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STAFF APPRAISAL REPORT

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

OCTOBER 23, 1995

Infrastructure and Operations Division
Country Department III
Latin America and the Caribbean Regional Office

CURRENCY EQUIVALENTS
(as of November 1994)

Currency Unit = Colombian Peso

US$ 1 = 840 Pesos
1 Col$ = US$ 0.00119

Fiscal Year

January 1 to December 31

ENERGY CONVERSION FACTORS

1 TOE	=	7.3 bbl
1 MTOE	=	12.4 TWh (heat content equivalent)
1 kcal	=	3.968 Btu
1 CF of gas	=	1000 Btu
1 kWh	=	860 kcal
1 m^3 gas	=	9000 kcal

ACRONYMS

CARBOCOL	Carbones de Colombia (Coals of Colombia)
CHB	Central Hidroeléctrica de Betania (Betania Hydroelectric Plant)
CONPES	Consejo Nacional de Política Económica y Social
CORELCA	Corporación Eléctrica de la Costa Atlántica
CVC	Corporación Autónoma del Valle del Cauca
DNP	Departamento Nacional de Planeación (National Planning Department)
ECC	Energy Control Center
ECOCARBON	Empresa Colombiana de Carbón
ECOPETROL	Empresa Colombiana de Petróleos
EEB	Empresa de Energía de Bogotá
EMCALI	Empresas Municipales de Cali
EPM	Empresas Públicas de Medellín
ERC	Energy Regulatory Commission
ESMAP	Energy Sector Management Assistance Program
FEN	Financiera Energética Nacional
FSC	Financial Settlement Center
IDB	Interamerican Development Bank
Interconexión Eléctrica	Former generation and transmission company
ISA	Interconexión Eléctrica S.A. "E.S.P." (ISA) - the new transmission company[1]
ISAGEN	ISAGEN S.A. - the new generation company
LRMC	Long-run-marginal-cost
MHCP	Ministry of Finance and Public Credit
MME	Ministry of Mines and Energy
OED	Operations Evaluation Department, World Bank

ABBREVIATIONS

BOE	Barrels of oil equivalent
Col $	Colombian pesos
GDP	Gross domestic product
kV	Kilovolt (1thousand V)
kW	Kilowatt (1thousand W)
LRMC	Long-run marginal cost
Mbbl	Million barrels
MBOE	Million barrels of oil equivalent
MW	Megawatt (1 million W)
Mt	Megatons (1 million metric tons)
Tcal	Tera calories (1 trillion Calories)
TWh	Terawatt-hour (1 trillion Wh)

[1] To avoid confusion this report will refer to Interconexión Eléctrica when naming the former generation and transmission company, which was also formerly known as ISA.

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POWER MARKET DEVELOPMENT PROJECT

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LOAN AND PROJECT SUMMARY

Borrower:	Interconexión Eléctrica S.A. - "E.S.P." (ISA)
Guarantor:	Republic of Colombia
Beneficiary:	N/A
Poverty:	Not applicable
Amount:	A package of two loans: (i) a US$145 million US dollar single currency laon; and (ii) a US$104.3 million equivalent currency pool loan.
Terms:	(i) repayable in 17 years, including four years' grace, at the standard LIBOR-based interest rate for US dollar single currency loans; and (ii) repayable in 17 years, including four year's grace, at the standard variable rate for currency pool loans.
Commitment Fee:	0.75% on undisbursed loan balances, beginning 60 days after signing, less any waivers.
Financing Plan:	IBRD: 249.3 ISA: 160.7 TOTAL: 410.0
Environmental Classification:	B
Estimated Economic Rate of Return:	ISA's 1994-99 investment program, which includes a number of small investments not included in the project, has an estimated net present value of US$64 million and a benefit/cost ratio of 1.34 at a discount rate of 12%. The estimated economic rate of return is 27%.
Map:	IBRD 26929
Project Identification Number:	CO-PA-6887

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

1. THE ENERGY SECTOR AND THE POWER SUBSECTOR

A. Background

1.1 Colombia's prudent macroeconomic management enabled it to achieve one of the highest and most stable growth rates in Latin America during the 1980s (3.7%). Solid economic growth of about 4.5 percent per year for the past four decades, combined with a drop in the population growth rate to 2.0 percent per year, have facilitated substantial improvement in social conditions.

1.2 The Government sought to further improve the economy's performance during the 1990s through appropriate institutional reforms. In order to spur growth, the Barco administration (1986-90) launched an economic reform program during the last year of its tenure which was vigorously pursued during the Gaviria government years (1990-94). It involved opening trade, exposing economic agents to competition and fostering private sector participation in areas where the public sector traditionally prevailed (e.g. ports, railways, state-owned banking, state-controlled industrial enterprises, the energy sector in general, and the power subsector in particular). The Samper government's (1994-98) policies have emphasized socially-oriented priorities, but it has continued to support the Gaviria-era structural reforms. Its major economic challenge will consist of taking advantage (and avoiding the pitfalls) of the large foreign currency revenues associated with massive increases in oil production which have the potential for putting the economy (GDP per capita of US$1620) on a faster growth path with sustained GDP growth of more than 5 percent per year.

B. The Energy Sector

1.3 Within the last decade the energy sector has become the single most important agent in the Colombian economy. It has replaced coffee as the prime source of foreign exchange and will continue to grow in importance during the next ten to fifteen years.

Energy Sector Organization

1.4 The energy sector has been characterized by the predominance of large public enterprises in the power, coal, and hydrocarbon industries. Empresa Colombiana de Petróleos, ECOPETROL, the state oil enterprise, has been responsible for oil and gas exploration, for running the refineries and for importing oil products. In the coal subsector, Carbones de Colombia, CARBOCOL owns, together with EXXON, the Cerrejón coal mine and Empresa Colombia de Carbón, ECOCARBON is responsible for managing mining concessions and policy. The power subsector is characterized by a more decentralized structure with a large number of utilities which until recently were owned by the central or local governments.

1.5 In the power subsector, a major reorganization has been taking place since 1991: a competitive market at the generation level is being organized, an Energy Regulatory Commission has been set up and Interconexión Eléctrica S.A., the major generation and transmission enterprise, has been split into a transmission and dispatch enterprise which kept the name ISA[1], and a generation company (ISAGEN).

1.6 The energy sector is under the jurisdiction of the Ministry of Mines and Energy (MME). The Ministry is in charge of overall sector policy making; the independent Energy Regulatory Commission is in charge of regulating prices for electricity and natural gas.

1.7 Other major government agencies involved in the energy sector are the National Planning Department (DNP), the National Energy Finance Corporation (FEN) and the Ministry of Finance (MHCP). The latter became the owner of a number of power plants together with substantial equity in the sector's enterprises due to a financial restructuring operation which took place in 1991-92. It is now a major stockholder in the sector and it intends to divest its holdings which amount to as much as 50% of the power sector's assets. DNP is in charge of approving major publicly funded investments in the energy sector. FEN lends to companies in the energy sector. It raises funds in the capital market and it also manages sector loans.

Energy Reserves and Consumption

1.8 Colombia has abundant energy resources: proven oil reserves are currently on the order of 3.2 billion barrels, equivalent to a Reserves/Production (R/P) ratio of around 20 years; proven (8.3 trillion cubic feet) and probable gas reserves amount to around 12.5 trillion cubic feet, equivalent to a R/P ratio of about 70 years; coal reserves are estimated to be on the order of 2.2 billion tones (R/P in excess of 100 years); the hydroelectric potential is around 90 Gigawatt (GW), of which less than 10% (about 8 GW) has been installed.

1.9 Final energy consumption in Colombia amounted to 244,000Tcal (171MBOE) in 1994, which is equivalent to around 5BOE per capita. This amount is low when compared to the Latin American average (around 8BOE) and is less than a quarter of the European per capita consumption. The vigor exhibited by the increased energy production in the last decade, which grew at 6% per year in the last decade, was not followed by a corresponding increase in consumption. Between 1984 and 1994, internal demand grew by less than 3% per year, slightly below the rate of GDP growth. (See Annex 3 for details.)

Lessons from Previous Bank Involvement

1.10 The Bank has lent more than US$2 billion in 32 operations to support the Colombian energy sector, mainly by financing investments in power generation and transmission. Bank borrowers for power projects in Colombia since 1970 include Interconexión Eléctrica (3 loans,

[1]To avoid confusion, this report will refer to "Interconexión Eléctrica" when naming the former generation and transmission company, which was also formerly known as ISA.

US$ 250 million), EPM (4 loans, US$ 430 million), EEB (4 loans, US$ 700 million), Government (3 loans, US$ 362 million), FEN and CORELCA (1 loan each for US$ 170 and US$ 36 million, respectively). The last investment loan to the sector became effective in May 1987 and corresponded to a US$ 172 million credit to EEB ("Bogotá Power Distribution II Project" Loan 2643 CO).

1.11 In 1990 an extensive OED study[2] found that the Bank supported projects generally met their physical objectives, and helped advance technical capabilities in the beneficiary agencies, but failed to establish a sustainable institutional and financial framework for the sector. It identified weaknesses in the power subsector and recommended its restructuring through the introduction of adequate regulation and private sector participation.

1.12 Despite its institutional problems, overall experience with project execution in the Colombian power sector has been positive, with the exception of (a) two loans to Empresa de Energía de Bogotá - EEB (the Guavio project loan supported a hydroelectric project with major construction delays and problems, and the Distribution II project was partially canceled by mutual agreement due to non-achievement of the project's institutional objectives) and (b) the FEN Power Development Finance Project. The Project Completion Report for the latter project (June 1993) points out that the financial problems of the sector could not be solved by creating a specialized financial intermediary such as FEN, and that its potential for mobilizing resources was not effective unless the utilities it lent to were restructured and became credit-worthy borrowers. These problems, coupled with the OED findings, led to the Bank's support for institutional restructuring before new operations could be contemplated.

1.13 Having achieved the major institutional reforms required for restructuring the energy sector, the Bank is now providing support for their implementation through the Energy Sector Technical Assistance Project (Loan 3827-CO) which was approved by the Board in December, 1994.

1.14 Key lessons which have been learned from other Bank loans include the need to: (a) position infrastructure projects within a sector-wide institutional context; (b) complement investments with technical assistance components to ensure that projects do not fail due to an inadequate institutional framework; (c) systematically assess the economic and financial sustainability of tariff levels; and (d) embed projects within a balanced investment program. The project will internalize these lessons by: (a) coordinating the proposed actions with the umbrella Energy Sector Technical Assistance project currently under execution; (b) providing specific specialized training and technical assistance in the power planning, dispatch and operations areas to complement the latter; and (c) by designing the project to support the overall institutional framework of the sector.

[2] OED, Colombia-The Power Sector and the World Bank, 1970-1987, Report No. 8893 (June 28, 1990).

C. The Power Subsector

Electricity Demand and Supply

1.15 During 1994 gross generation reached 39 TWh with a peak demand of around 6900 MW. Until the late seventies, electricity demand grew at rates in excess of 10% per year. During the early 1980s demand growth decreased to rates on the order of 5% per year. A number of economic and social factors explain this change: economic growth diminished and new service extensions decreased with the saturation of coverage. Starting in the late eighties and continuing into the 1990s, the substitution of electricity by natural gas and LPG has been actively promoted and exerted a moderating influence on electricity growth. This effect is expected to continue in future years with the extension of natural gas supplies to major cities like Medellín and Cali. Finally, tariff adjustments in electricity are expected to continue until they reach marginal cost levels, and will also contribute to restrain demand growth.

1.16 Forecasts for electricity demand have been made within the context of overall energy requirements, considering such factors as population growth, economic growth, relative prices and interfuel substitution. In 1995, the Ministry of Mines and Energy prepared a forecast using a base scenario corresponding to an economic growth rate of 5.1 -5.3% until 2000, stabilizing at the 5% level thereafter (these values are slightly lower than the Bank's own projections). On this basis, electricity requirements are expected to increase at about 5.3% for the same period.

1.17 Total effective generation capacity amounts to 10100 MW of which 7900 MW correspond to hydro facilities. The major generation enterprise is ISAGEN (2600 MW) followed by the municipal utilities of Bogotá (EEB - 2200 MW) and Medellín (EPM - 1500 MW); regional utilities on the Atlantic Coast (CORELCA), in the South West (CVC and CHB), and several distribution companies, which also operate power plants, account for another 3000 MW; the Ministry of Finance owns 272 MW in four plants which are operated by local utilities. Finally, 240 MW of private generation are in service.

1.18 System dispatch is performed by ISA, which also operates the principal transmission lines. Electricity distribution is accomplished by three major municipal utilities in Bogotá, Medellín and Cali, by 24 regional distribution companies owned by the National Government, and by smaller municipal companies, one of which was recently privatized.

System Expansion

1.19 System expansion is taking place within the new commercial and institutional framework whereby compulsory planning has been replaced by "indicative" planning. In this context, future plans are drawn up with the purpose of serving as guidelines for interested investors (which include both existing companies as well as prospective entrepreneurs).

1.20 The incorporation of new investors in the power business (both as a consequence of the new institutional framework and the drought-induced emergency) has been successful as evidenced by projects such as a 90 MW generation plant in Cartagena developed with local capital (Proeléctrica), the 100 MW combined cycle gas plant in Barranquilla operated by Sevillana de Electricidad, and the ongoing construction of an aggregate 1129 MW of thermal generation with the participation of foreign investors.

1.21 Power plants under construction which are expected to come on line by 2000 include[3]: (a) 747 MW of combined cycle gas-fired turbines in the Atlantic Coast owned by ABB/Distral and 232 MW in the Valle Region owned by Enron/Propal; (b) 450 MW of coal-fired plants to be developed by private independent power producers (150 MW of which have already been awarded); (c) the 390 MW Porce II hydro plant under construction by EPM (a municipal utility); (d) the 340 MW Urrá I and the 375 MW Miel I hydro plants under construction by two mixed capital consortia and (e) 400 MW (probably gas-fueled) for which potential investors will be sought. The response to requests for providing this additional capacity is expected to be highly competitive: 21 private sector consortia have expressed interest in developing different power plants. Interested investors include existing private generators, oil companies, and industrial and agricultural enterprises. The prospective developments include a variety of plant types encompassing a large proportion of gas-fueled units, together with coal, fuel oil, heavy crude, bagasse and small hydro stations.

1.22 The expansion of the transmission system is to be developed by ISA. The capacity expansion will be achieved by strengthening transmission links through a combination of 500 kV and 230 kV lines in order to avoid potential bottlenecks which could lead to either peak rationing or to higher operating costs in the system. Furthermore, the development of the transmission system is essential for a competitive energy market to operate.

Electricity Pricing

1.23 Until 1994, electricity prices were regulated at both the wholesale and retail levels. This pricing system was replaced, under the new institutional arrangements, by a competitive market for bulk (wholesale) supplies where distribution companies and major consumers (with loads in excess of 2 MW) enter into contracts with generation enterprises at freely agreed prices. On a day to day basis, generators are reimbursed for sales to the power pool at system marginal cost. In addition, regulated transmission charges are levied to remunerate ISA, the interconnection company.

