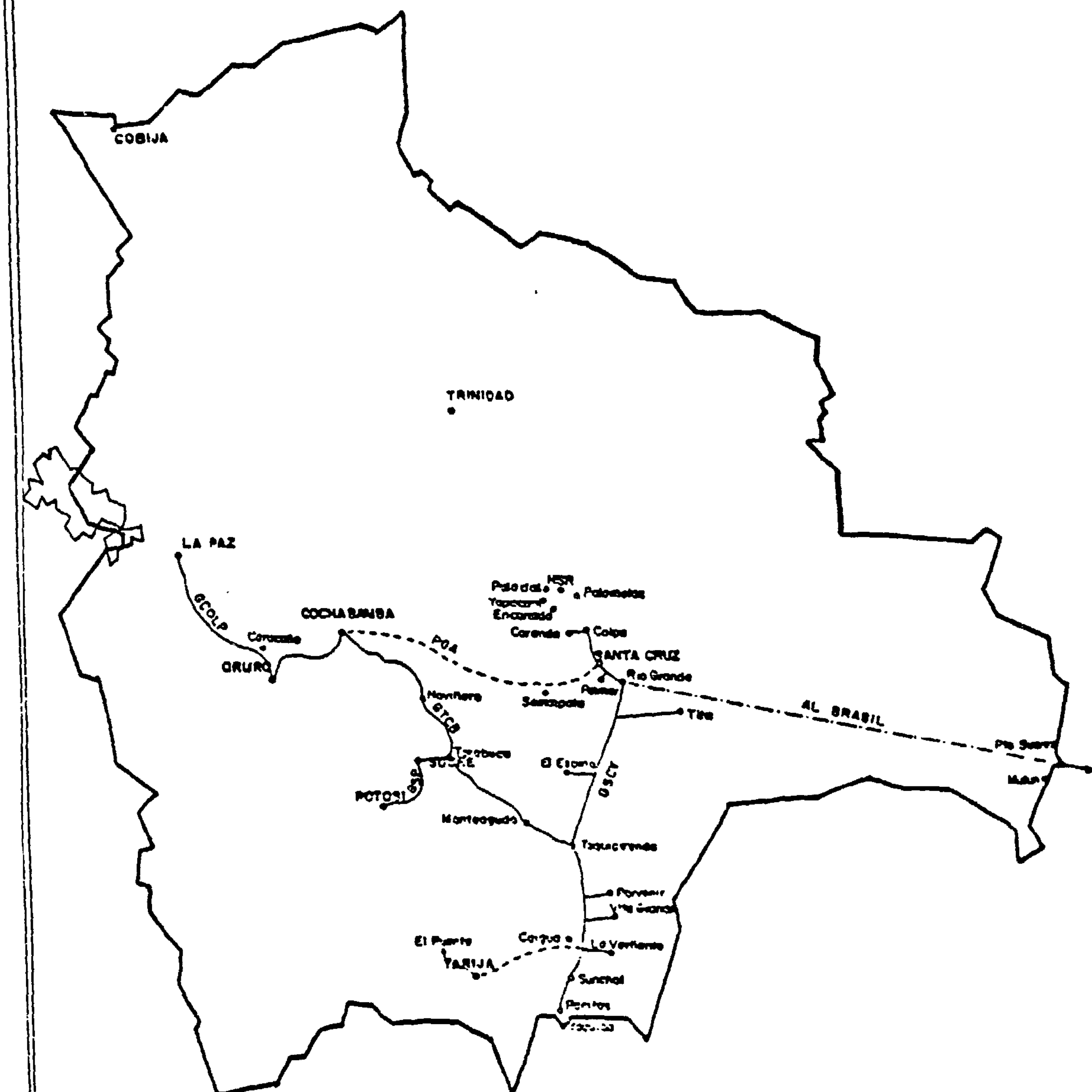
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
I. Export. a la Argentina	215	215	215	215	215	215	215													
II. Consumo Interno	45	50	55	60	65	70	75	80	85	90	95	100	100	105	110	110	115	120	120	125
III. Export. al Brasil																				
Yapacani						60	60	60	60	60	60	60	60	60	60	30	30	30	30	30
Rio Grande						80	80	80	80	80	80	80	80	80	80					
Vuelta Grande																130	130	130	130	130
Escondido						60	60	60	60	60	60	60	60	60	60	40	40	40	40	40
Subtotal	0	0	0	0	0	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
Total (MMPCD)	260	265	270	275	280	485	490	280	285	290	295	300	300	305	310	310	315	320	320	325
Acumulado (MMMPC)	95	192	290	391	493	670	849	951	1,055	1,161	1,268	1,378	1,487	1,599	1,712	1,825	1,940	2,057	2,174	2,292

Programa de Inversiones
(millon de $us.)

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Campo																				
Yapacani				18.5	18.5															
Rio Grande																				
Vuelta Grande															10.0					
Escondido				11.8	12.8															
Subtotal	0.0	0.0	0.0	30.3	31.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.0	0.0	0.0	0.0	0.0	0.0
Incr. Neto en Ventas de Gas (MMMPC)	0.91	1.83	2.74	3.65	77.56	78.48	0.91	1.83	2.74	3.65	4.56	4.56	5.48	6.39	6.39	7.30	8.21	8.21	9.13	

Costo Incremental Promedio = 0.42 $us/MPC, bajo los supuestos del 12% de interes, mas nuevas inversiones en desarrollo de campos y para la exportacion de 200 MMPCD

29-Jun-97



BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH - PNUD - BM

RED DE GASODUCTOS

———	Gasoducto	GTCB	Gasoducto Taquiperenda - Cochabamba
- - - -	Proyecto Gasoducto en ejecución	GSCY	Gasoducto Santa Cruz - Yacuiba
—·—·—	Gasoducto en proyecto	PGVTP	Proyecto Gas Villamontes - Tarija - El Puente
GCOLP	Gasoducto Cochabamba - Oruro - La Paz	PGA	Proyecto Gasoducto al Altiplano

ELECTRIC POWER

Electricity Demand Projections

ENDE's planning unit recently prepared demand projections by sectors, regions, and companies for 1986-1995 after substantial consultation and discussion with the World Bank's mission which appraised the Powcr Rehabilitation Project, and with other units at ENDE. The projections are based, by and large, in empirical procedures using desegregated demand information. The projected annual rates of growth by sectors for the period 1986-1991 are:

Residential:	9.5%
Industrial:	5.3%
Mining:	-2.5%
General:	7.3%

The National Energy Plan team carried out an independent analysis of the demand projections using regression models based on demographic and economic explanatory variables. The analysis was based on data for the period 1975-1985 which includes a period of normal development (1975-1980) and a period of crisis (1980-1985). A sector and a global analysis was carried out based on national statistics. A regional analysis was not attempted due to lack of reliable regional economic and demographic statistics.

In general, simple regression models using GDP or value added as explanatory variables give poor results, as shown below:

DTOT = 2.75*10^(6)*GDP^1.71	R-Squared = .75
DIND = 277.1*VAIND^.015	R-Squared = 0
DMIN = 656.2*VAMIN^(-.04)	R-Squared = .04

Where DTOT, DIND, DMIN are total, industrial, and mining demand, and VAIND, VAMIN are value added in industry and mining.

This is not surprising for both the mining and industrial sectors were subject, beginning in 1981, to a severe crisis with a substantial drop in production, and the GDP statistics are distorted by the presumably large participation of the informal economy.

The introduction of time as explanatory variable resulted in substantial improvements over the models mentioned above and over trend models, as shown below:

DTOT = 1.87*E^(.046*T)*GDP^.53	R-Squared = .98
DIND = 0.13*VAIND^.76*E^0.78*T	R-Squared = .97
DMIN = 11.6*VAMIN^.37*E^.034*T	R-Squared = .95

These models were used to project demand for these sectors, based on two scenarios for the projection of GDP and value added growth of 3.5% p.a. (prepared by UDAPE and adopted by the Bank), and a lower growth of 2% p.a. The results are shown in tables, and are compared with ENDE's projections. The main conclusions are:

(a) For the total demand, the results are consistent with ENDE's projection assuming a 2% p.a. growth of GDP.

(b) For the industrial and mining demand, the model projects substantially higher growths (about 10% and 4%) than ENDE (+5% and -3%). This can be explained by the fact that, on one hand, ENDE's projections for these sectors assume that no recuperation would take place in the near future, while on the other hand, the regression model is driven basically by a trend component, which was necessary to fit the historic curve and compensate for a very large drop in value added in the 1980s.

For the residential sector, a regression model using population and income per capita as explanatory variables gave very good results (R-Squared = .99, Durwin Watson = 1.5). The model projects a 10% p.a. rate of growth which is consistent with ENDE's projection.

For the general sector (commercial, government), a regression model using value added in commerce and population as explanatory variables also gave results consistent with ENDE's projection. For the other sectors (public lighting and others), simple trend models were used.

Finally, a projection for total consumption was prepared based on the individual projections by sectors. This projection results in a growth of about 10% p.a., which is much higher than projected by the global model (6.6%). This reflects the impact of a very high growth for the industrial and mining sectors discussed above, and raises some questions about the regression model used in these cases. If we use instead ENDE's projection for these sectors, the projected total consumption would be consistent with the global model. In light of the above, and taking into account the grim prospects for the mining industry, one reaches the conclusion that ENDE's projections for these sectors are more realistic.

Regarding the demand projections by regions, ENDE is projecting the following rates of growth:

Table 1: ANNUAL RATE OF GROWTH

	Annual Rate of Growth	
	1986-1990	1990-1995
	(%)	(%)
Central	2.8	4.7
South	2.6	4.0
North	5.6	6.0
East	13.0	10.1
Isolated	1.9	2.6
Total	5.6	6.3

Source: ENDE.

This projection is consistent with a low rate of growth projected for the industrial and mining sectors, which affects mainly the Central and Southern systems, and a high rate of growth for the residential sector which affect the Eastern system. In this case, the NEP estimates confirmed the growth of residential consumption based on the new connections planned by the distribution company and on reasonable assumptions regarding annual consumption per consumer.

Summarizing, the demand projections prepared by ENDE are reasonable, taking into account major uncertainties in future economic development. However, the following matters need to be investigated further:

(a) In the case of residential consumption, the impact of substitution of gas for electricity in water heating and cooking, the impact of required large increases in retail tariffs (ENDE is now projecting an increase of about 70% in the bulk tariffs to distribution companies in a three year period), and the possibilities of implementing load management programs to reduce peak load. This analysis is necessary specially in the case of the Eastern region which has by far the largest consumption per residential consumer.

(b) In the case of the mining and industrial sector, ENDE should gather information regarding the use of electricity in these sectors, cogeneration possibilities, the potential of substitution of gas for electricity, and major plans for the rehabilitation and expansion of the tin industry. This information is essential for implementing needed improvements in forecasting electricity demand for these sectors.

The Central East Interconnection

Background

The Central East interconnection project consists of the interconnection of the Central System (La Paz-Cochabamba-Oruro-Sucre) with the Eastern System (Santa Cruz) through a 9 km, 115 kV single circuit line from the Santa Isabel hydro plant to substation San Jose, near Cochabamba, and a 335 km, 230 kV single circuit transmission line connecting this substation to substation Huaracachi in Santa Cruz. The project also includes the construction of a new substation at San Jose with 3 x 20 MVA transformer capacity (115/230 kV), the expansion of substations Santa Isabel and Huaracachi, and the installation at Huaracachi of a 3 x 20 MVA transformer capacity (230/69 kV).

The interconnection project has been under execution for about six years. The need for this interconnection was established by ENDE in the National Electrification Plan of 1976, and the feasibility study was completed in the late 1970s. The project was appraised by the World Bank at that time and ENDE proceeded with the design and bidding of the transmission line in 1980. The Bank's loan was never approved due to country-related problems, and the ENDE awarded in 1981 contracts for the supply of all the materials for the line (Brazilian suppliers, CACEX financing) and its construction (ICE-Bolivia). The materials were supplied in 1982 and have been in storage ever since. The switching, control, and protection equipment for the substations were supplied by ASEA in 1984 under a grant of the Swedish Government. The contract with ICE was cancelled in 1982 when it was clear that the World Bank's loan would not be approved, and other sources of financing were unlikely due to the economic recession in the 1980s.

ENDE resumed the execution of the project in 1986 with a US$10.5 million loan from the CAF (Corporacion Andina de Fomento). It requested bids from contractors in the Andean countries and received in late 1986 three bids, two locals and one from a Peruvian contractor. Unfortunately, the lowest evaluated bid is about 34% over the cost estimate, and ENDE is now evaluating the cost estimate with the assistance of a foreign consultant, to determine if it is adequate. Concurrently, ENDE has requested proposals for the supply and financing of transformers and reactors for the substations. ENDE expects that these problems would be resolved shortly and the contracts could be awarded by mid-1987. Taking into account a construction period of about two years, the earliest date for its commissioning would be in late 1989.

After all these delays, the basic assumptions used to justify the interconnection have substantially changed. First, the interconnection was planned to substitute surplus hydro energy for gas-fired thermal energy in the Eastern region, and to meet future demand with hydroelectric plants, assuming a cost of gas of about US$3.6/MCF; now the cost of gas is US$1/MCF and there would not be surplus hydro energy by the time the project is commissioned. Second, the interconnection was planned before the severe decline of the mining and industrial loads, and the fast development of the Eastern region. And third, the project cost has increased substantially over the original estimate. This section analyzes the role and timing of the interconnection project under the new conditions, as well as its economic justification.

Economic Justification

Under the current demand projections, and considering that the earliest date for commissioning the interconnection would be in late 1989 and that the most attractive alternative for generation expansion are gas turbines, the interconnection would not result in major benefits in traditional areas like fuel substitution, development of large projects (economy of scale), reduction of reserve requirements, and improvements in reliability, because:

(a) By 1990, both the Central-North-South (C-N-S) interconnected system (hydro-based) and the Eastern system (thermal-based) would require additional generation to meet peak demand. Furthermore, the hydro surplus in the C-N-S system would be almost nil after 1990.

(b) The most attractive projects are now small gas turbines which have a low capital cost and can be adapted very well to follow the small demand increases (about 30 MW/year). There are not large hydro schemes that could be competitive in the near future.

(c) The reserve requirements are now modest due to the fact that the largest unit is now 20 MW. Improvements in reliability are questionable because the system would be more vulnerable operating with a single line interconnection.

The interconnection, however, is interesting from the following point of view:

(a) Complementing the hydro generation in the C-N-S system with the large thermal base in the Eastern system during dry years and dry seasons.

(b) Providing the means to transport gas (as electricity) from the gas fields in the Eastern region to the load in the central regions.

(c) Providing high flexibility for generation expansion in case of major changes in the cost of gas or in the cost of hydro-electric alternatives.

(d) Reducing the need for power expansion in 1990 when both the C-N-S and the Eastern systems would require additional generation, and utilizing a small hydro surplus in the C-N-S system in that year.

The NEP focused in the analysis of points (b) and (d) in the above paragraph. The analysis of point (a), complementation of hydro generation, was not feasible due to the lack in ENDE of a good operation planning model that considers hydrology as a random variable. To complete the analysis of points (b) and (d), the following cases were considered: (i) a delay of one year in commissioning the interconnection; and (ii) cancellation of the project, and use of materials in storage for other purposes.

To this end a simplified expansion program for the C-N-S system, the Eastern system, and the interconnected CNSE system was prepared based on 22 MW gas turbines located in Santa Cruz and Cochabamba. The major differences between the two locations are the loss of output capacity caused by altitude, and the loss of efficiency and output capacity caused by temperature (Cochabamba: 2,558 m.a.s.l. and 18°C; Santa Cruz: 416 m.a.s.l. and 24.5°C). The net effect is that in Santa Cruz the turbine delivers 19.5 MW @ 13 CF/kWh, whereas in Cochabamba it delivers 16 MW @ 12.66 CF/kWh. The generation expansion was determined by the peak demand requirements and the adopted reserve criteria (about 10% or the largest unit).

The economic analysis was based in the following assumptions:

(a) A cost of gas in Santa Cruz of US$1/MCF and in Cochabamba of US$1.1/MCF.

(b) An investment cost for gas turbines of about US$385/kW installed. An incremental investment of US$22 million to complete the line, and an additional investment of US$3.9 million in 1992 to expand the capacity at the substation to 120 MVA.

(c) A salvage value of 80% of the original face price for the materials and equipment in storage, for the no-interconnection case. This investment is considered a sunk cost for the interconnection case.

(d) Sensitivity to the salvage value (0%) and the price of gas in Cochabamba (US$1.2/MCF) was considered.

The results of the analysis are summarized below in Table 2:

Table 2: INTERCONNECTION ECONOMIC ANALYSIS

	----Net Present Value-----		
	1990	1991	No Interc.
	(US$ Million)		
Base Case	164.8	167.4	161.7
Salvage Value (0%)	164.8	167.4	168.3
Gas Cochabamba US$1.2/MCF and salvage value 0%	164.8	167.5	170.0

Source: NEP.

Based on these results, the major conclusions are:

(a) The benefits of delaying one year the investment are outweighted by the additional fuel costs and investment in new generation. It is not, therefore, economic to delay the interconnection one year.

(b) In the no-interconnection case, the additional cost of transporting gas to Cochabamba and the loss of output of gas turbines in this city are not sufficient to compensate for the additional investment in the interconnection, unless the salvage value for the materials in storage is not considered. The difference in net present values of total costs is, however, less than 2%.

In spite of the negative result in (b) above, the interconnection should proceed, based on the following additional arguments:

(a) This simplified analysis does not take into account either the benefits related to the complementation of hydro by thermal during dry periods, nor the benefits related to a reduced reserve margin for the interconnected system, which would compensate for the small difference in net present values.

(b) An interconnected system is much more flexible in adjusting to changing conditions in gas cost and generation expansion alternatives.

It is important, however, to negotiate with the lowest evaluated bidder a reduction in its bid price.

Netback of Gas for Power Generation

Gas consumption for power generation would increase from current levels of about 14 MMCFD to about 22 MMCFD by 1990, mostly to operate existing and ongoing expansion of gas turbines in the Santa Cruz region. The price of gas for power generation is currently at US$0.88/MCF, which is very close to the incremental cost of gas estimated as US$1/MCF. In the short term, if the supply of gas for power generation were interrupted, the only viable alternative would be to use diesel oil in the existing gas turbines. On the other hand, there are not opportunities for converting existing thermal plants to gas, except for some small diesel engines in isolated areas, where natural gas is not available. In effect, although in 1986 50% of the installed capacity in thermal generation were diesel engines (installed in small isolated systems), and only 9% of gross generation in thermal plants was non-gas generated, the only practical opportunity for increasing gas consumption for power generation is to install new thermal power plants.

At the current cost of US$1/MCF for gas, gas turbines operating in base load are the most economic solution for power generation. The lower fuel costs related with improvements inefficiency of combined cycle plants are not compensated by their higher capital costs, and only a few small hydroelectric plants would compete at that cost level. On the other hand, fuel oil fired thermal plants are out of the picture due to the scarcity and high costs of residuals in Bolivia. It is evident, therefore, that the netback of gas for power generation would be determined, by and large, by hydroelectric alternatives.

The calculation of the netback in this case requires a careful analysis of the optimum expansion plans and the operation of the system under different scenarios of gas consumption. Such an analysis was carried out in 1986 by ENDE staff who estimated the netback at US$2.2/MCF based on the comparison of an all-thermal expansion and an all-hydro expansion. 1/ An independent analysis was carried out to confirm this conclusion, due to the fact that there were some hydroelectric alternatives that were not considered in this analysis (the Zongo River expansions).

The analysis focused on three basic cases: (a) an all-hydro expansion plan; (b) an all-thermal expansion plan; and (c) an expansion plan where a limited number of gas turbines were considered. In all three cases, the existing gas turbines operated utilizing gas. The scenario of zero gas supply was not analyzed for it is, in our opinion,

---

1/ "El Papel del Gas Natural en la Planificacion Energetica y la Seleccion de Inversiones de Equipamento Electrico," by Marcelo Valenzuela dated November, 1986.

only of academic interest. 2/ For each case, the expansion program for 1987-2000 was optimized using the WASP III program, constraining the solution to the most attractive hydroelectric projects with a feasibility study already completed, and to gas turbines of 22 MW. The netback of gas was calculated based on the results for the three cases. The details are summarized below in Table 3.

Table 3: POWER GENERATION GAS NETBACK

Case	Gas Consumption	Netback
	(MMCFD) a/	(US$/MCF)
All hydro	24.6	--
Mixed	41.0	2.2
All thermal	88.5	1.7

a/ This is the peak consumption in a single year.

One should take into account the following qualifications and comments on these results:

(a) The decrease of the netback with higher gas consumptions reflects the fact that initially the most expensive hydroelectric projects are displaced, and later, the most efficient.

(b) The expansion of the system was optimized using the opportunity cost of gas (US$1/MCF). This facilitated the calculation of gas consumption and the comparison of gas turbines and combined cycle plants.

(c) The results may be considered an upper bound for the netback of gas, for it was obvious from the results that the plant factor of the hydroelectric alternatives was not optimized for a low cost of gas, and as a result, the hydroelectric projects displaced a substantial amount of gas-fired thermal generation which does not make economic sense when the fuel cost is only 13 mills/kWh.

2/ Assuming that the existing dual fuel gas turbines would be operated with diesel oil at an opportunity cost of US$226/ton, the fuel cost would be about US$76/mills/kWh and the netback of gas, disregarding differences in operating and maintainence costs and other effects in availability and economic life, would be about US$5.8/MCF.

(d) On the other hand, the capital cost used for gas turbines (US$387/kWh), derived from the cost of ENDE's existing turbines, is in the high range, and underestimates the etback.

(e) Investments required to strengthen the interconnection system were not considered in this preliminary analysis. We assumed that the investment costs in the transmission system at the interconnection level would ' common to all alternatives. This is not correct, however, d the alternative with thermal plants based at Santa Cruz most likely would require further strengthening than the others.

Marginal Electricity Costs

The objective of the marginal cost preliminary analysis was to determine entative values for the marginal costs of electricity at different voltage levels and consumer categories, in order to identify major deviations in the existing tariff structure and to define a reference for tariff levels for bulk and retail consumers. The analysis used the best data available on the generation, transmission, and distribution systems. However, the results should be considered tentative for there are still major gaps in the information which are discussed below. For the generation, transmission, and sub-transmisssion systems, ENDE was considered basically responsible for the development of these systems. For the distribution system the case of ELFEC was selected since it is the only utility which has available a long-term expansion program and a minimum of information necessary to carry out this preliminary analysis.

Power Generation

It is important to highlight some peculiarities of the generation system, which determine the approach taken to the marginal cost analysis. First, there would not be available a well-defined Power Development Plan until late 1987; therefore a tentative expansion program had to be prepared for this marginal cost analysis. Second, until 1990, when the Central-East interconnection is commissioned, there would be two large systems, the Eastern and the Central, which are substantially different in marginal costs: the Central system with hydro surplus and the Eastern System with gas-fired thermal generation. In this regard, the two systems are analyzed separately for the period 1987-1989. Third, both the Central and the Eastern systems are demand constrained and their expansion programs are determined by peak demand requirements. Furthermore, for both systems, gas turbines operating with cheap gas (US$1/MCF) are one of the most attractive expansion alternatives. And fourth, the Central system ha a l... reservoir with annual regulation. Therefore, it is necessary ' ... carefully the operation of the reser... r in calculating the ... gy cos's.

Regarding the demand curve, the .53 annual load factor for the system demand is very low, and has been decreasing during the past years; it reflects the decline of the industrial and mining sectors and the increasing participation of the residential sector (38% in 1986). Seasonally, there is not a major variation in peak demand (<10%) and it has been neglected for this analysis. Daily, the load curve for most of the distribution companies have only a pronounced evening peak from 18-22 hours.

Regarding the power expansion plan, the following generation expansion program for 1987-1995 was prepared and summarized, as shown in Table 4 below:

Table 4: POWER GENERATION PROGRAM, 1987-1995

Year	Project Addition	Capacity	Reserve
		(MW)	(%)
1987	Gas Turbine	22	a/
1988	Gas Turbine	22	--
1990	Gas Turbine	22	7
1991	Gas Turbine (2)	44	9
1992	Gas Turbine	22	6
1993	Zongo River Hydro	61	12
1994	Gas Turbine	22	6
1995	Gas Turbine (2)	44	6

a/ The two systems have not been interconnected.

Source: ENDE and NEP.

This expansion program is almost identical to one recently prepared by ENDE, except for the addition of two gas turbines to keep reserves at minimum acceptable levels. 3/ It includes the most attractive projects identified at this time, but it has not been optimized yet (for example, the sizing of the turbines). In our opinion, it is a reasonable base to estimate average incremental costs and marginal costs for generation in this horizon.

For the period 1987-1989, all the proposed gas turbine expansion would be seated at the Eastern system. The capacity and energy balances analysis show that although the Central system has a hydro

3/ The analysis carried out for a mixed expansion program using the WASP program, shows that a reserve of about 10% required to have a LOLP<5.3 days/year.

surplus in this period, it would have to operate a jet gas turbine (Karachipampa) at peak to meet the projected demand. The Eastern system, on the other hand, would keep a satisfactory reserve.

Average Incremental Cost

The generation average incremental cost for the proposed expansion program was estimated at 23.5 mills/kWh. This is based on an average fuel cost of just 13 mills/kWh and is consistent with a power development using gas turbines.

Marginal Energy Costs

Regarding the Central System and the interconnected system after 1990, the marginal energy costs for this hydrothermal system are a function of the fuel costs and the probability of having to operate the gas turbines. Normally, one would expect a seasonal variation of the marginal energy cost due to the dry and wet hydrological seasons. There are about 250 MW installed basically in two basins (Zongo and Corani), with a large 450 GWh reservoir at Corani. Based on a simple simulation program, the frequency distribution of the regulated hydro generation was analyzed, and concluded that with the Corani reservoir it is possible to regulate the seasonal variations. Additionally, the probability of requiring thermal generation is about the same in both seasons, as shown below in Table 5:

Table 5: PROBABILITY OF USING THERMAL

	Wet Season	Dry Season
1987-1989	0	0 a/
1990-1995	1	1

a/ This value has been approximated to 0.

Source: NEP.

These results simplify the calculation of the marginal energy cost. On the one hand, there is no need to differentiate between wet and dry seasons; on the other, the Central system has a zero marginal energy cost for the period 1987-1989 for the probability of operating thermal is zero in that period, 4/ and the interconnected system after 1990 and the Eastern system before the interconnection, would have a maraginal cost equal to the variable production costs of the gas turbines. These costs

4/ Thermal generation would be needed, however, during peak hours; this is a capacity-related cost and does not affect this calculation.

are estimated at 13.5 mills/kWh. 5/ Summarizing, the marginal energy costs are shown in Table 6:

Table 6: MARGINAL ENERGY COSTS

	C-N-S System	Eastern System
	(mills/kWh)	(mills/kWh)
1988-1989	0	13.5
1990-1995	13.5	--

Source: ENDE and NEP.

Marginal Capacity Costs

The marginal unit to meet peak demand is a gas turbine in all cases. The reserve margins are low, and peak load units are required to meet demand. The most economic option for this purpose so far are gas turbines. 6/ The capacity cost is estimated at US$70/kW-year (assuming a 22 MW installed turbine, 19.5 MW-effective, 7/ additional derating of 10% to account for outages, investment cost of US$8.5 million, fixed O&M operating costs of US$0.35/kW/month, 20 years economic life, and 12% discount rate).

Transmission and Sub-transmission

In this case, the average incremental costs are used as a proxy for the marginal capacity cost. It consists of 115 kV lines and 69 kV lines. ENDE normally delivers to the distribution companies and major industrial clients at the low voltage end of 115 kV or 69 kV substations. To estimate the incremental cost, the Central-East interconnection, the only major transmission project in the period 1987-1995, and also ENDE's substation program were selected. The average incremental cost for the selected transmission expansion was estimated at US$35/kW-year.

5/ Gas consumption: 13 CF/kWh; gas cost: US$1/MCF; variable O&M costs estimated at US$0.5/MWh.

6/ The capacity expansion of existing hydroelectric plants may result in a lower cost; however, a component of the Zongo river expansion meets this condition and the improvement in cost is marginal.

7/ Derating caused by altitude and temperature.

For subtransmission, the average incremental capacity cost was used, and selected a sub-transmission project of about 120 kms of 69 kV and 25 kV lines to connect the area of Telemayu and supply energy to private mining companies that now use diesel engines. The incremental cost is calculated as follows:

Investment:	US$4.2 million
Demand:	4.5 MW
Annual Cost	US$.62 MM (25 years, 12%, 2% O&M)
Incremental Cost:	.62/4.5 = US$137.8/kW-year

The marginal energy and capacity costs at the generation, transmission and sub-transmission levels were calculated based on the previous results, and on the following values as shown in Table 7 for transmission and sub-transmission losses, estimated by ENDE for 1986:

Table 7: POWER SYSTEM LOSSES

	Energy	Demand a/
Transmission	3.1%	4.0%
Sub-transmission	4.1%	4.1%

a/ Estimated assuming a load factor of .53 for transmission and 1.0 for sub-transmission.

Source: NEP.

Distribution

In this case also, we used the average incremental capacity costs as a proxy for the marginal costs. As it was mentioned before, ELFEC's system was selected for the analysis. ELFEC's distribution system consists of 25 kV lines and 10 kV lines. The 25 kV lines are used in rural areas and to supply large consumers, and 10 kV is used for urban distribution. ELFEC purchases energy from ENDE at the low voltage end of 115 kV substations. Customers are classified as follows in Table 8:

Table 8: CUSTOMERS CLASSIFICATION

Consumer Class	Number	Voltage	Description
I3	3	MV	Large Industrial
I2 and I1	1,238	MV	Medium and Small Ind.
C2	2,934	MW	Large Commercial
C1	8,074	LV	General
R	80,362	LV	Residential
AP		LV	Public Lighting

Source: NEP.

It was important, therefore, to analyze the incremental cost for MV customers connected to primary lines, and for LV customers connected to secondary lines. To do so, we analyzed the demand and costs for the primary and secondary systems. The 1987-1995 investment program prepared by ELFEC had sufficient detail to identify the investment in the MV and LV systems. The peak demand for the secondary system was estimated using the following procedure:

(a) use as a basis the peak demand projections prepared by ELFEC for the 10 kV and 25 kV systems net of I3 customers' demand;

(b) estimate the peak load for I2 and I1, and C2 consumers based on annual load factors for these consumers and projected consumption. For the C2 consumers, however, as there are not typical load curves available, we used as a proxy the system load factor;

(c) estimate the diversity factor for the I1, I2 consumers based on the analysis of daily load curves fortypical feeders, and calculate the peak coincidental demand for these consumers using the estimated diversity; and

(d) estimate the peak demand for the secondary system as the difference between the peak demand in (a) and the estimated demand in (b).