1.24 Final user prices are set by the Energy Regulatory Commission. During the 1970s and early 1980's important cross-subsidies were incorporated into retail prices, by charging relatively high prices to industrial and commercial users in order to maintain low prices for domestic consumers. This policy became financially untenable but tariffs were not reformed and massive subsidies were required from the central government. As part of the power sector's financial restructuring, tariffs charged to final customers maintained an increasing trend during 1991-94. Towards the end of 1994, sector average electricity rates amounted to about 90% of long-run

[3] "Plan de Expansión de Referencia Generación-Transmisión", Ministerio de Minas y Energía- Unidad de Planeación Minero-Energética and ISA, April 1995.

marginal costs. The average rate applied to final customers ranged between 6 and 10 UScent/kWh.

1.25 In 1994 the Public Services Law and the Electricity Law provided directives for price adjustment by setting strict limits on cross-subsidies and mandating that cost based rates be put into place by July 2000 at the latest. Improvements regarding pricing can be expected to continue due to (a) the fact that bulk supply prices (which account for over 50% of retail supply costs) are to respond to market forces thereby exerting pressure on distribution companies and Government to support the ERC in achieving pricing goals; (b) the policy to incorporate private capital into the distribution business, which will require sound pricing assurances; (c) the functioning of the Energy Regulatory Commission where independent regulators outnumber Government representatives and can be expected to resist attempts to freeze prices or otherwise imperil the sector's financial health; and (d) provisos in the Domiciliary Public Services Law which explicitly require public agencies, which frequently fail to pay their bills, to budget funds for paying for public services such as electricity.

Power Subsector Financial Performance

1.26 The 1984-90 period was characterized by a considerable deterioration of the subsector's financial indicators (see Annex 8 for details). This decline took place because of short-sighted policies that prevented electricity prices from keeping up with inflation and the devaluation of the Colombian peso. The power sector was heavily subsidized by the Government and average rates during 1980-84 covered only about 50-60% of marginal costs.

1.27 As a result of overbuilding power plants, utilities incurred significant amounts of external debt to fund new investments. The consolidated indebtedness of the power subsector amounted to about US$5.2 billion in 1990, roughly equivalent to one third of the country's total external debt. The devaluation of the local currency, coupled with low prices, forced many utilities to seek Government support for servicing their debt.

1.28 The sector also showed signs of administrative, financial and commercial mismanagement. Power losses, ranging between 14% and 32% in 1990, were out of control in many companies. Arrears of energy bills from distributors to generators, and from government agencies and private customers to distributors exceeded 6 months in many utilities.

1.29 As part of the Economic Adjustment Program implemented in 1991, the Government defined a long-term strategy to improve both efficiency and the financial situation of power utilities. This strategy aimed at: (a) reducing the utilities' foreign debt service; (b) establishing a rational tariff structure and a sustainable rate level; and (c) improving managerial efficiency of distribution companies.

1.30 The debt issue was successfully dealt with through a debt/equity swap and a debt/asset swap whereby the Government took charge of many company debts in exchange for assets or for equity shares in the enterprises. Pricing reforms were implemented in order to reflect economic costs and to reduce subsidies to residential customers by following a well-defined plan. Finally, the Government established performance contracts with utilities profiting from Government loans and guarantees; although there have been some positive gains in efficiency, there remains vast room for improvement in most distribution utilities.

Power Sector Financial Perspectives

1.31 As a result of the actions taken during the 1991-94 period, most power sector companies now exhibit satisfactory indicators. Rates of return exceed 8% in the large companies as well as many smaller, solvent and profitable companies. Future performance will depend on a continued application of pricing adjustments together with efficiency improvements to keep costs under control.

1.32 Financial projections for the sector indicate that the performance of most enterprises in the sector is satisfactory, with the exception of a few small distribution companies whose assets only account for about 4% of total subsector assets, and who would still remain insolvent and unprofitable. The latter group includes utilities with a predominantly residential market structure of low income customers. A number of such utilities are expected to require support due to the cross-subsidization applied to retail sales. Under LRMC pricing levels, the support required from the Government in 1995 would amount to around US$56 million, or less than 5% of the sector's revenues.

1.33 At current average price levels, on the order of 90% of marginal costs, most companies exhibit a healthy financial position. However, there is room for efficiency improvements particularly in regard to lowering commercial losses and controlling theft which are only possible through strong management action. For example, if commercial losses could be reduced, through metering controls, from their present level of 22% to levels on the order of 10% to 12%, the increase in gross revenues would have the same financial effect of an immediate increase in prices to marginal cost levels.

D. Power Subsector Policy and Issues

1.34 **Energy Sector Policy.** The Government's overall policy regarding the energy sector [4] consists of implementing the mandates contained in the Public Service Law and the Electricity Law. The general orientation consists of: (a) limiting the state's intervention in the sector to the formulation of general policy guidelines and to regulation, thereby allowing the private sector to undertake investment and operational tasks; (b) stimulating competition; (c) encouraging private sector participation; and (d) establishing cost-reflective tariffs with due consideration to low income users.

1.35 The sector is emerging from a traumatic supply crisis which curtailed energy demand by as much as 15% during the period February 1992-March 1993. This crisis provided additional

[4] See Annex 2 - Minister of Mines and Energy policy letter of November, 1994, COMPES Document No. 2763 (2/15/1995) "Strategies for the Expansion of the Power Sector, 1995-2007, and Law No. 188 (6/2/1995) "National Development Plan".

impetus for reform by forcing the installation of emergency generation with hitherto nonexistent private sector participation.

1.36 The Bank has supported the Government since 1991 in the process of power sector institutional reform. The Bank has helped to shape and to define a new vision for the energy sector by: (a) supporting analyses of the sector's problems and identifying the issues; (b) exploring the options for addressing them; (c) fostering constructive debate concerning past conceptual and systemic deficiencies attributable to inadequate institutions; (d) designing a reform program; and (e) by supporting the implementation of this program.

1.37 The sector was gradually reorganized, with Bank support, during the 1991-94 period. The process incorporated efficiency, accountability and financial responsibility incentives into sector corporations. Financial restructuring whereby the Government injected massive resources into the sector was accompanied by tariff reforms which have steadily raised electricity prices with a view to reaching economic cost levels by 1998.

Power Subsector Reform Program

1.38 The major elements of the restructuring process culminated in 1994 with the approval by Congress of two major statutes: a Public Services Law which provides a general framework for the supply and pricing of electricity, water, natural gas and local telephone services; and an Electricity Law which spells out sector-specific provisions regarding organization, responsibilities and functions of different entities. Both of these laws emphasize the introduction of competitive incentives and provide for the regulation of non-competitive supplies. The Government anticipated the approval of these laws by creating the required regulatory institutions, by fostering the incorporation of private capital into the generation business and by reorganizing some of the major companies in the sector in order for them to operate according to the proposed structure.

1.39 The objectives behind the Government's power subsector institutional reforms include: (a) fostering efficiency through competition together with a strong, transparent and independent regulatory framework; (b) an institutional restructuring involving the separation of national transmission from generation and the corporatization of existing state power companies by ultimately transforming them into joint stock corporations; (c) completing the financial restructuring and rehabilitation of the subsector through tariff and subsidy reforms;(d) promoting the participation of private sector capital in new projects; and (e) the divestment of existing power plants and utilities.

1.40 The implementation of these reforms has proceeded successfully: the Energy Regulatory Commission (ERC) has been operating since 1993; the conditions for a competitive market at the generation level have been defined and their implementation was initiated in early 1995. Private sector participation has been concentrated mainly in generation through the installation of more than 1000 MW of thermal capacity. These developments were followed by the organization of the open access network operated by ISA (the borrower) as an independent, regulated, transmission company, following provisions in the Electricity Law.

Current Reform Implementation Issues

1.41 The major hurdles regarding the power sector's reorganization and financial rehabilitation were cleared during 1991-94, and the system can be characterized as entering a period of institutional consolidation which will require assistance while experience is gained under the new rules, as well as putting in place supportive infrastructure. Some of the issues to be addressed in this new phase are:

(a) **Power Market and System Expansion.** Since early 1995 a market for bulk energy and capacity has been operating. The final objective of this market is to create an environment whereby private producers will engage in generation investments based on the income they can derive either from the spot market or from long term contracts with large users (such as major consumers or distribution companies). This has enabled the Government to limit its commitments and exposure to the transmission and distribution components of the industry. Although no major investments in new capacity are required in addition to those already planned or in execution until 2000, beyond that date the system will have to prove that it can survive as a mature, competitive, industry. Until now the private sector's response has been encouraging, as evidenced by the numerous proposals, both local and foreign, for new plant development.

(b) **Transmission and Dispatch.** A major responsibility for enabling the market concept to be successful has been vested in ISA, the transmission and dispatch enterprise. ISA is in the process of upgrading its system in order to fulfill the required dispatching and clearing house functions for the market to function smoothly. The interconnection network will also require reinforcements in order to allow an unimpeded flow of energy between generators and demand centers. These investments are to be partially financed by the proposed loans and paid through adequate, regulated, network charges.

(c) **Distribution.** At the distribution level, private sector participation has been less successful. Since the initiation of the reform process only one small distribution company has been privatized. This can be partially explained by the reluctance of local politicians to relinquish the power they exert over a number of these companies. However, the possibilities for the ultimate privatization of distribution companies have improved with the approval of the Public Services Law and will continue to do so with planned tariff increases. Through the Energy Sector Technical Assistance Project, the Bank is assisting the Government to evaluate options and formulate a strategy to introduce private management and equity in distribution companies, and to increase their overall efficiency. In addition, the Government has requested Bank assistance in the preparation of a Power Distribution Project to reduce costs,to adopt main distribution companies' structure to the reformed sector organization and to improve and expand distribution services.

(d) **Tariff Adjustment Program.** The proposed tariff adjustment path appears to be sound and strikes a balance between financial objectives and a constitutional mandate to provide subsidies to lower income consumers (see the financial projections in Annex 8). The adjustment is taking place within the context of the new sector laws promulgated in 1994 which allow a six-year period for executing it. Nevertheless, Government plans are to reach the full economic cost levels by 1998.

1.42 The most pressing short term implementation problem facing the sector consists of setting up the competitive market for bulk supplies. This involves regulatory issues, which constitute a major challenge for the Energy Regulation Commission and transmission and dispatch issues under responsibility of ISA.

1.43 The sound functioning of the bulk power market, under the reformed legal and regulatory framework requires that appropriate procedures are set in place to: (a) avoid monopolistic pricing, collusion and other price-distorting behavior and (b) allow price signals to operate so that they attract investors to the generation business. This issue is being addressed with support from the Technical Assistance Loan for the energy sector, which has a component exclusively oriented towards ERC support.

1.44 The transmission and dispatch issues involve the need for upgrading dispatching procedures and implementing financial clearing house functions that are acceptable to participants in the bulk market. This upgrading will require investments in both telecommunications and computing equipment and software. For the market to function effectively, transmission bottlenecks should be lifted in order to allow free energy flows between generators and bulk consumers. The proposed project will support ISA in addressing these issues by: (a) financing the required control center hardware and software; (b) financing transmission lines and substations; and (c) complementing the Technical Assistance Project with an additional training component oriented towards dispatch and clearing-house functions.

2. THE PROJECT

A. Project Context

2.1 The country's prospects for economic development and the Bank's assistance strategy were discussed by the Board on December 16, 1993. The country assistance program seeks to help the Government consolidate and increase its structural reforms, to support private-sector-led growth, to improve the delivery of basic services, to protect the environment, and to strengthen institutional capabilities. It proposes to maintain a lending program with emphasis on technical assistance and it explicitly endorses support for a comprehensive reform of the power sector which would create an environment which attracts private capital into the sector. The proposed project responds to this strategy by supporting the implementation of the ongoing power sector reform program. It is also the first major lending operation for the power subsector since 1987 and the first loan to ISA since 1978.

2.2 Over the past four years, the Bank has had an active role in promoting institutional reform in the Power Sector in Colombia. During this period, substantial changes have been made to the legal/regulatory and the institutional frameworks to introduce competition and transparent regulation. Two complementary approaches have been adopted for this support: (a) provision of technical assistance in preparing and implementing the sector reform program, and institutional strengthening; and (b) lending support for specific projects and investments which will consolidate the reform process and promote the effective operation of key sector institutions.

2.3 Technical assistance will continue to be provided through the Energy Sector Technical Assistance Project which has supported institutional reform within the energy sector as a whole. It includes: (a) assistance in setting up regulatory agencies and developing pricing policies for power and gas; (b) assistance to the power and gas sectors in the process of incorporating private capital and introducing competitive incentives; (c) assistance in developing environmental regulations and guidelines for the energy sector; and (d) development of a demand side management strategy.

2.4 Processing of the proposed project would be a continuation in the implementation of Bank-endorsed policies: It will advance the power sector reform program by consolidating a stronger national transmission system and by supporting the organization of a bulk supply market for electricity.

B. Project Objectives and Description

2.5 The project's overall objective is to support power sector reform by facilitating the operation of a competitive bulk supply market for electricity. Specifically, the project seeks to lift transmission constraints that hinder an open access of publicly as well as privately owned power generators to the grid and to support ISA in its role as transmission network operator, system generation dispatcher and commercial transactions coordinator. The project will be a key component of the comprehensive power sector restructuring that is being put in place with Bank assistance.

2.6 The project consists of three components (see also Annex 10 - Project Description, Costs and Implementation Plan):

PART A: Energy Control Center (ECC) and Financial Settlement Center (FSC).

2.7 This component includes the upgrading of the data acquisition and control functions of ISA's existing ECC and the installation of a FSC. The project will finance the purchase of measurement, data acquisition, telecommunications, data processing equipment and software.

PART B: Strengthening and Expansion of the Interconnected Transmission System.

2.8 This component includes investments to strengthen and expand the national transmission system; the following is a summarized list of major elements:

(i) **San Carlos-San Marcos System**. (a) construction of a single circuit, 384 km, 500 kV transmission line interconnecting the East Antioquia hydroelectric complex to the Valle del Cauca Department; (b) construction of a single circuit, 30 km, 230 kV transmission line interconnecting the La Virginia and La Hermosa substations; (c) expansion of the San Marcos 500/230 kV substation; (d) construction of the La Virginia 500/230 kV substation; and (e) construction of the San Carlos 500/230 kV substation.

(ii) **Atlantic Coast System:** (a) reactive compensation for the Chinú substation; (b) expansion of the Cerromatoso 500/230 kV substation; (c) construction of the Urabá 230/115 kV substation; (d) construction of the double circuit, 80 km, 230 kV La Loma- El Copey transmission line; (e) expansion of the 500/115 kV Chinú substation; (f) expansion of the 500/230 kV Sabanalarga substation.

(iii) **Other Transmission Components:** (a) reactive compensation for the Caño Limón substation; (b) construction of the single circuit, 160 km, 230 kV transmission line between Paipa and Bucaramanga; (c) construction of the Paipa 230 kV substation; (d) construction of the Bucaramanga 230 kV substation; and (e) construction of a link between the San Felipe substation and the 230 kV Esmeralda-La Mesa transmission line;

PART C: Technical Assistance:

2.9 This part includes the provision of consulting services and training programs to assist ISA in the strengthening of its capabilities to assume its roles of: (i) transmission network operator, (ii) power dispatch coordinator and (iii) bulk electricity transaction clearing house all in the areas of power market, planning and engineering, systems operations and dispatch, management of financial matters and environmental issues and other areas agreed with the Bank. Corresponding activities will be agreed upon between ISA and the Bank subject to an annual plan to be approved by the Bank. An initial list of studies and training activities for the first year of execution of the project is included in Annex 10.

C. Project Cost and Financing

2.10 The cost estimate for the project is summarized in Table 1, details are in Annex 10. The project's total cost including taxes, duties, physical contingencies, price contingencies and interest during construction is estimated at US$ 410.0 million, of which US$ 249.3 million (60%) corresponds to direct plus indirect foreign costs and US$ 160.7 million (40%) corresponds to local costs. Taxes and import duties are estimated at US$43.9 million. Cost estimates are in December 1994 prices.

2.11 Costs are based on ISA's estimates, which have been reviewed by the Bank and found acceptable. ISA maintains a database of transmission and substation costs with similar characteristics to those of the project; it was updated during project preparation on the basis of recent international bids for similar projects. Physical contingencies, which amount on average to 12%, were estimated based upon the type of project and the status of its design. Price contingencies assume: (a) a project execution period of six years based on the 1994 Bank standard disbursement schedule for power projects in LAC, and (b) escalation rates over and above base cost plus physical contingencies of 2.6% for 1995-2001.

TABLE 1
COLOMBIA - POWER MARKET DEVELOPMENT PROJECT
COST ESTIMATE
(US$ thousand)

		SUBTOTAL FC	SUBTOTAL LC	TOTAL
	PART A: Energy Control Center and Financial Settlement Center			
1.	Engineering and Administration	6,323	2,380	8,703
1.1	Engineering	6,323	2,061	8,384
1.2	Administration	0	319	319
2.	Direct Construction Cost	10,096	1,686	11,782
	Subtotal	16,419	4,066	20,485
3.	Physical Contingencies	2,463	610	3,073
	SUBTOTAL PART A	**18,882**	**4,676**	**23,558**
	PART B: Expansion of the Interconnected Transmission System			
1.	Engineering and Administration	530	21,204	21,734
1.1	Engineering	530	14,887	15,417
1.2	Administration	0	6,317	6,317
2.	Direct Construction Cost	153,370	94,502	247,872
2.1	Land Purchase	0	6,507	6,507
2.2	Lines and Substations Construction	153,370	87,995	241,365
	Subtotal	153,900	115,706	269,606
3.	Physical Contingencies	23,085	17,356	40,441
	SUBTOTAL PART B	**176,985**	**133,062**	**310,047**
	PART C: Technical Assistance to ISA			
1.	Technical Assistance	1,927	1,021	2,948
1.1	Studies	964	443	1,407
1.2	Training	964	578	1,542
	Subtotal	1,927	1,021	2,948
3.	Physical Contingencies	289	153	442
	SUBTOTAL PART C	**2,216**	**1,175**	**3,391**
	Total A+B+C			
1.	Engineering, Administration and Technical Assistance	8,780	24,606	33,386
2.	Direct Construction Cost	163,466	96,188	259,654
	Subtotal	172,246	120,794	293,040
3.	Physical Contingencies	25,837	18,119	43,956
	SUBTOTAL A+B+C	**198,083**	**138,913**	**336,996**
	Escalation	14,460	6,807	21,267
	Subtotal (Including Escalation)	212,544	145,719	358,263
	Interests During Construction	36,770	15,009	51,779
	TOTAL PROJECT INCLUDING TAXES AND DUTIES	**249,314**	**160,729**	**410,042**
	Taxes and Duties	0	43,908	43,908
	TOTAL PROJECT WITHOUT TAXES AND DUTIES	**249,314**	**116,821**	**366,134**

2.12 To estimate total required financing, the Bank's interest rate of 7.1% per annum (effective at the time of the appraisal) and a 0.25% p.a. commitment fee were used for the foreign component. Interest during construction for the local currency was estimated at 5% per annum in constant terms, which is equivalent to the rate applied by FEN to loans to utilities for power projects. Bank loans for a total of US$ 249.3 million are proposed to cover the foreign currency component. Local financing would be provided by ISA's own cash generation (see Financial Analysis).

Financing Plan
(US$ million)

	LC	FC	TOTAL
IBRD	0	249.3	249.3
ISA	160.7	0	160.7
TOTAL	160.7	249.3	410.0

2.13 The proposed loan package comprises two loans. A first loan for US$145 million (58% of total) would be a LIBOR-based US$ Single Currency Loan, with 17 years repayment including a grace period of 4 years. A second loan equivalent to US$104.3 million (42% of total) would be a Currency Pool Loan involving 17 years repayment, including a grace period of 4 years.

D. Institutional Arrangements

2.14 Responsibility for overall oversight of ISA's expansion plans is vested in the Ministry of Mines and Energy (MME) and the National Planning Department (Department Nacional de Planeación, DNP). MME and DNP are responsible for evaluating ISA's proposals and making recommendations to the CONPES. The proposed project, which is part of the Third Transmission Expansion Plan of ISA, has been reviewed by MME and DNP and approved by CONPES (National Council for Economic and Social Policy). CONPES's approval includes authorization to enter into financial arrangements for internal and external financing for the project.

2.15 The project would be implemented under Loan Agreements between the Bank and the Borrower and Guarantee Agreements between the Bank and the Government.

E. Project Implementation

2.16 The project will bė implemented by ISA. Interconexión Eléctrica, ISA's predecessor had extensive, lengthy experience and performed well in implementing Bank financed projects. Part A of the project (Energy Control Center and Financial Settlement Center) would be the responsibility of ISA's National Dispatch Directorate. Implementation of Parts B (Expansion of the Interconnected Transmission System) and C (Technical Assistance) of the project would be the responsibility of a Project Executing Unit (PEU) under the Transmission Directorate. The PEU is well staffed with experienced professionals and has enough resources and autonomy to seek consultant support whenever this is needed. The Project Execution Directorate has successfully carried out several projects financed by loans from the Bank and IDB and has proven implementation capabilities.

2.17 Project preparation is well advanced. Pre-feasibility studies for the ECC and FSC centers have been prepared by ISA, have been reviewed by the Bank and found satisfactory. Additionally, ISA has procured and will finance from its own resources the participation of a specialized consulting firm for completing the project design and the preparation of bidding documents for the implementation of the ECC and the FSC. These are expected to be ready by end 1995; before any procurement for this project component takes place. However, to ensure that designs for the ECC and the FSC are completed in time, during negotiations agreements were reached with ISA that, as a condition for disbursement for goods and services under part A of the project, ISA will provide satisfactory final design of the ECC and the FSC. Planning and engineering design studies for the transmission component, which accounts for about 95% of the total project cost, have been prepared by ISA. ISA will procure in due time and will finance with own resources specialized support from engineering firms for the preparation of executive design and bidding documents and for the supervision of the construction for each subcomponents of part B of the project in accordance with corresponding execution schedules. Implementation procedures submitted by ISA have been reviewed by the Bank and found satisfactory.

2.18 In view of the new functions assigned to the company, the appraisal team reviewed with ISA those areas that require strengthening. These include: (a) the modification of dispatch rules and the establishment of clearing house functions; (b) power system planning; (c) training for the use of new dispatch and settlement models; and (d) development of costing tools to calculate network costs and network charges.

2.19 To deal with the latter subjects, Part C of the project would provide technical assistance in the form of studies by specialized consultants and training --mostly abroad-- for ISA's professional staff. During negotiations ISA and the Bank agreed that ISA will prepare two annual plans for the carrying out of Parts C1 (studies) and C2 (training) of the Project to be approved by the Bank before the end of the preceding year. A list of the activities comprised in the studies program for the first year of execution of the Project was agreed upon, including the terms of reference for the consultant services and is available in the project file (see Annex 14).

2.20 **Project Implementation Plan (PIP):** During appraisal ISA submitted a satisfactory Project Implementation Plan (PIP). The PIP details the project management and implementation arrangements, is part of the project file and is referenced in the loan documents. For each component of the project the PIP addresses its principal features: scope and objectives, implementation plan, and implementation and disbursement schedules. The PIP will be the basic reference for ISA's management in order to monitor project implementation. The PIP will also provide the reference benchmarks for Bank supervision of the project's components.

2.21 **Procurement** arrangements for the proposed project are summarized in Table 2 [5]. Purchase of goods and equipment and contracting of construction works to be financed with proceeds of the loans for the following activities would be carried out in accordance with the Bank procurement guidelines, **Bank Guidelines for Procurement under IBRD Loans and IDA Credits** (January 1995). Purchases of goods and equipment for transmission lines and substations for a total of US$129.0 million would be procured under International Competitive Bidding (ICB). Computers and other electronic equipment for implementing the ECC and FSC for a total amount of US$ 12.3 million would be procured through Limited International Bidding (LIB) because there is only a limited number of potential suppliers. Works for construction of

[5] ISA is exempted from application of Law 80, which regulates contracts involving public entities, in respect to all aspects of Project execution, including procurement. (See Annex 1, Electricity Law.)

transmission lines and substations for a total of US$31.6 million would be procured under ICB. Equipment and installation services for substations and transmission lines for a total amount of US$50.0 million would be procured under ICB. Procurement of consultant services for a total amount of US$5.0 million will be carried out in accordance with the **Bank Guidelines for the Use of Consultants** (August 1981). An aggregate amount of US$1.0 million would be used to reimburse foreign expenditures incurred by ISA in its training abroad of ISA staff, such as tuition fees and travel expenses for attending courses and seminars. Bank issued standard bidding documents would be used for all procurement of goods and works. For complex time-based consulting assignments Bank issued standard form of contract for consulting services will be used. To expedite procurement, an initial list of procurement packages was agreed with ISA and is available in Annex 10. Procurement packages under ICB arrangements would be about 30 with an average cost of about US$ 7.4 million, a minimum cost of US$ 1.0 million and a maximum cost of about US$ 38 million. There would also be about 50 locally procured packages not financed by the Bank with an average cost of about US$500,000; these packages are not likely to attract foreign bidders and local procurement is considered to be the most efficient procedure. Goods and services not financed with proceeds of the loans would be procured locally under ISA's established procurement practices, which have been reviewed by the Bank and found to be satisfactory.

Table 2: Procurement Arrangements

(US$ million)

A. Procurement Method(1)	**ICB**(2)	**NCB**	**OTHER**	**NBF**(6)	**TOTAL**
Goods	129.0		12.3 (3)	50.0	191.3
	(113.6)		(10.0)		(123.6)
Works	31.6			12.5	43.4
	(25.0)				(25.0)
Equipment and installation	50.0			34.6	84.5
	(43.0)				(43.0)
Consultant services			28.6(4)	8.4	37.0
			(5.0)		(5.0)
Training courses			1.9(5)		1.9
			(1.0)		(1.0)
Total	210.0		42.8	105.4	358.3
	(181.6)		(16.0)		(197.5)

(1) Figures in parentheses are amounts financed by the proposed Bank Loan, including contingencies. Table does not include US$ 51.8 million of interest during construction.
(2) Goods and services to be procured by International Competitive Bidding in accordance with Bank guidelines
(3) Limited International Bidding only for Part A.
(4) Contracting of Consultants in accordance to Bank guidelines.
(5) Training: reimbursement of foreign currency expenses.
(6) Not Bank financed. To be procured locally under ISA's established procurement practices.

2.22 **Prior Review**. All contracts for goods and works under ICB and LIB and all contracts related to training services (other than consultant services) equal or exceeding US$ 300,000 would be subject to the Bank's prior review. The provisions of the Consultant Guidelines requiring prior Bank review or approval of budgets, short lists, selection procedures, letters of invitation, proposals, evaluation reports and contracts, shall not apply to: (a) contracts for the employment of consulting firms estimated to cost less than US$100,000 equivalent each; or (b) contracts for the employment of individuals estimated to cost less than US$50,000 equivalent each. However, said exceptions to prior Bank review shall not apply to: (a) the terms of reference for such contracts; (b) single-source selection of consulting firms; (c) assignments of a critical nature, as reasonably determined by the Bank; (d) amendments to contracts for the employment of consulting firms raising the contract value to US$100,000 equivalent or above; or (e) amendments to contracts for the employment of individual consultants raising the contract value to US$50,000 equivalent or above. Contracts subject to prior review would cover about 85% of Bank financed goods and services. The balance of contracts would be subject to ex-post review by the Bank after contracts are awarded. When evaluating bids for goods, qualified domestic manufacturers would be eligible for a 15% margin of preference, or the import duty, whichever is lower.

2.23 **Disbursements.** ISA expects to complete project implementation in four years. However, under the 1994 standard disbursement profile for power projects implemented in the LAC region, the loans would be disbursed over a seven years period. The disbursement schedule is attached in Annex 10. Proceeds from the loans would be applied to finance following estimated amounts of project expenditures:

(a) 90% of expenditures for works (US $25.0 million);

(b) 100% of foreign expenditures and 90% of local expenditures (ex-factory cost) for the purchase of goods (US$ 10.0 million for part A of the Project and US$ 103.6 million for parts B and C of the Project);

(c) 95% of expenditures for contracts for the supply of equipment and installation thereof (US$ 43.0 million);

(d) 100% of foreign expenditures for consultant services (US$ 0.5 million for part A of the Project and US$ 4.5 million for parts B and C of the Project);

(e) 100% of foreign expenditures for training of ISA staff abroad and training fees (US$ 1.0 million); and

(f) interest and other charges under the Bank loan, (US$ 36.8 million);

(g) unallocated expenditures (US$ 24.9 million).

2.24 Disbursements against statement of expenses (SOE) will be made in respect of training service contracts costing less than US$ 300,000 and for consultant services not subject to prior review. Retroactive financing of up to US$ 10 million for eligible expenditures (made after March 31, 1995, but no more than 12 months before signing) would be provided for under each loan. Eligible expenditures would have to follow procurement procedures acceptable to the Bank. The Project is expected to be substantially completed by 2001 with a closing date of December 31, 2002.

2.25 The Borrower would establish for each loan Special Accounts in US dollars with a commercial bank acceptable to the Bank to cover eligible Bank expenditures under the loan. The authorized allocation to the Special Accounts would be US$8 million for each loan. However, they should not exceed US$4 million during the start-up of the project. The balance could be requested when the total amount disbursed from each loan account plus outstanding commitments has reached US$20 million. Subsequent replenishment by the Bank into the Special Accounts would follow the procedures by which Bank funds are disbursed against actual expenditures.