Based on the estimated peak demand for the MV and LV systems, and the corresponding investment, the average capital incremental costs were estimated as shown in Table 9:

Table 9: AVERAGE CAPITAL
INCREMENTAL COSTS

US$/kW-year	
Primary	40.7
Secondary	66.5
Total a/	86.6

a/ Estimated on the basis of total load and total investment.

Source: NEP.

Finally, the marginal capacity and energy cost at MV and LV levels were calculated using the previous results 8/ and the distribution losses that ELFEC has estimated for the MV and the LV systems based on sample measurements and feeded models. These results were also used to calculate the marginal capacity and energy costs for the major consumer categories based on an analysis of coincidence factors. They should be considered as tentative for the information available to estimate load factors and coincidence factors corresponded to "typical feeders," basically for residential areas (North feeder) and industrial areas (Quillacollo line), and for many consumer categories there was no information available and a "typical" value was used in this case for the load factors and coincidence factors. The use of feeder's load averages the individual consumers; in this regard, the marginal cost for residential was estimated on the basis of the characteristics of the consumer class represented by a typical residential feeder. The results of the average cost per consumer category, assuming a load factor, and based on the estimated marginal capacity and energy costs are:

Table 10: AVERAGE COST PER CUSTOMER
CATEGORY

Category	Load Factor (%)	Avg. Cost (mills/kWh)
I3	75	30
I2 and I1	51	41
C2	48	39
C1	48	55
R	45	69
AP	40	83

Source: NEP.

8/ The marginal cost at the transmission level is taken as the purchase energy cost for ELFEC, which is much higher than the current electricity rate charged by ENDE.

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

ESTADISTICA DE DEMANDA

VENTAS TOTALES (GWH)

SISTEMA	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
SISTEMA CENTRAL												
MINERIA	207.5	214.8	237.3	235.7	243.6	248.2	257.7	250.8	242.9	234.1	217.2	178.8
INDUSTRIA	44.1	61.9	91.0	101.3	105.9	134.5	142.2	138.0	133.2	139.9	121.3	102.7
RESIDENCIAL	38.0	41.6	45.5	52.7	61.3	66.7	73.3	77.3	84.3	92.5	101.6	119.7
GENERAL	25.3	25.2	18.0	20.9	19.9	21.6	21.3	21.0	16.9	16.6	18.4	25.5
ALUMBRADO PUBLICO	4.0	5.4	6.3	7.5	11.4	12.7	13.5	14.8	15.9	16.4	12.4	12.3
OTROS	5.0	5.7	5.6	6.4	6.9	7.7	8.2	8.7	9.7	12.4	12.0	12.3
SUBTOTAL	323.9	354.6	403.7	424.5	449.0	491.4	516.2	510.6	502.9	511.9	482.9	451.3
SISTEMA SUR												
MINERIA	82.2	82.4	98.6	97.7	90.2	96.5	108.6	104.2	103.3	99.8	98.4	82.3
INDUSTRIA	8.5	12.3	11.1	15.7	17.6	17.4	22.5	29.5	22.8	16.5	23.8	21.6
RESIDENCIAL	8.5	8.9	9.7	11.3	13.4	15.2	17.0	17.8	19.5	22.4	24.2	30.2
GENERAL	5.1	5.6	6.3	7.0	7.9	8.1	8.8	8.9	8.9	8.2	8.0	9.0
ALUMBRADO PUBLICO	1.6	2.0	2.2	1.7	1.8	2.3	2.4	2.4	2.5	2.7	2.4	2.6
OTROS	0.0	0.0	0.1	0.7	0.9	0.5	1.6	2.5	1.5	1.9	1.9	2.1
SUBTOTAL	105.9	111.2	128.0	134.1	131.8	140.0	160.9	165.3	158.5	151.5	158.7	147.8
SISTEMA NORTE												
MINERIA	16.2	16.4	18.0	17.8	16.7	18.0	20.0	21.5	21.0	21.2	20.5	8.2
INDUSTRIA	55.1	59.7	68.4	71.3	79.3	89.9	89.1	75.4	74.0	66.2	63.3	69.6
RESIDENCIAL	141.2	142.8	147.7	157.2	169.3	177.0	188.6	186.2	181.3	198.2	211.5	236.2
GENERAL	50.4	54.6	58.4	63.3	69.3	70.5	77.8	74.3	67.3	68.4	67.9	75.5
ALUMBRADO PUBLICO	6.8	7.1	7.6	8.3	9.1	9.6	10.2	10.5	9.5	10.7	11.2	12.4
OTROS	0.0	0.0	0.0	0.0	0.0	0.6	2.4	4.3	5.3	5.9	6.5	7.3
SUBTOTAL	269.7	280.6	300.1	317.9	343.7	365.6	388.1	372.2	358.4	370.6	380.9	409.1
SISTEMA ESTE												
MINERIA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
INDUSTRIA	25.3	35.1	43.3	54.6	61.4	73.4	83.7	90.2	89.3	76.3	66.7	70.9
RESIDENCIAL	25.4	32.6	38.8	49.8	61.9	75.3	86.9	87.1	108.2	120.7	134.3	161.8
GENERAL	13.0	15.1	17.2	20.9	22.3	26.6	31.2	34.4	34.1	41.5	55.3	62.1
ALUMBRADO PUBLICO	3.9	4.6	4.9	5.9	8.7	10.8	12.2	12.9	12.9	12.9	13.0	13.0
OTROS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SUBTOTAL	67.6	87.4	104.2	131.2	154.3	186.1	214.0	224.6	244.5	251.4	269.3	307.8
SISTEMAS AISLADOS												
MINERIA	90.0	95.9	94.7	103.3	98.9	103.1	105.1	96.6	94.8	95.7	95.7	88.0
INDUSTRIA	52.2	54.9	62.5	65.1	66.4	70.0	71.1	69.1	69.3	68.4	68.5	67.3
RESIDENCIAL	10.4	15.6	18.7	20.2	23.9	27.8	30.0	30.6	31.7	34.4	34.7	35.9
GENERAL	2.3	6.4	7.3	8.0	10.0	10.8	11.7	11.2	11.2	11.5	13.4	13.7
ALUMBRADO PUBLICO	2.0	3.8	3.0	3.5	4.0	4.4	4.6	4.6	4.4	5.0	5.5	5.6
OTROS	0.0	0.0	0.0	0.1	0.3	0.7	1.7	2.2	3.1	3.0	3.0	3.0
SUBTOTAL	156.9	176.6	186.2	200.2	203.5	216.8	224.2	214.3	214.5	218.0	220.8	213.5
TOTAL												
MINERIA	395.9	409.5	448.6	454 5	449.4	465.8	491.4	473.1	462.0	450.8	431.8	357.3
INDUSTRIA	185.2	223.9	276.3	308.0	330.6	385.2	408.6	402.2	388.6	367.3	343.6	332.1
RESIDENCIAL	223.5	241.5	260.4	291.2	329.8	362.0	395.8	399.0	425.0	468.2	506.3	583.8
GENERAL	96.1	106.9	107.2	120.1	129.4	137.6	150.8	149.8	138.4	146.2	163.0	185.8
ALUMBRADO PUBLICO	18.3	22.9	24.0	26.9	35.0	39.8	42.9	45.2	45.2	47.7	44.5	45.9
OTROS	5.0	5.7	5.7	7.2	8.1	9.5	13.9	17.7	19.6	23.2	23.4	24.7
SUBTOTAL	924.0	1010.4	1122.2	1207.9	1282.3	1399.9	1503.4	1487.0	1478.8	1503.4	1512.6	1529.5

ESTADISTICA DE DEMANDA

TASAS DE CRECIMIENTO ANUAL

SISTEMA	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	75-80	80-86	75-86
SISTEMA CENTRAL														
MINERIA	3.5%	10.5%	-0.7%	3.4%	1.9%	3.8%	-2.7%	-3.1%	-3.6%	-7.2%	-17.7%	3.6%	-5.3%	-1.3%
INDUSTRIA	40.4%	47.0%	11.3%	4.5%	27.0%	5.7%	-3.0%	-3.5%	5.0%	-13.3%	-15.3%	25.0%	-4.4%	8.0%
RESIDENCIAL	9.5%	9.4%	15.8%	16.3%	8.8%	9.9%	5.5%	9.1%	9.7%	9.8%	17.8%	11.9%	10.2%	11.0%
GENERAL	-0.4%	-28.6%	16.1%	-4.8%	8.5%	-1.4%	-1.4%	-19.5%	-1.8%	10.8%	38.6%	-3.1%	2.8%	0.1%
ALUMBRADO PUBLICO	35.0%	16.7%	19.0%	52.0%	11.4%	6.3%	9.6%	7.4%	3.1%	-24.4%	-0.8%	26.0%	-0.5%	10.8%
OTROS	14.0%	-1.8%	14.3%	7.8%	11.6%	6.5%	6.1%	11.5%	27.8%	-3.2%	2.5%	9.0%	8.1%	8.5%
SUBTOTAL	9.5%	13.8%	5.2%	5.8%	9.4%	5.0%	-1.1%	-1.5%	1.8%	-5.7%	-6.5%	8.7%	-1.4%	3.1%
SISTEMA SUR														
MINERIA	0.2%	19.7%	-0.9%	-7.7%	7.0%	12.5%	-4.1%	-0.9%	-3.4%	-1.4%	-16.4%	3.3%	-2.6%	0.0%
INDUSTRIA	44.7%	-9.8%	41.4%	12.1%	-1.1%	29.3%	31.1%	-22.7%	-27.6%	44.2%	-9.2%	15.4%	3.7%	8.8%
RESIDENCIAL	4.7%	9.0%	16.5%	18.6%	13.4%	11.8%	4.7%	9.6%	14.9%	8.0%	24.8%	12.3%	12.1%	12.2%
GENERAL	9.8%	12.5%	11.1%	12.9%	2.5%	8.6%	1.1%	0.0%	-7.9%	-2.4%	12.5%	9.7%	1.8%	5.3%
ALUMBRADO PUBLICO	25.0%	10.0%	-22.7%	5.9%	27.8%	4.3%	0.0%	4.2%	8.0%	-11.1%	8.3%	7.5%	2.1%	4.5%
OTROS			600.0%	28.6%	-44.4%	220.0%	56.3%	-40.0%	26.7%	0.0%	10.5%			
SUBTOTAL	5.0%	15.1%	4.8%	-1.7%	6.2%	14.9%	2.7%	-4.1%	-4.4%	4.8%	-6.9%	5.7%	0.9%	3.1%
SISTEMA NORTE														
MINERIA	1.2%	9.8%	-1.1%	-6.2%	7.8%	11.1%	7.5%	-2.3%	1.0%	-3.3%	-60.0%	2.1%	-12.3%	-6.0%
INDUSTRIA	8.3%	14.6%	4.2%	11.2%	13.4%	-0.9%	-15.4%	-1.9%	-10.5%	-4.4%	9.9%	10.3%	-4.2%	2.1%
RESIDENCIAL	1.1%	3.4%	6.4%	7.7%	4.5%	6.6%	-1.3%	-2.6%	9.3%	6.7%	11.7%	4.6%	4.9%	4.8%
GENERAL	8.3%	7.0%	8.4%	9.5%	1.7%	10.4%	-4.5%	-9.4%	1.6%	-0.7%	11.1%	6.9%	1.1%	3.7%
ALUMBRADO PUBLICO	4.4%	7.0%	9.2%	9.6%	5.5%	6.2%	2.9%	-9.5%	12.6%	4.7%	10.4%	7.1%	4.3%	5.6%
OTROS						300.0%	79.2%	23.3%	11.3%	10.2%	11.7%			
SUBTOTAL	4.0%	6.9%	5.9%	8.1%	6.4%	6.2%	-4.1%	-3.7%	3.4%	2.8%	7.4%	6.3%	1.9%	3.9%
SISTEMA ESTE														
MINERIA														
INDUSTRIA	38.7%	23.4%	26.1%	12.5%	19.5%	14.0%	7.8%	-1.0%	-14.6%	-12.6%	6.3%	23.7%	-0.6%	9.8%
RESIDENCIAL	28.3%	19.0%	28.4%	24.3%	21.6%	15.4%	0.2%	24.2%	11.6%	11.3%	20.5%	24.3%	13.6%	18.3%
GENERAL	16.2%	13.9%	21.5%	6.7%	19.3%	17.3%	10.3%	-0.9%	21.7%	33.3%	12.3%	15.4%	15.2%	15.3%
ALUMBRADO PUBLICO	17.9%	6.5%	20.4%	47.5%	24.1%	13.0%	5.7%	0.0%	0.0%	0.8%	0.0%	22.6%	3.1%	11.6%
OTROS														
SUBTOTAL	29.3%	19.2%	25.9%	17.6%	20.6%	15.0%	5.0%	8.9%	2.8%	7.1%	14.3%	22.5%	8.7%	14.8%
SISTEMAS AISLADOS														
MINERIA	6.6%	-1.3%	9.1%	-4.3%	4.2%	1.9%	-8.1%	-1.9%	0.9%	0.0%	-8.0%	2.8%	-2.6%	-0.2%
INDUSTRIA	5.2%	13.8%	4.2%	2.0%	5.4%	1.6%	-2.6%	0.3%	-1.3%	0.1%	-1.8%	6.0%	-0.7%	2.3%
RESIDENCIAL	50.0%	19.9%	8.0%	18.3%	16.3%	7.9%	2.0%	3.6%	8.5%	0.9%	3.5%	21.7%	4.4%	11.9%
GENERAL	178.3%	14.1%	9.6%	25.0%	8.0%	8.3%	-4.3%	0.0%	2.7%	16.5%	2.2%	36.3%	4.0%	17.6%
ALUMBRADO PUBLICO	90.0%	-21.1%	16.7%	14.3%	10.0%	4.5%	0.0%	-4.3%	13.6%	10.0%	1.8%	17.1%	4.1%	9.8%
OTROS				200.0%	133.3%	142.9%	29.4%	40.9%	-3.2%	0.0%	0.0%			
SUBTOTAL	12.6%	5.4%	7.5%	1.6%	6.5%	3.4%	-4.4%	0.1%	1.6%	1.3%	-3.3%	6.7%	-0.3%	2.8%
TOTAL														
MINERIA	3.4%	9.5%	1.3%	-1.1%	3.6%	5.5%	-3.7%	-2.3%	-2.4%	-4.2%	-17.3%	3.3%	-4.3%	-0.9%
INDUSTRIA	20.9%	23.4%	11.5%	7.3%	16.5%	6.1%	-1.6%	-3.4%	-5.5%	-6.5%	-3.3%	15.8%	-2.4%	5.5%
RESIDENCIAL	8.1%	7.8%	11.8%	13.3%	9.8%	9.3%	0.8%	6.5%	10.2%	8.1%	15.3%	10.1%	8.3%	9.1%
GENERAL	11.2%	0.3%	12.0%	7.7%	6.3%	9.6%	-0.7%	-7.6%	5.6%	11.5%	14.0%	7.4%	5.1%	6.2%
ALUMBRADO PUBLICO	25.1%	4.8%	12.1%	30.1%	13.7%	7.8%	5.4%	0.0%	5.5%	-6.7%	3.1%	16.8%	2.4%	8.7%
OTROS	14.0%	0.0%	26.3%	12.5%	17.3%	46.3%	27.3%	10.7%	18.4%	0.9%	5.4%	13.7%	17.2%	15.6%
SUBTOTAL	9.4%	11.1%	7.6%	6.2%	9.2%	7.4%	-1.1%	-0.6%	1.7%	0.6%	1.1%	8.7%	1.5%	4.7%

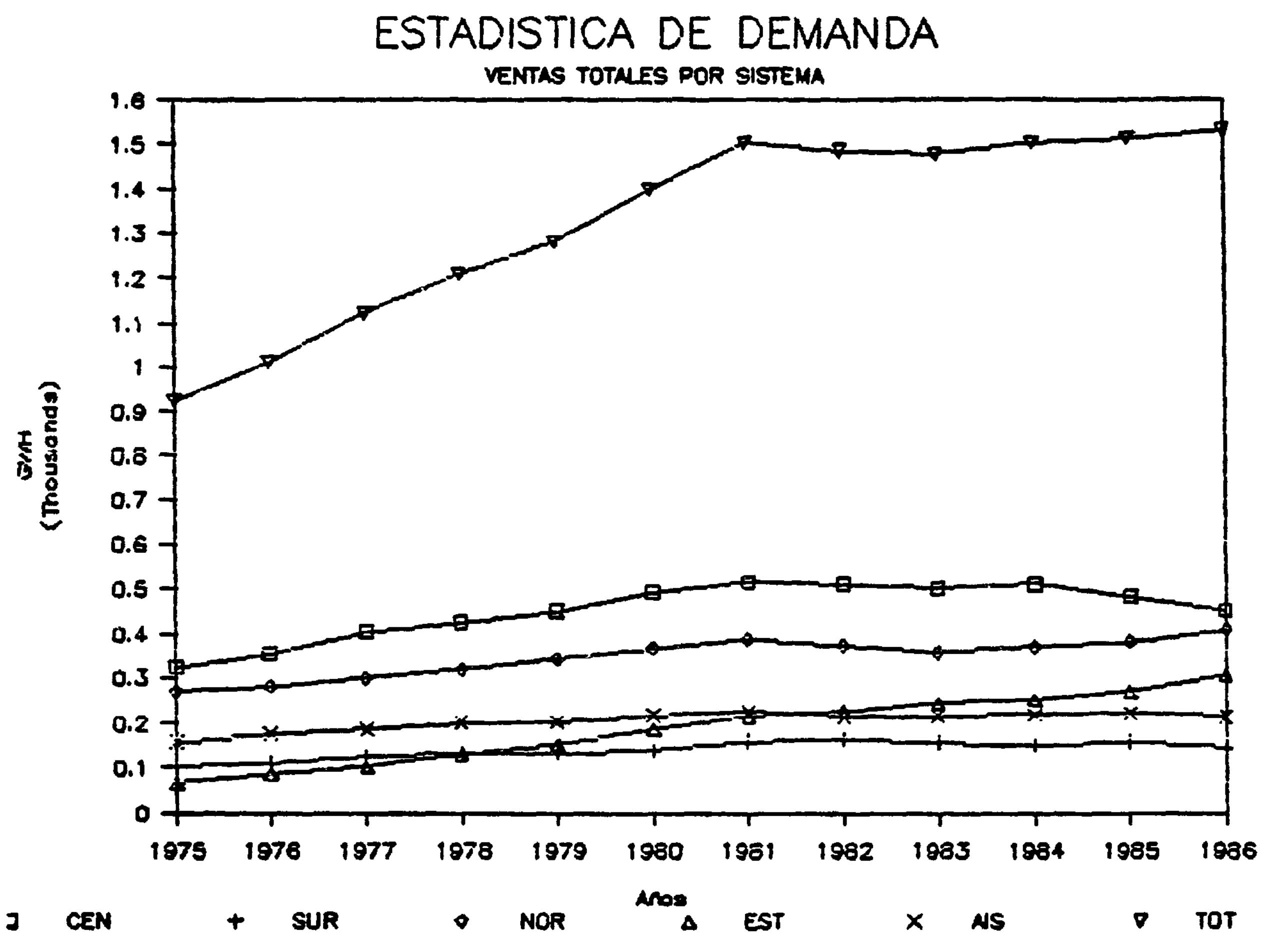
BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

ESTADISTICA DE DEMANDA

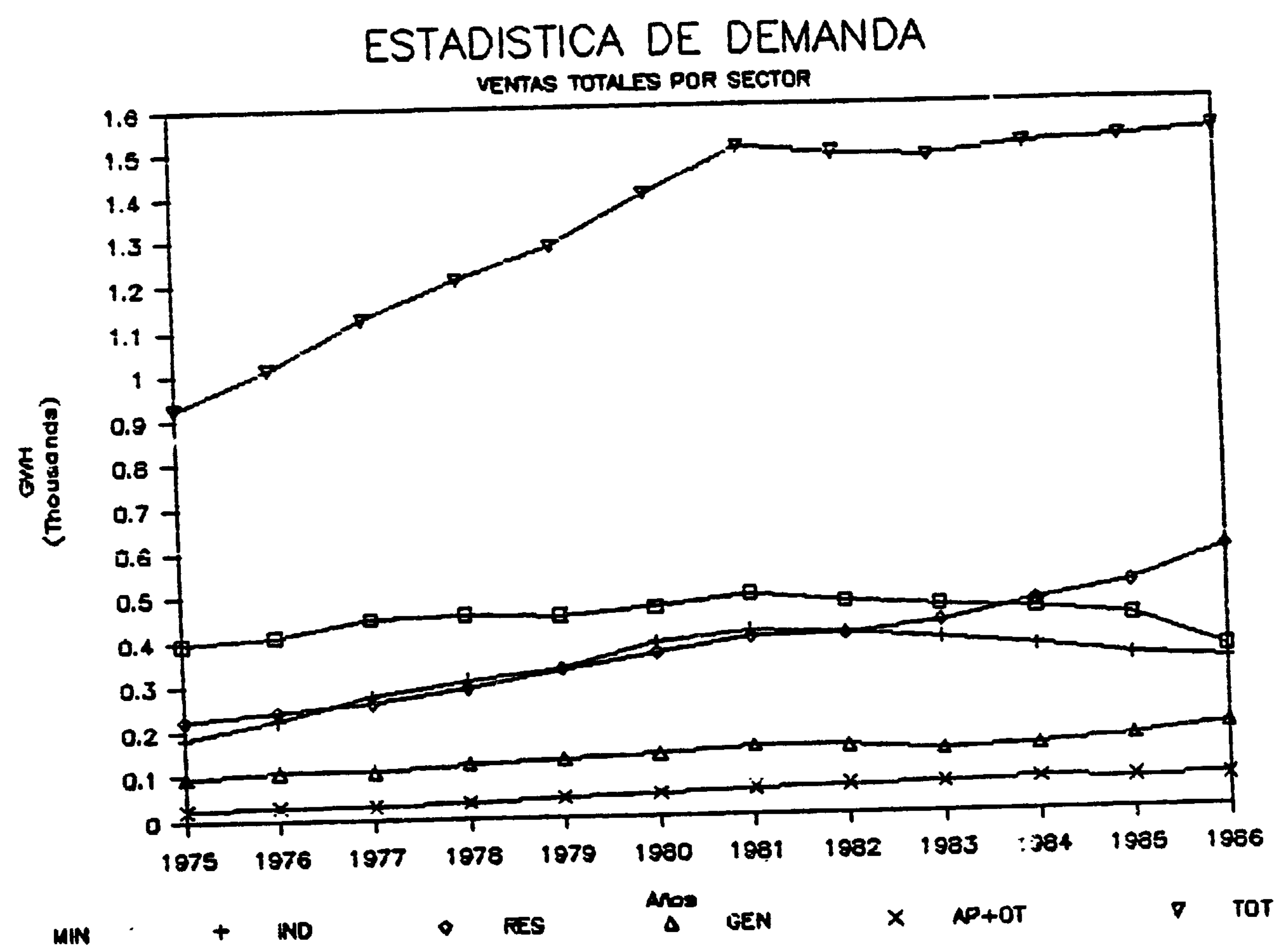
PARTICIPACION DE LA DEMANDA SECTORIAL EN LA DEMANDA TOTAL

SISTEMA	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
SISTEMA CENTRAL												
MINERIA	64.1%	60.6%	58.8%	55.5%	54.3%	50.5%	49.9%	49.1%	48.3%	45.7%	45.0%	39.6%
INDUSTRIA	13.6%	17.5%	22.5%	23.9%	23.6%	27.4%	27.5%	27.0%	26.5%	27.3%	25.1%	22.8%
RESIDENCIAL	11.7%	11.7%	11.3%	12.4%	13.7%	13.6%	14.2%	15.1%	16.8%	18.1%	21.0%	26.5%
GENERAL	7.8%	7.1%	4.5%	4.9%	4.4%	4.4%	4.1%	4.1%	3.4%	3.2%	3.8%	5.7%
ALUMBRADO PUBLICO	1.2%	1.5%	1.6%	1.8%	2.5%	2.6%	2.6%	2.9%	3.2%	3.2%	2.6%	2.7%
OTROS	1.5%	1.6%	1.4%	1.5%	1.5%	1.6%	1.6%	1.7%	1.9%	2.4%	2.5%	2.7%
SUBTOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
SISTEMA SUR												
MINERIA	77.6%	74.1%	77.0%	72.9%	68.4%	68.9%	67.5%	63.0%	65.2%	65.9%	62.0%	55.7%
INDUSTRIA	8.0%	11.1%	8.7%	11.7%	13.4%	12.4%	14.0%	17.8%	14.4%	10.9%	15.0%	14.6%
RESIDENCIAL	8.0%	8.0%	7.6%	8.4%	10.2%	10.9%	10.6%	10.8%	12.3%	14.8%	15.2%	20.4%
GENERAL	4.8%	5.0%	4.9%	5.2%	6.0%	5.8%	5.5%	5.4%	5.6%	5.4%	5.0%	6.1%
ALUMBRADO PUBLICO	1.5%	1.8%	1.7%	1.3%	1.4%	1.6%	1.5%	1.5%	1.6%	1.8%	1.5%	1.8%
OTROS	0.0%	0.0%	0.1%	0.5%	0.7%	0.4%	1.0%	1.5%	0.9%	1.3%	1.2%	1.4%
SUBTOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
SISTEMA NORTE												
MINERIA	6.0%	5.8%	6.0%	5.6%	4.9%	4.9%	5.2%	5.8%	5.9%	5.7%	5.4%	2.0%
INDUSTRIA	20.4%	21.3%	22.8%	22.4%	23.1%	24.6%	23.0%	20.3%	20.6%	17.9%	16.6%	17.0%
RESIDENCIAL	52.4%	50.9%	49.2%	49.4%	49.3%	48.4%	48.6%	50.0%	50.6%	53.5%	55.5%	57.7%
GENERAL	18.7%	19.5%	19.5%	19.9%	20.2%	19.3%	20.0%	20.0%	18.8%	18.5%	17.8%	18.4%
ALUMBRADO PUBLICO	2.5%	2.5%	2.5%	2.6%	2.6%	2.6%	2.6%	2.8%	2.7%	2.9%	2.9%	3.0%
OTROS	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.6%	1.2%	1.5%	1.6%	1.7%	1.8%
SUBTOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
SISTEMA ESTE												
MINERIA	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
INDUSTRIA	37.4%	40.2%	41.6%	41.6%	39.8%	39.4%	39.1%	40.2%	36.5%	30.4%	24.8%	23.0%
RESIDENCIAL	37.6%	37.3%	37.2%	38.0%	40.1%	40.5%	40.6%	38.8%	[illegible]4.3%	48.0%	49.9%	52.6%
GENERAL	19.2%	17.3%	16.5%	15.9%	14.5%	14.3%	14.6%	15.3%	13.9%	16.5%	20.5%	20.2%
ALUMBRADO PUBLICO	5.8%	5.3%	4.7%	4.5%	5.6%	5.8%	5.7%	5.7%	5.3%	5.1%	4.8%	4.2%
OTROS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
SUBTOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
SISTEMAS AISLADOS												
MINERIA	57.4%	54.3%	50.9%	51.6%	48.6%	47.6%	46.9%	45.1%	44.2%	43.9%	43.3%	41.2%
INDUSTRIA	33.3%	31.1%	33.6%	32.5%	32.6%	32.3%	31.7%	32.2%	32.3%	31.4%	31.0%	31.5%
RESIDENCIAL	6.6%	8.8%	10.0%	10.1%	11.7%	12.8%	13.4%	14.3%	14.8%	15.8%	15.7%	16.8%
GENERAL	1.5%	3.6%	3.9%	4.0%	4.9%	5.0%	5.2%	5.2%	5.2%	5.3%	6.1%	6.4%
ALUMBRADO PUBLICO	1.3%	2.2%	1.6%	1.7%	2.0%	2.0%	2.1%	2.1%	2.1%	2.3%	2.5%	2.6%
OTROS	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.8%	1.0%	1.4%	1.4%	1.4%	1.4%
SUBTOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
TOTAL												
MINERIA	42.8%	40.5%	40.0%	37.6%	35.0%	33.3%	32.7%	31.8%	31.2%	30.0%	28.5%	23.4%
INDUSTRIA	20.0%	22.2%	24.6%	25.5%	25.8%	27.5%	27.2%	27.0%	26.3%	24.4%	22.7%	21.7%
RESIDENCIAL	24.2%	23.9%	23.2%	24.1%	25.7%	25.9%	26.3%	26.8%	28.7%	31.1%	33.5%	38.2%
GENERAL	10.4%	10.6%	9.6%	9.9%	10.1%	9.8%	10.0%	10.1%	9.4%	9.7%	10.8%	12.1%
ALUMBRADO PUBLICO	2.0%	2.3%	2.1%	2.2%	2.7%	2.8%	2.9%	3.0%	3.1%	3.2%	2.9%	3.0%
OTROS	0.5%	0.6%	0.5%	0.6%	0.6%	0.7%	0.9%	1.2%	1.3%	1.5%	1.5%	1.6%
SUBTOTAL	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM



B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM



BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

ESTADISTICAS GENERALES

CONCEPTO	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
VENTAS TOTALES (GWH)												
MINERIA	395.9	409.5	448.6	454.5	449.4	465.8	491.4	473.1	462.0	450.8	431.8	359.7
INDUSTRIAL	185.2	223.9	276.3	308.0	330.6	385.2	408.6	402.2	388.6	367.3	343.6	330.3
RESIDENCIAL	223.5	241.5	260.4	291.2	329.8	362.0	395.8	399.0	425.0	468.2	506.3	578.7
GENERAL	96.1	106.9	107.2	120.1	129.4	137.6	150.8	149.8	138.4	146.2	163.0	181.2
ALUMBRADO PUBLICO	18.3	22.9	24.0	26.9	35.0	39.8	42.9	45.2	45.2	47.7	44.5	46.9
OTROS	5.0	5.7	5.7	7.2	8.1	9.5	13.9	17.7	19.6	23.2	23.4	30.9
SUBTOTAL	924.0	1010.4	1122.2	1207.9	1282.3	1399.9	1503.4	1487.0	1478.8	1503.4	1512.6	1527.7
POBLACION (000)	4894.4	5026.9	5163.3	5303.8	5449.3	5599.6	5755.1	5915.8	6081.7	6252.7	6429.2	6612.2
CONSUMIDORES RESIDENCIALES (000)	151.1	159.9	16[illegible].0	192.8	220.7	246.2	265.0	221.7	286.2	312.4	321.0	330.3
Promedio anual (000)	147.3	155.5	162.5	178.9	206.7	233.4	255.6	243.3	254.0	299.3	316.7	325.7
CONSUMO PER CAPITA (KWH/AÑO)	188.8	201.0	217.3	227.7	235.3	250.0	261.2	251.4	243.2	240.4	235.3	231.0
CONSUMO RESIDENCIAL (KWH/ABONADO)	1516.9	1553.1	1602.8	1627.7	1595.4	1550.8	1548.6	1639.7	1673.5	1564.5	1598.7	1777.0
TASA DE ELECTRIFICACION (%) 1/	18.5%	19.1%	19.2%	21.8%	24.3%	26.4%	27.6%	22.5%	28.2%	30.0%	30.0%	30.0%
TARIFA PROMEDIO RESIDENCIAL (US$mills/kwh 1986)	32.1	40.0	39.7	37.5	32.4	28.8	30.5	21.7	12.9	8.9	17.9	23.7
PRECIO GLP (US$/ton)	145.7	136.1	128.9	120.8	124.6	160.2	131.8	43.1	29.2	10.4	53.4	138.5
PIB (MMB$/80)	105049	111457	116150	120052	122249	122946	123375	119905	112050	111054	109113	105233
Valor Agregado Mineria (MMB$/80)	14180	14180	14519	1318[illegible]	12299	12679	12133	10635	10889	8565	6852	4796
Valor Agregado Industria (MMB$/80)	13833	15039	16084	16940	17750	17974	16664	14344	13387	11814	10729	11105
Valor Agregado Comercio (MMB$/80)	11865	12455	12766	13155	13548	13261	14360	13599	13055	12924	13195	12997
INDICE DE PRECIOS CONSUMIDOR (Prom)	317.9	332.2	359.1	396.3	474.5	698.6	923.1	2063.5	7750.3	107058.2	12686008.0	47722694.7
TASA DE CAMBIO (B$/US$) (Prom)	20.0	20.0	20.0	20.0	20.4	24.5	24.5	129.6	247.0	2791.7	452077.7	1916230.0

1/ Asumiendo 6 personas por familia.

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

ESTADISTICAS GENERALES

TASAS DE CRECIMIENTO ANUAL

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
VENTAS TOTALES (GWH)												
MINERIA		3.4%	9.5%	1.3%	-1.1%	3.6%	5.5%	-3.7%	-2.3%	-2.4%	-4.2%	-16.7%
INDUSTRIAL		20.9%	23.4%	11.5%	7.3%	16.5%	6.1%	-1.6%	-3.4%	-5.5%	-6.5%	-3.9%
RESIDENCIAL		8.1%	7.8%	11.8%	13.3%	9.8%	9.3%	0.8%	6.5%	10.2%	8.1%	14.3%
GENERAL		11.2%	0.3%	12.0%	7.7%	6.3%	9.6%	-0.7%	-7.6%	5.6%	11.5%	11.2%
ALUMBRADO PUBLICO		25.1%	4.8%	12.1%	30.1%	13.7%	7.8%	5.4%	0.0%	5.5%	-6.7%	5.4%
OTROS		14.0%	0.0%	26.3%	12.5%	17.3%	46.3%	27.3%	10.7%	18.4%	0.9%	32.1%
SUBTOTAL		9.4%	11.1%	7.6%	6.2%	9.2%	7.4%	-1.1%	-0.6%	1.7%	0.6%	1.0%
POBLACION (000)		2.7%	2.7%	2.7%	2.7%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%	2.8%
CONSUMIDORES RESIDENCIALES (000)		5.8%	3.2%	16.8%	14.5%	11.6%	7.6%	-16.3%	29.1%	9.1%	2.8%	2.9%
Promedio anual (000)		5.5%	4.5%	10.1%	15.5%	12.9%	9.5%	-4.8%	4.4%	17.8%	5.8%	2.8%
CONSUMO PER CAPITA (KWH/AÑO)		6.5%	8.1%	4.8%	3.3%	6.2%	4.5%	-3.8%	-3.3%	-1.1%	-2.2%	-1.8%
CONSUMO RESIDENCIAL (KWH/ABONADO)		2.4%	3.2%	1.6%	-2.0%	-2.8%	-0.1%	5.9%	2.1%	-6.5%	2.2%	11.2%
TASA DE ELECTRIFICACION (%) 1/		3.0%	0.5%	13.7%	11.4%	8.6%	4.7%	-18.6%	25.6%	6.2%	0.0%	0.0%
TARIFA PROMEDIO RESIDENCIAL (US$mills/kwh 1986)		24.6%	-0.7%	-5.5%	-13.6%	-11.1%	5.9%	-28.9%	-40.6%	-31.0%	101.1%	32.6%
PRECIO GLP (US$/ton)		-6.6%	-5.3%	-6.3%	3.1%	28.6%	-17.7%	-67.3%	-32.3%	-64.4%	413.5%	159.4%
PIB (MME$/80)		6.1%	4.2%	3.4%	1.9%	0.6%	0.3%	-2.8%	-6.6%	-0.9%	-1.7%	-3.6%
Valor Agregado Mineria (MME$/80)		0.0%	2.4%	-9.2%	-6.7%	3.1%	-4.3%	-12.3%	2.4%	-21.3%	-20.0%	-30.0%
Valor Agregado Industria (MMB$/80)		8.7%	6.9%	5.3%	4.8%	1.3%	-7.3%	-13.9%	-6.7%	-11.8%	-9.2%	3.5%
Valor Agregado Comercio (MMB$/80)		5.0%	2.5%	3.0%	3.0%	-2.1%	8.3%	-5.3%	-4.0%	-1.0%	2.1%	-1.5%
INDICE DE PRECIOS CONSUMIDOR (Prom)		4.5%	8.1%	10.4%	19.7%	47.2%	32.1%	123.5%	275.6%	1281.3%	11749.6%	276.2%
TASA DE CAMBIO (B$/US$) (Prom)		0.0%	0.0%	0.0%	2.2%	19.9%	0.0%	428.8%	90.6%	1030.2%	16093.8%	323.9%

PROYECCIONES DE DEMANDA

ESCENARIO BASICO
Proveccion Base de UDAPE 1986-1995
(GWH)

	1/ R2	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	TASAS DE CRECIMIENTO (% 86-91	91-95	86-
1 PIB (MMB$/80)		105233	107969	111413	116159	120783	125541	127651	132463	137722	143203	3.6%	3.3%	3.
3 Valor Agregado Mineria (MMB$/80)		4976	4898	4756	5205	5561	5982	6448	6966	7546	8156	3.8%	8.1%	5.
5 Valor Agregado Industria (MMB$/80)		11105	11327	11667	12250	12740	13250	13647	14125	14619	15131	3.6%	3.4%	3.
7 Valor Agregado Comercio (MMB$/80)		12997	13309	13841	14603	15333	16099	16421	16914	17506	18119	4.4%	3.0%	3.
9 Poblacion (000)		6612.2	6800.6	6994.5	7194.2	7399.7	7611.4	7829.3	8053.7	8284.7	8522.6	2.9%	2.9%	2.
11 Ingreso Per Capita (B$-80/capita)		15.91	15.88	15.93	16.15	16.32	16.49	16.30	16.45	16.62	16.80	0.7%	0.5%	0.
13 Tiempo		13	14	15	16	17	18	19	20	21	22	6.7%	5.1%	6.
14														
16														
17 DTOT (=854.36*EXP(.0577*T))	0.94	1808.9	1916.3	2030.1	2150.7	2278.5	2413.8	2557.2	2709.0	2870.0	3040.4	5.9%	5.9%	5.
19 DTOT (=1.8685*EXP(.045742*T)*PIB^.5337)	0.98	1622.6	1722.0	1833.1	1962.1	2097.1	2241.0	2366.9	2527.1	2700.9	2886.8	6.7%	6.5%	6.
21 DTOT (=POB*35.91*EXP(.03315*T)*ING^.5389)	0.94	1623.2	1723.4	1835.6	1965.9	2102.5	2248.2	2375.6	2538.0	2714.3	2903.1	6.7%	6.6%	6.
23 DTOT (=.098*PIB^.3092*DTOT(-1)^.8269)	0.99	1504.6	1496.1	1503.7	1529.5	1570.1	1623.7	1678.1	1744.3	1822.7	1913.3	1.5%	4.2%	2.
25 DTOT (ENDE)		1529.6	1594.0	1684.1	1794.5	1909.0	2027.9	2151.5	2283.8	2426.1	2579.2	5.8%	6.2%	6.
26														
29 DRES (=5.16E-12*POB^3.5072*ING^.5144)	0.99	536.5	591.3	653.7	726.6	806.5	895.2	982.5	1089.7	1210.0	1343.7	10.8%	10.7%	10.
31 DRES (=206.3*EXP(.0737*T))	[illegible]	537.8	578.9	623.2	670.8	722.1	777.4	836.8	900.8	969.7	1043.9	7.6%	7.6%	7.
33 DRES (ENDE)		583.8	647.9	713.7	783.1	850.8	916.9					9.4%		
34														
37 DIND (=.1265*VAIND^.7602*EXP(.0775*T))	0.97	412.1	452.1	499.6	560.3	623.8	694.4	767.5	851.3	944.2	1047.4	11.0%	10.8%	10.
39 DIND (ENDE)		332.1	341.4	356.8	378.4	403.3	431.3					5.4%		
40														
43 DMIN (=11.575*VAMIN^.3652*EXP(.0337*T))	0.95	401.8	413.2	422.8	452.0	478.9	508.7	540.8	575.4	612.8	652.0	4.8%	6.4%	5.
45 DMIN (ENDE)		357.2	330.3	319.2	316.4	314.3	314.7					-2.5%		
46														
49 DGEN (=5.5432E-8*VACOM^1.0162*POB^1.3837)	0.99	162.3	172.8	187.0	205.3	224.3	245.1	260.0	278.6	300.0	323.1	8.6%	7.2%	8.
51 DGEN (=83.929*EXP(.06007*T))	0.95	183.3	194.6	206.6	219.4	233.0	247.5	262.8	279.0	296.3	314.7	6.2%	6.2%	6.
53 DGEN (ENDE)		185.8	198.6	213.3	229.5	247.2	264.6					7.3%		
54														
57 DAP(=17.4074*EXP(.0956*T)		60.3	66.4	73.0	80.4	88.4	97.3	107.0	117.8	129.6	142.6	10.0%	10.0%	10.
59 DAP(ENDE)		45.9	49.2	52.4	56.0	59.9	64.0					6.9%		
60														
63 DOTROS (=3.1504*EXP(.1761*T))		31.1	37.1	44.2	52.7	62.9	75.0	89.4	106.6	127.2	151.7	19.3%	19.3%	19.
65 DOTROS (ENDE)		24.7	26.6	28.7	31.0	33.6	36.4					8.1%		
66														
69 DTOT1 (LINEAS 31+37+43+51+57+63)		1626.4	1742.3	1869.5	2035.7	2209.2	2400.3	2604.4	2831.0	3079.9	3352.3	8.1%	8.7%	8.4%
71 DTOT2 (LINEAS 29+37+43+49+57+63)		1604.2	1732.9	1880.4	2077.2	2284.8	2515.7	2747.2	3019.4	3323.8	3660.5	9.4%	9.8%	9.
72 DTOT3 (LINEAS 29+39+45+49+57+63)		1479.5	1539.3	1633.9	1759.8	1899.7	2058.5					6.8%		

PROYECCIONES DE DEMANDA DE ENDE

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	86-91	91-95	86-
A) POR SECTOR													
MINERIA	357.2	330.3	319.2	316.4	314.3	314.7					-2.5%		
INDUSTRIAL	332.1	341.4	356.8	378.4	403.3	431.3					5.4%		
RESIDENCIAL	583.8	647.9	713.7	783.1	850.8	916.9					9.4%		
GENERAL	185.8	198.6	213.3	229.5	247.2	264.6					7.3%		
ALUMBRADO PUBLICO	45.9	49.2	52.4	56.0	59.9	64.0					6.9%		
OTROS	24.7	26.6	28.7	31.0	33.6	36.4					8.1%		
TOTAL	1529.5	1594.0	1684.1	1794.4	1909.1	2027.9	2151.5	2283.8	2426.1	2579.2	5.8%	6.2%	6.0
B) POR REGION													
SISTEMA CENTRAL	451.3	449.4	460.3	480.8	502.3	524.8	548.3	572.8	598.4	625.1	3.1%	4.5%	3.7
SISTEMA SUR	147.8	149.3	152.7	158.5	164.4	170.5	176.9	183.5	190.4	197.5	2.9%	3.7%	3.
SISTEMA NORTE	409.2	430.9	455.3	482.8	511.9	542.7	575.5	610.2	646.9	686.0	5.8%	6.0%	5.
SISTEMA ESTE	307.8	349.2	396.7	448.3	501.7	556.1	610.9	671.2	737.9	811.5	12.6%	9.9%	11.4
SISTEMAS AISLADOS	213.5	215.2	219.1	224.1	228.7	233.8	239.9	246.1	252.5	259.1	1.8%	2.6%	2.2%
TOTAL	1529.6	1594.0	1684.1	1794.5	1909.0	2027.9	2151.5	2283.8	2426.1	2579.2	5.8%	6.2%	6.0

1/ Coeficiente de correlacion

PROYECCIONES DE DEMANDA

ESCENARIO PESIMISTA
Crecimiento del PIB a 2% anual
(GWH)

	1/ R2	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	TASAS DE CRECIMIENTO (%) 86-91	91-95	86-9
1 PIB (MMB$/80)		105233	107338	109484	111674	113908	116186	118509	120880	123297	125763	2.0%	2.0%	2.0
3 Valor Agregado Mineria (MMB$/80)		4976	5076	5177	5281	5386	5494	5604	5716	5830	5947	2.0%	2.0%	2.0
5 Valor Agregado Industria (MMB$/80)		11105	11327	11554	11785	12020	12261	12506	12756	13011	13272	2.0%	2.0%	2.0
7 Valor Agregado Comercio (MMB$/80)		12997	13257	13522	13793	14068	14350	14637	14929	15228	15533	2.0%	2.0%	2.0
9 Poblacion (000)		6612.2	6800.6	6994.5	7194.2	7399.7	7611.4	7829.3	8053.7	8284.7	8522.6	2.9%	2.9%	2.[illegible]
11 Ingreso Per Capita (B$-80/capita)		15.91	15.78	15.65	15.52	15.39	15.26	15.14	15.01	14.88	14.76	-0.8%	-0.8%	-0.8
13 Tiempo		13	14	15	16	17	18	19	20	21	22	6.7%	5.1%	6.0
14														
16														
17 DTOT (=854.36*EXP(.0577*T))	0.94	1808.9	1916.3	2030.1	2150.7	2278.5	2413.8	2557.2	2709.0	2870.0	3040.4	5.9%	5.9%	5.9
19 DTOT (=1.8685*EXP(.045742*T)*PIB^.5337)	0.98	1622.6	1716.6	1816.1	1921.3	2032.5	2150.3	2274.8	2406.6	2546.0	2693.5	5.8%	5.8%	5.8
21 DTOT (=POB*35.91*EXP(.03315*T)*ING^.5389)	0.94	1623.2	1718.0	1818.4	1924.7	2037.1	2156.3	2282.4	2415.9	2557.2	2706.9	5.8%	5.9%	5.8
23 DTOT (=.098*PIB^.3092*DTOT(-1)^.6269)	0.99	1504.6	1493.4	1493.3	1502.4	1519.3	1542.8	1572.1	1606.5	1645.6	1689.0	0.5%	2.3%	1.3
25 DTOT (ENDE)		1529.6	1594.0	1684.1	1794.5	1909.0	2027.9	2151.5	2283.8	2426.1	2579.2	5.8%	6.2%	6.[illegible]
26														
29 DRES (=5.16E-12*POB^3.5072*ING^.5144)	0.99	536.5	589.5	647.9	712.0	782.6	860.2	945.6	1039.6	1143.0	1256.8	9.9%	9.9%	9.9
31 DRES (=206.3*EXP(.0737*T))	0.96	537.8	578.9	623.2	670.8	722.1	777.4	836.8	900.8	969.7	1043.9	7.6%	7.6%	7.6
33 DRES (ENDE)		583.8	647.9	713.7	783.1	850.8	916.9					9.4%		
34														
37 DIND (=.1265*VAIND^.7602*EXP(.0775*T))	0.97	412.1	452.1	495.9	544.0	596.8	654.7	718.2	787.8	864.2	948.0	9.7%	9.7%	9.7%
39 DIND (ENDE)		332.1	341.4	356.8	378.4	403.3	431.3					5.4%		
40														
43 DMIN (=11.575*VAMIN^.3652*EXP(.0337*T))	0.95	401.8	418.6	436.1	454.4	473.4	493.2	513.8	535.3	557.7	581.0	4.2%	4.2%	4.[illegible]
45 DMIN (ENDE)		357.2	330.3	319.2	316.4	314.3	314.7					-2.5%		
46														
49 DGEN (=5.5432E-8*VACOM^1.0162*POB^1.3837)	0.99	162.3	172.1	182.6	193.7	205.5	218.0	231.3	245.4	260.4	276.3	6.1%	6.1%	6.1
51 DGEN (=83.929*EXP(.06007*T))	0.95	183.3	194.6	206.6	219.4	233.0	247.5	262.8	279.0	296.3	314.7	6.2%	6.2%	6.[illegible]
53 DGEN (ENDE)		185.8	198.6	213.3	229.5	247.2	264.6					7.3%		
54														
57 DAP(=17.4074*EXP(.0956*T)		60.3	66.4	73.0	80.4	88.4	97.3	107.0	117.8	129.6	142.6	10.0%	10.0%	10.0
59 DAP(ENDE)		45.9	49.2	52.4	56.0	59.9	64.0					6.9%		
60														
63 DOTROS (=3.1504*EXP(.1761*T))		31.1	37.1	44.2	52.7	62.9	75.0	89.4	106.6	127.2	151.7	19.3%	19.3%	19.3
65 DOTROS (ENDE)		24.7	26.6	28.7	31.0	33.6	36.4					8.1%		
66														
69 DTOT1 (LINEAS 31+37+43+51+57+63)		1626.4	1747.7	1879.2	2021.8	2176.7	2345.0	2528.0	2727.4	2944.7	3181.8	7.6%	7.9%	7.7
71 DTOT2 (LINEAS 29+37+43+49+57+63)		1604.2	1735.9	1879.8	2037.3	2209.6	2398.4	2605.4	2832.6	3082.1	3356.4	8.4%	8.8%	8.5%
72 DTOT3 (LINEAS 29+39+45+49+57+63)		1479.5	1536.8	1623.7	1733.6	1857.0	1996.5					6.2%		

PROYECCIONES DE DEMANDA DE ENDE

	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	86-91	91-95	86-9
A) POR SECTOR													
MINERIA	357.2	330.3	319.2	316.4	314.3	314.7					-2.5%		
INDUSTRIAL	332.1	341.4	356.8	378.4	403.3	431.3					5.4%		
RESIDENCIAL	583.8	647.9	713.7	783.1	850.8	916.9					9.4%		
GENERAL	185.8	198.6	213.3	229.5	247.2	264.6					7.3%		
ALUMBRADO PUBLICO	45.9	49.2	52.4	56.0	59.9	64.0					6.9%		
OTROS	24.7	26.6	28.7	31.0	33.6	36.4					8.1%		
TOTAL	1529.5	1594.0	1684.1	1794.4	1909.1	2027.9	2151.5	2283.8	2426.1	2579.2	5.8%	6.2%	6.0%
B) POR REGION													
SISTEMA CENTRAL	451.3	449.4	460.3	480.8	502.3	524.8	548.3	572.8	598.4	625.1	3.1%	4.5%	3.7%
SISTEMA SUR	147.8	149.3	152.7	158.5	164.4	170.5	176.9	183.5	190.4	197.5	2.9%	3.7%	3.3%
SISTEMA NORTE	409.2	430.9	455.3	482.8	511.9	542.7	575.5	610.2	646.9	686.0	5.8%	6.0%	5.9%
SISTEMA ESTE	307.8	349.2	396.7	448.3	501.7	556.1	610.9	671.2	737.9	811.5	12.6%	9.9%	11.1%
SISTEMAS AISLADOS	213.5	215.2	219.1	224.1	228.7	233.8	239.9	246.1	252.5	259.1	1.8%	2.6%	2.2%
TOTAL	1529.6	1594.0	1684.1	1794.5	1909.0	2027.9	2151.5	2283.8	2426.1	2579.2	5.8%	6.2%	6.0%

1/ Coeficiente de correlacion

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PROGRAMAS DE EXPANSION SIMPLIFICADOS

A) SISTEMA C-N-S

AÑO	REQUERIMIENTO BRUTO ENERGIA GWH	REQUERIMIENTO BRUTO CAPACIDAD MW	PROYECTOS NUEVOS	No UNID	ENERGIA DISPONIBLE (GWH) HIDRO	ENERGIA DISPONIBLE (GWH) TERMO EXIST.	ENERGIA DISPONIBLE (GWH) TERMO NUEVA	ENERGIA DISPONIBLE (GWH) TOTAL	CAPACIDAD DISPONIBLE (MW) HIDRO	CAPACIDAD DISPONIBLE (MW) TERMO EXIST.	CAPACIDAD DISPONIBLE (MW) TERMO NUEVA	CAPACIDAD DISPONIBLE (MW) TOTAL	BALANCE CAPACIDAD MW	BALANCE CAPACIDAD %	BALANCE ENERGIA GWH
1986	1162.1	246.0			1421	142.5		1563.5	251	28		279			401
1987	1186.3	251.2			1421	142.5		1563.5	251	28		279			377
1988	1231.2	260.7			1421	142.5		1563.5	251	28		279			332
1989	1293.3	273.9			1421	142.5		1563.5	251	28		279			270
1990	1358.6	287.7	Turbina a gas	2	1421	142.5	160	1723.5	251	28	32	311	23	8%	365
1991	1427.4	302.3	Turbina a gas	4	1421	142.5	320	1883.5	251	28	64	343	41	13%	456
1992	1499.7	317.7	Turbina a gas	5	1421	142.5	400	1963.5	251	28	80	359	41	13%	464
1993	1575.9	333.8	Turbina a gas	6	1421	142.5	480	2043.5	251	28	96	375	41	12%	468
1994	1656.0	350.8	Turbina a gas	7	1421	142.5	560	2123.5	251	28	112	391	40	11%	468
1995	1740.3	368.7	Turbina a gas	8	1421	142.5	640	2203.5	251	28	128	407	38	10%	463
1996	1828.9	387.5	Turbina a gas	10	1421	142.5	800	2363.5	251	28	160	439	52	13%	535

B) SISTEMA ORIENTAL

AÑO	REQUERIMIENTO BRUTO ENERGIA GWH	REQUERIMIENTO BRUTO CAPACIDAD MW	PROYECTOS NUEVOS	No UNID	ENERGIA DISPONIBLE (GWH) HIDRO	ENERGIA DISPONIBLE (GWH) TERMO EXIST.	ENERGIA DISPONIBLE (GWH) TERMO NUEVA	ENERGIA DISPONIBLE (GWH) TOTAL	CAPACIDAD DISPONIBLE (MW) HIDRO	CAPACIDAD DISPONIBLE (MW) TERMO EXIST.	CAPACIDAD DISPONIBLE (MW) TERMO NUEVA	CAPACIDAD DISPONIBLE (MW) TOTAL	BALANCE CAPACIDAD MW	BALANCE CAPACIDAD %	BALANCE ENERGIA GWH
1986	355.0	81.9				487.5		487.5		97.5		97.5	16	19%	132
1987	402.8	92.9				610.0		610.0		126.0		126.0	33	36%	207
1988	457.6	106.6				727.5		727.5		145.5		145.5	39	36%	270
1989	517.1	121.7				727.5		727.5		145.5		145.5	24	20%	210
1990	578.7	137.6	Turbina a gas	1		727.5	97.5	825.0		145.5	19.5	165.0	27	20%	246
1991	641.4	152.5	Turbina a gas	2		727.5	195.0	922.5		145.5	39.0	184.5	32	21%	281
1992	704.6	167.6	Turbina a gas	3		727.5	292.5	1020.0		145.5	58.5	204.0	36	22%	315
1993	774.2	184.1	Turbina a gas	4		727.5	390.0	1117.5		145.5	78.0	223.5	39	21%	343
1994	851.1	202.4	Turbina a gas	5		727.5	487.5	1215.0		145.5	97.5	243.0	41	20%	364
1995	936.0	222.6	Turbina a gas	6		727.5	585.0	1312.5		145.5	117.0	262.5	40	18%	377
1996	1029.8	244.9	Turbina a gas	7		727.5	682.5	1410.0		145.5	136.5	282.0	37	15%	380

C) SISTEMA C-N-S-O

AÑO	REQUERIMIENTO BRUTO ENERGIA GWH	REQUERIMIENTO BRUTO CAPACIDAD MW	PROYECTOS NUEVOS	No UNID	ENERGIA DISPONIBLE (GWH) HIDRO	ENERGIA DISPONIBLE (GWH) TERMO EXIST.	ENERGIA DISPONIBLE (GWH) TERMO NUEVA	ENERGIA DISPONIBLE (GWH) TOTAL	CAPACIDAD DISPONIBLE (MW) HIDRO	CAPACIDAD DISPONIBLE (MW) TERMO EXIST.	CAPACIDAD DISPONIBLE (MW) TERMO NUEVA	CAPACIDAD DISPONIBLE (MW) TOTAL	BALANCE CAPACIDAD MW	BALANCE CAPACIDAD %	BALANCE ENERGIA GWH
1986	1517.1	319.7			1421	630.0		2051.0	251	125.5		376.5			
1987	1589.1	335.5			1421	752.5		2173.5	251	154.0		405.0			
1988	1688.7	358.1			1421	870.0		2291.0	251	173.5		424.5			
1989	1810.4	385.7			1421	870.0		2291.0	251	173.5		424.5			
1990	1937.3	414.7	Turbina a gas	1	1421	870.0	97.5	2388.5	251	173.5	19.5	444.0	29.3	7%	451
1991	2068.8	443.5	Turbina a gas	3	1421	870.0	292.5	2583.5	251	173.5	58.5	483.0	39.5	9%	515
1992	2204.4	473.1	Turbina a gas	4	1421	870.0	390.0	2681.0	251	173.5	78.0	502.5	29.4	6%	477
1993	2350.0	505.0	Turbina a gas	7	1421	870.0	682.5	2973.5	251	173.5	136.5	561.0	56.0	11%	623
1994	2507.1	539.4	Turbina a gas	9	1421	870.0	877.5	3168.5	251	173.5	175.5	600.0	60.6	11%	661
1995	2676.3	576.5	Turbina a gas	11	1421	870.0	1072.5	3363.5	251	173.5	214.5	639.0	62.5	11%	687
1996	2856.7	615.4	Turbina a gas	14	1421	870.0	1365.0	3656.0	251	173.5	273.0	697.5	82.1	13%	799

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

INTERCONEXION CENTRAL-ESTE

ANALISIS ECONOMICO

CASO 1

AÑO	INTERCONEXION EN 1990: 1/ INVERSION LINEA	2/ INVERSION GENER	INVER TOTAL	3/ COSTO COMB	4/ COSTO O&M	COSTO TOTAL	INTERCONEXION EN 1991: INVERSION LINEA	INVERSION GENER	INVER TOTAL	COSTO COMB	COSTO O&M	COSTO TOTAL	SIN INTERCONEXION: 5/ INVERSION LINEA	6/ INVERSION GENER	INVER TOTAL	7/ COSTO COMB	COSTO O&M	COSTO TOTAL
1986			0.0	4.6	0.0	4.6			0.0	4.6	0.0	4.6			0.0	4.6	0.0	4.6
1987			0.0	5.2	0.0	5.2			0.0	5.2	0.0	5.2	-3.0		-3.0	5.2	0.0	2.2
1988	11.1		11.1	6.1	0.1	17.3			0.0	6.1	0.0	6.1	-3.0		-3.0	6.1	0.0	3.0
1989	11.1		11.1	7.0	0.2	18.3	11.1		11.1	7.0	0.1	18.2	-3.0		-3.0	7.0	0.0	4.0
1990		8.5	8.5	6.7	0.4	15.6	11.1	26.5	37.6	8.0	0.8	46.3		26.5	26.5	8.0	0.5	35.0
1991		17.0	17.0	8.4	0.7	26.2		3.1	3.1	8.4	0.8	12.3		26.5	26.5	9.0	1.1	36.5
1992	3.9	8.5	12.4	10.2	0.9	23.5	3.9	8.5	12.4	10.2	1.0	23.6		17.5	17.5	10.3	1.4	29.2
1993		25.5	25.5	12.1	1.5	39.0		25.5	25.5	12.1	1.5	39.1		17.5	17.5	12.2	1.8	31.5
1994		17.0	17.0	14.1	1.8	32.9		17.0	17.0	14.1	1.9	33.0		17.5	17.5	14.3	2.1	33.9
1995		17.0	17.0	16.3	2.1	35.4		17.0	17.0	16.3	2.2	35.5		17.5	17.5	16.6	2.5	36.6
1996		25.5	25.5	18.7	2.6	46.8		25.5	25.5	18.7	2.7	46.9		26.5	26.5	19.1	3.0	48.6
1997				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
1998				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
1999				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2000				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2001				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2002				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2003				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2004				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2005				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2006				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2007				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2008				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2009				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2010				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2011				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2012				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2013				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2014				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2015				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2016				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2017				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
2018				18.7	2.6	21.3				19.7	2.7	21.4				19.1	3.0	22.1
2019				18.7	2.6	21.3				18.7	2.7	21.4				19.1	3.0	22.1
VAN:tasa desc= 12% Valor Residual 80%			63.2	91.7	9.8	164.8	15.1	47.7	64.8	92.5	10.2	167.4	-6.5	63.0	56.5	94.0	11.2	161.7
Valor Residual 0%			63.2	91.7	9.8	164.8			64.8	92.5	10.2	167.4			63.0	94.0	11.2	168.3

Costo materiales 11.41
Costo gas Sta Cruz 1.0 US$/MPC
Costo gas Cbba 1.1 US$/MPC

1/ Incluye inversion adicional requerida para completar la linea y nuevo transformador en 1993.
2/ Inversiones en generacion adicional; 19.5 MWe en turbinas a gas a MMUS$ 8.5 por unidad.
3/ Costo de combustible estimado igual al precio del gas indicado y 13 MPC/KWH.
4/ Costo de O&M estimado como 1% de la inversion en la linea de transmision y 2% de la inversion en nuevas turbinas a gas.
5/ Incluye el valor residual de los materiales de linea en almacen.
6/ Incluye turbinas a gas en Santa Cruz indicadas en 2/ y 16 MWe en turbinas a gas en Cochabamba a MMUS$ 9 por unidad.
7/ Costo de combustible estimado igual al precio del gas indicado y 13 MPC/KWH para turbinas a gas en Cochabamba.