2.26 **Monitoring.** With regard to the overall company's performance, ISA and the Bank have agreed on a set of operational and financial performance indicators, which are attached as Annex 15. During negotiations agreement was reached that ISA would comply with these indicators. ISA would also be required to submit biannual reports on the progress of implementing the project together with an evaluation of its performance measured against targets defined in the PIP. Arrangements for auditing are discussed in para. 4.9. ISA and the Government will conduct with the Bank formal project review meetings within four months of the close of ISA's fiscal year starting in 1996, for the purpose of discussing project progress, overall project execution during the preceding year, and ISA's financial situation and local funding capability in subsequent years. The meeting to be held not later than April 30, 1998, will be the Mid-term Review of the project.

F. Environmental Considerations

2.27 Over the past years ISA has demonstrated a noteworthy commitment to incorporating environmental issues within the decision making process to select optimal expansion plans. ISA's methodology for taking into account socio-environmental aspects is considered by the Bank to be "state of the art" in the planning and management of its transmission system. During project preparation, following World Bank guidelines, ISA carried out a Sectoral Environmental Assessment (SEA) of the Colombian Power Sector[6]. The SEA included among others, a general evaluation of the status of socio-environmental issues at the sectoral level, a diagnosis of environmental impacts derived from the existing transmission system as well as the impact expected from the new transmission lines foreseen in the expansion plan.

2.28 The civil works to be financed include power transmission lines and substations which will involve small potential environmental risks. ISA prepared an environmental analysis[7] which

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[6] Evaluación Ambiental Sectorial. Sector Eléctrico Colombiano. Ministerio de Minas y Energía - ISA, 1994. This report is available from the Bank's Public Information Center.

[7] Informe de Restricciones Ambientales - Tercer Plan de Transmision. ISA. This report is available from the Bank's Public Information Center.

identifies the main environmental and social constraints within the proposed transmission corridors. The environmental constraints identified by the ISA report were incorporated in the design, construction and operation of the transmission lines.

2.29 The corridors do not affect indigenous reserves, cultural protected areas, densely populated settlements, natural reserves, national parks, water supply facilities or important productive activities. About 60 households currently located along the corridors will require relocation. This is usually simpler for transmission lines as compared to other types of infrastructure construction, as buildings only require a few meters displacement and in most cases land can continue to be used for agriculture or grazing. In this case it will consist of building new houses, and in most cases families will be able to remain on their land. In 1991 the Colombian Electric Power Sector, under ISA's leadership, approved a Resettlement Policy (RP) that meets the Bank's requirements. By applying the RP, ISA has successfully undertaken the resettlement of scattered populations through a participative approach; the concerned families have been contacted and informed of ISA's resettlement policies as well as their rights in terms of compensation and indemnity. According to Bank policy, a resettlement plan is not required for projects with this number of displacements; nonetheless, ISA is preparing resettlement plans and environmental management plans which will be submitted for Bank approval before opening the bidding process for the civil works of each transmission line (see para. 2.30 bellow).

2.30 The project has been rated in the "B" environmental category, i.e. no major environmental impacts are expected as a result of either construction or operation of the new transmission facilities. Although the project was rated with environmental category "B", the borrower was required to prepare a project-specific environmental report for each transmission line. Each report must contain a detailed Environmental Management Plan (EMP) to mitigate undesirable effects on human populations and natural resources during construction and operation of the project. Once the EMP and resettlement plan for each line have been agreed with the Bank, and before authorizing any contractor to initiate the construction and assembly phase of each transmission line, ISA will provide each of the persons affected by the works enforceable rights to a new home or adequate compensation or both, according to the corresponding resettlement plan.

2.31 It is worth noting that ISA has put in place an Environmental Management System (EMS) specially designed for transmission projects, which is being successfully applied to the existing 500kV system and to other 230kV lines. The current EMS designed by ISA has been applied in other electric power sectors in Latin America, particularly in Ecuador and Uruguay where ISA is providing technical assistance. Finally, by encouraging more efficient power generation and by helping to reduce electricity losses, the project will promote energy efficiency and thereby have a positive indirect environmental impact.

3. ECONOMIC ANALYSIS

A. Economic Evaluation

Control Center and TA Benefits

3.1 The benefits of the new dispatch and financial settlement centers, and of the technical assistance to help in their operation, are not directly quantified because of the difficulties associated with estimating the corresponding benefits. They are essential for the power market to develop. Without such new equipment and the requisite training, the existing dispatch center, which is based on equipment that is substantially out of date, will be unable to either operate the network efficiently or to create proper financial accounting for the settlements required under the new commercial rules. It is recognized worldwide that energy management control centers represent a small portion of sector investments while their benefits are high.

Transmission Component Benefits and Costs

3.2 The project for the investment in new transmission plant would help Colombia to reduce the costs of electricity supply through increasing both its quantity and quality by: (a) reducing transmission losses by upgrading certain sections of the grid from 230 kV to 500 kV; (b) allowing more power and energy to be transmitted and delivered to consumers; and (c) allowing generation to take place at lower cost plants than would otherwise be possible, hence leading to a reduction in total fuel costs for the system as a whole. In addition, the strengthening of the national grid will promote competition between generators by reducing the likelihood that, because of transmission bottlenecks, high cost plants may operate when lower cost plants are available. The stronger transmission system will therefore act as an increased stimulus to the entry of private power producers by ensuring that they will be able to fully utilize any cost advantages that they possess.

3.3 The economic analysis consists of: (a) a **cost-effectiveness** analysis whereby it is shown that the components of the project are (i) the least cost alternative for accomplishing their objective and (ii) each element of the project is more economic than its second best alternative which would provide equivalent services; and (b) an **economic analysis** which shows that the resources used in the proposed investment program provide an acceptable rate of return. The detailed results are included in Annex 11 and are summarized below.

Cost-effectiveness analysis.

3.4 In February 1995 the Ministry of Mines and Energy and Interconexión Eléctrica prepared a least cost generation and transmission expansion plan, covering the period up to 2007, based on a detailed macroeconomic scenario and an associated electricity demand forecast. This plan defined reliability criteria for both generation and transmission and then estimated costs of a number of alternative scenarios for expanding generating capacity and the transmission system, in order to determine the least cost program. The transmission lines and substations included in the project are part of the least cost expansion plan which was reviewed by the Bank and found satisfactory. This indicative expansion plan was officially endorsed by the Government on 15 February 1995[8].

3.5 The two main components of the project, namely the San Carlos-San Marcos system and the Loma-El Copey system were evaluated. The approved expansion plan provides a joint generation/transmission optimization and the analysis performed for the appraisal seeks to verify that they constitute a least cost solution by comparing them with second-best alternatives.

3.6 **San Carlos-San Marcos Component.** The second-best alternative to the San Carlos-San Marcos project consists of relocating gas-based generation plants to the Southwest of the country where they would supply the equivalent load carried by the project. The tradeoff involved consists of comparing the costs of the project (i.e. electricity transportation) with the alternative of transporting natural gas. The analysis yielded an Equalizing Discount Rate (EDR) of 20%, i.e. the discount rate whereby the project becomes equivalent to the second-best alternative; this discount rate exceeds the benchmark discount rate (12%). The ratio between the project's costs and the savings provided against the second-best alternative yields a Benefit/Cost (B/C) ratio of 1.6. These results confirm the San Carlos-San Marcos project as the best technical alternative for supplying electricity to the Southwest of the system.

3.7 **Loma-Copey Component.** The Loma-Copey project will provide an additional interconnection between the central and Atlantic Coast subsystems. It is also closely associated with evacuating energy from the 300 MW Termocesar coal-based power plant which is included in the approved expansion plans for 1995-2000 and which will provide fuel diversification in the future. The second-best alternative to the Loma-Copey project would require replacing this coal plant by equivalent coal-based generation in the Northeast and Atlantic Coast regions. Two alternatives were identified; however, they require higher investments compared to the Termocesar/Loma-Copey project, and although their fuel costs are slightly lower they do not compensate for the additional investment. The cost ratio between the project and the alternatives is on the order of 1.04. The Equalizing Discount Rate is higher than 50%. The results confirm the Loma-Copey project as a required component of the expansion plan. It should be noted that the project will provide additional benefits by strengthening the Central-Atlantic Coast links which are critical under low-runoff conditions.

3.8 **Economic Analysis**. This phase of the analysis consists of evaluating the rate of return for ISA's overall investment program. The benefits associated with the program consist of (a) operating benefits due to lower generating costs associated with lifting bottlenecks in the transmission system and (b) incremental energy benefits which can be provided to consumers. Operating benefits were quantified by comparing operating costs with and without the investment program. Incremental energy benefits were quantified using as proxy the increased sales at the price of electricity (which provides a lower bound to consumer surplus) minus the subtransmission and distribution investment costs required to reach the consumer.

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[8] "Estrategias para el Desarrollo y la Expansión del Sector Eléctrico 1995-2007", Documento CONPES 2763, 15 February 1995.

3.9 The results of the analysis yield an Internal Rate of Return for ISA's investment program of 27% which exceeds the 12% benchmark discount rate. It should be noted that the proposed project accounts for a large portion (over 90%) of ISA's investment program. Over 90% of the benefits associated with the project are operating benefits associated with the lower running costs of thermal plants which the transmission reinforcements will achieve. This confirms the role of the project as a major element required to facilitate the operation of the bulk market for electricity.

B. Risk Analysis

3.10 This is a low risk project. Implementation risks will be minimized by the use of experienced consultants in the preparation and evaluation of bids, and contracting the execution of critical components of the project through "erect and build" schemes.

3.11 Regarding the institutional risk, the execution of the proposed project is essential for the success of the overall power sector reform process, which hinges on the satisfactory implementation of the new Public Services and Electricity Law approved by Congress in July, 1994. The new law establishes sound principles, but opposition from regional and other interest groups, such as unions, management of a number of existing utilities, and some local governments could slow down its enforcement. However, since the approval of the Electricity Law, no major problems of this nature have appeared and the Government intends to continue with its implementation.

3.12 Other risks which could impact negatively on the project include: (a) insufficient institutional capabilities in government to develop and enforce the regulations needed for the successful implementation of the competitive power market; (b) sluggish private sector response; and (c) political reluctance to implement the mechanisms for tariff and transmission charge adjustments. The Energy Sector Technical Assistance Project is addressing the issue of institutional weakness. Regarding (b), the private sector has responded positively by investing in over 1000 MW of power generation and by expressing interest in developing another 1700-2600MW. Regarding the price adjustment risk, although the Government has lost its discretionary power and can no longer set prices by fiat, it is conceivable that it could pressure the Regulatory Commission in order to reduce the rate of adjustment of electricity prices for the sake of achieving short term macroeconomic goals or fulfilling political commitments. Three safeguards exist for avoiding this contingency: (i) the terms of the Public Services Law itself; (ii) the attitude of the regulators who may be amenable to marginal revisions but would oppose major changes to the price adjustment plan due *inter alia* to the personal legal risks involved, including penal risks, in disregarding the mandates of the Law and (iii) pressures from private sector interests in the generation business who form a constituency in favour of a sound tariff policy to protect their revenues from the consequences of uneconomic pricing. Environmental risks are small and hedged.

3.13 ISA selected US dollar single currency loan terms to the maximum extent possible to reduce its currency risk. ISA has substantial yen liabilities and has chosen US dollar to achieve a better overall balance in its foreign currency exposure. ISA's choice of a LIBOR interest rate basis marginally increases interest rate risk since ISA's tariff level is subject to a cap imposed by the Regulatory Commission. ISA has capacity to bear this risk, however, as most of its liabilities carry stable interest rates.

3.14 A series of sensitivity analyses against less favorable cases are considered in order to determine the robustness of the conclusion that the transmission components of the project are economically justified. In the case of the cost-effectiveness analysis, increases in investment costs and decreases in gas transportation and coal costs were analyzed. The projects are justified under reasonable variations of these critical variables.

3.15 Similarly, the Internal Rate of Return for ISA's transmission investment program continues to be justified (IRR of 19%) when investment costs are increased by 10% or when operating benefits are decreased by 10%. The IRR shows negligible sensitivity to changes in the value of incremental energy benefits. If demand fails to develop as expected (e.g. a 4.3% average growth rate), the investment program yields a lower IRR of 18% which still exceeds the 12% benchmark. Finally, the project risks becoming uneconomic in the unlikely event that operating savings decrease by around 27% over the program's lifetime with respect to their estimated values, or that investment costs increase by 30% with respect to their budgeted amounts.

4. THE BORROWER

A. ISA

4.1 The borrower of the proposed loans would be ISA, one of the two companies which originated from Interconexion Electrica. ISA has kept the full name of the former Interconexión Eléctrica S.A. and the alternative denomination of the acronym ISA[9]. Interconexión Eléctrica was established in 1967 with Bank sponsorship in order to interconnect the regional electricity companies, to develop future generation projects and to coordinate system dispatch. It was a stock company (Sociedad Anónima) whose assets by end 1994 were estimated at US$ 2.7 billion, constituted by generation plants for a total of 2,542 MW of installed capacity, about 6,300 km of transmission lines, about 8,000 MVA of installed capacity in transformer facilities, and headquarters offices and other facilities in Medellin. In December 1994, Interconexion Electrica employed a total of 1380 skilled and well trained staff.

4.2 Interconexión Eléctrica was initially owned by three regional companies and a government institute. In subsequent years, ownership was expanded to include CORELCA, the Atlantic Coast utility. With the financial restructuring that took place in 1991-92, the Government became the major shareholder in the company. The Bank has supported the development of Interconexión Eléctrica since 1968 through four loans totaling US$ 300 million which financed the national interconnection grid and three power stations. The execution of all these projects was successful. The company also executed the 500 kV interconnection project between the central region and the Atlantic Coast, partially financed by a US$ 50 million Bank loan.

4.3 The development of Interconexión Eléctrica can be traced through four distinct periods: (a) during 1967-76 it accomplished the 230 kV interconnection of the generation companies in the central region of the country and established itself as the sector's leader, by assuming responsibility for sector planning and implementing most of the sector's expansion; (b) during 1976-90 Interconexión Eléctrica reinforced the national interconnection by implementing the 500 kV Sabanalarga-San Carlos system and became the major generator with the development (with Bank support) of the Chivor, San Carlos and Jaguas hydro power plants, together with smaller thermal units; (c) in 1990 it initiated a four-year period of financial consolidation which improved and strengthened the company's finances; and (d) in 1994 it initiated a major reorganization which eventually facilitated the unbundling of generation and transmission services in Colombia in line with the newly established regulatory reform.

4.4 As part of the power subsector reform program, Interconexión Eléctrica was split into two autonomous corporations in 1995: a generation company (ISAGEN) which is now in charge of the generation facilities and a transmission company which has continued to be known as ISA. ISA will constitute the backbone of the power market, responsible for transmission and dispatch functions, and, by delegation, will operate the commercial settlement facilities of the newly

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[9] To avoid confusion this report refers to Interconexión Eléctrica when naming the former generation and transmission company, which was also formerly known as ISA.

established power market. ISA's assets have been defined at the vesting date as US$ 690 million or 26% of the total assets of Interconexión Eléctrica. ISA and ISAGEN are controlled by the National Government, who owns 76% of their shares. Currently the Government is considering alternatives for privatizing ISAGEN, while privatization of ISA will eventually take place only when both the company and the commercial system have further consolidated.