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

INTERCONEXION CENTRAL-ESTE

ANALISIS ECONOMICO

CASO 2

	INTERCONEXION EN 1990						INTERCONEXION EN 1991						SIN INTERCONEXION					
	1/ INVERSION	2/ INVERSION		3/	4/		INVERSION	INVERSION					5/ INVERSION	6/ INVERSION		7/		
AÑO	LINEA	GENER	INVER TOTAL	COSTO COMB	COSTO O&M	COSTO TOTAL	LINEA	GENER	INVER TOTAL	COSTO COMB	COSTO O&M	COSTO TOTAL	LINEA	GENER	INVER TOTAL	COSTO COMB	COSTO O&M	COSTO TOTAL
1986			0.0	4.6	0.0	4.6			0.0	4.6	0.0	4.6			0.0	4.6	0.0	4.6
1987			0.0	5.2	0.0	5.2			0.0	5.2	0.0	5.2	-3.0		-3.0	5.2	0.0	2.2
1988	11.1		11.1	6.1	0.1	17.3			0.0	6.1	0.0	6.1	-3.0		-3.0	6.1	0.0	3.0
1989	11.1		11.1	7.0	0.2	18.3	11.1		11.1	7.0	0.1	18.2	-3.0		-3.0	7.0	0.0	4.0
1990		8.5	8.5	6.7	0.4	15.6	11.1	26.5	37.6	8.0	0.8	46.4		26.5	26.5	8.0	0.5	35.0
1991		17.0	17.0	8.4	0.7	26.2		3.1	3.1	8.4	0.8	12.3		26.5	26.5	9.0	1.1	36.6
1992	3.9	8.5	12.4	10.2	0.9	23.5	3.9	8.5	12.4	10.2	1.0	23.6		17.5	17.5	10.4	1.4	29.3
1993		25.5	25.5	12.1	1.5	39.0		25.5	25.5	12.1	1.5	39.1		17.5	17.5	12.4	1.8	31.7
1994		17.0	17.0	14.1	1.8	32.9		17.0	17.0	14.1	1.9	33.0		17.5	17.5	14.6	2.1	34.2
1995		17.0	17.0	16.3	2.1	35.4		17.0	17.0	16.3	2.2	35.5		17.5	17.5	17.0	2.5	37.0
1996		25.5	25.5	18.7	2.6	46.8		25.5	25.5	18.7	2.7	46.9		26.5	26.5	19.6	3.0	49.1
1997				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
1998				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
1999				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2000				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2001				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2002				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2003				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2004				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2005				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2006				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2007				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2008				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2009				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2010				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2011				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2012				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2013				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2014				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2015				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2016				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2017				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2018				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
2019				18.7	2.6	21.3				18.7	2.7	21.4				19.6	3.0	22.6
VAN:tasa desc= 12% Valor Residual 80%			63.2	91.8	9.8	164.8	15.1	49.7	64.8	92.5	10.2	167.5	-6.5	63.0	56.5	95.7	11.2	163.5
Valor Residual 0%			63.2	91.7	9.8	164.8			64.8	92.5	10.2	167.4			63.0	94.0	11.2	168.3

Costo materiales 11.41
Costo gas Sta Cruz 1.0 US$/MPC
Costo gas Cbba 1.2 US$/MPC

1/ Incluye inversion adicional requerida para completar la linea y nuevo transformador en 1993.
2/ Inversiones en generacion adicional; 19.5 MWe en turbinas a gas a MMUS$ 8.5 por unidad.
3/ Costo de combustible estimado igual al precio del gas indicado y 13 MPC/KWH.
4/ Costo de O&M estimado como 1% de la inversion en la linea de transmision y 2% de la inversion en nuevas turbinas a gas.
5/ Incluye el valor residual de los materiales de linea en almacen.
6/ Incluye turbinas a gas en Santa Cruz indicadas en 2/ y 16 MWe en turbinas a gas en Cochabamba a MMUS$ 9 por unidad.
7/ Costo de combustible estimado igual al precio del gas indicado y 13 MPC/KWH para turbinas a gas en Cochabamba.

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

TRANSPORTE DE ELECTRICIDAD VS. TRANSPORTE DE GAS

ANALISIS ECONOMICO

	TRANSPORTE DE ELECTRICIDAD							TRANSPORTE DE GAS			
AÑO	1/ INVERSION LINEA	2/ INVERSION GENER	INVERSION TOTAL	3/ COSTO COMBUST	5/ COSTO PERDIDAS	4/ COSTO O&M	COSTO TOTAL	6/ INVERSION GENER	7/ COSTO COMBUST	COSTO O&M	COSTO TOTAL
1986				4.6		0.0	4.6		4.6	0.0	4.6
1987				5.2		0.0	5.2		5.2	0.0	5.2
1988	11.1		11.1	6.1		0.1	17.3		6.1	0.0	6.1
1989	11.1		11.1	7.0		0.3	18.4		7.0	0.0	7.0
1990		8.5	8.5	6.7	0.0	0.5	15.7	26.5	8.0	0.5	35.0
1991		17.0	17.0	8.4	0.0	0.8	26.2	26.5	9.0	1.1	36.5
1992	3.9	8.5	12.4	10.2	0.0	1.0	23.6	17.5	10.3	1.4	29.2
1993		25.5	25.5	12.1	0.1	1.5	39.2	17.5	12.2	1.8	31.5
1994		17.0	17.0	14.1	0.1	1.9	33.1	17.5	14.3	2.1	33.9
1995		17.0	17.0	16.3	0.1	2.2	35.6	17.5	16.6	2.5	36.6
1996		25.5	25.5	18.7	0.1	2.7	47.0	26.5	19.1	3.0	48.6
1997				18.7	0.1	2.7	21.5		19.1	3.0	22.1
1998				18.7	0.1	2.7	21.5		19.1	3.0	22.1
1999				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2000				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2001				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2002				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2003				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2004				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2005				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2006				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2007				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2008				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2009				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2010				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2011				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2012				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2013				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2014				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2015				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2016				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2017				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2018				18.7	0.1	2.7	21.5		19.1	3.0	22.1
2019				18.7	0.1	2.7	21.5		19.1	3.0	22.1
VAN (12%)			63.2	91.7	0.4	10.2	165.6	63.0	94.0	11.2	168.3

Costo del gas en Santa Cruz 1.0 US$/MPC
Costo del gas en Cochabamba 1.1 US$/MPC

1/ Incluye la inversión adicional requerida para completar la línea y un nuevo transformador en 1993.
2/ Inversiones en generacion adicional; 19.5 MWe en turbinas a gas a un costo de MMUS$ 8.5 por unidad.
3/ Costo del gas estimado, considerando el precio indicado y un consumo de 13 PC/KWH.
4/ Costo de O&M estimado como 1% de la inversion en la linea y 2% de la inversion en nuevas turbinas a gas.
5/ Costo de la generacion adicional requerida para compensar las perdidas en transmision.
6/ Incluye las turbinas a gas en Santa Cruz indicadas en 2/ y turbinas a gas de 16MWe en Cochabamba, a un costo de MMUS$ 9.0 por unidad.
7/ Costo del gas estimado, considerando el precio indicado y un consumo de 13 PC/KWH para turbinas en Santa Cruz y 12.66 PC/KWH para turbinas en Cochabamba.

COSTOS PROMEDIO DE GENERACION TERMICA

		TURBINA A GAS STA CRUZ			TURBINA A GAS COCHABAMBA			CICLO COMBINADO STA CRUZ		
		Precio del gas			Precio del gas			Precio del gas		
	UNIDAD	1.0 US$/MPC	1.5 US$/MPC	2.0 US$/MPC	1.0 US$/MPC	1.5 US$/MPC	2.0 US$/MPC	1.0 US$/MPC	1.5 US$/MPC	2.0 US$/MPC
Capacidad Instalada	MW	22.8			22.8			65.6		
Capacidad Firme	MW	19.5			16			59		
Costo de Inversión	MMUS$	8.50			9.00			38.30		
Periodo de Construcción	AÑOS	1			1			3		
Costo de O&M	% INV	2.0%			2%			3%		
Costo de O&M	MMUS$ p.a.	0.17			0.18			1.15		
Vida Económica	AÑOS	20			20			25		
Combustible	GAS									
Consumo de Combustible	PC/KWH	13.00			12.66			8.60		
Costo Actualizado de inversión	MMUS$	8.50			9.00			43.08		
Costo de Capacidad	US$/KW	435.9			562.5			730.2		
Costo de Capital + O&M	MMUS$ p.a.	1.31			1.38			6.03		
Costo de Combustible	MILLS/KWH	13.0	19.5	26.0	12.7	19.0	25.3	8.6	12.9	17.2
Costo Total	MILLS/KWH									
1000h		80.1	86.6	93.1	99.2	105.5	111.9	110.8	115.1	119.4
2000h		46.5	53.0	59.5	55.9	62.3	68.6	59.7	64.0	68.3
3000h		35.4	41.9	48.4	41.5	47.8	54.2	42.7	47.0	51.3
4000h		29.8	36.3	42.8	34.3	40.6	47.0	34.2	38.5	42.8
5000h		26.4	32.9	39.4	30.0	36.3	42.6	29.0	33.3	37.6
Costo Total	US$/KW-año									
1000h		80.1	86.6	93.1	99.2	105.5	111.9	110.8	115.1	119.4
2000h		93.1	106.1	119.1	111.9	124.5	137.2	119.4	128.0	136.6
3000h		106.1	125.6	145.1	124.5	143.5	162.5	128.0	140.9	153.8
4000h		119.1	145.1	171.1	137.2	162.5	187.8	136.6	153.8	171.0
5000h		132.1	164.6	197.1	149.9	181.5	213.2	145.2	166.7	188.2

Nota: Se considera 12% como tasa de descuento para el cálculo de valores anualizados y futuros.

PROGRAMA DE EXPANSION DE GENERACION

CARACTERISTICAS DE PLANTAS

A) CARACTERISTICAS DE PLANTAS TERMICAS

NOMBRE	UBICACION	ESTADO	TIPO 1/	NUMERO DE UNIDADES	CARGA MINIMA	CARGA MAXIMA	CONSUMO EN CARGA MINIMA Kcal/Kwh	CONSUMO INCREM. Kcal/Kwh	COSTO COMB US$/ MMkcal	TASA DE SALIDA FORZADA	MANTEN. PREVENT. Dias	COSTOS DE O&M FIJOS US$/ Kw-mes	COSTOS DE O&M VARIAB. US$/ Mwh
Karachipampa	POTOSI	EXIST.	T.G.	1	9.0	16.4	3430	2244	397	3.9	73	0.35	0.50
Norberg	SUCRE	EXIST.	DIESEL	3	1.5	2.6	2893	1888	462	8.0	76	0.94	0.60
Worthington	SUCRE	EXIST.	DIESEL	2	1.7	2.8	3770	1774	462	8.0	76	0.94	0.60
Huaracachi	STA CRUZ	EXIST.	T.G.	5	9.0	19.5	4600	2376	380	5.0	73	0.35	0.50
Turbina a gas	STA CRUZ	FUTURO	T.G.		9.0	19.5	4600	2376	380	5.0	73	0.35	0.50
Ciclo Combinado	STA CRUZ	FUTURO	T.G.V.		12.0	59.0	3024	2076	380	7.8	73	0.80	0.50

B) CARACTERISTICAS DE PLANTAS HIDROELECTRICAS

NOMBRE	CAPACIDAD INSTALADA (Mw)	FECHA ENTRADA OPERACION	-1r CUATRIMESTRE- GENERAC. PROMEDIO (Gwh)	-1r CUATRIMESTRE- POTENCIA FIRME (Mw)	-2o CUATRIMESTRE- GENERAC. PROMEDIO (Gwh)	-2o CUATRIMESTRE- POTENCIA FIRME (Mw)	-3r CUATRIMESTRE- GENERAC. PROMEDIO (Gwh)	-3r CUATRIMESTRE- POTENCIA FIRME (Mw)	-4o CUATRIMESTRE- GENERAC. PROMEDIO (Gwh)	-4o CUATRIMESTRE- POTENCIA FIRME (Mw)	GENERAC. PROMEDIO ANUAL (Gwh)
Exist.(grandes)	235.0		328.8	231.4	313	217.4	299.2	217.4	289.6	231.4	1230.6
Exist.(pequenas)	29.0		52	29	49	29	40	29	50	29	191
San Jose Fase I	84.6	1994	170.3	84.6	151.3	84.6	149.6	84.6	166.4	84.6	637.6
San Jose Fase II	42.3	1994	86.3	42.3	36.4	42.3	32.5	42.3	26.5	42.3	181.7
Sakhahuaya	76.0	1992	142.4	76	76.8	76	76.9	76	86	76	382.1
Molineros	79.0	1997	110.6	79	111.5	79	118.1	79	112	79	452.2
Palillada	110.0	1996	204.8	110	121.6	110	106.5	110	127.1	110	560
FaseI (Cuticucho/ Santa Rosa/Zongo)	20.4	1991	29.1	19	20	19	15.7	19	29.6	19	94.4
FaseII (Tiquimani/ Botijlaca)	13.0	1992	6.8	13	9.1	12	10.4	12	7	13	33.3
Fase III (Huaji)	28.0	1992	47.4	28	34	20	27.3	20	48.3	28	157

1/ T.G.= turbina a gas; T.G.V.= Combinacion de turbinas a gas y vapor.

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PROGRAMA DE EXPANSION DE GENERACION

A) EXPANSION HIDROELECTRICA

AÑO	DEMANDA MAXIMA (MW)	1/ PROGRAMA DE EXPANSION	CAPACIDAD INSTALADA (MW)	2/ RESERVA (%)	INVERSION MMUS$	VALOR RESIDUAL MMUS$	3/ COSTO COMB MMUS$	COSTO O&M MMUS$	COSTO TOTAL MMUS$
1987	335.5		405.0	21%			0.00	1.87	1.87
1988	358.1		424.5	19%			0.01	1.87	1.88
1989	385.7		424.5	10%			0.03	1.87	1.90
1990	414.7	1 TG	444.0	7%	8.50	0.96	8.30	2.78	18.63
1991	443.5	1 TG +Fase I	482.5	9%	27.79	5.56	8.98	3.01	34.22
1992	473.1	Fase III	502.5	6%	43.39	11.03	8.52	3.17	44.05
1993	505.0	Sakhahuaya	578.5	15%	156.69	44.66	5.31	3.52	120.86
1994	539.4		578.5	7%	0.00	0.00	7.33	3.59	10.92
1995	576.5	Fase II+San Jose I- 1TG	655.6	14%	149.93	53.74	1.27	3.77	101.24
1996	615.4	- 1 TG	636.1	3%	0.00	0.00	3.30	3.76	7.06
1997	657.0	San Jose II	678.4	3%	52.56	23.68	4.14	4.04	37.06
1998	701.3	Palillada- 1 TG	768.9	10%	198.45	100.20	1.19	4.51	103.95
1999	748.6		768.9	3%	0.00	0.00	3.54	4.59	8.13
2000	799.2	Molineros - 1 TG	828.4	4%	153.76	97.52	1.12	4.91	62.26
2001	799.2		828.4	4%	0.00	0.00	1.12	4.91	6.02
2002	799.2		828.4	4%	0.00	0.00	1.12	4.91	6.02
2003	799.2		828.4	4%	0.00	0.00	1.12	4.91	6.02
		Valor Actual Neto 4/			297.48	113.58	26.12	23.24	233.27

1/ TG:Turbina a gas; Fase I: Cuticucho, Santa Rosa y Zongo; Fase II: Tiquimani y Botijlaca; Fase III: Huaji
2/ capacidad firme de reserva sobre la demanda maxima.
3/ Precio del Gas: 1.0 US$/MPC.
4/ Tasa de descuento: 12%

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

PROGRAMA DE EXPANSION DE GENERACION

B) EXPANSION TERMOELECTRICA

AÑO	DEMANDA MAXIMA (MW)	1/ PROGRAMA DE EXPANSION	CAPACIDAD INSTALADA (MW)	2/ RESERVA (%)	INVERSION MMUS$	VALOR RESIDUAL MMUS$	3/ COSTO COMB MMUS$	COSTO O&M MMUS$	COSTO TOTAL MMUS$
1987	335.5		405.0	21%	0.00		0.00	1.87	1.87
1988	358.1		424.5	19%	0.00		0.01	1.87	1.88
1989	385.7		424.5	10%	0.00		0.03	1.87	1.90
1990	414.7	1 TG	444.0	7%	8.50	0.96	8.30	2.78	18.63
1991	443.5	2 TG	483.0	9%	17.00	2.38	10.35	3.01	27.98
1992	473.1	2 TG	522.0	10%	17.00	2.90	12.32	3.25	29.67
1993	505.0	2 TG	561.0	11%	17.00	3.49	14.57	3.49	31.58
1994	539.4	2 TG	600.0	11%	17.00	4.14	16.57	3.73	33.17
1995	576.5	4 TG-1 TG	658.5	14%	34.00	9.75	18.89	3.94	47.08
1996	615.4	4 TG-1 TG	717.0	17%	34.00	11.39	21.36	4.27	48.24
1997	657.0	2 TG	756.0	15%	17.00	6.61	23.77	4.53	38.69
1998	701.3	4 TG-1 TG	814.5	16%	34.00	15.13	26.41	4.88	50.16
1999	748.6	3 TG	873.0	17%	25.50	13.19	29.31	5.24	46.86
2000	799.2	4 TG-1 TG	931.5	17%	34.00	20.17	32.31	5.60	51.74
2001	799.2		931.5	17%	0.00	0.00	32.31	5.60	37.92
2002	799.2		931.5	17%	0.00	0.00	32.31	5.60	37.92
2003	799.2		931.5	17%	0.00	0.00	32.31	5.60	37.92
		Valor Actual Neto 4/			98.38	30.01	92.30	24.50	185.17

1/ TG:Turbina a gas; Fase I: Cuticucho, Santa Rosa y Zongo; Fase II: Tiquimani y Botijlaca; Fase III: Huaji
2/ capacidad firme de reserva sobre la demanda maxima.
3/ Precio del Gas: 1.0 US$/MPC.
4/ Tasa de descuento: 12%

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PROGRAMA DE EXPANSION DE GENERACION

A) EXPANSION MIXTA TERMO-HIDROELECTRICA

AÑO	DEMANDA MAXIMA (MW)	1/ PROGRAMA DE EXPANSION	CAPACIDAD INSTALADA (MW)	2/ RESERVA (%)	INVERSION MMUS$	VALOR RESIDUAL MMUS$	3/ COSTO COMB MMUS$	COSTO O&M MMUS$	COSTO TOTAL MMUS$
1987	335.5		405.0	21%	0.00		0.00	1.87	1.87
1988	358.1		424.5	19%	0.00		0.01	1.87	1.88
1989	385.7		424.5	10%	0.00		0.03	1.87	1.90
1990	414.7	1 TG	444.0	7%	8.50	0.96	8.30	2.78	18.63
1991	443.5	1 TG+ Fase I	482.5	9%	27.79	5.56	8.98	3.01	34.22
1992	473.1	1 TG+ Fase II	514.0	9%	21.59	4.78	10.37	3.22	30.40
1993	505.0	2 TG	553.0	10%	17.00	3.49	12.67	3.46	29.65
1994	539.4	2 TG	592.0	10%	17.00	4.14	14.96	3.70	31.52
1995	576.5	San Jose I - 1 TG	657.1	14%	136.85	49.05	8.05	3.77	99.62
1996	615.4	San Jose II - 1 TG	679.9	10%	52.56	21.12	7.90	3.97	43.31
1997	657.0	1 TG+Fase III	719.4	9%	51.89	22.85	8.40	4.21	41.66
1998	701.3	Sakhauhaya - 1 TG	775.9	11%	156.69	79.12	6.51	4.53	88.61
1999	748.6	Palillada	885.9	18%	198.45	112.31	3.56	5.09	94.79
2000	799.2	- 1 TG	866.4	8%	0.00	0.00	6.10	5.10	11.19
2001	799.2		866.4	8%	0.00	0.00	6.10	5.10	11.19
2002	799.2		866.4	8%	0.00	0.00	6.10	5.10	11.19
2003	799.2		866.4	8%	0.00	0.00	6.10	5.10	11.19
		Valor Actual Neto 4/			239.17	96.92	44.47	23.68	210.42

1/ TG:Turbina a gas; Fase I: Cuticucho, Santa Rosa y Zongo; Fase II: Tiquimani y Botijlaca; Fase III: Huaji
2/ capacidad firme de reserva sobre la demanda maxima.
3/ Precio del Gas: 1.0 US$/MPC.
4/ Tasa de descuento: 12%

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

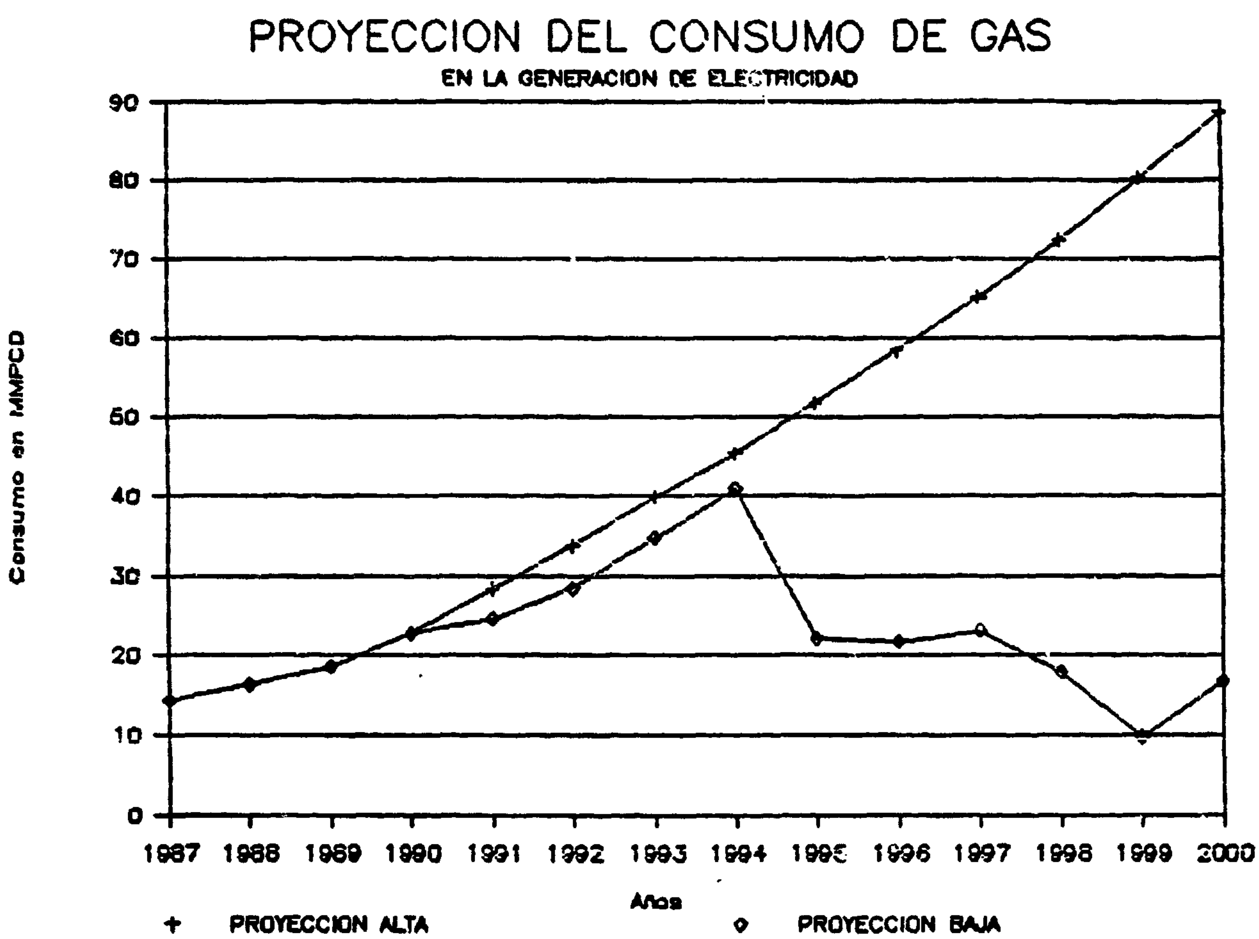
PRECIO DE INDIFERENCIA DEL GAS NATURAL
PARA LA GENERACION DE ELECTRICIDAD

	EXPANSION HIDRO				EXPANSION TERMO				EXPANSION MIXTA			
	INVERSION	VALOR RESIDUAL	CONSUMO COMBUST	COSTO O&M	INVERSION	VALOR RESIDUAL	CONSUMO COMBUST	COSTO O&M	INVERSION	VALOR RESIDUAL	CONSUMO COMBUST	COSTO O&M
	MMUS$	MMUS$	MMPC	MMUS$	MMUS$	MMUS$	MMPC	MMUS$	MMUS$	MMUS$	MMPC	MMUS$
1987			5239.2	1.87	0.00		5239.2	1.87	0.00		5239.2	1.87
1988			5957.2	1.87	0.00		5957.2	1.87	0.00		5957.2	1.87
1989			6752.5	1.87	0.00		6752.5	1.87	0.00		6752.5	1.87
1990	8.50	0.96	8299.2	2.78	8.50	0.96	8299.2	2.78	8.50	0.96	8299.2	2.78
1991	27.79	5.56	8977.9	3.01	17.00	2.38	10345.4	3.01	27.79	5.56	8977.9	3.01
1992	43.39	11.03	8515.3	3.17	17.00	2.90	12320.7	3.25	21.59	4.78	10372.0	3.22
1993	156.69	44.66	5306.1	3.52	17.00	3.49	14574.0	3.49	17.00	3.49	12674.6	3.46
1994	0.00	0.00	7332.8	3.59	17.00	4.14	16574.5	3.73	17.00	4.14	14958.5	3.70
1995	149.93	53.74	1267.7	3.77	34.00	9.75	18890.4	3.94	136.85	49.05	8050.2	3.77
1996	0.00	0.00	3300.0	3.76	34.00	11.39	21358.6	4.27	52.56	21.12	7898.7	3.97
1997	52.56	23.68	4141.4	4.04	17.00	6.61	23770.8	4.53	51.89	22.85	8404.9	4.21
1998	198.45	100.20	1186.4	4.51	34.00	15.13	26407.7	4.88	156.69	79.12	6511.4	4.53
1999	0.00	0.00	3540.5	4.59	25.50	13.19	29310.5	5.24	198.45	112.31	3563.8	5.09
2000	153.76	97.52	1117.4	4.91	34.00	20.17	32314.1	5.60	0.00	0.00	6097.3	5.10
2001	0.00	0.00	1117.4	4.91	0.00	0.00	32314.1	5.60	0.00	0.00	6097.3	5.10
2002	0.00	0.00	1117.4	4.91	0.00	0.00	32314.1	5.60	0.00	0.00	6097.3	5.10
2003	0.00	0.00	1117.4	4.91	0.00	0.00	32314.1	5.60	0.00	0.00	6097.3	5.10
NPV (12%)	297.5	113.6	41148.5	23.2	98.4	30.0	107330.4	24.5	239.2	96.5	59504.0	23.7

CALCULO DEL PRECIO DE INDIFERENCIA

		EXPANSION HIDRO	EXPANSION TERMO	EXPANSION MIXTA
VAN (Capital+O&M)	MMUS$	207.1	92.9	165.9
VAN (consumo de gas)	MMPC	41148.5	107330.4	59504.0
Consumo maximo de gas	MMPCD	24.6	88.5	41.0
Precio del gas (US$/MPC)			1.7	2.2

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM



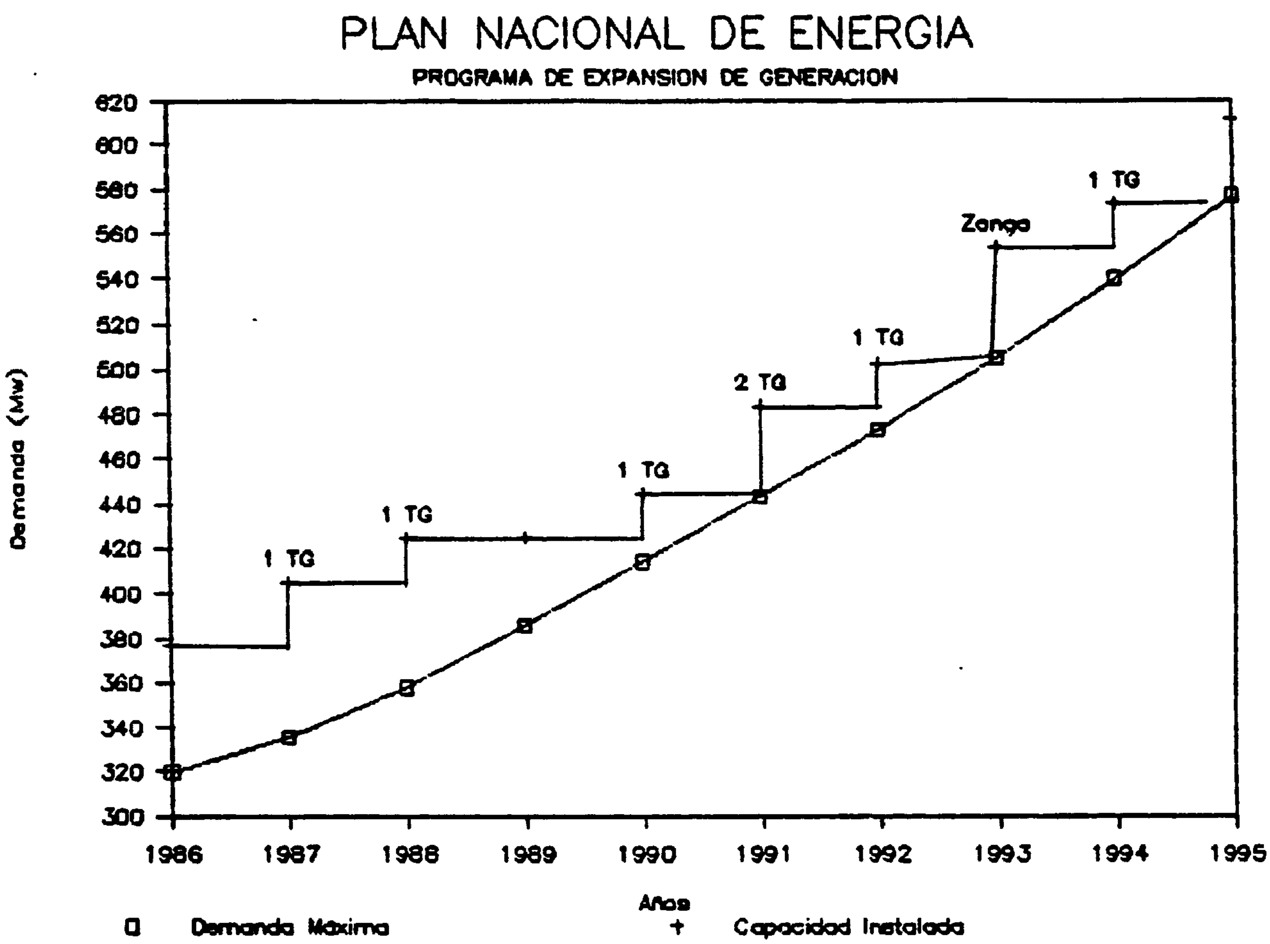
PROGRAMA DE EXPANSION PARA EL CALCULO DEL COSTO INCREMENTAL

SISTEMA C-N-S-E

REQUERIMIENTO BRUTO				GENERACION PROMEDIO (GWH)				CAPACIDAD FIRME (MW)				BALANCE		
AÑO	ENERGIA	CAPACIDAD	PROYECTOS NUEVOS		TERMO				TERMO			CAPACIDAD		ENERGIA
	GWH	MW		HIDRO	EXIST.	NUEVA	TOTAL	HIDRO	EXIST.	NUEVA	TOTAL	MW	%	GWH
1986	1517.1	319.7		1421	630		2051	251	126		377			
1987	1589.1	335.5	Turbina a gas (1)	1421	675	98	2194	251	135	20	405			
1988	1688.7	358.1	Turbina a gas (1)	1421	675	195	2291	251	135	39	425			
1989	1810.4	385.7		1421	675	195	2291	251	135	39	425			
1990	1937.3	414.7	Turbina a gas (1)	1421	675	293	2369	251	135	59	444	29.3	7%	451
1991	2068.8	443.5	Turbina a gas (2)	1421	675	488	2584	251	135	98	483	39.5	9%	515
1992	2204.4	473.1	Turbina a gas (1)	1421	675	585	2681	251	135	117	503	29.4	6%	477
1993	2350.0	505.0	Rio Zongo	1706	675	585	2966	302	135	117	554	48.5	10%	616
1994	2507.1	539.4	Turbina a gas (1)	1706	675	683	3063	302	135	137	573	33.6	6%	556
1995	2676.3	576.5	Turbina a gas (2)	1706	675	878	3258	302	135	176	612	35.5	6%	582

Nota:
Todos los datos corresponden al Sistema Interconectado C-N-S-E asumiendo un factor de diversidad de 1.025 .

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM



BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

COSTO PROMEDIO INCREMENTAL DE GENERACION

	INVERSION					COSTO	COSTO COMBUSTIBLE 4/			COSTO	GENERAC	GENERAC	DEMANDA	DEM MAX	COSTO 5/
	ZONGO EXP	STA CRUZ GAS	TOTAL	ANUAL 1/	ACUM 2/	O&M INC 3/	GENERAC (GWH)	COSTO TOTAL	COSTO INC	TOTAL	BRUTA (GWH)	INC (GWH)	MAXIMA (MW)	INC (MW)	PROMEDIO MILLS/KWH
							357	4.64			1517.10		319.7		
1987		7.42	7.42	0.99	0.99	0.15	403	5.24	0.59	1.73	1589.10	72.00	335.5	15.8	24.09
1988		8.50	8.50	1.14	2.13	0.32	458	6.10	1.46	3.90	1688.70	171.60	358.1	38.4	22.76
1989			0.00	0.00	2.13	0.32	517	7.00	2.36	4.81	1810.40	293.30	385.7	66.0	16.39
1990	12.20	8.50	20.70	2.62	4.75	0.61	516	6.71	2.07	7.43	1937.30	420.20	414.7	95.0	17.68
1991	24.40	17.00	41.40	5.24	9.98	1.19	648	8.42	3.78	14.96	2068.80	551.70	443.5	123.8	27.11
1992	18.30	8.50	26.80	3.36	13.34	1.55	783	10.18	5.54	20.43	2204.40	687.30	473.1	153.4	29.73
1993	6.10		6.10	0.74	14.08	1.61	644	8.37	3.73	19.42	2350.00	832.90	505.0	185.3	23.32
1994		8.50	8.50	1.14	15.22	1.78	801	10.41	5.77	22.77	2507.10	990.00	539.4	219.7	23.00
1995		17.00	17.00	2.28	17.50	2.12	970	12.61	7.97	27.59	2676.30	1159.20	576.5	256.8	23.80
VAN(i)	33.63	42.32	75.95		38.37	4.67			16.52	59.57		2532.78			

COSTO PROMEDIO INCREMENTAL (mills/Kwh) 23.52 6/

Notas:

Tasa de descuento= 12.0%

Precio gas (US$/MPC) 1.0

1/ Valores anualizados de inversión asumiendo 20 años para turbinas a gas y 40 años para plantas hidroeléctricas.
2/ Valores acumulados de la inversion anualizada.
3/ Costos de O&M calculados como 1% y 4% de la inversión acumulada en plantas hidroelectricas y turbinas a gas respectivamente.
4/ Costo de combustible para turbinas a gg=as asumiendo un consumo de 12.55 FC/KWH y el precio del gas mencionado.
5/ Costos Promedio basados en los costos totales acumulados y los valores de generación incremental.
6/ Costo Promedio Incremental basado en los Valores Actuales Netos del costo total y la generación incremental.

OPERACION DE PLANTAS TERMICAS

SISTEMA INTERCONECTADO C-N-S-E

CONCEPTO	1987		1988		1989		1990		1991		1992		1993		1994		1995	
	LLUV	SECO	LLUV	SECO	LLUV	SECO	LLUV	SECO	LLUV	SECO	LLUV	SECO	LLUV	SECO	LLUV	SECO	LLUV	SECO
Generacion Bruta requerida (GWH)	488	692	502	718	523	754	550	1130 2/	829	1207	885	1286	943	1371	1005	1462	1073	1561
Pequeñas Existentes (Hidro)	85	106	85	106	85	106	85	106	85	106	85	106	85	106	85	106	85	106
Subtotal	404	586	417	612	439	648	465	1024	744	1101	800	1180	858	1265	921	1356	988	1455
Probabilidad de que la generacion hidroeléctrica exceda los requerimientos 1/	1	1	0.9	1	0.85	1	0.8	0	0	0	0	0	0	0	0	0	0	0
Probabilidad de que se requiera generacion termica	0	0	0.1	0	0.15	0	0.2	1	1	1	1	1	1	1	1	1	1	1

1/ Calculada en base a la curva de distribución de probabilidades de la generacion hidroeléctrica siguiente.
2/ Supone que la interconexión Central Oriental inicia su operacion al principio de la época seca de 1990.

PROBAB EXCED	EPOCA LLUVIOSA					EPOCA SECA				
	EXIST		ZONGO	TOTAL		EXIST		ZONGO	TOTAL	
	MW	GWH	MW	MW	GWH	MW	GWH	MW	MW	GWH
10%	158	571	42	199	722	158	809	30	188	963
20%	145	525	40	185	671	148	758	29	177	907
30%	143	516	40	182	660	143	732	29	171	879
40%	143	516	39	182	658	142	729	28	170	875
50%	139	504	39	178	644	142	728	28	170	872
60%	139	504	38	177	643	141	724	28	169	868
70%	138	500	38	176	638	141	722	27	167	860
80%	128	464	38	166	600	140	719	27	167	856
90%	115	417	37	152	550	131	674	26	157	809

Notas:
PROBAB EXCED: Probabilidad que el valor indicado sea excedido.
EXIST: Grandes Plantas Hidroeléctricas existentes (Corani, Santa Isabel y Rio Zongo).
La generacion de las plantas existentes toma en cuenta los efectos de la regulación del reservorio.
Todos los valores en MW indican Potencia Promedio
ZONGO: Expansión propuesta de las Plantas del Rio Zongo.

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

COSTO PROMEDIO INCREMENTAL DE TRANSMISION

AÑO	INVERSION (MMUS$) INTERC C - E 4/	CHAPARE 7/	S/E I 8/	S/E II 9/	TOTAL	ANUAL 1/	ACUM 2/	O&M INC 3/	TOTAL ANUAL	DEMANDA MAXIMA (MW)	DEM MAX INC (MW)	COSTO PROMEDIO US$/KW 5/
										319.7		
1987	9.9	0.9	0.8	0.1	11.7	1.4	1.4	0.2	1.7	335.5	15.8	106.4
1988	7.4	0.3		0.6	8.3	1.0	2.5	0.4	2.9	358.1	38.4	74.8
1989	7.4			0.9	8.3	1.0	3.5	0.6	4.1	385.7	66.0	61.7
1990				1.2	1.2	0.1	3.6	0.6	4.2	414.7	95.0	44.6
1991				1.2	1.2	0.1	3.8	0.6	4.4	443.5	123.8	35.5
1992				1.0	1.0	0.1	3.9	0.6	4.5	473.1	153.4	29.6
1993				0.6	0.6	0.1	4.0	0.6	4.6	505.0	185.3	25.0
1994				0.2	0.2	0.0	4.0	0.6	4.7	539.4	219.7	21.2
1995					0.0	0.0	4.0	0.6	4.7	576.5	256.8	18.2
VAN(i)	19.9	1.0	0.7	3.5	25.2	3.1	17.1	2.8	19.8		565.2	288.4

COSTO PROMEDIO INCREMENTAL (US$/Kw-año) 35.1 6/

Notas:

TASA DE DESCUENTO= 12.0%

PRECIO DEL GAS (US$/MPC) 1.0

1/ Valores anualizados de inversión asumiendo 30 años de vida util.
2/ Valores acumulados de la inversión anualizada.
3/ Costos de O&M calculados como 2% de los valores de inversión acumulada.
4/ Linea de Interconexión Central Este.
5/ Costos Promedio basados en los costos totales acumulados y los valores de demanda máxima incremental.
6/ Costo Promedio Incremental basado basado en los Valores Actuales Netos de del costo total y la demanda máxima i
7/ Linea de transmisión al Chapare.
8/ Expansión de subestaciones Fase I.
9/ Expansión de subestaciones Fase II.

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

COSTOS MARGINALES DE ELECTRICIDAD

(GENERACION Y TRANSMISION)

A) COSTO MARGINAL DE ENERGIA (MILLS/KWH)

PERIODO	SISTEMA C-N-S 1/			SISTEMA ESTE	
	GENERACION	TRANSMIS.	SUBTRANSM.	GENERACION	TRANSMIS.
1988-1989	0.0	0.0	0.0	13.5	13.6
1990-1995	13.5	13.9	14.5		
Pérdidas		3.1%	4.1%		0.5%

B) COSTO MARGINAL DE CAPACIDAD (US$/KW-MES)

CONCEPTO/NIVEL		SISTEMA C-N-S-E		
		GENERATION	TRANSMIS.	SUBTRANSM.
Generación	5.8	5.8	6.1	6.3
Transmisión	2.9		3.0	3.2
Subtransmisión	11.5			11.5
Pérdidas			4.0%	4.1%

Nota:
1/ Los valores corresoonden al sistema C-N-S-E luego de la puesta en operación de la linea de interconexión Central-Este.

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

COSTO PROMEDIO INCREMENTAL DE DISTRIBUCION (ELFEC) 4/

AÑO	INVERSION (MMUS$) TOTAL	INVERSION (MMUS$) ANUAL 1/	INVERSION (MMUS$) ACCUM 2/	COSTO INC O&M 3/	COSTO TOTAL	DEMANDA MAXIMA (MW)	DEM MAX INC (MW)	COSTO PROMEDIO US$/KW-AÑO
						45.3		
1987	2.41	0.31	0.31	0.06	0.37	48.1	2.8	131.3
1988	2.29	0.29	0.60	0.12	0.72	51.2	5.9	121.5
1989	1.46	0.19	0.79	0.15	0.94	54.4	9.1	103.2
1990	1.46	0.19	0.97	0.19	1.16	57.8	12.5	93.0
1991	1.71	0.22	1.19	0.23	1.42	61.5	16.2	87.8
1992	1.44	0.18	1.37	0.27	1.64	65.3	20.0	82.1
1993	1.59	0.20	1.58	0.31	1.88	69.4	24.1	78.2
1994	1.53	0.20	1.77	0.35	2.12	73.8	28.5	74.3
1995	1.89	0.24	2.01	0.39	2.41	78.5	33.2	72.5
VAN(i)	9.66		5.45	1.07	6.52		75.33	

COSTO PROMEDIO INCREMENTAL (US$/KW-año)	86.6
COSTO PROMEDIO INCREMENTAL (US$/KW)	679.0

Notas:

Tasa de descuento= 12.0%

1/ Valores anualizados de inversión asumiendo 25 años de vida util.
2/ Valores acumulados de la inversión anualizada.
3/ Costos de O&M calculados como 2.5% de la inversión acumulada.
4/ Datos extractados del programa de inversiones preparado por ELFEC en 1986 excluyendo inversiones en subestaciones.

COSTOS MARGINALES DE ELECTRICIDAD

(Distribución - ELFEC)

A) COSTO MARGINAL DE CAPACIDAD (US$/kw-mes)

CONCEPTO\NIVEL	1/	ELFEC 2/	MV(10&25KV) 3/	BV (220V) 3/
Generación y Transmisión	9.1	8.9	9.1	9.9
MV (10 Kv & 25 Kv)	3.4		3.5	3.8
BV (220 V)	5.5			6.2 7/
TOTAL			12.6	19.8
Pérdidas			2.7%	8.3%

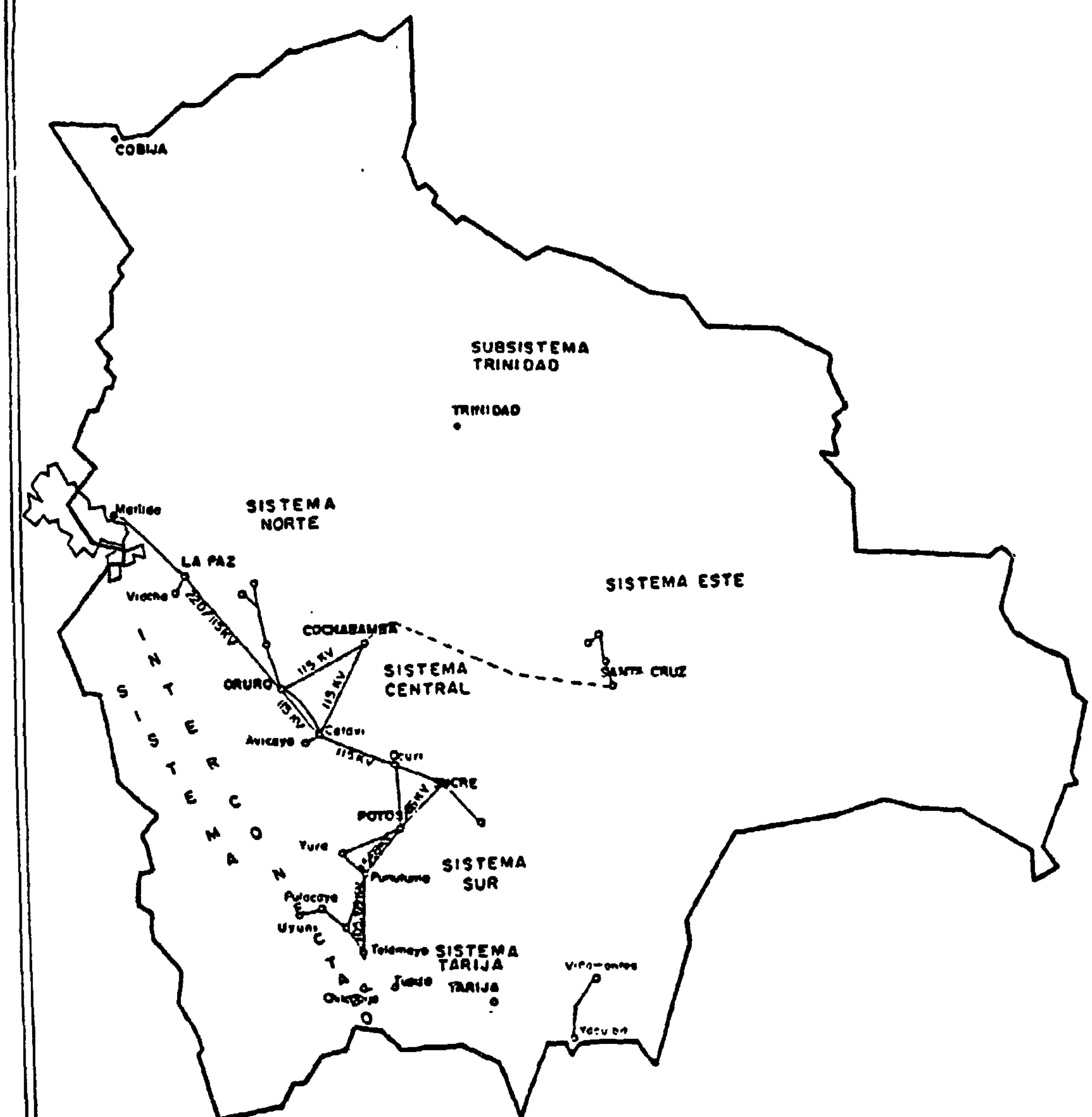
B) COSTO MARGINAL DE ENERGIA (mills/kwh)

CONCEPTO\NIVEL	ELFEC 4/	MV(10&25KV) 3/	BV (220V) 3/
Costo de Energía (mills/kwh)	13.9	14.2	15.0
Pérdidas		2.0%	5.5%

C) COSTOS MARGINALES POR CATEGORIA DE CONSUMO

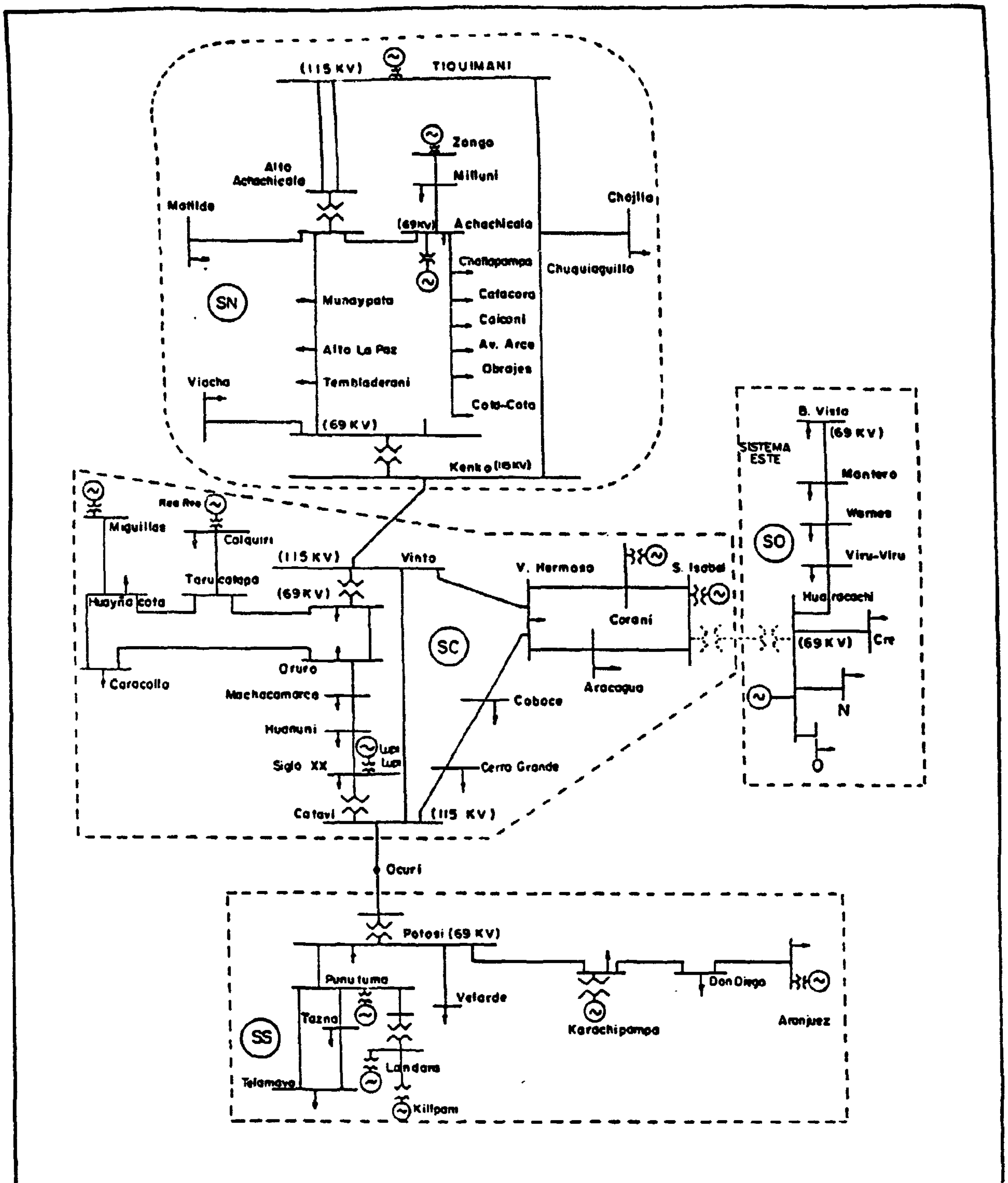
CONCEPTO\CATEGORIA	ELFEC (BLOQUE)	Industrial I3	Industrial I2 & I1	Comercial C2	Comercial C1	Residencial 8/	Alumbrado Público
nIVEL	Transmisión	Transmisión	MV	MV	BV	BV	BV
Responsabilidad en la punta	0.975	0.975	0.8	0.7	0.7	0.9	1
Costo de Capacidad(US$/kw-m)5/	8.9	8.9	10.1	8.8	13.9	17.8	19.8
Costo de Energía (mills/kwh)	13.9	13.9	14.2	14.2	15.0	15.0	15.0
Factor de Carga	0.48	0.75	0.51	0.48	0.48	0.45	0.40
Costo promedio (mills/kwh) 6/	39.3	30.1	41.2	39.3	54.5	69.2	82.8
Capacidad	25.4	16.2	27.1	25.2	39.6	54.3	67.8
Energía	13.9	13.9	14.2	14.2	15.0	15.0	15.0

Notas:
1/ Costo correspondiente al "Item de Concepto".
2/ Considera Factor de Coincidencia=0.975 .
3/ Considera pérdidas al nivel correspondiente de acuerdo con los porcentajes mostrados en la linea final de la tabla.
4/ Costo marginal de energía a nivel de transmisión.
5/ Calculado como el costo total de capacidad al nivel correspondiente, multiplicado por el valor respectivo de responsabilidad en la punta.
6/ Costo promedio calculado en base al factor de carga mostrado en la línea anterior.
7/ Las pérdidas para los sistemas primario y secundario fueron aplicadas a este caso, pues el costo incremental del sistema secundario fue estimado en base a la demanda final en las subestaciones.
8/ Los valores correspondientes a la categoría residencial, fueron estimados en conjunto, en base a las características del alimentador Norte. El valor de 0.9 de responsabilidad en la punta, se adopta considerando que la curva de carga de esta categoría, coincide con la demanda máxima del sistema.



BOLIVIA
PLAN NACIONAL DE ENERGIA
MEM - PNUD - BM

SISTEMAS ELECTRICOS PRINCIPALES
MAPA DE UBICACION



BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH - PNUD - BM

DIAGRAMA UNIFILAR DE LAS INSTALACIONES DE TRANSMISION DEL SISTEMA INTERCONECTADO

RURAL ENERGY

Geographical Divisions

The nine political departments of Bolivia comprise a diverse range of social, cultural and physical resources. The traditional geographical descriptions of Bolivia divide the country into three physical regions that share climatological and geographical attributes--the Altiplano, the Valleys, and the Tropics. Even within these areas, clear political, social, and cultural differences exist. The contrasts in climate and availability of energy resources between the high valleys and the low valleys (Yungas) are notable. The Tropics consist of regions as diverse as the Amazonas department of Pando and the dry Chaco in the southern part of the department of Santa Cruz. For the purposes of the National Energy Plan of Bolivia, rural energy strategy will be defined on the basis of the three geographical regions defined above. Specific variations in energy issues within each of the three regions will be noted where appropriate. The data on energy demand and supply are primarily received according to department, therefore departments are grouped into three regions, even though some departments may contain elements of all three regions. Where possible, data were reallocated to correspond with the three regions.

Table 1: DEPARTMENTS BY REGION

Region	Departments
Altiplano	La Paz
	Oruro
	Potosi
Valleys	Cochabamba
	Chuquisaca
	Tarija
Tropics	Santa Cruz
	Beni
	Pando

Definition of Rural Areas. No clear lines distinguish rural areas from urban or smaller urban (larger rural) centers. Rural areas in the Altiplano tend to consist of subsistence farms. Valley rural areas are characterized by small farming plots. Rural areas in the Tropics are dedicated in general to cattle-raising, with some commercial farms. For the purposes of collecting data and developing regional energy plans, the National Statistical Institute (INE) defines rural areas as towns containing fewer than 2,000 inhabitants. The INE estimates that the rural population in Bolivia in 1985 was 55% of the total national population. The INE criteria will, of necessity, be used in estimating rural energy consumption in the three regions.

Altiplano

Overview

The Altiplano constitutes an estimated 19% of the national superficial area. Most rural residents of the Altiplano, which is estimated at one-half of the total national rural population, live at an altitude of about 4,000 meters. Rural areas in the Altiplano are dominated by subsistence farming. A recent survey estimated that over 36% of the farms in the Altiplano contained less than one hectare of land (MACA-USAID, 1978). Rural inhabitants in the department of Potosi, whose lands have suffered severe droughts in recent years, often supplement their inadequate land resources by working part-time for the mines. The mine closures begun in the early 1980s, due to declining international markets for Bolivia's metal products, have resulted in abandonment of agricultural lands by rural farmers and caused them to migrate to urban centers, principally La Paz.

High precipitation in the Lake Titicaca region over the last two to three years raised the level of the lake. The resulting high flows into the Desaguadero River, which drains Lake Titicaca and feeds Lake Poopo in Oruro, caused the salt water of Lake Poopo to flood and damage farmland adjacent to that lake, a process which is continuing. These circumstances have exacerbated the existing difficulties of subsistence farming in the departments of Oruro and Potosi.

The inadequacies of the present transportation networks, which consist for the most part of gravel roads and poorly maintained dirt roads, is a major impediment to development and distribution of commercial energy supplies in the rural Altiplano and other areas in Bolivia. Energy supplies for most households are poor--the consumption of fuelwood per inhabitant in the Altiplano is the lowest of the three regions. Electricity supplies from 0-10% of energy needs in rural areas in Altiplano provinces. The cumulative effects of deforestation and high levels of current consumption have forced families in rural areas to rely on dung and small shrubs for household cooking and heating needs.

Potable water and water for irrigation are in short supply in the Altiplano (with additional problems in Oruro) due to the contamination of the water table with salt water. The lack of irrigation has restricted increased productivity of farms in all three regions of

Bolivia. Approximately 88,800 hectares were irrigated in Bolivia in 1976. In 1986 approximately 109,000 hectares were irrigated, out of 2.9 million hectares under cultivation. In 1995, 133,280 hectares could be irrigated out of an estimated 4.1 million hectares under cultivation. Over half of the national irrigation needs are in the Altiplano.

Fuels for Cooking and Rural Industry

Fuelwood. Much of the Altiplano was deforested in the 19th century to provide fuel for the operation of the railroad from Chile to La Paz. The poor condition of the soil and the lack of irrigation in much of the Altiplano has resulted in stunted growth of fuelwood species. The principal source of fuelwood in the Altiplano is the shrub thola, with minor consumption of the shrub yareta, and quisuara (a tree species). In the 19th century, thola purportedly grew to heights of one to two meters. However, field visits showed that thola is currently collected at relatively short heights above ground of between 30 and 60 centimeters, reflecting a short growth period of only two to three years before the plant is harvested. The use of thola and dung as cooking fuels in many parts of the Altiplano reflects the increased shortage of fuels for household cooking. Rural residents generally devote one day to collecting a week's supply of thola, although in some households fuelwood is collected daily. Thola is generally collected in a radius of a few kilometers from households.

Thola burns very quickly, and thus it is not an ideal cooking fuel. In addition, as indicated above, it is relatively slow-growing, and its supply in many parts of the Altiplano is inadequate. However, in many areas in the Altiplano thola and dung are the only cooking fuels currently available. Thola is a hardy specie and has grown relatively well in the Altiplano, whereas the few experiments with imported tree species have not been successful. The growth patterns of thola in the Altiplano and its use as a cooking fuel in households deserve further study and evaluation.

Quantitative data on total available fuelwood supply in Bolivia was based on satellite studies (ERTS program, 1978). The ERTS estimates showed that approximately 51% of the superficial area of Bolivia, or almost 57 million hectares, was covered by woods in 1978, This constitutes approximately 5.211 million m^3 of wood (Von Borries, 1986). The estimated 1987 supply of fuelwood in the Altiplano is 7.2 million tons of oil equivalent (toe). 1/

Most rural households in the Altiplano use a combination of dried animal dung and fuelwood (consisting to a large extent of thola)

1/ This includes 5.9 million toe of forest and 1.2 million toe of shrubs.

for cooking fuel. Some areas in Oruro, especially near the salt lake Poopo, where there are virtually no trees or shrubs, use pure dung. Fuelwood is generally consumed in rural households in an enclosed two-pot mud "kery" stove, with no flue, usually located inside one of several living structures in a family compound. The stoves have an estimated heat efficiency of 9-14%. 2/ The stove can be constructed in various sizes, and one stove is used for burning both thola and dried dung. In general, families use their stove for two to three meals per day. Little would be gained by further improvements in stove efficiency in the Altiplano, although a study of the possible application of the Kery stove in the Valleys and Tropics, where the relatively inefficient three-stone stove is used, would be justified.

Historical fuelwood consumption in the Altiplano was estimated using data from household surveys. The survey results were confirmed where possible by visits to rural areas, of daily fuelwood consumption per person per day. 3/ For the Altiplano, an average of 2.05 kg/person/day was used. 4/ The proportion of Altiplano residents that uses predominantly fuelwood (including trees and shrubs) for cooking was approximately 47% (Saal, 1986). Consumption of fuelwood in the Altiplano was estimated at 210,808 toe, or 37.5% of the 1985 national total rural household fuelwood consumption. Fuelwood consumption was based on rural population for each year from 1980-1985 and the average rate of growth in household fuelwood consumption for the Altiplano for that period reflected the rate of population growth, or about 1.6%. Projected household demand for fuelwood in the Altiplano was derived from projected national rural population growth obtained from INE. This analysis yielded an expected demand of 245,213 toe in 1995, a 16% increase over 1985, the last year for which historical population data is available.