4.5 When Interconexión Eléctrica was split, its assets were assigned to ISA and ISAGEN according to their function; a similar process was performed for long term debts, whereby the latter were allocated according to which company owned the assets financed by a given credit. Formalizing this process requires lenders' cooperation, mainly from the Bank, IDB and FEN who are creditors for over 95% of Interconexión Eléctrica's debt. ISA and ISAGEN are in the process of petitioning their respective creditors to concur with its proposed division of liabilities and to implement the required modifications in the outstanding loan agreements; in principle, the banks' operational management have agreed to submit in due time this proposal to their boards. In the interim ISA and ISAGEN have maintained joint and several liability with respect to the former Interconexión Eléctrica's debts, contracted on or before April 30, 1995. In those cases where the original borrower Interconexión Eléctrica received the guarantee of Colombia, both ISA and ISAGEN expect to be released from the joint and several liability, to complete the seperation of the companies. ISA has shown satisfactory evidence that any residual liability it may have with respect to ISAGEN's debts will not imperil the performance indicators agreed during negotiations.

4.6 **Structure.** ISA is structured along business centers: transmission, dispatch and telecommunications, duly supported by financial, administrative, legal and environmental services. As part of the restructuring of Interconexión Eléctrica, ISA has sustained a major reorganization aimed at: (i) improving the efficiency of the technical development process; (ii) separating accounts and establishing performance indicators to identify sources of income and room for improvement; (iii) improving planning methods; and (iv) instituting a client oriented attitude. Interconexión Eléctrica was an efficient, well run utility and prospects are that ISA, which has kept 959 staff from the former utility, will follow suit. ISA's current organization chart is shown in Annex 9.

4.7 **Accounting**. ISA keeps its accounts in accordance with generally accepted accounting principles regulated by decree #2649 issued in December 1993, which are consistent with those of international accounting standards. Since 1992 ISA's accounting system is adjusted monthly due to inflation in accordance with decrees #2911 and #2912. ISA has a well developed computerized system for financial, inventory, and budget control, billing, banking, and payroll.

4.8 **Financial Planning**. Since December 1989, ISA's budget has been submitted to the National Council for Fiscal Policy (CONFIS - Consejo Nacional de Política Fiscal) for inclusion in the National Budget. In addition to the annual budget, ISA prepares a corporate budget in November of each year. A preliminary ten-year investment plan is also prepared with its corresponding financial projections. MME revises the plan and presents it to CONPES for approval. ISA has adopted adequate long-term financial planning software based on a model developed by IDB to provide management with a reliable long-term view of the expected financial performance of the utility.

4.9 **Audits**. ISA's financial statements are audited by Paez y Asociados, an independent auditing firm. Audit regulations and standards are based on international auditing practices. During negotiations, agreement was reached with ISA that: (i) ISA's annual and Bank-financed project accounts will be audited by independent auditors acceptable to the Bank; (ii) ISA will maintain separate accounts for the project; and (iii) ISA will provide the Bank, within four months after the end of each fiscal year, audits covering project accounts, the special accounts, the statement of expenditures, and the company's financial statements.

4.10 **Internal Audit**. The Internal Audit Unit reports to the general manager; it is in charge of periodically examining the operational, financial and accounting procedures, the management controls, and making a security assessment of the computational software system. Currently, ISA is developing an internal auditing control plan, which would include periodic operational and financial auditing to improve efficiency in the use of ISA's resources, based on the recommendations made by a consultant firm.

4.11 **Insurance**. ISA follows sound insurance practices, generally consistent with power utilities practices. 39% of ISA's transmission power sub-stations are insured against fire, explosion, and flooding. For cost reasons, ISA's transmission lines are not insured. Replacement of transmission assets eventually damaged becomes part of the operating costs, which is normal practice for large utilities.

4.12 **Taxes**. As a result of the Public Services Law, ISA is taxed under conditions similar to other sector companies. ISA is now required to pay 37.5% income tax. ISA must pay 15% custom duties, 14% VAT on imported goods and engineering consultant services, and on profits of construction and assembly services. VAT paid for capital expenditures is discounted from income tax at the commissioning year.

B. Financial Analysis

4.13 ISA was recently created on a sound financial footing. Most of Interconexión Eléctrica's financial problems were related to the generation business and were inherited by ISAGEN. ISA's financial performance is expected to continue being satisfactory as long as the ERC's rules are applied consistently. In particular, ISA's income hinges on a periodic adjustment of transmission charges as well as its regulated revenue ceiling. The rules for adjusting these values provide for keeping up with inflation as measured by the Wholesale Price Index, plus an additional allowed real growth rate to generate cash needed for expansion investments.

4.14 ISA's projected financial statements for 1995-2004 are presented in Annex 12, and are summarized in Table 3 for the disbursement period. The rate of return on revalued assets between 1995 and 2004 is expected to average 6-8% depending on the depreciation method. The cash operating ratio (total cash operating expenses/total gross revenues) would improve from 21% in 1995 to about 20% in 2001, indicating that annual revenues tend to increase more rapidly than operating costs. The self-financing ratio is expected to be over 50% during the period. The debt service coverage is expected to vary between 1.7 and 2.3 and to exceed the benchmark value of 1.5.

Table 3: ISA- Projected Financial Performance
(Col$ billion)

	1995	1996	1997	1998	1999	2000	2001
Total Operating Revenues	129.8	166.7	201.0	239.6	288.3	354.2	418.2
Total Operating Expenses	88.1	105.4	124.1	149.2	186.0	233.5	255.2
Net Operating Income	41.7	61.3	76.9	90.4	102.3	120.6	163.0
Annual Capital Expenditure	85.0	107.8	182.3	272.9	78.6	52.4	321.2
Borrowings	93.9	59.3	107.6	165.1	15.9	0.0	116.8
Net Debt Service	56.7	70.5	82.7	75.6	91.5	144.7	151.9
Net Fixed Operating Assets	930.1	1092.1	1235.0	1673.8	1810.1	2267.6	2425.6
Total Long-Term Debt	312.5	369.2	486.2	668.8	675.0	653.6	744.1
Rate of Return							
accelerated depreciation (%)	4.9	6.1	6.6	6.2	5.9	5.9	6.9
linear depreciation (%)	8.2	8.9	9.1	8.2	8.0	8.0	8.3
Cash Operating Ratio %	20.6	19.5	19.1	21.2	20.2	20.5	19.7
Self Financing Ratio (%)	34.4	75.0	30.1	30.4	110.3	224.0	54.2
Debt Service Coverage	1.7	1.8	1.9	2.1	2.2	2.0	2.2
Debt as % of (Debt + Equity)	32.8	32.5	33.6	36.6	34.2	30.5	29.6

4.15 Sensitivity analyses of the financial projections were carried out for the following cases: (A) revenues are not adjusted according to the regulatory provisions to provide for increase of investment made after 1999; (B) same as case A plus a delay in the execution of the investment program, which forces ISA to pay penalty charges; (C) same as case A plus higher inflation (local inflation 3 percentage points higher and foreign inflation 1 point higher). Cases DI and DII simulate an eventual delay in payment by the weaker distribution companies; the case corresponds to a one-year cessation of payments during 1997 (a year when ISA's cash flow is more demanding), followed by a resumption of payments and a settlement of arrears. Case DI assumes that "small and unsolvent utilities" (see Annex 8, Table 8-7) delay payments. Case DII assumes that in addition to the arrears supposed in DI "small and under recovery utilities" also delay payments, resulting in a shortfall of 20% of ISA's revenues. Case D is unlikely to materialize: the Energy Regulatory Commission has set stiff penalties for non-payment of transmission charges; the delinquent company must settle its debts and tender a bank guarantee covering the next year's payments; otherwise, if the company does not comply, fines can be imposed and managers can be discharged and denied employment in utility companies for a ten year period. Annex 12, Attachment 6 shows the results of this analysis for 1995-99 and for 2000-04. The results for the coming five years (1995-99) are summarized in Table 4.

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Table 4 Financial Sensitivity Analysis
(Current US$ million)

Financial Indicators	Base Case Period (95- 99)	Case A Period (95-99)	Case B Period (95-99)	Case C Period (95-99)	Case DI Year 1997 D-1	Case DII Year 1997 D-II
Operating Revenues	868	865	865	878	174	174
Operating expenses	554	554	554	575	107	107
Net Income	314	312	312	302	67	67
Gross Internal Cash Generation	714	711	683	714	153	153
Debt Service (excludes IDC)	325	326	328	327	71	71
Internal Cash Generation	388	385	355	387	82	82
Borrowings	395	395	395	413	93	93
Investment (includes IDC)	624	623	623	639	158	158
Average Rate of Return %	8.5	8.5	8.5	8.3	9.1	9.1
Average Cash Operating Ratio %	20.2	20.2	20.2	20.7	19.0	19.0
Average Debt Service Ratio	1.9	1.9	1.8	1.9	1.9	1.9
Average Self-financing Ratio %	37	37	35	35	16	16
Debt as of % of (Debt plus Equity)	34	34	34	34	34	34

4.16 These indicators show that ISA's financial performance would remain sound even under these scenarios. Even in the event of a higher foreign inflation, which would affect debt service payment and the amount of capital expenditure, ISA internal cash generation would be sufficient to fund over 30% of the investment program. The cash operating ratio, average rate of return, and the debt service coverage ratio also remain at an acceptable level (under 21%, over 8.0% and 1.5, respectively). Among the information to be routinely provided by ISA once a year would be the results concerning the monitoring indicators shown in Annex 15.

4.17 To ensure a sound financial performance during project implementation, agreement was reached at negotiations with ISA and the Government that:

(a) ISA's cash operating ratio be no higher than 23%;

(b) ISA incur additional debt only if its debt service coverage ratio exceeds 1.5;

(c) ISA's self financing ratio remain equal to or above 30%;

(d) ISA provide the Bank by June 30 of each year with updated financial reports for the previous year and projections for the next five years, including monitoring indicators (Annex 15).

4.18 Another source of financial risk could consist of the Government's desire to pressure the Regulatory Commission in order to reduce the rate of adjustment of electricity prices for the sake of achieving short term macroeconomic or political goals. This risk has been considerably reduced as the Government has lost its discretionary power and would have to overcome the following obstacles: (a) the terms of the Public Services Law which would require revising its conditions in Congress; (b) the attitude of the regulators who may eventually agree to marginal changes but would oppose major adjustments due, among other, to long term penal risks involved in disregarding the mandates of the Law; and (c) pressures from private sector generators who form a constituency in favour of sound pricing policies.

4.19 The nominal rate of adjustment of regulated tariffs decreased in 1995 relative to 1994, but prices have continued to rise with the objective of reaching marginal cost levels. Furthermore, the slower adjustment rate has been compensated by two factors: (a) the lower devaluation of the colombian peso as compared to inflation (which is significant as most power system costs are dollar-denominated) and (b) lower generation prices (10-15% below 1994 levels) which have emerged from the competitive market in 1995.

5. AGREEMENTS REACHED AND RECOMMENDATION

5.1 During negotiations, agreement on the following arrangements were obtained:

(a) ISA will complete the final design of the Energy Control Center and the Financial Settlement Center before disbursements for goods and services under part A of the project are made (see para. 2.17). ISA will prepare before the end of each year two annual plans, one for studies and one for training (see para. 2.19).

(b) ISA will use Bank standard documents for procurement of the goods and services financed under the Bank loans (see para. 2.21)

(c) ISA and the Government will conduct with the Bank formal project review meetings within four months of the close of each of ISA's fiscal year starting in 1996, for the purpose of discussing project progress, overall project execution during the preceding year, and ISA's financial situation and local funding capability in subsequent years. The meeting to be held not later than April 30, 1998, is expected to be the Mid-term Review of the project. (see para. 2.26.)

(d) Prior to inviting bids for construction of each transmission line, ISA will submit a resettlement plan and an environmental management plan to the Bank for approval. ISA may invite bids for the construction and erection of the transmission lines after resettlement plans and environmental management plans have been agreed with the Bank and thus the contractor could start manufacturing of the equipment to be used in the construction of the transmission lines. However, before authorizing any contractor to initiate the line construction and assembly phase, all corresponding rights on land shall have been acquired and each of the persons affected by the works shall have been provided, according to the corresponding resettlement plan, with enforceable rights to have a new home or adequate compensation, or both (see para. 2.29 and 2.30).

(e) ISA will execute in a timely manner all actions determined in the resettlement plans and environmental management plan (see para. 2.30).

(f) ISA will: (i) have its annual and Bank-financed project accounts audited by independent auditors acceptable to the Bank; (ii) maintain separate accounts for the project; and (iii) furnish to the Bank within four months after the end of each fiscal year the audited project accounts, special accounts, statement of expenditures, and ISA's financial statements (see para. 4.9).

(g) All necessary measures will be taken to ensure that from 1996 onwards ISA's cash operating ratio does not exceed 23% (see para. 4.17).

(h) ISA may incur additional debt only if its debt service coverage ratio exceeds 1.5 of its projected debt service obligations (see para. 4.17).

(i) ISA's self financing ratio will be not lower than 30% from 1996 onwards (see para. 4.17).

(j) ISA will furnish the Bank by June 30 of each year, updated financial reports for the previous year and projections for the next five years for its revenues, capital expenditures, borrowing and debt service, accounts receivable, and finances (see para. 4.17).

(k) ISA will implement the project in accordance with the agreed Project Implementation Plan (Annex 10) and coordinated through a project unit, with an adequate implementation structure.

Recommendations: On the basis of the agreements reached, two Bank loans are recommended: (i) a US$145 million LIBOR-based US dollar single currency loan; and (ii) a US$104.3 million equivalent currency pool loan.

ANNEX 1

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POWER SECTOR REGULATORY FRAMEWORK

A. Background

1. The Colombian power sector underwent a major restructuring during the 1991-94 period. The restructuring was initiated by the government after the Operations Evaluation Department (OED) reviewed 1970-87 Bank lending to the power sector in Colombia and concluded that the sector was a source of chronic administrative and financial problems for the government and an obstacle to development[1]. The power rationing suffered by the country in 1992, as a consequence of inadequate system reliability and severe drought deepened the perception by the government and the public at large that major reforms should be introduced in the sector.

2. The major elements of the restructuring process culminated in 1994 with the approval by Congress of primary legislation in the form of two major statutes: a **Public Services Law** which provides a general framework for the supply and pricing of electricity, water, natural gas and local telephone services, and an **Electricity Law** which defines the sector structure and the organization, responsibilities and functions of different entities. Both laws emphasize the introduction of competition and provide appropriate regulation of non-competitive supplies.

3. Based on provision of the Public Services law, a regulatory entity, the Superintendency of Domiciliary Public Services (SSP), was created and, in accordance with provisions of the Electricity Law, the electricity and gas regulator (the Regulatory Commission for Electricity and Gas) is also in place. In addition to the primary legislation, these entities are in charge of issuing secondary legislation as appropriate.