Energy consumption for thermal uses in rural industry consists primarily of alternatives similar to those for household cooking fuels: fuelwood, kerosene and LPG. There is relatively little small industry in rural areas in the Altiplano. One of the key small industries in rural areas in many developing countries is brickmaking. Although brick factories open occasionally in the rural Altiplano to meet periodic needs, brickmaking factories are not generally found there because virtually all structures are built with dried mud or adobe. In Oruro, especially near Lake Poopo, there are a number of lime kilns, most of which consume fuelwood, but data on consumption patterns was

---

2/ JUNAC Study.

3/ The average family interviewed on mission field trips to the Altiplano had five persons.

4/ Results from CONNAL survey of rural households in the north of the department of Potosi (1982).

unavailable. No data on industrial fuel consumption in rural areas has been collected in Bolivia, however, small rural industry probably consumed 10% of the total rural fuelwood demand in the Altiplano in 1985, or about 23,423 toe.

The annual natural growth rate of fuelwood supply (from trees) for the Altiplano was estimated at 2,620 m^3/year, or 134,982 toe/year. 5/ Based on growth rate and projected consumption for the Altiplano, the 1992 fuelwood supply was estimated at 6,766,000 toe, a decrease of 6.1% from 1987. Doubling the consumption rate to 4.00 kg/person/day resulted in 5,174,000 toe in 1992. The projections described above do not project deficits in fuelwood supply in the short term, although in the long term the supply will clearly be exhausted. 6/ As noted above, these projections do not include increases in the supply of shrubs (thola, for example), for which annual growth data were not available.

Data were sought on commercial fuelwood prices in the Altiplano. Fuelwood is, for the most part, not commercialized on a household level in the rural Altiplano. In the sparsely populated (dispersed) rural areas, wood is collected by each household for individual consumption. Field trips did reveal a few cases of commercialized fuelwood, often in small rural towns, which do not have adequate supplies of fuelwood or dung (although most small towns visited in the Altiplano used LPG and kerosene for cooking). Some bakeries in small towns use fuelwood that must be purchased, and data on the price of wood for bakeries provided most of the rural price information for fuelwood. The range of prices obtained are assumed to reflect the marginal costs of cutting and transporting wood to the place of sale.

As noted earlier, there have been no known successful wood plantation or reforestation projects in the Altiplano, except for the eucalyptus stands in the well-watered area near Lake Titicaca. Pilot projects in Oruro (eucalyptus) yielded trees with stunted growth. Sources indicate that hardier trees with faster growth rates might be

---

5/ This assumes an average density of 0.8 MT/m^3 and calorific value of .35 toe/MT. Growth rates were estimated for forests only (no data were available for estimation of shrub growth).

6/ The net growth rate in fuelwood supply in the Altiplano should decrease with diminished total fuelwood supply, leading to accelerated exhaustion of fuelwood supply. However, this was not accounted for in the estimated total projected supply due to lack of data. The projections estimated here for total fuelwood supply are, therefore, high.

suitable for the Altiplano. 7/ There is no evidence of any studies of species appropriate for use as fuelwood and capable of sustained and rapid growth in the Altiplano. A visit to a farm near Oruro did reveal an interesting pattern. Farmers in that area rotate crops every two year for six years, and then let the land lie fallow. Thola grows naturally on the fallow land and is used as fuelwood. As noted earlier, thola growth patterns should be further studied.

The opportunity cost of a hypothetical Altiplano eucalyptus plantation was estimated at about 84 mills/1,000 kcal, 8/ or 930 mills/ 1,000 kcal useful energy. 9/ These costs reflect the fact that planned plantations in the Altiplano would be, for the most part, dedicated almost to energy end uses, so that 100% of the reforestation cost can be attributed to energy. In the short term, the high opportunity cost of plantation fuelwood in the Altiplano makes it an unfavorable alternative for household cooking fuel.

Dung. Because of the short supply of fuelwood in many parts of the Altiplano, dried dung is commonly used as the primary cooking fuel. It is burned in the "Kery" stove, described earlier. Dried dung has a lower estimated calorific value than fuelwood (no laboratory measurements are available in Bolivia), and therefore a greater quantity by weight is required for the same thermal output. For the purpose of the NEP, a consumption of 2.6 kg/person/day of dried dung in the Altiplano, compared to 2.05 kg/person/day for thola. Given an estimated calorific value of 3,500 kcal/kg for Altiplano fuelwood, dried dung has an implied calorific value of 2,760 kcal/kg to meet the same thermal needs for household cooking. Using a methodology similar to that used for estimation, for the years 1980-1985, dung consumption in the Altiplano (about 95% of the estimated national dung consumption) was 152,058 toe in 1985.

7/ For example, there is a hardy species of eucalyptus that grows in parts of Australia that has been recommended as appropriate for study in the Altiplano. Another possibility is the Albezia Lophanta, which grows at altitudes of about 4,000 meters in Papua New Guinea. The Canadian International Development Agency (CIDA) is experimenting with hardy rapid-growth eucalyptus species near Lake Titicaca.

8/ This estimate was based on a 5 m^3/hectare/year yield and 3,500 kcal/kg average calorific value. For the purposes of this evaluation, it was assumed that there was no opportunity cost of wood used for fuel, because in most cases wood used as fuel is not used for other purposes (for example for forest industry products). In addition, land used for plantations is assumed to have no opportunity cost, given that most plantations are planned for land not suitable for farming or other uses.

9/ Based on 9-14% estimated efficiency for the "kery" stove.

Farmers interviewed in the department of La Paz on field visits use about half of their collected dung supply for cooking, and the other half is returned to cultivated land as fertilizer. Many farmers in the Altiplano purchase urea (rich in potassium) commercially to supplement the nitrogen-rich dung for fertilizing crops. In fuelwood-poor areas visited in Oruro, there are indications that the need for dung as a cooking fuel (because of the almost total absence of wood or shrubs appropriate as cooking fuels) is restricting its use as natural fertilizer, although no such tendency for the Altiplano as a whole was quantifiable. However, experience in other developing countries suggests that increasing energy demand in households and decreasing fuelwood supplies (indicated by the collection of small plants for fuelwood) will increase the use of dung as a fuel where other alternatives are not available. This deprives farmers of an important source of fertilizer, which would make their cultivated land more productive. 10/

Projections for dung consumption through 1992, based on expected population growth, showed a demand in 1992 of 169,642 TOE, an increase of almost 8% over the expected demand for 1987. There have been no studies in the Altiplano relating the consumption of dung as cooking fuel to nutrient (fertilizer) deprivation of farmland. Such deprivation could result in restraints on additional production of agricultural products, or, if fuelwood supplies are very low, insufficient fertilizer for present production. For the purposes of the NEP, it has been assumed that the supply of dung exactly meets demands for cooking and fertilizer, and that projected increases in dung demand will be met by increases in animal stock. This must be confirmed through further study. If there are deficits in fuelwood supply, the subsequent need for additional cooking fuel could come from dung currently used for fertilizer. Little is known regarding the relationship between agricultural productivity and necessary quantities of natural fertilizer (dung) in the Altiplano. This relationship requires further evaluation before definitive conclusions can be reached on the impacts of fuelwood shortages in the Altiplano. There is reason to believe, however, that in areas where there is a deficit of fuelwood, and where dung is used as a substitute cooking fuel, agricultural productivity will eventually suffer from deficits in supplies of natural fertilizer.

Petroleum Products. The primary petroleum products consumed in rural households, small industry, and commercial establishments in the Altiplano are LPG and kerosene. LPG is used as a cooking fuel in dispersed rural areas primarily during the rainy season, when unprotected wood or dung (usually stored uncovered outdoors) become damp. Rural towns appear to have less fuelwood or dung available, and so use greater shares of petroleum products, particularly LPG.

10/ Although no price of dung for use as a cooking fuel was available, a price of sheep dung for use as fertilizer was about 17 mills/kg. This figure was obtained in Copacabana, in the department of La Paz.

LPG and kerosene are available at YPFB distribution centers in Oruro, La Paz (including El Alto and Rio Seco), and Potosi. Delivery of LPG (usually in 10 kg bottles) and kerosene to small towns is usually undertaken by private contractors and truck owners, so that costs in rural towns include transport from the YPFB distribution centers. LPG and kerosene are also often available at the revolving regional markets. In order to obtain LPG for household cooking use, residents must travel with their empty cannisters, usually by bus, to the nearest town with available LPG. This often involves a day of travel and, in La Paz and elsewhere, long lines at the YPFB distribution centers. Rural LPG users are usually charged for transport of bottles as well. Rural cooperatives often save costs by sending a collective vehicle to markets for LPG.

Consumption in households varied from one bottle per week to one bottle per month, or 10-40 kg per month during the rainy season (December through March). Larger towns use LPG or kerosene as primary cooking fuels and therefore use larger quantities, about 30 liters of kerosene per month. In general, distribution of LPG to rural areas was not considered reliable, and delayed deliveries often leave households without energy supplies, especially in larger rural towns, which are more dependent on petroleum products.

In all areas visited in the Altiplano, kerosene delivery was reported to be regular and reliable. In the dispersed rural households, kerosene is used almost entirely for small home-made kerosene lamps, and typical consumption per household is 1 liter/month. In some households, kerosene is used to light fuelwood, increasing consumption in households visited to approximately 10 liters/month. 11/

LPG prices were very much dependent on the distance from major distribution centers. In Achacachi, 12/ for example, which is 98 km from La Paz, LPG prices ranged from US$2.85/10 kg bottle, compared to the YPFB price of US$1.43/10 kg bottle in La Paz, an implied transportation cost of about 1.5¢/km/10 kg bottle. The picture is further complicated by the way most rural residents obtain LPG (described above), making the final LPG price dependent on bus or truck fares to the nearest town or market that sells LPG. Although consumers are assumed to choose the cheapest source of LPG, this often does not occur, possibly because there are other reasons for trips to markets. The full cost of trips to markets cannot be charged to the cost of LPG if, for example, food supplies are also purchased. The long lines for LPG at YPFB distribution centers

---

11/ A Danish study of LPG (Haff and Over Gaard, 1983) estimated total national rural consumption of LPG at about 10% of the total national consumption, which would have been 196,400 barrels in 1986.

12/ Private haulers bring LPG and kerosene into Achacachi. Kerosene is sold by a distributor and LPG is sold in various shops (which also sell gas stoves).

imply further social costs. In general, however, LPG prices for most rural households are at least twice the YPFB price. Unlike LPG, kerosene was almost consistently priced at US$0.24/liter.

Charcoal. Estimates of charcoal consumption in the Altiplano, all of which is imported from the Valleys and Tropics, and from Argentina, show that most of the national production is consumed by National Metal Smelting Company (ENAF) as a reducing agent, mostly in the Vinto Smelter in Oruro, with relatively limited uses as a cooking fuel. Charcoal is available in markets in the major cities, and use is limited to grills in restaurants. 13/

Supplies of charcoal at urban markets appear to be ample. Prices obtained by NEP inquiries are summarized below. These prices are more than double the unit price for charcoal delivered in bulk to the smelters in Oruro.

Table 2: CHARCOAL PRICES IN ALTIPLANO MARKETS

Market	Price	Approximate Distance From Source
	(US$/kg)	(kms)
Mercado Rodriguez (La Paz)	0.36	164
Rio Seco	0.42	164
Oruro	0.48	n/a

Source: NEP estimates.

Biogas. The MEH signed an agreement with OLADE in 1980 to build nine biodigestors in Bolivia, three in each of the Departments of La Paz (Altiplano), Cochabamba (Valleys), and Beni (Tropics), with the main objective of promoting technology transfer. The plan called for each department to have one of each of the following biodigestor designs: China, OLADE-Guatemala, and Mexican. INER, the predecessor of COFER, was selected to coordinate the program in Bolivia. From 1980, construction of about 23 biodigestors was begun in the various regions of Bolivia by various public organizations and private concerns, including the OLADE-MEH project, with various stages of completion and no apparent coordination.

13/ Charcoal is available by bags of approximately 2.5 kg, or cans of approximately 4.5-5.5 kg. The charcoal in the La Paz markets are brought from Alto Beni and Carrasco.

Only two biodigestors were built in the Altiplano, a modified OLADE-Guatemala in Oruro, and a Chinese biodigestor in Oronco (department of Oruro). The Altiplano, with average annual temperatures between 7°C and 11°C, is less than optimal for biodigestor operation. 14/ A solar hot water heater would be required to maintain temperatures in the biodigestor, with additional possible need for insulation of the biodigestor walls. 15/ These entail extra costs (estimated at US$500 or more) for the Altiplano biodigestor. The Altiplano is, in one way, uniquely suited for biogas digestors, in that dung is currently being collected in enclosed corrals where animals are kept each night, for cooking fuel and fertilizer. There is no consistent collection of dung in the Valleys and Tropics.

At approximately 3 m^3 gas production/day, or .125 m^3/hour, the gas from biodigestors could probably satisfy cooking and lighting needs. The opportunity cost for biogas from a one-family biodigestor was estimated at 51 mills/1,000 kcal, or 102 mills/1,000 kcal useful energy. 16/ With an additional $500 capital cost for a solar heater, the opportunity cost of biogas is 57 mills/1,000 kcal, or 114 mills/1,000 kcal useful energy. A cheaper alternative would be construction of a greenhouse over the biodigestors for maintaining operating temperatures.

Because of the lack of data on existing biodigestors in the Altiplano and absence of a cohesive pilot program, the technology cannot be recommended for commercialization in the short term. However, the rising costs of petroleum products, especially in remote areas, suggest that biogas could be an economically competitive technology in the future, if technological and social barriers can be removed. This warrants the creation of a well-organized pilot program and feasibility study for the region.

Household Lighting

Kerosene. The useful energy price of kerosene for lighting in rural households in the Altiplano was estimated at 311 mills/1,000 kcal, with an opportunity cost of 281 mills/1,000 kcal, based on an estimated efficiency for the crude household kerosene lamps most commonly used ("mecheros") of 8.6%.

Electricity. Electricity is the only current alternative to kerosene for lighting in rural areas. Rural electric lines in the

---

14/ Optimal temperatures for biodigestor reactions range from 25-35°C.

15/ GTZ, in coordination with the University of Cochabamba, is building a small experimental biodigestor with a solar heater.

16/ This assumed a biogas efficiency of about 50%.

Altiplano, where they exist, are underutilized. Discussions with rural residents cited high connection costs, estimated at US$400-800 17/ (in dispersed areas; connection costs in towns would be lower), as a barrier to electric service. Rural towns with diesel generating units supply power for illumination and little else (most of these units run approximately 3-4 hours every night). A great number of these units have been shut down due to high expenses. The marginal costs of rural electricity was estimated at between 120 and 370 mills/kWh, or 139-430 mills/ 1,000 kcal. However, for most homes in rural areas, electricity is simply not available, and for the few rural areas where there is a power line, connection costs are prohibitive. The opportunity cost of electricity for rural households indicates that it may be more costly than kerosene. Furthermore, expansion of electric grids to rural areas, or installation of local diesel electric generators or hydroelectric plants, is not recommended if there are no productive end uses for the power. Household illumination is not considered sufficient reason for the introduction of electric power. This analysis holds true for the Valleys and Tropics as well.

Irrigation

The lack of irrigation, as discussed earlier, is a major problem in the Altiplano. Additional irrigation could significantly increase agricultural production in that region. Alternatives for water pumping for irrigation are reviewed below.

Solar. Because of the high insolation rates in the Altiplano, due in part to the high altitude, solar energy has the greatest potential of the three regions in Bolivia. Daily insolation rates range from 400-725 cal/cm^2, with 2,360-2,530 hours of sun per year. The major applications include solar greenhouses, crop drying, solar hot water heaters, and solar (photovoltaic (PV)) water pumps for crop irrigation and potable water supply.

The use of PV water pumps, with the panels alone costing approximately US$10/watt, is currently an expensive alternative to diesel or gasoline pumps, where irrigation by gravity alone is not possible. A possible exception would be for low-power output PV pumps (that is, low head and low capacity) in remote areas, where the costs of diesel and gasoline are high. The opportunity costs of a PV water pump have been estimated at 120 mills/m^3. This is high compared to wind and diesel water-pumping costs.

Electricity. A recent meeting of farmers in Los Andes province in the department of La Paz, sponsored by COFER, is seeking funding for

---

17/ Costs for 200-600 kVp transformer capacity in Chuquisaca.

rural electrification in the province. Farmers were especially interested in electricity for water pumps, for irrigation, and water supply. However, connection costs and potentially high marginal costs of electric service make this a poor alternative for water pumping, unless there are multiple productive end uses for electricity.

Wind. Wind regimes in Bolivia can be characterized, in general, as low to moderate in terms of applications for wind energy. This virtually eliminates cost effective use of wind energy for electric generation. In addition, the technology for generation of electricity by wind is currently beyond the capabilities of manufacture in rural areas in Bolivia. However, the application of wind to water pumping is promising at certain locations, and windmills for water pumping have been used in the past in Bolivia, especially in the Lake Titicaca area in the Altiplano. Furthermore, there are a number of local wind machine technologies, advantageous because of their low cost, ease of maintenance by the user, and availability of spare parts.

Most currently installed windmills in the Altiplano are in the northern part of that region, and most were installed for pumping water. The minimum start-up power needed for such pumps require minimum wind speeds of 1.5-2 meters/second, and no more than 15 meters well depth. Optimal wind speeds for water pumping are between 3 and 8 meters/second. The disadvantage imposed by the Altiplano for wind energy consists of the low air density at 4,000 meters above sea level. Estimated efficiencies of components of an Altiplano wind machine are shown below.

Table 3: CONTRIBUTIONS TO SYSTEM EFFICIENCY FOR WIND MACHINES IN THE ALTIPLANO

Component	Efficiency (%)
Effects of altitude (4,000 m)	66.0
Windmill	25.0
Pump/piston	70.0
System	11.5

Source: NEP estimates.

This system efficiency was used to estimate pumping capacities for a number of wind sites in the Altiplano for which monthly average wind speed was available.

Table 4: WIND WATER PUMPING CAPACITIES FOR SITES IN THE ALTIPLANO

Site	Wind Velocity	Power	Pumping Capacity	Cost
	(m/s)	(w/m^2)	(m^3/hr)	($mills/m^3$)
Desaguadero	1.52	0.26	2.1	174
Oruro	1.79	0.42	2.4	152
Charana	2.77	1.56	3.6	101
Belen	3.19	2.39	1.7	215
El Alto	3.34	2.74	1.4	261
Guaqui	3.93	4.47	1.3	281
Huarina	4.50	6.71	5.2	70
Calamarca	7.79	34.79	6.4	57

Source: NEP estimates.

Each site would have to be evaluated to determine whether the need for irrigation exists, and to ascertain the local crop requirements. Estimated cost for a local wind machine, with an estimated life of five years, is about US$1,000/kW. 18/ Long run costs of pumping are given above for each site. An improvement is needed in the current system of distribution of wind data from the National Hydrologic and Meteorological Service in La Paz. Furthermore, collection of reliable data at promising wind sites should be implemented.

Comparison of Alternatives. For locations with sufficient wind velocity, wind is the favored technology for water pumping. A cost comparison of water pumping alternatives for micro-irrigation systems was based on 20 m^3/day irrigation requirements, a 5-meter pumping head, and irrigation for 0.5 hectares of land.

18/ Provided by IAI in Oruro.

Table 5: WATER PUMPING COST COMPARISON

Technology	Cost (mills/m^3)	System Efficiency (%)
Wind	71	11.5
Diesel		
Opportunity cost	83	
\$0.30/liter	86	
\$0.40/liter	88	
\$0.50/liter	90	
Photovoltaic	120	

Source: NEP estimates.

In the Altiplano, only the sites at Calamarca and Huarina have sufficient measured wind velocity to be competitive with diesel. Despite the great resource of solar energy in the Altiplano, its use for photovoltaic pumps is currently too costly, although if diesel costs greatly exceed US$50/liter in very remote locations or is not available, PV might be considered, where wind is not sufficient to justify wind machine water pumping. PV might be reinvestigated in the future when the panel costs are reduced.

Other Uses

Electricity. Electricity can provide power for a variety of productive end uses in the rural Altiplano. At present, the major sources of electricity, other than rural electrification through expansion of the major electric grids, are diesel generators and hydroelectric plants.

There are major differences between implementation of large hydroelectric plants and small hydroelectric plants. 19/ The large hydroelectric plants require a more sophisticated technology, more detailed feasibility studies, and in general imply much greater environmental impacts, attributable to the large reservoir required for the plant to operate. Small hydroelectric plants can accomplish two goals. One, these plants can facilitate the decentralization of power supply, in order to better meet local end uses and reduce transmission costs. Second, small hydroelectric (PCH) potential is often available in remote underpopulated areas with electricity needs, where there may be no economic justification for extension of the central power grid. As noted

---

19/ The standard classification of small hydroelectric plants is as follows:

Micro	< 50 kW
Mini	50-500 kW
Small	500-5,000 kW.

earlier, the underutilization of power extensions in rural areas is well documented. Experience in Bolivia suggests a 15-kilometer radius limit of extension of small hydroelectric grids. 20/

The Altiplano contains part of three major drainage systems, the Beni River system (part of the Amazon drainage basin), the Pilcomayo and Bermejo River basins (part of the Plate River system), and an internal drainage system. 21/ Current small hydroelectric plants have an approximate installed capacity of over 55 MW, all in the "mini" or "small" range. 22/ The 14 projects identified in the Altiplano, out of 139 small hydroelectric projects identified in Bolivia, have a combined potential of 14,024 kW, or approximately 41,231 MWh/year. Estimated total cost for these projects is US$26 million with a total small hydroelectric power available in Bolivia of 807,000 kW. The 139 identified current projects have a total potential of 63,592 kW, less than 8% of the total estimated small hydroelectric potential.

A typical small hydroelectric plant in the Altiplano was estimated to have a potential of 105 kW, for 100 meters head. Two costs were calculated based on estimation methodology for total small hydroelectric plant cost. 23/ The cost of conventional small hydroelectric technology in the Altiplano was US$2,376/kW, and the cost for non-conventional technology was US$1,427/kW. Estimates gave long run marginal costs of 120 mills/kWh for conventional technology and 73 mills/kWh for non-conventional technology. 24/

Non-conventional hydroelectric units have an economic advantage over diesel generators even at the opportunity cost of diesel. The following data permits comparison between small hydroelectric plants and thermal (diesel) generating units.

20/ Costs of a 24.9 kV line are approximately US$8-8,000/km.

21/ The Altiplano system covers approximately 145,081 km^2, an area encompassing 13.2% of the total superficial area of Bolivia, and includes the salt Lake Poopo (in the department of Oruro) and the salt flats of Uyuni and Coipasa.

22/ Of these plants, some are running at reduced capacities, and for some no information exists on whether they are in operation or not.

23/ The cost formulas used were extracted from an OLADE report on small hydroelectric plants, for conventional and non-conventional (local or appropriate) technology.

24/ The estimates assumed operating for 8 hours/day, or 2,920 hours/year, a 40-year plant life, 12% discount rate, and an increasing schedule of maintenance costs.

Table 6:

Technology	Cost
	(mills/kWh)
Hydroelectric (non-conventional)	73
Hydroelectric (conventional)	120
Diesel (opportunity cost)	113
Diesel (US¢30/l)	133
Diesel (US¢40/l)	166

Source: NEP estimates.

The conventional hydroelectric units are nearly competitive with diesel at the opportunity cost of diesel fuel, but are less costly than diesel in remote areas, where the costs of diesel fuel are higher. The great variability of site development costs, stream flows, heads, and diesel costs must be studied at particular sites when considering installation of a small electric generation plant. In addition, as mentioned earlier, productive uses for the electric power must be available for long-term success of such projects.

No manufacturers of small hydroelectric turbines were identified in Bolivia. The group operates on a budget of US$5,000/year, and turbine costs are in the range of US$1,200-1,500. For steam flow rates of 5 liters/second, Pelton turbines are available for a range of 4-70 m head (a 40 m head, 60 kW turbine costs US$500-600). In addition, SEMTA is developing 10 kW micro-turbines for approximately 7 m minimum head and small stream flows in their El Alto plant.

Charcoal as a Reduction Agent. As noted earlier, most charcoal produced in Bolivia is consumed in the smelters of Oruro. The poor price of metal products on the international markets has resulted in dramatic declines in smelter production in Oruro, resulting in decreased demand for charcoal (about 80% from the most recent peak of 13,308 TOE in 1981-85), and resulting decline in charcoal production in the Chaco. Expected 1987 production by the Vinto smelter in Oruro is 8,403 MT of metal product, which needs about 8,000 MT of charcoal. 25/

Charcoal is supplied in bulk to the smelters of Oruro. Although in the past the charcoal arrived from the Chaco by train via Argentina, much of the Bolivian charcoal is currently delivered by

---

25/ About 1 MT of charcoal is required to process 1 MT of metal product. About 100 MT of charcoal are now imported annually from Argentina.

truck. Prices for Bolivian charcoal obtained from ENAP by CUMAT for charcoal delivered to Vinto in Oruro by truck are as follows:

Table 7:

Route	Price
	(US$/MT) a/
From Santa Cruz	130
From Chaco via Santa Cruz	140
From Chaco	150

a/ Includes transportation.

Source: NEP estimates.

Although transport costs were estimated at US$80/MT, transport costs clearly vary with distance from the place of Charcoal manufacture, with variation in costs of charcoal production (about US$70/ton) assumed to be minor. OAS estimated show transportation costs of 70-80% of the price of charcoal at the Vinto in Oruro. Charcoal imported from Argentina costs US$82/MT at Villazon, plus US$52/MT transportation to Oruro. 26/

Regional Institutional Issues

Regional Development Corporations. The regional development corporations of the Altiplano (CORDEPAZ, CORDEOR, and CORDEPO) are involved in a wide range of development activities in their respective departments. However, energy plays a relatively small role. CORDEOR and CORDEPAZ are planning a number of small hydroelectric projects (PCH) in their respective departments. None of the three Altiplano development corporations have collected data on energy consumption in rural areas. There is very little coordination or contact among the regional development corporations of Bolivia. Most of the financing for the corporations, as mandated by national law, consists of a percentage of corporate profits from major departmental industries. CORDEOR, for instance, receives financing from the Vinto smelter. The downturn in smelter operations has resulted in loss of financing for CORDEOR, which also owns a brick factory outside of Oruro, and other business interests dedicated to departmental development. The national government must act to improve financing for the poorer regional corporations (a national issue currently subject to great controversy vis-a-vis the natural gas royalties). Furthermore, the corporations should be encouraged to create

26/ There is an additional 20% tax.

energy departments, with assistance from the MEH, that will allow them to plan global energy strategies for their respective departments. Greater coordination on energy issues and technologies with other regions should be encouraged through the Ministry of Planning (to which the corporations technically report) and the MEH.

Small Rural Development Organizations. There are a number of rural organizations in the Altiplano which have integrated energy into their rural development plans, including the earlier-mentioned Plan de Padrinos (and related Club de Madres), SEMTA (La Paz), and the IAI in Oruro. The IAI is developing a number of solar technologies and wind machines for rural areas. CORDEOR has maintained no ties at all with the IAI, although they are currently seeking improved relations. In general there is very little coordination between the regional development corporations and small rural organizations dedicated to rural development. The regional development corporations involve themselves, in general, in larger-scale projects.

SEMTA has implemented a variety of development projects in 62 rural communities in the department of La Paz. Part of their work involves development and implementation of alternative energy technologies, including solar greenhouses, solar water heaters (for public baths and public laundries), windmills, and small hydroelectric turbines. SEMTA maintains a factory in El Alto (Villa Tunari) near La Paz. The organization, which is non-profit, is funded by a number of international organizations, including UNICEF (which funded the public laundry projects), the Inter-American Fund, and GATE/GTZ of West Germany. SEMTA usually works with rural cooperatives in implementing development projects in rural communities. Projects are financed through a revolving fund. The cooperatives pay installments to the SEMTA revolving fund out of collective finances (SEMTA has worked frequently with seed cooperatives, for example). The revolving fund has expanded and this allows financing of a greater range of rural development projects.

The MEH and regional development corporations should provide better coordination and support for rural development organizations. These organizations are the only entities in touch with needs and development methodology of rural areas in Bolivia. SEMTA in particular has developed an apparently successful means of financing rural development projects, where more global organizations have failed. Furthermore, SEMTA maintains relations with areas where they have projects ongoing, in order to ensure their continued success. As noted earlier, many projects in rural energy (biogas is a notable example) have failed because of poor coordination of technology, poor knowledge of the rural social environment, and poor or nonexistent follow-up. Rural development corporations and the MEH should implement the development of organizations like SEMTA in rural areas where energy needs have been identified and no such organizations exist.

Rural Cooperatives. Small agricultural cooperatives do exist on a small scale in parts of the Altiplano, but they are generally not involved in energy planning on a provincial, departmental or regional level. Discussions with cooperatives in the field in the Altiplano indicated that they utilize the benefits of common trucks for transportation of products to and from markets, resulting in some savings. One cooperative planned a small common gravity irrigation project. The cooperatives take advantage of pooled resources to finance projects beneficial to members of the cooperatives. All capital costs for equipment must, in general, be paid up front, because rural agricultural loans are in general nonexistent. Diesel-fueled electric generators, used to supply electricity for illumination in small rural towns in the Altiplano (similarly in the Valleys and Tropics) are operated by electric cooperatives, who also must fund capital costs by pooling financial resources.

The MEH and regional development corporations should encourage relations between regional development organizations (patterned after SEMTA) and rural cooperatives. These relationships will allow technology transfer, financing, and follow-up for rural energy plants in the Altiplano, and the potential for these plants and productive uses for power produced should be investigated.

Recommendations

(a) Investment into fuelwood plantations cannot at this time be recommended due to the very high opportunity costs. The very high cost of reforestation in the Altiplano is attributed to poor growth of currently identified species, attributable to the relatively poor-quality soil and dry climate. Initiate studies on current life cycle of thola and other hardy fast-growing species in various parts of the Altiplano and on the appropriateness of other local or imported species for Altiplano climate and soil conditions need to be initiated. Based on these studies, long-term projects for reforestation in the Altiplano need to be assessed.

(b) Initiate site studies of irrigation needs for cultivated land, and possible expansion of irrigation systems. Compare wind, electricity, diesel and gasoline pumping technologies on a site-specific basis.

(c) Continued investment into small hydroelectric plants is recommended, in areas where there is an advantage over diesel, and where a productive use for electricity is available. Considerable cost advantages may be realized if the central government were to finance development of locally manufactured turbines and other equipment, with international assistance. There are very few "micro" hydroelectric plants in the Altiplano, and the potential for these plants and productive uses for power produced shoudl beinvestigated.

(d) Coordinate current information on the applicability of the various solar technologies in the rural Altiplano. Recommend and initiate studies which will lead to implementation of appropriate solar technologies in the long term. The recommended technologies include solar greenhouses for small farms, crop drying, and hot water heaters for industrial applications.

(e) Analyze Altiplano biogas data obtained so far, with the goal of reducing costs and eliminating technological barriers. Investigate possible sites. Take advantage of information for successful biogas network in Guatemala to study ways of improving the local application of the technology.

(f) The following recommendations should be considered in addition those specified in the main text:

Valleys

Overview

The valleys contain about 31% of the 1985 total rural population, and 12% of the total area. The Valleys have a greater resource base than the Altiplano, due to the more temperate climate and the wide range of agricultural activity that this implies, in addition to the greater availability of gas and petroleum products. However, penetration of these products and other commercialized forms of energy into rural areas has evidently been small, in spite of the fact that rural electrification has been reported to be as high as 20% in some provinces in the Valleys (OAS, 1986). Although the rate of deforestation in the Valleys is not known, a number of reforestation projects underscore the perceived fuelwood shortages in certain areas. The dramatic deforestation in the valley of the departmental capital of Tarija, which occurred centuries ago, and subsequent erosion problems, are well-documented. Consolidation and further development of rural agriculture and agro-industry activities are major development goals in the Valleys.

Fuels for Cooking and Rural Industry

Fuelwood. The estimated wood supply for the Valleys in 1987, estimated from data from the ERTS program as for the Altiplano, was 333 million TOE. Visits to the department of Tarija revealed that in the valley in which the city of Tarija is located, where terrain was marked by deep erosion, fuelwood from naturally growing trees is consumed for cooking by virtually all rural residents. Households interviewed indicated that approximately one day each week was spent accumulating a week's supply of fuelwood. Fuelwood is also used to fire furnaces at the brickmakers in Tarija, and by selected bakeries in town. Households along the way to Entre Rios, 100 km east of Tarija in the subtropical lower valleys, indicated the use of fuelwood for cooking, to the exclusion of other energy resources. There was no evidence of fuelwood supply problems in the lower valleys. Adequate fuelwood supplies were available in the immediate area. Only two areas in the Valleys are considered to have shortages in fuelwood supply, in Tarija and in the province of Yamparaez in the department of Chuquisaca.

Visits to households in rural areas near Tarija showed sole use of three-stone stoves. Most stoves were located outdoors. There was considerable variation in household fuelwood consumption. However, the survey results 27/ gave an average of 2.67 kg/person/day which was used to estimate household fuelwood consumption in the Valleys based on rural population similarly to the methodology used for the Altiplano. This gave 199,464 TOE fuelwood consumption in 1985, or 36.5% of the national rural fuelwood consumption. 28/

The UNDP is financing a joint Bolivian-Brazilian program to improve the efficiency of wood-burning household stoves and foster the development of fuelwood plantations. 29/ The project is a demonstration program for both stove improvement and fuelwood plantations. In the town of Lavadero, in the province of Yamparaez (department of Chuquisaca), 32 families have been chosen for installation of efficient stoves developed in Brazil, to be constructed entirely from local material. The site was apparently selected for reforestation and the stove program because of the small supplies of fuelwood. Twenty-five hectares will be reserved for the 18-month project. 30/ Discussions with local consultants participating in the project indicated no plans to study either the Altiplano "Kery" stove, or to introduce stoves that have been highly successful in the past in rural areas (the Lorena stove, for example, developed in Guatemala and exported to Honduras with great success). The introduction of the Altiplano stove to the Valleys could result in an annual savings of 66,468-113,945 TOE of fuelwood consumed in

---

27/ OLADE-MEH surveys of Yungas and valleys in 1981.

28/ A small area in Cochabamba was estimated to consume dried dung for household cooking fuel, about 8,774 TOE in 1985.

29/ "Plantacion y Eficiente Utilizacion de la Lena como Combustible en Areas Rurales de Brasil y Bolivia." The UNDP will provide US$28,730 for the project. The program will be coordinated by the MEH, the Fundacion Centro Technologico de Minas Gerais (CETEC), and the United Nations Environment Programme (UNEP).

30/ Nurseries at Sirichaca (CDF) and Cieneaa (CORDECH) will be used for the purposes of the project, presumably for the selection of appropriate species.

households in the Valley, or 43-67% of current consumption. Economic costs indicate that for Yamparaez and Tarija, the most cost-efficient policy choice would be to improve the delivery of LPG to those areas. For other areas in the Valleys, there appear to be sufficient fuelwood supplies to warrant their continued use. Therefore, investment in reforestation in most areas in the Valley cannot be recommended.

The charcoal producers of the Valleys (in Chuquisaca and Tarija) consumed 3,507 TOE of fuelwood ion 1985, 46% of the national commercial consumption of fuelwood for charcoal. This reflected an 84.7% decrease from the most recent peak in 1981 of 22,874 TOE, a function of the reduction of smelting activities mentioned earlier. The 1985 consumption was 11% of the total rural fuelwood consumption in the Valleys. The charcoal industry of the Chaco consumes a hardwood species, "Quebracho colorado," unique to the Bolivian Chaco, with no replanting. Charcoal is a by-product of Quebracho colorado, the main use of which is railroad ties. The costs for the manufacture of charcoal are, therefore, marginal costs.

The sugar industry in the province of Arco in the department of Tarija consumes relatively insignificant quantities of fuelwood (compared to consumption by the sugar industry in Santa Cruz) in furnaces in the sugar refining process. In 1985, 15 TOE of fuelwood was consumed in Tarija, 2.7% of the total national fuelwood consumption by the sugar industry for that year, and 86.2% below the most recent peak in 1984.

Projections to 1992, estimated similarly to those for the Altiplano, estimated an increase of 1.8% to 338,944,000 TOE. Doubling the consumption rate of 2.6 kg/person/day still results in a net increase of supply over 1987. The estimated supply in 1992 suggests that the Valleys will not have a fuelwood deficit even in the long term, if current growth rates are stable.

Current commercial prices for fuelwood were sought in Tarija. As in the Altiplano, fuelwood is generally not commercialized in rural areas in the Valleys. Prices obtained from brickmakers and other consumers of fuelwood in Tarija averaged US$0.04/kg. Wood is brought into Tarija from a distance of approximately 5-20 km. The price of fuelwood in Tarija is representative of relatively fuelwood-poor areas in the Valleys. Prices for fuelwood in areas in the Valleys where fuelwood is relatively abundant was not available.

A great deal of attention has been given to reforestation in the eroded valley of the city of Tarija. PERTT, FAO, and the CDF run reforestation projects in the department of Tarija (the CDF has established a nursery in Entre Rios). The PERTT program is considered to be the most advanced, and the only one which has planned multipurpose use of reforested areas, including for supply of fuelwood, as well as the primary objective of erosion control. The program is run by GTZ and financed by the government of West Germany. The first stage of the GTZ program, which began in 1984, will end in 1988, and was directed primarily towards developing planting methodologies in eroded areas. PERTT has begun to work with rapid growth local species in addition to Eucalyptus. Species are being studied for nitrogen fixation and for use as fuelwood. PERTT has targeted the Camacho River drainage basin between Concepcion and Padcaya for reforestation. Activities in the second stage of the project will be directed toward a massive implementation of the methodology developed in the first stage, with an initial goal of reforesting approximately 500-1,000 ha/year, with a final goal of reforesting 240,000 ha of eroded land, by a direct seeding program. Local farmers contribute 30-40% of the labor needs with no direct compensation from the program.

PERTT estimates that native species grow at approximately 5 m^3/ha/year, with an expected consumption of wood of 0.5-1 m^3/ha/year. Eucalyptus and other rapid-growth species grown at about 10-15 m^3/ha/year. For native species, 240,000 ha would yield approximately 42,000-84,000 TOE of fuelwood/year.

The FAO and PERTT are conducting a joint reforestation project, financed by the Government of Norway, in the upper drainage basin of the Guadalquivir River.

Reforestation costs in the Valleys were estimated at 270-349 mills/1,000 kcal. Other than the PERTT program in Tarija (mostly dedicated to erosion control) and plantation programs in the province of Yamparaez, reforestation programs in the Valleys were, for the most part, not concerned with production of fuelwood. However, thinning operations for these plantations could contribute a sufficient supply of fuelwood for local use, if a shortage of fuelwood exists. In Tarija, for example, if energy uses for the PERTT plantations contribute 10% of the cost of reforestation, the opportunity costs of fuelwood would drop to 27-35 mills/ 1,000 kcal, much lower than the price of wood delivered from longer distances. On this basis, continued investment in reforestation projects is recommended in Tarija in the long term.

Petroleum Products. As in the Altiplano, LPG and kerosene penetrate rural areas as, respectively, cooking fuel and fuel for illumination, although kerosene is also used by some households to light fuelwood similarly to the Altiplano. In Tarija, distribution of LPG is poor to areas just outside of the city limits, and little LPG is consumed, although in the city of Tarija, LPG is the predominant household cooking fuel. LPG and kerosene prices were similar to those obtained in the Altiplano, and were similarly dependent on distances from distribution centers. In general, LPG distribution problems in the Valleys are considered to be similar to those in the Altiplano.

Charcoal. There is virtually no household, small industrial or commercial consumption of charcoal for energy purposes in the Valleys, other than insignificant consumption for grilling meats in restaurants in the larger towns and cities. Charcoal is produced commercially in the Chaco region of Tarija and in Chuquisaca for use as a reducing agent in the smelters of Oruro. Data showed a total capacity for production of 1,263 MT in the Valleys, 64% of the estimated total national capacity. ANICARVE, the trade association of the charcoal industry (approximately 54 members), provided data indicating that the kilns used an average of 6.78 MT wood/ ton of charcoal product, or 14.8% by weight conversion, between 1978 and 1982. This is equivalent to about 32% thermal conversion. This compares with conversion of the commercial, albeit more costly Missouri beehive kilns (available in Brazil). At an estimated cost of US$12,000 (about US$3/ton of charcoal product), the conversion of the Missouri kiln is about 1 MT of charcoal/6 m^3 wood charge. This is approximately 17% weight basis conversion, and about 36% thermal conversion. 31/ This would seem to suggest that the technology used in the Bolivian Chaco is fairly efficient, although the data on which yields for those kilns were based may not be reliable. Life cycle costs must be considerably higher for the Bolivian kilns, because they last anywhere from six months to a year or two (no reliable data is available). The Missouri beehive has an average life of eight years.

The costs without transport were US$83.24/MT for eucalyptus-based charcoal and US$37.72/MT for native wood-based charcoal. The eucalyptus forest is probably a plantation, hence the higher costs. Costs for Bolivian charcoal given replanting were estimated in an OAS study in Quime (department of La Paz) estimated the costs of eucalyptus plantation-based charcoal, including transport to the Vinto in Oruro, was about US$108/MT (Quime is much closer to Oruro than the charcoal producers in the Chaco, which are 1,000-1,500 km away). 32/

Opportunity costs of charcoal for charcoal produced from wood plantations were estimated in an OAS study (Von Borries and Walker, 1986). The following costs were estimated:

31/ Thermal yields vary somewhat with the thermal content of the wood.

32/ The charcoal produced from native hardwood in the Chaco region has a density that varies between 0.53 and 0.78 g/cm^3. Although this density range is suitable for the use of charcoal as a reducing agent in the smelters, it is considered too high for use as an energy source. The lower density of eucalyptus-based charcoal is probably more appropriate.

Table 8:

Description	Cost
	(US$/ton)
Cost of wood transport	8
Cost of carbonization	3
Cost of loading and unloading kiln	2
Total	13

Source: OAS.

The estimated opportunity cost of wood from plantations in the Valleys was US$58/$m^3$, or about US$72.50/ton of wood. This gives total opportunity cost of charcoal of US$290/ton, 33/ or 40 mills/1,000 kcal (approximately 186 mills/1,000 kcal useful energy). This is more costly than the charcoal produced in the Chaco (without replanting), but the cost of transportation to the smelters in Oruro would be considerably less.

Biogas. Of the 25 biodigestors in Bolivia, 14 were located in the Valleys, all in the department of Cochabamba, most of which were not completed or have been shut down because of poor coordination and supervision. The Valleys have the required resources for optimal biogas production: temperate climate, adequate water supply, and availability of animal dung. Dung is produced amply by small pig farms in all three departments in the Valleys. Biogas might be appropriate in those areas of the Valleys where there is not sufficient fuelwood supply, and where LPG is costly or not available. The plants would be also suitable for dairy farms. The fertilizer slurry product could be used for cultivation of "hortalizas." The biogas product is recommended for cooking and lighting fuel, and, if there is sufficient supply, for water pumping, in those areas where the opportunity costs of other fuels is higher than that for biogas. A pilot program and program of education in rural areas, coordinated on a national level, may be justified if biogas is found to be competitive in a number of areas in the Valleys.

Comparison of Cooking Fuels. The relatively low opportunity cost of LPG makes it the recommended fuel for fuelwood-poor areas like Tarija and the province of Yamparez in Chuquisaca. However, areas where fuelwood is abundant suggests continued use of fuelwood as a cooking fuel and fuel for rural industry.

33/ This assumed 5 m^3 of wood/ton of charcoal.

Irrigation

Solar. GTZ is planning to install photovoltaic panels for water pumping at three sites in the department of Tarija. There is no indication that such units would be competitive at current PV costs with diesel water pumps.

Wind. Wind machines in the Valleys, with elevation above sea level ranging from 1,000-3,000 meters, face approximate losses of 18% due to lower air densities. Average annual wind velocity based on known sites is about 1.77 meters/second, corresponding to a power density of 0.5 w/m^2. The best wind potential is in the department of Tarija, for water pumping, as follows.

Table 9: WIND POTENTIAL FOR WATER PUMPING IN TARIJA

Location	Average Wind Speed	Power Density	Water Pumping Capacity	Cost
	(m/s)	(w/m^2)	(m^3/h)	(mills/m^3)
Yacuiba	2.73	3.6	3.6	101
Tarija	2.26	2.5	2.5	146

Source: NEP estimates.

Neither site is competitive with diesel water pumping, and the Tarija site would be more appropriate for PV than for wind. Unless further data on wind sites in the Valleys indicate potential for economic water pumping, wind machines cannot be recommended as an alternative in the Valleys. GTZ is studying data from an experimental wind machine for water pumping near the city of Tarija.

Other Uses

Small Hydroelectric Plants. The first small hydroelectric plant in Bolivia was built in the 1920s in Epizana in the department of Cochabamba. It was a privately built plant and the power was used by the mining industry. There is over 10 MW total installed small hydroelectric capacity in the Valleys, including 6 mini hydroelectric plants (about 11% of the total installed capacity) and the balance small hydroelectric plants. There are no micro plants. Projects currently underway have a total potential of 33,502 kW.

Costs for a typical small hydroelectric plant was estimated, similarly to those for the Altiplano. 34/ The results gave US$2,716/kW for conventional plants, and US$1,619/kW for non-conventional plants with, respectively, 138 and 83 mills/kWh long run marginal costs. The conventional plant of the Valleys is less competitive with diesel than the conventional plant of the Tropics. With respect to rural electrification, conditions hold the same as analyzed in the Altiplano section previously.

Agricultural Production Drying. Agricultural product drying is one of the major issues in the predominantly agricultural rural sector in the Valleys, and aji is one of the major crops that requires drying. Chuquisaca is the leading Bolivian producer of aji, with an estimated 80-90% of the national annual aji production of 3,215 MT in 1983. 35/ In the past, the peppers used to produce aji were dried in the sun, a process that required 10-15 days for the product to reach the required moisture content of 13-20%. Considerable effort is devoted to turning the aji every three days. Because of the time required for drying, large losses often occur due to spillage (30-40% losses due to handling, spoilage, poor drying and other causes). Losses during humid weather can reach 70%. CORDECH furthermore estimated an unsatisfied demand for aji greater than 1,000 MT/year. The study recommended that five communal aji-drying plants be built, two of them with mills for preparation of powdered aji, in Luis Calvo province in the department of Chuquisaca. The plants will be designed to operate 10 hours daily and process 24 MT of aji in 60 days. 36/

The only operating plant for drying and grinding aji in Chuquisaca, installed in 1978, is in San Miguel, between Monteagudo and Muyupampa, and processes aji grown on about 40 ha. The plant operates 56 days/year, with two LPG-fired ovens (32.4 m^3 each). The ovens charge aji at 85% humidity, and in 24 hours reduces humidity to 16%. A second drying period (5 hours) reduces humidity to 3%. The process requires 110,000 kcal/hour (about 10 kg of LPG each hour). 37/ Sources indicate that with improved irrigation, aji could be cultivated and processed 6 months/year.

Cost estimates of the LPG drying process were not available, nor were conversion efficiencies. However, rough efficiencies estimated

---

35/ Estimated production for 1986 was 3,382 MT.

36/ Investment costs are approximately US$235,280, with an expected internal rate of return of approximately 54%.

37/ The plant began operating with fuelwood in 1978, and operating problems forced a changeover to electric burners and diesel grinding machines in 1980. Further operating and safety problems brought the change to LPG burners in 1981.

for consumption of LPG and wood in furnaces allowed calculation of useful energy costs of 43-54 mills/1,000 kcal for LPG. 38/

Table 10:

Year	Number of Aji Producers	Aji Processed (kg)
1983	17	14,400
1984	36	33,200
1985 a/	27	24,900

a/ 1985 was a very sunny year and some producers preferred natural drying.

Source: NEP estimates.

Solar drying of agricultural products has been used with some success in Peru. Both natural convection and forced convection systems are available commercially in Peru and elsewhere. The systems have been used for drying rice, corn, fish, yucca, bananas, cereals, vegetables, and aromatic herbs. The efficiencies and drying capacities of such systems depend primarily on ambient temperature, ambient humidity, and the product being dried. Given these constraints, the cost for a natural convection unit for a drying capacity of approximately 300 kg of product would be approximately US$150, for a reduction in moisture content from 30% to 80%. Based on limited data available, pilot studies of small-scale solar driers are recommended, and continued use of LPG driers on for larger-scale operations. The feasibility of drying other agricultural products in the Valleys should be studied.

Regional Institutional Issues

Like the three regional development corporations of the Altiplano, CORDECH, CODETAR and CORDECO have not in general focussed on energy problems in their development activities, with the exception of electric power. CORDECH has, with the aid of the OAS, set up an energy department, and is currently putting together a budget for a five-year energy plan. All three regional corporations are financially well-off relative to the Altiplano corporations. Both Tarija and Chuquisaca are gas-producing departments, and so receive substantial contributions to finance regional projects.

38/ This assumed the JUNAC estimate of 38% thermal efficiency for industrial LPG heaters.

CODETAR has plans to initiate studies of potential small hydroelectric sites in the department. CODETAR also intends to study sites for possible biogas plants. A number of wells were drilled by CODETAR for use by farmers in the dry Tarija valley. CORDECH and CORDECO have been involved with reforestation projects, the latter with the cooperation of the Swiss firm COTESU.

The energy plan for Chuquisaca should be evaluated, and energy departments and long-term energy plans should be integrated into development activities in the regional development corporations, in coordination with the implementation by the MEH of the National Energy Plan. As with the corporations of the Altiplano, the corporations should encourage and support the work of rural development organizations (like SEMTA in the Altiplano), largely absent in the Valleys.

Recommendations

The following recommendations should be considered in addition to those specified in the main text:

(a) Improve the distribution of LPG to rural areas in those parts of the Valleys where fuelwood is in short supply (Tarija and Yamparaez province in Chuquisaca).

(b) Examine, on a site-specific basis, the needs for irrigation in the Valleys and compare costs of pumping alternatives.

(c) Study in various parts of the Valleys, the need and appropriateness of drying of agricultural products, based on experience with aji drying and the energy requirements.

(d) Initiate studies on productive end uses for small hydroelectric power on a site-specific basis. Investments in current hydroelectric projects in the Valleys total US$67 million (to be spent within the next ten years). Electric needs for agro-industry and the cattle industry should be investigated in the Valleys. As in the Altiplano, the promotion of more "micro" plants should be studied.

(e) Coordinate with the UNDP program regarding cooking stoves in rural households.

(f) Study patterns of dung handling on pig farms, ranches, and dairies, and assess the possibilities for application of biogas. Study end uses of biogas and compare to opportunity costs of other energy resources. Recommended sites for pilot biodigestors as follows:

Table 11:

Location	Department	Number of Plants
Valle Bajo	Cochabamba	2
Rosario del Ingre	Chuquisaca	1
Palos Blancos	Tarija	1

Tropics

Overview

The Tropics, with 17% of the 1985 estimated rural population of Bolivia, occupies 69% of the total land mass. Santa Cruz is the principal center of industrial and agricultural activities (including the forest products industry). The recent surge in development of the department of Santa Cruz is due principally to the development of natural gas fields and increased trade with Brazil. Tropical Beni and Pando have relatively untouched forests, and potential for development of petroleum resources. These two departments are the most unpopulated and undeveloped departments in Bolivia. The naturally treeless pampas of central Beni supports a major cattle industry. Whereas Santa Cruz is expanding its cultivated areas, Beni has less than 4% estimated land developed for agricultural purposes. This is due in part to the annual floods in Beni. Transportation in Beni is largely by water all year round (including portage of diesel from Cochabamba to Trinidad and other towns). The few population centers in Pando can only be reached by plane. Major products in Pando include natural rubber, bananas and other fruits, and chestnuts.

Fuels for Cooking and Rural Industry

Fuelwood. The three departments of the Tropics have by far the greatest per capita supply of fuelwood in Bolivia. There is no indication of fuelwood shortages. However, well-founded fears of future shortages are supported by the high speculated rate of clearing for cultivation, poor management of the forest industry, and high estimated consumption rates in rural households. Estimated fuelwood supply in the Tropics is approximately 1.849 million TOE in 1987. Projections for 1992 yielded 1.875 million TOE, an increase of over 1%. 39/ This indicates a relatively small increase in supply for 1992, due in part to aggressive land-clearing and to poor forest industry practices.

Although no reliable data is available, it has been estimated that the Institute for Colonialization and Agrarian Reform, with activities focussed on the Tropics, may be deforesting areas at over 80,000 ha/year. If one assumes an availability in the Tropics of about .5-1 m^3 availability of native species for fuelwood/ha, colonialization activities could be responsible for the loss of over 12,000-24,000 TOE/year, or 8-16% of the 1985 estimated household consumption in the Tropics.

Rough estimates indicate 40-50% losses in cutting, and 40-60% losses in processing by the forest industry, all of which could be used as fuelwood. This implies that of approximately 20-25% of forest volume cut, only 5-10% is utilized.

The consumption of fuelwood for cooking in rural households was estimated similarly to that for the Altiplano and the Valleys, using a coefficient of 4.55 kg/person/day. Although enclosed bread-baking ovens are periodically fired-up, most cooking is done outdoors in three-stone stoves. Even in the pampas of Beni, sufficient wood is gathered from within 1-2 km of the households.

Fuelwood is also consumed by the charcoal-producing industry in the department of Santa Cruz, and by the sugar industry, also in Santa Cruz. The charcoal kilns of Santa Cruz have a total installed capacity of 710 TOE (corresponding to 65 kilns). In 1985, the charcoal industry consumed 4,115 TOE of fuelwood, 54% of the national consumption, and down 81% from the most recent peak in 1982. The sugar industry consumed 547 TOE of fuelwood in 1985, an increase of 34% over 1984, and 97% of the total national consumption of fuelwood by the sugar industry.

There are few reforestation efforts in progress in the Tropics. All known projects are in the department of Santa Cruz. The project at Samaipata grows E. Grandis and other species, on 250 ha. Other projects in Santa Cruz grow pines on about 110 ha, for a total of 360 ha.

Prices of fuelwood in Trinidad, where LPG is the principal cooking fuel, range from 9.5-12.7 mills/kg. Wood is brought to Trinidad from approximately 10 km away. Long run marginal cost of wood from

---

39/ This included an estimated 326,250 m^3/year forest industry losses, which yielded approximately 176,000 m^3 fuelwood losses (from branches in tree cutting operations, and unused sawdust and other waste in the processing operations), or approximately 52,875 TOE/year. The calculation did not include losses to agricultural expansion.

plantation, based on a study for a wood combustion plant in Trinidad, a fuelwood deficit area, was estimated at 233 mills/1,000 kcal.

Petroleum Products. Field visits to Beni indicated that LPG and kerosene are consumed in and near the larger cities and rural towns, but that supply is poor. Similar supply problems exist for diesel oil. Prices for LPG ranged from US$0.21-0.29/10 kg bottle, and for kerosene from US$0.24-0.48/liter.

Charcoal. The charcoal industry in the Tropics is based in the Chaco area of the department of Santa Cruz, adjacent to the charcoal-producing zone in the Chaco of Tarija. An estimated total of 65 kilns are located in the department of Santa Cruz, with estimated production capacity of 710 MT of charcoal. Virtually all production is delivered to the Vinto in Oruro for metal reduction. A possible future market may exist for charcoal as a reducing agent for the planned development of steel industry in the department of Santa Cruz. Use of charcoal as an energy source in the Tropics is considered negligible. Charcoal production costs are similar to those for the Chaco in the department of Tarija.

Biogas. Biogas plants may be an alternative in Beni, due to the great supply of dung from the cattle industry. Unfortunately, local practices allow cattle to graze freely until they are sent to markets in Cochabamba or Santa Cruz (ranch owners often do not know how many head of cattle they possess). The lack of nightly corraling makes the prospects of collection of sufficient dung for biodigestors dim. Construction began on a pilot biogas plant near Trinidad but it has not been completed.

Irrigation

Wind. Wind energy has greater potential for development in the Tropics than in the Valleys, due to the higher average wind velocities. The data below shows that Magdalena and Santa Ana are marginally competitive with diesel for water pumping. Other sites in the Tropics must be evaluated for wind speed to compare the economic costs of water pumping.

Table 12:

Site	Power Density	Pumping Capacity	Cost
	(w/m^2)	(m^3/hr)	($mills/m^3$)
Trinidad	3.25	2.0	182
Magdalena	5.20	4.0	91
Santa Ana	5.20	4.0	91

Source: NEP and AASANA estimates.

Precipitation data, also obtained from AASANA, allowed comparison of rainfall, and indicated lower irrigation needs and wind speed. This data indicated that wind speeds in Santa Ana and Magdalena are fairly constant all year, and that, if economically viable, wind energy could supply water in the dry winter season.

Other Uses

Small Hydroelectric. Small hydroelectric potential in the Tropics is substantial, although costs are high due to the low available heads. Current known installed capacity consists of one 50 kW plant, with capacity of projects underway totalling 16,066 kW. Calculations for a typical plant, with 10 meters head, 1,300 liters/second average stream flow, and 97.5 kW potential capacity, gave costs of US$3,457 for conventional technology, and US$2,061 for non-conventional technology. Although these costs are high relative to the Altiplano and the Valleys, the cost of the competing source of electricity, diesel generation, is also expensive in rural areas, especially in Beni and Pando, due to the high costs of transportation. Even so, the conventional hydroelectric technologies are probably not competitive with diesel generators in remote areas. The non-conventional technologies, if available, would be economically favorable. With respect to rural electrification, conditions hold the same as analyzed inthe Altiplano section previously.

Regional Institutional Issues

The regional development corporations of the Tropics have very different financial resources. CORDECRUZ has more than sufficient funding for a variety of projects, due to a large extent to the profitable natural gas industry in the department of Santa Cruz. They are aware of rural energy problems within the department, and have cooperated in studies of alternative energy projects (wind, wood gasification, and especially small hydroelectric projects). There has been, as in most departments of Bolivia, little collection of energy data in rural areas. The problems of deforestation are not being dealt with, nor does data apparently exist detailing rates of deforestation. CORDEBEN and CORDEPANDO (especially the latter) are drastically short of funds. CORDEBEN initiated a study several years ago which collected data in rural areas in four provinces, including energy information (currently out of date). CORDEBEN's main problem is to cope with development in the department given the yearly flooding of large portions of the central pampas.

Recommendations

The following recommendations should be considered in addition to those specified in the main text:

(a) Continue support of hydroelectric program, especially in

Northern Beni, where such technologies have lower opportunity costs than diesel plants. Such projects must be tied into productive uses of electricity. Suggested productive end uses in the Tropics include the cattle industry (including refrigeration), the wood industry, 40/ and other small rural industries where electric power would be appropriate. Expenditures on current small hydroelectric projects in the Tropics total US$41 million.

(b) Conduct studies of wind regimes. At locations where wind is sufficient for water pumping during the dry season, consider implementation of a pilot program.

(c) Explore possibilities of changes in dung-gathering infrastructure for possible implementation of a biogas program. This could also relieve pressure on wood supplies.

40/ Sources suggest that power from small hydroelectric plants may not be adequate for high start-up power required for some forest industry equipment.