B. Primary Legislation

The Domiciliary Public Services Law

4. This "umbrella-type" law covers the following main subjects:

- Responsibilities entrusted to different government levels;
- Corporate organization of public service enterprises;
- Taxes;
- Concessions for use of public goods;

[1] The World Bank 1990. Colombia - The Power Sector and the World bank, 1970-1987, Operations Evaluation Department, Report No. 8839.

- Market structure and regulation;
- Regulatory organizations;
- Pricing rules and subsidies;
- Conditions for supplying public services; and
- Special short term provisos for evolving from the then current setup.

5. **Government Rsponsibilities**. The central government is assigned the responsibility for overall policy making. Sector objectives are: to make electricity available to the population at reasonable prices, to increase service coverage, and to enhance quality of service. Government responsibilities are to assign concessions for the use of public goods (water sources and the electromagnetic spectrum) through the different Ministries (Ministry of Development for water, Ministry of Mines and Energy and Ministry of Telecommunications). The municipalities are entrusted with the primary responsibility of ensuring the provision of public services within their jurisdiction. Public enterprises are constrained to incorporating adequate funding for the payment of public services in their budgets, and to paying for them. Disciplinary penalties for non-compliance are set.

6. **Corporate Oganization.** Organizations that provide public services are constrained to operate in the form of stock corporations, with the exception of publicly owned companies which can either become stock corporations or "industrial and commercial state enterprises". In any case, the emphasis is on assuring that the regulated companies operate as corporations with no links to political bodies such as city councils or other government entities. In particular, municipalities are limited to providing public services directly only as a last resort, which would presumably apply to small communities for services such as water supply. The budget for public service enterprises is to be approved by their Boards, thereby eliminating the interference of city councils which have traditionally used this power to influence corporate decisions. Public service corporations are constrained as far as possible to being "single purpose" in order to avoid conflicts of interest and monopolistic practices.

7. **Taxes.** Public service corporations are constrained to be taxed in conditions similar to other private sector companies. The existing municipal companies are exempted for a period of seven years from this requirement.

8. **Concessions.** This type of contract is required for using public goods such as water resources or the electromagnetic waves for communications. These concessions are to be negotiated with the Government. All providers of public services are subject to performance controls by the Regulatory Commissions set up by the law and are required to retain external auditors.

9. **Market Sructure and Regulation.** Contracts regarding the supply of public services are to be treated as private sector contracts. The law seeks explicitly to promote competition whenever possible and emphasizes the limitation of monopolies or monopolistic practices. "Exclusive service areas" are acknowledged as necessary for supplying certain services. They are constrained to being assigned by the municipalities using competitive bidding procedures and are subject to Regulatory Commission approval. Such rights must have a termination date. The law

acknowledges the right for alternative suppliers to challenge the exclusivity to provide services by offering lower cost services.

10. **Regulatory Organizations.** The law establishes three Regulatory Commissions (water, telecommunications and energy) and a Superintendency of Public Services. The Regulatory Commissions are composed by the Minister responsible for a given service, three commissioners and the director of DNP. The role of the Regulatory Commissions consists of supervising the supply condition of services, resolving conflicts between suppliers, supervising market operations to prevent non-competitive behavior on the part of suppliers, establishing prices for regulated services and, when necessary, ordering the liquidation of deficient official organizations. The Superintendency evaluates the performance of public service suppliers in accordance with guidelines furnished by the Regulatory Commissions. The Superintendency and the Regulatory Commissions are to be funded from levies on the suppliers of public services.

11. **Pricing**. Prices fall into two categories: regulated supplies and those that respond to market supply and demand, which are allowed to fluctuate. The Regulatory Commissions can establish optional tariff categories and consumers are allowed to choose between different options subject to paying for the required metering equipment. Prices for regulated supplies are established following "tariff formulae" defined by the Regulatory Commission. The resulting tariffs should have a five-year application span with periodic updating using the CPI index.

12. **Subsidies**. Subsidies and cross subsidies are regulated according to the following guidelines:

- Funds for cross subsidies can be levied by charging prices above service costs, as long as they do not exceed 20%;
- Subsidies are to be channeled to users of strata 1, 2 and 3. Limits for subsidy allocation, as a percentage of service costs are 50%, 40% and 15% for strata 1, 2 and 3, respectively.
- In any case, the prices charged should cover the operations, maintenance and administrative costs of the service.
- Subsidies can be assigned by the national government or by local governments.

13. The Ministries are responsible for assessing the overall subsidy requirements to be paid by the Government and incorporating them in the National Budget.

14. **Supply Conditions.** The law sets out detailed rules concerning the relationships between suppliers and consumers, regarding billing and measurement procedures and consumer rights.

15. **Short Term Provisos.** The law orders the division of Interconexión Eléctrica into a transmission company and a generation company. The law allows a maximum period of six years for the adjustment of existing tariffs to the guidelines concerning pricing and subsidies.

The Electricity Law

16. This sector-specific statute covers the following subjects:

(a) Sector policy and planning;
(b) Regulation
(c) Electricity generation
(d) Interconnection functions
(e) Operations
(f) Network charges
(g) Pricing
(h) Environment
(i) Legislation applicable to contracts
(ij) Concession contracts
(jk) Energy conservation and demand management
(kl) Short term and transitory provisos

17. **Policy.** The law entrusts the definition of electricity policy to the Policy and Planning Unit of the Ministry of Mines and Energy; the functions assigned to this unit consist of assessing overall energy requirements and formulating strategies and policies for assuring efficient energy supplies. Expansion plans determined by the unit are of a non-compulsory character and the corresponding investments are open to be executed by any interested party.

18. **Subsidiary Role of the State**. The Government is entrusted with the ultimate responsibility for executing projects which do not elicit interest from other parties.

19. **Regulation.** The Regulatory Commission for energy consists of the Minister of Mines and Energy, the Minister of Finance, the director of DNP and five experts. The Commission's budget will be underwritten by the regulated enterprises. Its functions consist of gradually putting in place a competitive market, defining network charges, defining a methodology for calculating regulated tariff and setting regulated prices, setting the Operations Rules for the electricity system, overseeing the operation of the market and resolving conflicts between suppliers.

20. **Electricity Generation.** The generation activity is open to all economic agents who will be subject to the operating rules of the system. Generators can participate in the system either within a spot market or within a regulated mode whereby they strike contracts with distributors or unregulated consumers. Prices in the latter mode are freely established between the parties to the contract.

21. **Interconnection.** Owners of transmission lines will continue to own them but must comply with the operations rules. The transmission system will be operated by ISA once it is reorganized as a single-purpose interconnection enterprise.

22. **System Operations.** The law defines the functions of the national dispatch center and the national operations council.

23. **Pricing.** The law allows prices for contracts between generators and bulk consumers to be freely agreed upon. It establishes the obligation of network owners to allow access of unregulated consumers to the bulk market and spells out penalties for impeding it, and defines the structure of regulated network charges.

24. **Subsidies**. The law ratifies the sources of cross-subsidies (up to 20% in excess of costs) and establishes the obligation of the government to provide any subsidy shortfall from the national budget. It also ratifies the obligation of public and government enterprises to provide funds for payment of electricity bills from their budgets and to pay their bills.

25. **Legislation Applicable to Contracts.** The legislation applicable to contracts involving power utilities, including those owned by the state, is the same applied to private companies.

26. **Concession Contracts.** The law spells out the terms of a concession contract whereby the supplier acquires an obligation to serve within a given service area for those cases in which supplies are not forthcoming as a result of market forces.

27. **Final Provisos.** The Regulatory Commission is allowed a period of three years for putting in place a competitive market at the generation level. Public enterprises at the national level are given six months to be transformed into mixed capital enterprises.

C. Secondary Legislation

28. Secondary legislation for the power sector is constituted by detailed by-laws (Reglamentos) issued by the Regulatory Commission and any other regulations which might be specifically delegated by the commission to particular Agents (any enterprise of person engaged in generation, transmission, distribution or commercialization of electric energy). Regulations issued by the ERC, so far cover the following aspects:

- General provisions for public service, Resolution (Resolución, Res.) 56,
- Generation, Res. 55,
- Transmission in the National Interconnected System, Res. 1,
- Transmission in regional networks and distribution, Res. 3,
- Commercialization, Res. 54,
- Transmission access and tariffs, Res. 2,
- Distribution access and tariffs, Res. 4,

- Maximum tariff schedules to be charged by distribution companies, Ress. 38 though 43,

- Long term contracts by distribution companies, Res 9,

- Energy purchases by vertically integrated utilities, Ress. 10 trough 37,

- Firm capacity payments by the Pool, Res. 53, and
- 1995 tariff schedules to final users, Ress. 57 and 58,

29. Following there is a summarized content of the main regulations issued by the ERC.

Resolución No. 56, December 28, 1994, General Dispositions on Electricity Services

- Definitions for this and any other regulations on the main industry parameters and actors.

- Only duly registered electric enterprises can act in the sector as public utilities.

- Separation of activities for any enterprise constituted after the enactment of the electricity law (EL). However, current vertically integrated enterprises can continue doing so, provided they separate accounts no later than January 1, 1996, under procedures and accounting practices to be issued by the SSP.

- Obligation to provide to the ERC information on all contracts subscribed by public utilities.

- Specific provisions to protect competition.

- Obligation to publish tariffs and prohibition of discrimination.

- All Agents to collaborate with authorities in cases of emergency, as declared by the ERC.

- All Agents to abide by provision of the Grid Code and all other relevant regulations (technical, industrial, municipal, environmental, water concessions and usage).

Resolución 55, December 28, 1994, Generation Activities in the National Interconnected System (NIS).

- All generators (over 10 MW of installed capacity) that are connected to the NIS must become members of the Pool, participate in the bulk market transactions and coordinate their operations with the National Dispatch Center (NDC).

- Defines the Commercial Transactions System (CTS) associated to the Pool.

- Energy offered to the Pool should be based on short term marginal cost: (i) for thermal units: fuel incremental cost plus variable operational incremental costs, and (ii) for hydro plants: opportunity cost of water.

- Ancillary services to be quoted at NDC request.

- The NDC to be responsible for operational planning and dispatch based on least cost principles and define the opportunity cost of water and other parameters; all the above information should be disclosed to all Pool participants.

- Dispatch to be made by merit order on the basis of offered prices; the NDC is responsible for instructing generators and Regional Dispatch Centers (RDCs) on how to operate their equipment and for supervising compliance.

- Pool marginal price to be calculated hourly as the variable cost of the last unit in the load curve.

- NDC can take discretionary actions with regard to dispatching in cases of emergency.

- The CTS to be responsible to settlement of commercial transactions.

Resolución No. 1, November 2, 1994, Transmission Access and Charges.

- Defines access to the grids, interconnections and Grid Code.

- Only Transmission Companies (TCs), duly registered, can provide transmission services publicly.

- TCs are obliged to provide indiscriminate access to their systems to all users, under technical conditions to be set by the ERC; TCs should maintain records.

- The expansion plan for the National Transmission System will be carried out by ISA, and other TCs in their respective regions; reference plans to be defined by the Energy and Mining Planning Unit at the Ministry of Mines and Energy (UPME).

- Defines purpose and content of the Grid Code.

- Obligations of TCs to adhere to the Grid Code.

- Defines maximum tariffs to be charged for transmission. These are: (i) connection fees, (ii) use of system, (iii) charges due to system restrictions, and (iv) ancillary services.

- Losses to be borne by the Agents; ERC to define distribution method for charging losses.

Resolución No. 3, Transmission in Regional Systems and Distribution

- Defines conditions for providing distribution services.

- Ensures free access to networks of local distributors for any user, retailer (comercializador) or generator.

- Establishes rules and obligations to ensure free competitiveness.

- Defines technical criteria for designing regional transmission and distribution networks, in particular details aspects that should be included in the grid code.

- Defines general basis and procedures for establishing connection and user charges and for solicitation, quotation, and connection of consumers.

Resolución 54, 28 December 1994, Commercialization of Electric Power.

- With the exemption of currently existing vertically integrated utilities, transmission enterprises can not carry out commercialization activities.

- Suppliers (comercializadores) are obliged to trade energy in the Pool, but distribution companies can be represented in the Pool by a third party.

- Suppliers are obliged to supply energy to all those who request services under regulated regime.

- Suppliers are obliged to collect subsidies and transfer them to a special fund.

- Suppliers must maintain and publish power purchase tariffs which should be estimated on the basis of avoided costs.

- Agents who perform activities in generation and commercialization must have separate accounts for both activities (exception, utilities existing at the date of enacting of the Law).

- Suppliers acting in the regulated market must contract energy through competitive bidding.

Resolución 2, 2 November 1994, Access to and Use of Transmission Networks; Methodology and Procedures for Setting Tariffs for Use of System and Connection.

- Defines methodology and procedures for the payment by generators and suppliers to the transmission company for accessing and using the NIS. Such method is based on the costs imposed on the networks during peak hours computed as the investment, operations and maintenance costs of a system able to transport flows produced at peak hours.

- The total revenues to the transmission company are, however, reviewed and, if granted, revised to provide for the financial requirements of the network operator for operating, maintaining and expanding the networks in accordance to expected demand.

- Charges are separated as use of system and connection charges.

- The above charges are defined by regions and sub-regions (nodes).

- Use of system charges will be levied: (i) for generators on the basis of installed capacity and in service for six or more months during the year, and (ii) for suppliers on the basis of effective demand measured for particular times and seasons to reflect the stress imposed on the network by their respective loads.

- Connection charges are paid by generators, large consumers, regional transmission companies or distributors in accordance with rates defined by the ERC, which are based on the investment costs required to connect the loads.

Resolución 4, November 2, 1994, Access to and Use of Distribution Systems, Methodology for Estimating Charges for Connection and Use of System and Procedures for Payments.

- Defines charges for use of system to be paid by suppliers (and large consumers through suppliers) to local distributors. These charges include costs associated to the electrical systems required to provide the service. They do not include the cost of electrical losses, which should be paid by the suppliers. There are charges for energy and for power.