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

POBLACION RURAL

DEPARTAMENTO	1980	1981	1982	1983	1984	1985
La Paz	891,030	905,444	921,036	934,265	948,755	963,956
Oruro	168,035	168,974	169,858	170,590	171,285	171,945
Potosi	549,024	557,148	565,812	574,044	582,834	591,320
TOTAL ALTIPLANO	1,608,089	1,631,566	1,656,706	1,678,899	1,702,874	1,727,221
Cochabamba	517,909	525,910	534,038	541,735	549,946	558,326
Chuquisaca	325,123	329,584	332,240	339,068	343,615	348,208
Tarija	136,645	139,469	142,366	145,290	148,298	151,394
TOTAL VALLES	979,677	994,963	1,008,644	1,026,093	1,041,859	1,057,928
Santa Cruz	387,733	394,956	402,338	409,658	417,204	424,998
Beni	99,926	101,824.	103,459	105,388	107,047	109,084
Pando	35,539	36,526	38,071	39,138	40,793	41,944
TOTAL TROPICO	523,198	533,306	543,868	554,184	565,044	576,026
TOTAL NACIONAL	3,110,964	3,159,835	3,209,218	3,259,176	3,309,777	3,361,175

FUENTE: Estimacion Propia

01-Jul-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM ENDE AM

PROYECCION DE ENERGIA EN AREAS RURALES

LEÑA (Toneladas Metricas)

REGION	1986	1987	1988	1989	1990	1991	1992	1995	2000
Altiplano	610,978	619,795	628,849	638,139	647,742	657,656	667,916	700,853	762,877
Valles	611,606	621,158	630,943	641,043	651,454	662,203	673,300	709,034	776,367
Tropico	512,344	522,282	532,473	542,998	553,847	565,048	576,617	613,848	684,241
TOTAL	1,734,928	1,763,235	1,792,261	1,822,180	1,853,043	1,884,907	1,917,833	2,023,735	2,223,485

LEÑA (Toneladas equivalentes de Petroleo)

Altiplano	213,842	216,928	220,095	223,348	226,709	230,179	233,770	245,298	267,007
Valles	214,062	217,405	220,830	224,365	228,009	231,771	235,655	248,162	271,728
Tropico	179,320	182,798	186,365	190,049	193,846	197,767	201,816	214,846	239,484
TOTAL	607,224	617,131	627,290	637,762	648,564	659,717	671,241	708,306	778,219

ESTIERCOL (Toneladas Metricas)

REGION	1986	1987	1988	1989	1990	1991	1992	1995	2000
Altiplano	562,248	570,362	578,691	587,243	596,081	605,203	614,645	644,956	702,032

ESTIERCOL (Toneladas Equivalentes de Petroleo)

Altiplano	155,181	157,420	159,719	162,080	164,519	167,037	169,643	178,008	193,762

01-Jul-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PRODUCCION ESTIMADA DE LEÑA

(Arbustos)

REGION	DEPARTAMENTO	SUPERFICIE (KM2)	VOLUMEN (1000 TM)	EQUIV. CALORICO	FACTOR RESIDUAL	OFERTA DE LEÑA (TEP)
ALTIPLANO	La Paz	1,340	7,370	0.30	1.45	3,206
	Cochabamba	1,280	6,400	0.30	1.45	2,784
	Total	2,620	13,770			5,990
VALLES	La Paz	32,462	173,541	0.30	1.40	74,907
	Santa Cruz	28,234	176,638	0.30	1.40	75,838
	Beni	11,319	118,850	0.30	1.40	51,700
	Cochabamba	15,972	87,846	0.30	1.40	36,895
	Chuquisaca	14,337	93,334	0.30	1.40	39,200
	Tarija	12,525	101,303	0.30	1.40	42,547
	Total	114,931	736,512			321,087
TROPICO	La Paz	27,636	289,338	0.25	1.35	97,652
	Santa Cruz	253,554	2,145,925	0.30	1.40	901,734
	Beni	73,764	1,078,236	0.25	1.35	363,922
	Pando	50,764	699,334	0.25	1.35	236,042
	Cochabamba	8,927	115,999	0.25	1.35	39,150
	Chuquisaca	3,439	24,073	0.37	1.45	12,915
	Tarija	10,579	87,032	0.37	1.45	46,693
	Total	428,979	4,441,098			1,698,108
TOTAL NACIONAL		606,530	5,211,380			2,025,185

FUENTE: Estimacion Propia y Oscar von Borries

01-Jul-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PRODUCCION ESTIMADA DE LEÑA

(Recurso Forestal)

REGION	DEPARTAMENTO	SUPERFICIE (KM2)	VOLUMEN (1000 TM)	FACTOR TON/HA	FACTOR TRANSPORT.	OFERTA DE LEÑA (TEP)
ALTIPLANO	La Paz	18,465	4,801	2.60	0.06	288
	Oruro	25,391	5,586	2.20	0.04	223
	Potosi	29,171	6,418	2.20	0.04	257
	Cochabamba	7,835	2,351	3.00	0.08	158
	Chuquisaca	9,434	2,830	3.00	0.08	226
	Tarija	2,741	822	3.00	0.08	66
	Total	93,037	22,808			1,218
VALLES	La Paz	6,034	9,051	15.00	0.12	1,086
	Potosi	6,918	9,685	14.00	0.10	969
	Cochabamba	13,434	20,151	15.00	0.14	2,921
	Chuquisaca	21,954	32,951	15.00	0.14	4,610
	Tarija	5,965	8,948	15.00	0.14	1,253
	Santa Cruz	5,260	7,890	15.00	0.14	1,105
	Total	59,565	88,576			11,844
TROPICO	La Paz	8,800	44,000	50.00	0.20	8,800
	Cochabamba	2,162	10,810	50.00	0.20	2,162
	Chuquisaca	1,177	1,177	10.00	0.25	294
	Tarija	4,317	4,317	10.00	0.25	1,079
	Santa Cruz	80,334	321,336	40.00	0.22	70,694
	Beni	90,477	331,695	35.00	0.20	66,339
	Pando	2,137	7,480	35.00	0.20	1,496
	Total	189,404	720,215			150,864
TOTAL NACIONAL		342,006	832,299			163,926

FUENTE: Estimacion Propia y Oscar von Borries

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

ESTIMADO DEL HIDROELECTRICO - PROYECTOS PEQUEÑOS

CUENCA DE DRENAJE	AREA	DEPARTMENTO	POTENCIAL (kW)	ENERGIA ANUAL (Millon kWH)
Amazonas				
Rios Itenez y Mamore	201,100	Santa Cruz Cochabamba Beni Pando	90,000	264
Rio Beni	182,400	Potosi La Paz Beni Pando	654,000	1,922
Rio de la Plata				
Rio Pilcomayo y Rio Bermejo	41,700	Potosi Santa Cruz Tarija Chuquisaca	46,000	137
Altiplano	31,760	Potosi Oruro La Paz	17,000	50
TOTAL NACIONAL	456,960		807,000	2,373

FUENTE: Estimacion Propia

[illegible]

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PRODUCCION DE BAGAZO

DEPARTAMENTO	1980	1981	1982	1983	1984	1985
Santa Cruz						
TM	677,389	579,911	580,087	517,227	512,293	619,454
TEP	121,920	115,184	104,416	93,101	92,213	111,502
Tarija						
TM	173,271	27,593	26,924	28,342	22,860	10,737
TEP	31,199	4,967	4,846	5,102	4,115	1,933
Total						
TM	850,660	607,504	607,011	545,569	535,153	630,191
TEP	153,119	120,151	109,262	98,202	96,328	113,434

FUENTE: CNECA

01-Jul-87

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

CONSUMO DE LA POBLACION RURAL

DEPARTAN	LEÑA %	LEÑA Consumidores	ESTIERCOL SECO %	ESTIERCOL SECO Consumidores	HIDROCARBUROS %	HIDROCARBUROS Consumidores	POBLACION RURAL %	POBLACION RURAL Hab.
ALTIPLANO								
La Paz	40%	384,618	41%	399,078	19%	180,260	100%	963,956
Oruro	36%	62,588	39%	66,715	25%	42,642	100%	171,945
Potosi	61%	357,749	20%	118,264	20%	115,307	100%	591,320
VALLES								
Tarija	36%	54,502	0%	0	64%	96,892	100%	151,394
Chuqui	55%	190,644	0%	0	45%	157,564	100%	348,208
Cochab	65%	360,120	6%	33,500	30%	164,706	100%	558,326
TROPICO								
Santa	44%	186,999	0%	0	56%	237,999	100%	424,998
Beni	70%	76,632	0%	0	30%	32,452	100%	109,084
Pando	93%	39,008	0%	0	7%	2,936	100%	41,944

30-Jun-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

CONSUMO DE LEÑA EN LA INDUSTRIA DEL CARBON VEGETAL

DEPARTAMENTO	1980	1981	1982	1983	1984	1985
Santa Cruz						
TM	55,447	49,667	72,763	37,975	21,927	13,716
TEP	16,634	14,900	21,829	11,392	6,578	4,115
Chuquisaca						
TM	21,560	32,958	17,574	13,140	8,529	5,336
TEP	6,468	9,887	5,272	3,942	2,559	1,601
Tarija						
TM	25,669	43,290	20,001	15,201	10,150	6,353
TEP	7,701	12,987	6,000	4,560	3,045	1,906
Total						
TM	102,676	125,915	110,338	66,316	40,606	25,405
TEP	30,803	37,774	33,101	19,895	12,182	7,621

CONSUMO DE LEÑA EN LA INDUSTRIA DEL AZUCAR

DEPARTAMENTO	1980	1981	1982	1983	1984	1985
Santa Cruz						
TM	9,931	9,948	5,186	3,560	1,359	1,823
TEP	2,979	2,984	1,556	1,068	408	547
Tarija						
TM	42	42	122	83	363	50
TEP	13	13	37	25	109	15
Total						
TM	9,973	9,990	5,308	3,643	1,722	1,873
TEP	2,992	2,997	1,592	1,093	517	562

FUENTE: Estudio de la OEA

01-Jul-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

CONSUMO DOMESTICO DE LEÑA EN AREAS RURALES

DEPARTAMENTO	1980	1981	1982	1983	1984	1985
TONELADAS METRICAS						
La Paz	266,019	270,222	274,977	278,926	283,252	287,791
Oruro	45,767	46,022	46,263	46,462	46,652	46,831
Potosi	248.538	252,215	256,138	259,965	263,844	267,685
TOTAL ALTIPLANO	560,324	568,560	577,378	585,253	593,748	602,307
Cochabamba	276,339	280,605	284,945	289,051	293,403	297.904
Chuquisaca	204.367	207,171	208,641	213,133	215,991	218,978
Tarija	47,940	48,931	49.947	50,973	52,029	53,115
TOTAL VALLES	528,645	536.710	542,733	553,157	561,453	569,897
Santa Cruz	287.223	293.606	298,300	299,349	304,363	310,559
Beni	116,581	118,796	120,703	122,934	124,989	127,266
Pando	54,990	56.414	58,201	60,449	63,005	64,782
TOTAL TROPICO	458,799	467.816	477.504	482,732	492,757	502,607
TOTAL NACIONAL	[illegible]	[illegible]	[illegible]	1.621,162	1,647,958	1,674,911
TONELADAS EQUIVALENTES DE PETROLEO						
La Paz	93,106	94,612	96,241	97,623	99.138	100,726
Oruro	16.018	16,108	16.192	16,262	16,328	16,391
Potosi	86,988	88,275	89,648	90,952	92,345	93,689
TOTAL ALTIPLANO	196,112	198,995	202,081	204,877	207,810	210,806
Cochabamba	96,719	98,212	99,730	101.167	102,711	104,266
Chuquisaca	71,528	72,509	73,024	74,596	75.596	76,607
Tarija	16,779	17,126	17,481	17,840	18,210	18,591
TOTAL VALLES	185,025	187,847	190,235	193,604	196,507	199,463
Santa Cruz	99.163	101,011	102,599	104,771	106,701	108,695
Beni	40,803	41.578	42,246	43,074	43,711	44,543
Pando	19.211	19,745	20,390	21,157	22.052	22,674
TOTAL TROPICO	159,179	162,334	165,735	168,952	172.464	175,911
TOTAL NACIONAL	540,316	549,176	558,111	567,403	576,781	586,180

FUENTE: Estimacion Propia

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEM PNUD BM

CONSUMO INDUSTRIAL DE CARBON VEGETAL

DEPARTAMENTO	1980	1981	1982	1983	1984	1985
ENEF						
TM	14,959	18,356	16,137	9,752	5,989	3,747
TEP	10,845	13,308	11,699	7,070	4,342	2,717
MINERIA						
TM	185	217	136	0	0	0
TEP	134	157	99	0	0	0
TOTAL						
TM	15,144	18,573	16,273	9,752	5,989	3,747
TEP	10,979	13,465	11,798	7,070	4,342	2,717

FUENTE: ANICARVE, COMIBOL, ENAF

01-Jul-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

CONSUMO DOMESTICO DE ESTIERCOL EN AREAS RURALES

TONELADAS METRICAS						
DEPARTAMENTO	1980	1981	1982	1983	1984	1985
La Paz	350,073	355,736	361,362	367,060	372,753	378,725
Oruro	61,873	62,213	62,544	62,913	63,069	63,312
Potosi	104,205	105,747	107,391	108,954	110,622	112,233
TOTAL ALTIPLANO	516,151	523,701	531,797	538,827	546,444	554,270
Cochabamba	29,490	29,945	30,409	30,846	31,314	31,791
TOTAL NACIONAL	545,641	553,646	562,205	569,673	577,758	586,061
TONELADAS EQUIVALENTES DE PETROLEO						
La Paz	96,620	98,193	99,874	101,308	102,990	104,528
Oruro	17,077	17,172	17,262	17,335	17,407	17,474
Potosi	28,761	29,126	29,640	30,071	30,532	30,976
TOTAL ALTIPLANO	142,457	144,541	146,776	148,716	150,818	152,978
Cochabamba	8,139	8,265	8,393	8,513	8,643	8,774
TOTAL NACIONAL	150,597	152,806	155,169	157,230	159,461	161,753

FUENTE: Estimaciones Propias

01-Jul-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

SUPERFICIE BAJO IRRIGACION EN BOLIVIA

(Diciembre 1978)

	AREA (Hectareas)
1.- Sistemas de irrigacion bajo el control de MACA	
a) Sistema Nacional de irrigacion No.1 "La Angostura" en Cochabamba	6,500
b) Sistema Nacional de irrigacion No.2 "Tacagua" en Oruro	3,500
	10,000
2.- Pequeños sistemas de irrigacion en otras areas, bajo el control de comunidades y asosiaciones campesinas	
a) Sistemas de Micro-irrigacion en el Altiplano	5,000
b) Otras areas rurales en el norte, centro y sur del Altiplano	5,000
c) Pequeños sistemas en los Valles de La Paz	4,000
d) Pequeños sistemas en los Valles de Cochabamba	21,000
e) Pequeños sistemas en los Valles de Chuquisaca	15,000
f) Pequeños sistemas en los Valles de Potosi	8,000
g) Pequeños sistemas en los Valles de Tarija	3,000
h) Otros sistemas en las areas tropicales	7,000
	68,000
3.- Otros proyectos de sistemas de Micro-irrigacion en diferentes partes del pais implimentadas por el Servicio Nacional de Desarrollo de la Comunidad.	10,000
4.- El proyecto de Villamontes, con el patrocinio de la Corporacion Boliviana de Fomento	400
5.- El proyecto de Abapo-Izozog (Santa Cruz)	350
6.- Area que incluye al proyecto Ingavi con dos (2) pozos que pertenecen a los campesinos (La Paz)	50
	10,800
AREA TOTAL BAJO IRRIGACION	88,800

FUENTE: Ismael Montes de Oca, "Geografia y Recursos Naturales de Bolivia", La Paz, Bolivia, 1982.

01-Jul-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

PROYECCION DEL DEFICIT DE IRRIGACION EN AREAS CULTIVADAS

DESCRIPCION	1976	1986	1995
Area Cultivada (1,000 hectareas)	2,979	4,100	5,284
Poblacion Total (1,000 personas)	4,613	6,612	8,523
Area cultivada/persona (has./person)	0.62	0.62	0.62
Tasa de crecimiento		3.66%	2.86%
Areas cultivables bajo irrigacion	89	109	133
Deficit	2,791	3,991	5,151

NOTA: Se asume que el espacio cultivable per capita permanece constante
Se asume que MACA y el Servicio de Desarrollo de la Comunidad
ampliaran sus sistemas de irrigacion a tasas de crecimiento constantes

01-Jul-87

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

COSTO DE REFORESTACION - PLANTACION

COMPONENTE	1987	1990	1995	2000	2005	2009
PLANTACION	0	246	56	70	63	70
CAMINOS FORESTALES	0	18	5	4	4	4
TALADO Y CONVERSION	0	64	63	83	83	83
TRANSPORTE	0	122	120	87	87	87
ALMACENAJE Y DESPACHO	0	23	34	34	34	34
ADM. Y ENTRENAMIENTO	165	393	150	111	163	111
AREA FORESTAL	0	0	0	0	0	0
FLUJO NETO DE CAJA (1986 US$)	310	1610	803	732	816	732
PRODUCCION (M3)	0	28400	46400	48400	48400	48400
TASA DE DESCUENTO RATE	10%	16%				
VALOR PRESENTE NETO	11860	8964				
CMLP ($/M3)	40	50				
CMLP (MILLS/KWH)	11	14				
ENERGIA UTIL.(MILLS/KWH)	190	238				

FUENTE: ENDE Estudio de la Planta de Combustion de Leña en Trinidad

30-Jun-87

INVENTARIO DE PLANTAS HIDROELECTRICAS PEQUEÑAS - 1987

NOMBRE	PROPIETARIO	DEPARTMENTO	NUMERO UNIDADES	TIPO	FLUJO (m3/seg)	CAIDA NETA (M)	CAPACIDAD (Kw)	POTENCIA DE DISEÑO (Kw)	ESTADO ACTUAL
ALTIPLANO									
Pto.Acosta	Public	La Paz	1	PELTON	0,01	300	22	22	En Servicio
Gritado	FERRECO	La Paz	2	PELTON	S/I	S/I	500	1000	En Servicio
Chaquiri	COMIBOL	Potosi	S/I	S/I	S/I	S/I	900	1150	S/I
Yocalla	COMSUR	Potosi	S/I	PELTON	4.6	33	600	1200	S/I
Caracoles	COMIBOL	La Paz	S/I	S/I	S/I	S/I	1300	1300	S/I
Landara	COMIBOL	Potosi	S/I	S/I	S/I	S/I	2200	2200	S/I
Rea Rea	COMIBOL	La Paz	S/I	S/I	S/I	S/I	2400	2400	S/I
Punutuma	COMIBOL	Potosi	S/I	S/I	S/I	S/I	2300	2500	S/I
Santa Rosa	COBEE	La Paz	1	PELTON	S/I	S/I	2500	2700	En Servicio
Lupi Lupi	COMIBOL	Potosi	S/I	S/I	S/I	S/I	1200	3100	S/I
Colquiri	NI	Potosi	2	PELTON	S/I	430	S/I	3200	S/I
Botijlaca	COBEE	La Paz	2	PELTON	2.1	382	3500	3700	En Servicio
Cayara	COMIBOL	Potosi	1	PELTON	S/I	S/I	S/I	400	S/I
Miguillas	COBEE	La Paz	2	PELTON	S/I	473	2700	4000	En Servicio
Kilpani	COMIBOL	Potosi	S/I	S/I	S/I	S/I	3300	4000	S/I
Angostura	COBEE	La Paz	2	PELTON	S/I	503	3300	4560	En Servicio
Zongo	COBEE	La Paz	3	PELTON	2.0	377	4500	4800	En Servicio
Telamayu	COMIBOL	Potosi	2	S/I	S/I	S/I	3.500	5300	S/I
Chojlla	INT. MINING	La Paz	1	FRANCIS	S/I	S/I	S/I	640	S/I
Achachicala	COBEE	La Paz	3	PELTON	S/I	S/I	4000	6400	En Servicio
Cerro Potosí	NI	Potosi	1	PELTON	S/I	S/I	S/I	650	S/I
Bolsa Negra	NI	La Paz	1	PELTON	S/I	S/I	600	S/I	En Servicio
Viloco	NI	La Paz	S/I	S/I	S/I	S/I	S/I	S/I	S/I
Palca	Private	La Paz	1	PELTON	S/I	S/I	S/I	S/I	En Servicio
VALLES									
Epizana	Public	Cochabamba	1	BANKI	0,05	150	90	90	En Instalacion
Duraznillo	CESSA	Chuiquisaca	S/I	PELTON	S/I	S/I	50	100	En Servicio
Ruffo	CESSA	Chuiquisaca	S/I	PELTON	S/I	S/I	700	1400	En Servicio
IndependenciaPublic		Cochabamba	1	PELTON	0,25	80	S/I	160	Fuera de Servici
Chocaya	ELFEC	Cochabamba	S/I	PELTON	S/I	S/I	80	160	En Servicio
Angostura	ELFEC	Cochabamba	S/I	PELTON	S/I	S/I	1500	2120	S/I
Fancesa	FANCESA	Chuiquisaca	S/I	S/I	S/I	S/I	1200	2300	En Servicio
Angosto	ENDE	Tarija	2	FRANCIS	1.04	19	300	304	En Servicio
Tuilma	CESSA	Chuiquisaca	S/I	PELTON	S/I	S/I	150	350	En Servicio
Incachaca	ELFEC	Cochabamba	S/I	PELTON	S/I	S/I	2000	3530	S/I
Arocagua	NI	Cochabamba	S/I	S/I	S/I	38	S/I	S/I	S/I
TROPICO									
Comarapa	CORDECRUZ	Santa Cruz	1	PELTON	0,320	60	150	150	En Servicio
NO IDENTIFICADA									
Aceruni	Montreal Eng.	NI	1	PELTON	S/I	500	S/I	2000	S/I

S/I = Sin Informacion
FUENTE: Datos ensamblados por Ing. [illegible]

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

INVENTARIO DE PEQUEÑOS PROYECTOS MICROELECTRICOS - 1997

PROYECTO	RIO	DEPARTMENTO	CAPACIDAD (Kw)	ESTADO ACTUAL	ORGANIZACION
ALTIPLANO					
Apolo	S/I	La Paz	100	Bajo Estudio	MIN PLANEAMIENTO
P. Acosta	S/I	La Paz	100	Bajo Estudio	COFER
Fátima	S/I	Tarija	200	Bajo Estudio	COOP.FATIMA LTDA.
Ulla	Cañuma	La Paz	200	Factibilidad	COFER
V. Cangalli	Capitan	La Paz	500	Bajo Estudio	FERRECO
Lonlaya	Charazani	La Paz	544	Factibilidad	COFER
Todos Santos	Todos Santos	Oruro	570	Factibilidad	CORDEOR-COFER
Sapuwni	Sapucuni	La Paz	600	Prefactibilidad	1o. MAYO LTDA.
Gritado	Gritado	La Paz	1400	Diseño Final	FERRECO
Yolosani	Yolosani	La Paz	1510	Prefactibilidad	ENDE
Caranavi	S/I	La Paz	2000	Bajo Estudio	Publico
Janico Jaque	Challana	La Paz	2315	Prefactibilidad	ENDE
Churihumani	Tipuani	La Paz	2390	Prefactibilidad	ENDE
VALLES					
Arque	Ballia	Cochabamba	12	S/I	S/I
Tarvita	El Salto	Chuquisaca	40	Bajo Estudio	CORDECH
Poroma	Pangorasi	Chuquisaca	40	Bajo Estudio	CORDECH
Azurduy	Misca Mayu	Chuquisaca	120	Bajo Estudio	CORDECH
Entre Rios	Salinas	Cochabamba	192	S/I	S/I
Chakheri	Chakheri	Cochabamba	442	Factibilidad	ENDE
Tapera	Mizque	Cochabamba	850	Prefactibilidad	ENDE
Azero	Azero	Chuquisaca	1670	Factibilidad	CORDECH
Incachuasi	Rodeo Khocha	Chuquisaca	1700	Bajo Estudio	CORDECH
San Jeronimo	Mizque	Cochabamba	1714	Factibilidad	ENDE
Aguas Blancas	Bermejo	Tarija	1935	Prefactibilidad	ENDE
San Telmo	San Telmo	Tarija	3400	Prefactibilidad	ENDE
TROPICO					
Chochis	S/I	Santa Cruz	20	Perfil	CORDECRUZ
San Isidro	S/I	Santa Cruz	100	Bajo Estudio	CORDECRUZ
San Javier	S/I	Santa Cruz	120	Diseño Final	CORDECRUZ
Concepción	S/I	Santa Cruz	150	Diseño Final	CORDECRUZ
Valle Grande	S/I	Santa Cruz	300	Diseño Final	CORDECRUZ
San Ignacio	S/I	Santa Cruz	300	Bajo Estudio	CORDECRUZ
S.B. Ventura	Maije	Beni-La Paz	500	Bajo Estudio	COFER
Robore	S/I	Santa Cruz	680	S/I	CORDECRUZ
C. Esperanza	Beni	Beni	5000	Prefactibilidad	ENDE-CORDEBENI

FUENTE: Datos Compilados por Ing. Jorge Zarate

COMENTARIO: Total 34 proyectos - Capacidad de [illegible]

01-[illegible]-97

B O L I V I A
PLAN NACIONAL DE ENERGIA
MEH PNUD BM

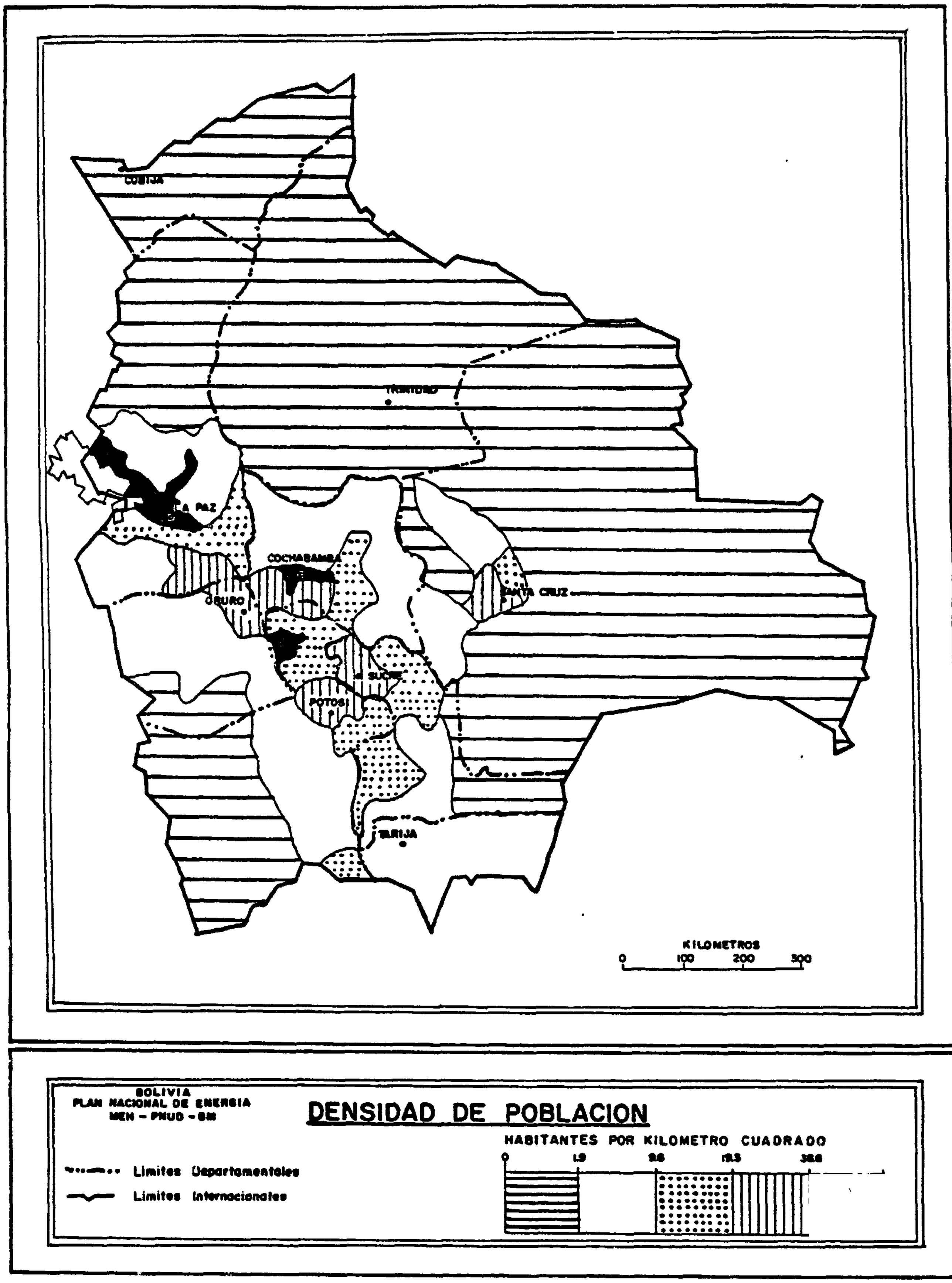
INVENTARIO DE MOLINOS DE VIENTO - 1987

ITEM	LOCALIZACION	PROVINCIA	DEPTO.	DIAMETRO DEL ROTOR (METROS)	TIPO	CHARACTERISTICAS DEL ROTOR	COMMENTARIO
1	Batallas	Los Andes	La Paz	3	Bombeo de agua	Multiaspas horiz.	Fuera de opera.
2	Huatajata	Omasuyos	La Paz	2	Bombeo de agua	Multiaspas horiz.	Sin infor. add.
3	Chua Col. Nac.	Munecas	La Paz	2	Aereo Motor	Sin Inform.	Id.
4	Pillapi		La Paz	3	Bombeo de agua	Multiaspas horiz.	Id.
5	Curahuara,San Pedro de	Gualberto Villarroel	La Paz	sin inf.	Bombeo de agua	Sin Inform.	Id
6	Tiquina	M.Kapac	La Paz	sin inf.	Bombeo de agua	Sin Inform.	Id
7	Kallutaca(CORDEPAZ)	Murillo	La Paz	3	Aereo Generador	Multiaspas horiz.	Fuera de opera.
8	Patacamaya	Aroma	La Paz	sin inf.	Bombeo de agua	Sin Inform.	Sin Infor.add.
9	Sicasica	Aroma	La Paz	sin inf.	Bombeo de agua	Sin Inform.	Sin Infor.add.
10	Viacha	Ingavi	La Paz	sin inf.	Bombeo de agua	Sin Inform.	Sin infor.add.
11	Penas	Los Andes	La Paz	1.2	Generador D.C.	Multiaspas horiz.	Fuera de opera.
12	Univ.Tec.Oruro	Cercado	Oruro	3	Bombeo de agua	Multiaspas horiz.	En servicio
13	Colonia Menonita	Andres Ibanes	Sta. Cruz		Bombeo de agua	Multiaspas horiz.	En servicio
14	UMSA	Murillo	La Paz	sin inf.	Bombeo de agua	SAPONIUS	Sin infor. add.
15	Santa Ana	Yacuma	Beni	2	Bombeo de agua	Multiaspas horiz.	Fuera de opera.
16	Hacienda Ganadera	Yacuma	Beni	1.8	Generador DC-AC	2 - aspas, horiz	En servicio

FUENTE: Informacion Recopilada por Ing. Jorge Zarate (1987)

COMENTARIO: Contactos en Santa Ana de Yacuma, reportan que en la provincia de Yacuma, estan operando 10 genradores eolicos

01-Jul-87


COBIJA
TRINIDAD
LA PAZ
COCHABAMBA
ORURO
SANTA CRUZ
SUCRE
POTOSI
TARIJA
KILOMETROS
0 100 200 300
BOLIVIA
PLAN NACIONAL DE ENERGIA
MEN - PNUD - BM
DENSIDAD DE POBLACION
HABITANTES POR KILOMETRO CUADRADO
0 1.9 9.6 19.3 38.6
Limites Departamentales
Limites Internacionales

BOLIVIA
PLAN NACIONAL DE ENERGIA
MEH - PNUD - BM

RECURSOS FORESTALES Y VEGETALES

Area Forestales
Vegetación Diversa
Rios
Matorrales y Pastizales
Limite Internacionales