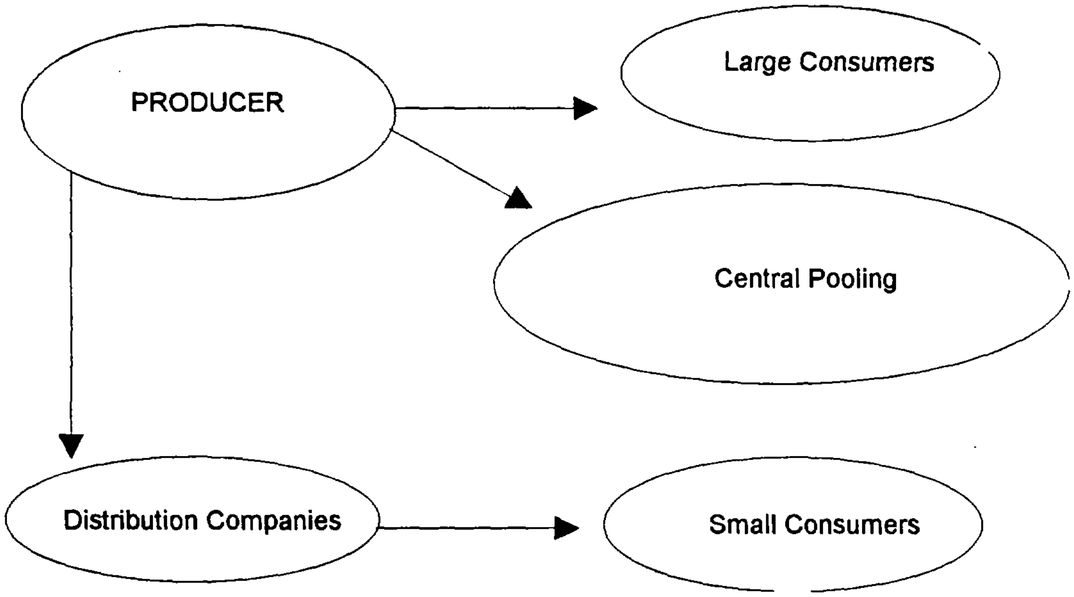
- Estimates of charges are based on the assets of the corresponding company, assuming 10% discount rate and 25 years useful life for the equipment.

- Operating costs are estimated at 2% of the investment costs.

Charges for connection of new generator or large consumer are to be set by the REC.

COLOMBIA
POWER SECTOR

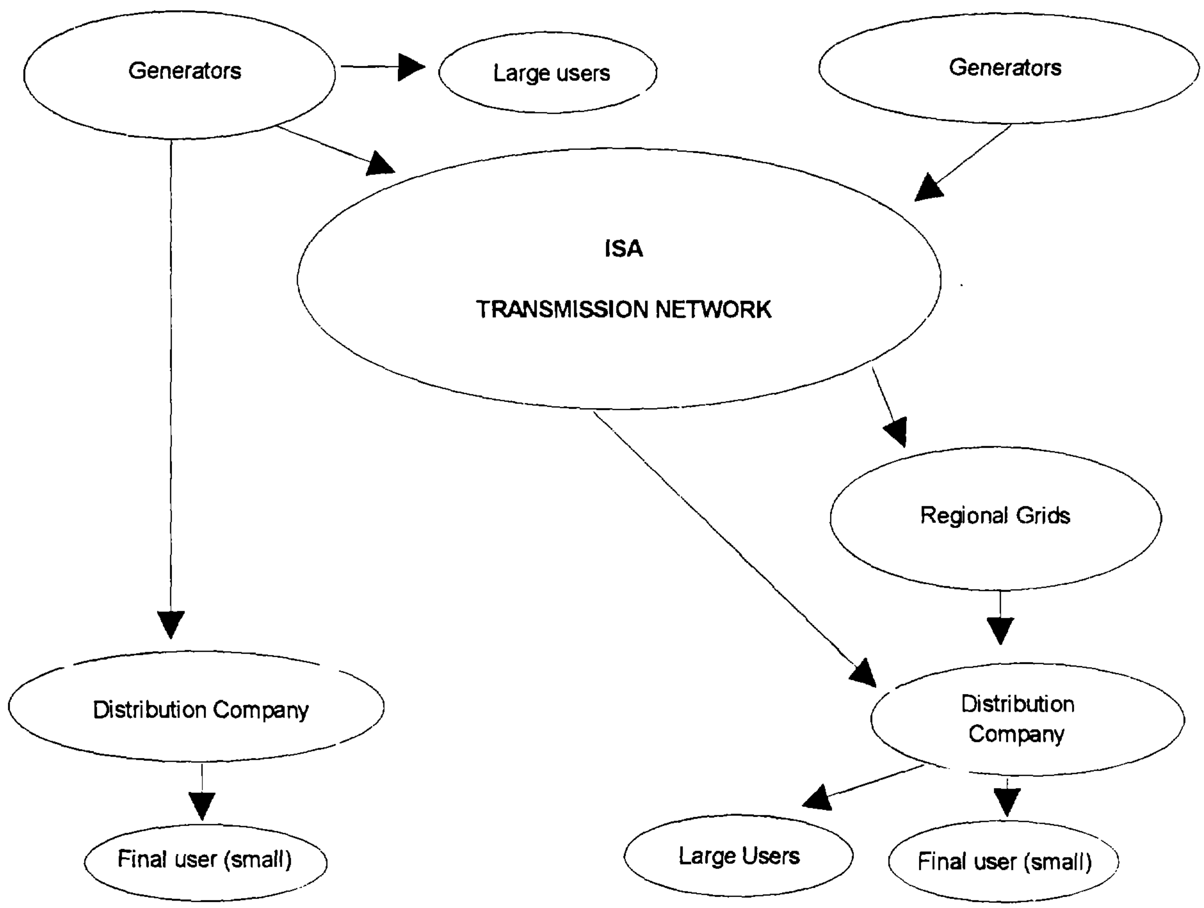
COMMERCIAL TRANSACTIONS



NOTE: Transmission companies CAN NOT buy or sell; only transport

COLOMBIA
POWER SECTOR

USE OF PHYSICAL INSTALLATIONS



Colombian Power Utilities

Generation Utilities

CEDELCA	Centrales Eléctricas del Cauca
CEDENAR	Centrales Eléctricas de Nariño
CENS	Centrales Eléctricas de Norte de Santander
CET	Compañia de Electricidad de Tuluá
CHB	Central Hidroeléctrica de Betania
CHEC	Central Hidroeléctrica de Caldas
CHIDRAL	Central Hidroeléctrica del Alto Anchicayá
CORELCA	Corporación Eléctrica de la Costa Atlántica
EBSA	Electrificadora de Boyacá S.A.
EDEQ	Empresa de Energía del Quindío
EEB	Empresa de Energía de Bogotá
EEC	Empresa de Energía de Cundinamarca
EEPPML	Empresas Públicas de Medellín

ELECTRANTA	Electrificadora del Atlántico
ELECTRIBOL	Electrificador de Bolívar
ELECTROCORDOBA	Electrificadora de Córdoba
ELECTROLIMA	Electrificadora del Tolima
EEP	Empresas Públicas de Pereira
EPSA	Empresa de Energía del Pacífico S.A.
ESSA	Electrificadora de Santander S.A.
ICEL	Instituto Colombiano de Energía Eléctrica
PROELECTRICA	Proeléctrica S.A.
ISAGEN	

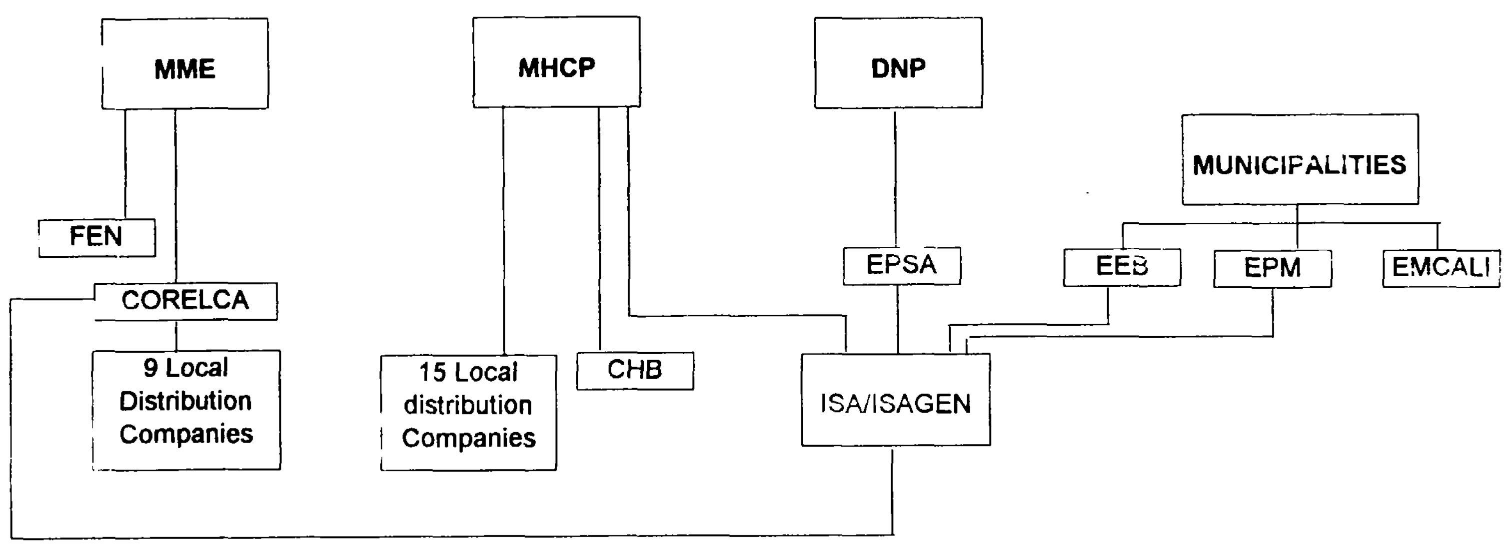
Distribution Utilities

CEDELCA	Centrales Eléctricas del Cauca
CEDENAR	Centrales Eléctricas de Nariño
CENS	Centrales Eléctricas de Norte de Santander
CET	Compañia de Electricidad de Tuluá
CHEC	Central Hidroeléctrica de Caldas
CORELCA	Corporación Eléctrica de la Costa Atlántica
EADE	Empresa Antioqueña de Energía
EBSA	Electrificadora de Boyacá S.A.
EDEQ	Empresa de Energía del Quindío
EEB	Empresa de Energía de Bogotá
EEC	Empresa de Energía de Cundinamarca
EEM	Empresa de Energía de Magangué
EEPPM	Empresas Públicas de Medellín
ELECTRANTA	Electrificadora del Atlántico
ELECTRIBOL	Electrificadora de Bolívar
ELECTROCAQUETA	Electrificadora del Caquetá
ELECTROCESAR	Electrificadora del Cesar
ELECTROCHOCO	Eelctrificadora del Chocó
ELECTROCORDOBA	Electrificadora de Córdoba
ELECTROGUAJIRA	Electrificadora de la Guajira
ELECTROHUILA	Electrificadora de Huila
ELECTROLIMA	Electrificadora del Tolima
ELECTROMAGDALENA	Electrificadora del Magdalena
ELECTROSUCRE	Electrificadora de Sucre
EMCALI	Empresas Municipales de Cali
EMCARTAGO	Empresas Municipales de Cartago
EMSA	Electrificadora del Meta S.A.
ENELAR	Empresa de Energía del Arauca
EEP	Empresas Públicas de Pereira
EPSA	Empresa de Energía del Pacífico S.A.
ESSA	Electrificadora de Santander S.A.
PROELECTRICA	Proeléctrica S.A.

Utilities that own Transmission lines:

CENS	Centrales Eléctricas del Norte de Santander
CORELCA	Corporación Eléctrica de la Costa Atlántica
EEB	Empresa de Energía de Bogotá
EPPM	Empresas Públicas de Medellín
EPSA	Empresa de Energía del Pacífico S.A.
ESSA	Electrificadora de Santander S.A.
ISA	Interconexión Eléctrica S.A.

D. Power Sector - Government Entities



ANNEX 2

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

ENERGY POLICY LETTER

Ministry of Mines and Energy
The Minister

Mr. Yoshiaki Abe
Latin America and the Caribbean Region
IBRD
Washington, D.C.

November 23, 1994

Subject: Energy Policy Letter

Dear Mr. Abe:

I have pleasure in setting out below the principal aspects of the Colombian Government's Energy Policy, dealing specifically with aspects of the power sector.

POWER POLICY OUTLINE

The following general strategies have been formulated for Colombia's power sector:

A. Efficient demand management and rational use of energy within a framework of social equity. This strategy includes the definition of a coherent pricing policy and the development of a number of energy substitution programs, designed to bring the structure of consumption into line with the economic cost and availability of the sources. A subsidy structure will be set up as provided in the Power Sector Law. In particular, the use of CNG and LPG will be promoted for urban and highway transport, as will programs ensuring a rational use of electricity in its various applications.

B. Full and efficient energy supply, with appropriate infrastructure and optimum resource allocation among energy subsectors, taking account of the vulnerability of the systems and promoting private sector participation in the expansion programs.

C. Maintain and increase levels of energy source production and participation in the external market. It is particularly important to promote oil exploration and develop mechanisms for promoting Colombian coal as part of foreign trade policy.

D. Supply energy to rural areas and contribute to regional development. Efforts will be made to step up grassroots participation, and the use of such fuels as LPG will be boosted as substitutes for wood, as well as the use of unconventional energy sources in the country's most remote regions, such as micro hydro plants, where such installations are feasible.

E. Improve and preserve the quality of the environment. Action will be taken to strengthen the capabilities of the utilities to meet present-day environmental standards, and various programs will be promoted to lessen the environmental impact in the different basins.

F. Provide effective stimulus to research and scientific and technological development, strengthening existing subsectoral research centers and forging stronger ties with university programs and with Colciencias concerning specific topics.

G. Consolidate the sector's institutional modernization. While competition will continue to be regarded as crucial to efficient performance, attention will also be given to the need for a regulatory framework that guarantees consumer protection and controls dominant market positions.

The Government's basic aim in formulating the above strategies is to bring its energy policies into line with macroeconomic policy goals and with the country's economic and social development targets. Within this framework, the following medium and long term objectives will be sought: a more reliable and efficient composition of energy source supply, rationalization of resource use, cost reduction, expanded coverage, and increased production.

POWER SECTOR STRATEGY

The focal points of this strategy are as follows:

- Concentrate government action on the basic functions of regulation, planning and oversight of sectoral activities, leaving the business side to be managed by other economic agents.

- Stimulate competition so as to achieve appropriate levels of sectoral efficiency.

- Open up the sector to private investment as a means of strengthening competition, enhancing efficiency, and bringing in fresh development capital.

- Make the sector's expansion plans less complex and diversify energy supply.

- Set tariffs reflecting the economic cost of power service delivery in the sectors where this is possible, and adopt a system of direct and explicit subsidies to meet the basic consumption requirements of low-income groups.

- Promote financial rehabilitation of the government power companies to strengthen their net worth and improve their operational performance.

ROLE OF THE GOVERNMENT

In the specific case of the power sector, restructuring is now proceeding within the framework of Law 142 "governing residential utilities and enacting other provisions" of July 11, 1994, and Law 143 of the same date "governing the generation, interconnection, transmission, distribution and marketing of electricity throughout the national territory, ..."

As provided in these two laws, the Government will: (a) promote free competition; (b) prohibit practices representing unfair competition or the abuse of a dominant market position; (c) regulate those situations where, because of the existence of a natural monopoly, free competition cannot guarantee efficient service delivery in economic terms; (d) ensure the protection of users' rights and the performance of their obligations; (e) incorporate environmental aspects into the sector's activities; (f) ensure adequate electricity service coverage in the country's different regions to meet the basic needs of lower-income consumers; (g) make available the necessary resources to cover the subsidies granted to those consumers for basic electricity coverage.

The above laws ratify and supplement the functions assigned to the Energy and Gas Regulatory Board [*Comisión de Regulación de Energía y Gas - ERC*] and the Mining and Energy Planning Unit [*Unidad de Planeación Minero Energética - UPME*] under Decree 2119 of 1992. Also to be borne in mind is the creation of the Utilities Superintendency [*Superintendencia de Servicios Públicos*] as a technical agency under the Ministry of Economic Development, with juridical personality, administrative autonomy, and ownership of its assets.

PRIVATE SECTOR PARTICIPATION

To promote competition, improve efficiency, and bring in fresh development capital, private investment in the power sector will be promoted, especially in connection with the expansion programs. The basic conditions for such participation will be created with adoption of the implementing regulations to the Electricity Law and completion of the process of financial rehabilitation of the enterprises in the sector.

The following strategies will apply to private capital participation:

- Promote the participation of private investors in development of the generation projects included in the expansion plan, preferably through an energy supply contract or through association in a mixed enterprise.

- Encourage private individuals to develop projects on their own initiative as additional agents in the competitive market for large blocks of energy, and to assume the respective transaction risks.

- Encourage the purchase of equity participations in the various generating companies to be set up using generating plant presently owned by ISA or the Government.

ENVIRONMENTAL ISSUES

Law 56 of 1981, its Regulatory Decree (2024 of 1982), and Law 99 of 1993 represent the most significant pieces of legislation for the electricity subsector in terms of environment-related provisions. The environmental variable in electricity projects has become extremely important, a fact reflected in the newly-created Power Sector Environmental Committee [*Comité Ambiental del Sector Eléctrico - CASEC*].

Since 1986, the appraisal of projects under the power sector expansion plan has included the costs of environmental protection, based in general on a multipurpose, integrated project approach covering technical, social and environmental components. For this reason (and as a requirement for approval of loans from the multilateral banks), new generation, transmission and distribution projects are now factoring in environmental costs.

During 1993, a Sectoral Environmental Assessment was conducted for the power sector, based on the World Bank's terms of reference and general guidelines for an assessment of this type. This study resulted in the identification of a number of strategies and actions that will be implemented to improve the sector's environmental performance. The National Energy Plan proposes the creation in the Ministry of Mining and Energy of an Environmental Unit, with Special Administrative Unit status, to propose and coordinate the energy sector's environmental policy and serve as its authorized spokesman vis-à-vis the environmental authorities. This proposal is currently under study, and should be finalized during the first half of 1995.

PROGRESS OF RESTRUCTURING PLAN

Institutional restructuring is progressing satisfactorily. At end-1992, the Ministry of Mines and Energy was restructured under Decree-Law 2119, which set up three new units: the Energy Regulation Board [*Comisión de Regulación Energética*], the UPME, and the Mining and Energy Information Unit [*Unidad de Información Minero Energética*], while also redefining the role of the Nuclear Affairs Institute [*Instituto de Asuntos Nucleares - IAN*], changing its name to Institute of Nuclear Science and Alternative Energy Sources [*Instituto de Ciencias Nucleares y Energías Alternativas - INEA*]. In addition, Decree-Laws 2120 and 2121 provided for conversion of the Colombian Electricity Institute [*Instituto Colombiano de Energía Eléctrica - ICEL*] and the Atlantic Coast Electricity Corporation [*Corporación Eléctrica de la Costa Atlántica - CORELCA*] into state commercial and industrial enterprises. The Cauca Valley Corporation [*Corporación del Valle del Cauca - CVC*] was subdivided, its electricity side being converted into an independent company.

Under the restructuring legislation, ISA is to be subdivided into two parts. Its General Meeting of Shareholders has already approved the subdivision, which will take place during the first months of the coming year. Using its existing generating plant and related administrative capabilities, ISA will set up a new generating company, eventually giving birth to a number of independent companies that will be progressively opened up to private capital. ISA's remaining units will be combined into another company, which will be responsible for high-voltage transmission and optimum load dispatch in accordance with ERC criteria and parameters, acting completely independently of its shareholder companies.

ERC ACTIVITIES

ERC became operational in September 1993. It was initially responsible for supervising the Colombian Energy Sector Restructuring Program study carried out by Coopers & Lybrand in 1992 and 1993, and on the basis of the study's findings and recommendations it embarked on a course of action to deregulate the market.

In December 1993, ERC enacted Resolution No. 010 deregulating the market for large industrial and commercial consumers. Large consumers were initially identified as those with requirements in excess of 2 MW. This threshold could be lowered over time.

A few days ago, a resolution was published setting out the charges for use of the transmission and interconnection network. ERC is also working on the transmission and distribution code, operating regulations, and other pieces of secondary legislation essential to the creation of a free energy market.

The regulations will basically address the establishment of standards to promote competition in the electricity market and private-sector participation in the expansion of generating capacity.

The policy will be geared to the strengthening of ERC, since together with the standards now being prepared it represents the basic instrument for stimulating private-sector participation, modernizing companies, and establishing competition in the electricity market.

UPME ACTIVITIES

UPME became operational in September 1993. In early 1994 it started work on a study for formulation of a first National Energy Plan. During the first six months of this year it completed the first integrated energy demand study. It took over the planning functions that the former National Energy Board [*Comisión Nacional de Energia - CNE*] had been carrying out for the power sector, and is responsible for devising a reference plan for the expansion of generation and transmission, which is required by law "... to seek to direct and rationalize both government and private-sector efforts to meet the domestic demand for electricity in a manner consistent with the National Development Plan and the National Energy Plan." It is currently reviewing the Power Sector Expansion Plan.

Pursuant to the government guidelines, based on the Power Sector Law, UMPE is the instrument that will facilitate the development of integrated energy planning, and on that basis give the appropriate signals to the enterprises that design and implement subsectoral policies. Consequently, the Government proposes to provide UMPE with those integrated and subsectoral planning tools that will enable it to properly perform its functions.

TARIFF POLICY

Law 143 addresses the need for a stratified tariff policy to reflect conditions in the municipalities and rural areas.

A major tariff adjustment program was initiated in 1990, designed to achieve targets consistent with the economic costs of delivering the service. Through a combination of isolated adjustments to certain tariff categories and monthly adjustments in excess of inflation in all categories, the average charge to the final consumer was successfully brought up from US$0.041/kWh in 1990 to US$0.054/kWh in 1992. In 1993, Resolutions 13, 14 and 15/93 were adopted, introducing an adjustment strategy whereby the reference cost based on the economic cost of service delivery would be achieved by 1997-98.

The program of monthly adjustments will be continued over the next few years, with introduction of a direct and explicit subsidy system for low-income consumers and introduction of the cross-subsidy system provided for in the Power Sector Law and the Residential Utilities Law. Such measures are essential to facilitate the operation of a free market of large blocks of energy, and to ensure the financial health of efficient enterprises with weak markets, with a high proportion of low-income group consumption.

FINANCIAL SITUATION

The Government has taken action in terms of capitalization, debt restructuring, and debt/equity swaps to address the difficulties of those of the sector's major enterprises which had fallen into insolvency or bankruptcy as a result, generally speaking, of stagnating electricity tariffs, accelerated devaluation of the peso, and their own high debt levels. During the past few years, the Government has contributed over US$1.5 billion to enterprises such as ISA, CHB, ICEL, CORELCA, and EEB, and in return has received productive assets and share capital in ISA and the ICEL subsidiaries.

These measures succeeded in bringing about a substantial recovery in the sector's finances, although some of the enterprises still face certain isolated and cyclical cash flow problems for which additional measures need to be enacted. An analysis is currently in progress, and an additional financial recovery plan is expected to be launched by July 1995.

To ensure the financial viability of the enterprises, their financial recovery will be supplemented by the following actions:

- Capitalization and refinancing of certain liabilities.

- Setting of tariffs reflecting the economic costs of service delivery, gradually eliminating cross-subsidies to the level prescribed by law, and progressively introducing a system of explicit direct subsidies for low-income residential consumers.

- Improved efficiency for the enterprises in the power sector, through energy loss and delinquent portfolio control and reduction of operating costs.

As regards efficiency improvements, the former system has been amended by law and placed on a more solid legal footing. Based on their strategic plans and on the criteria developed by ERC, the enterprises are required to propose a management control plan, which will need to be approved by UPME. This plan will form the basis for the preparation of management contracts to be signed with the Superintendency of Public Services, which will also supervise their performance. This Superintendency will remain in operation until June 1995.

EXPANSION OF ELECTRICITY SUPPLY

The demand for electricity will be met within the context of an integrated energy policy, which will ensure that consumption is oriented toward those uses for which it is the most efficient energy source. Energy diversification will be a priority, with emphasis on the widespread use of natural gas in urban residential areas and of LPG in the remote rural areas.

The generation and transmission plan, currently being overhauled to bring it into line with the new demand forecasts, should be completed by the end of this year. The generation expansion capacity projected for the period 1993-2000, before the present updating, consisted in the installation of 750 MW (gas), 450 MW (coal), and 1,000 MW (hydro), all projects that can easily be replaced. For transmission, the plan was to construct 1,800 km of 230- and 500-kW lines.

Through flexible indicative planning, the policy will seek to give appropriate signals to encourage the private sector to implement the new minimum-cost expansion plan projects, so that the Government will execute projects only when it is not possible to obtain private-sector collaboration. Particular attention will need to be paid to project execution, to avoid delays that could cause future restrictions on supply.

The projects included in the strategy approved for the generation expansion program are:

PROJECT	CAPACITY (MW)	COMMISSIONING DATE (quarter)
1. Barranquilla capacity upgrade (g)	747	240 MW IV 1995 507 MW 1996-97
2. Termo Valle (g)	212	212 MW II 1996
3. Termo Cesar (c)	300	IV 1999
4. Termo Paipa IV (c)	150	III 1997
5. Central region hydro station (g)	150	100 MW IV 1996 50 MW IV 1997
6. Porce II (h)	392	III 1999
7. Urrá (h)	340	III 1999
8. La Miel (h)(*)	375	2001-2004

(g): gas-fired thermal station (c): coal-fired thermal station (h): hydro station
(*): recommended as part of the strategy for 2001-2004

One of the basic aims of the power policy is to upgrade distribution through attention to infrastructure as well as to the utilities' institutional and administrative aspects. Energy losses within the electricity distribution system are equivalent to over 20% of energy demand, and around 13% of potential users have no access to the service. The distribution system is thus to be modernized, with a view to improving service quality and expanding coverage. The modernization program, together with the actions set down in the management contracts to be discussed below, will help to reduce the level of losses.

CONCLUSIONS

This overall strategy has produced successful results, the planned actions having been accomplished to the extent described above. The sector has overcome its rationing crisis, and has made progress in handling its financial predicament, with a significant drop in the utilities' energy arrears to Interconexión Eléctrica S.A., private-sector participation has been achieved through mechanisms such as BOOM in thermal generation projects of over 1,000 MW, and laws have been enacted regulating the delivery of public services in general and the supply of electrical energy in particular. It may be affirmed that the restructuring process, having passed through the stages of implementation and institutional organization, is now entering the consolidation phase.

Very truly yours,

/s/ Jorge Eduardo Cock London
Minister of Mines and Energy

ANNEX 3

ENERGY SUPPLY AND DEMAND

Table 3.1 - Energy Supply

(Teracalories)

Sectors	1975	1980	1985	1990	1991	1992	1993	Average annual growth rate
Production	188,781	189,327	268,133	483,762	494,684	496,633	496,926	5.9%
Hydroelectricity[1]	18,286	13,427	21,224	29,566	28,287	21,567	21,569	1.0%
Natural Gas	21,173	33,973	41,033	42,173	43,354	42,227	42,244	4.1%
Petroleum	83,978	67,530	95,836	220,776	214,354	221,549	221,680	5.9%
Carbon	20,978	25,362	58,331	133,042	153,400	154,544	154,737	12.5%
Fuelwood/bagasse	44,366	49,035	51,709	58,205	55,289	56,746	56,755	1.5%
Imports								
Hydrocarbons	2,324	27,964	22,078	12,354	11,601	17,920	17,943	12.8%
Exports								
Hydrocarbons	12,863	14,044	29,085	136,425	123,638	121,617	121,788	14.1%
Coal	213	922	23,146	94,848	105,830	108,205	108,684	44.3%
Change in stocks	372	(504)	3,890	2,010	4,488	5,963	-	
Not used[2]	16,456	10,854	11,127	5,959	5,166	5,388	5,388	
Total Supply	**161,201**	**191,975**	**222,963**	**256,871**	**267,163**	**273,380**	**279,008**	
Adjustments	483	(2,767)	2,298	(1,661)	8,813	4,714	-	
Total demand	**160,718**	**194,742**	**220,665**	**258,532**	**258,350**	**268,666**	**279,008**	**3.1%**
Self Consumption	8,246	8,144	10,420	6,993	8,448	18,549	10,133	
Losses	27,714	38,224	42,986	48,163	42,274	28,645	38,001	
Final Consumption	**124,758**	**148,374**	**167,259**	**203,376**	**207,628**	**221,472**	**230,874**	**3.4%**

[1] Conversion coefficient 0.86 Tcal/Gwh

[2] Mainly bagasse

Source: PEN (Plan Energético Nacional Ministerio de Energía y Minas) and mission estimates.

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

Table 3.2
Final Energy Consumption by Sector
(Teracalories)

Sectors	1975	1980	1985	1990	1991	1992	1993	Average Annual Growth rate (%)
Residential	42,365	45,356	49,273	55,747	56,751	55,947	56,842	1.6
Commercial	2,654	3,352	6,252	7,384	7,793	8,206	8,772	6.9
Industrial	31,376	37,485	44,104	57,521	62,863	59,154	61,402	3.8
Transport	34,269	43,392	51,194	59,757	60,931	65,554	66,200	3.9
Agriculture	10,049	12,370	11,589	16,014	13,007	14,890	18,315	23.0
Construction	901	1,957	2,075	2,443	2,508	2,762	2,950	6.8
Others	3,144	4,462	2,772	4,511	3,775	14,958	16,394	9.6
Total	**124,758**	**148,374**	**167,259**	**203,377**	**207,628**	**221,471**	**230,874**	**3.4**

Source: MME-UIME.

ANNEX 4

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

ELECTRICITY PRICES

Average Tariff and Subsidies

Utility	June 1993		December 1993		December 1994	
	Tariff (Col$/kWh)	Subsidies (%)	Tariff (Col$/kWh)	Subsidies (%)	Tariff (Col$/kWh)	Subsidies (%)
Atlántico	54.06	2.83	59.74	2.34	70.15	1.68
Bolívar	54.85	2.51	60.93	1.51	72.31	(0.22)
Cesar	51.23	21.25	57.48	19.65	69.47	16.72
Córdoba	49.42	27.80	55.72	25.98	66.83	23.87
Guajira	50.13	22.90	55.96	21.72	68.03	18.41
Magdalena	51.64	14.63	57.56	13.47	68.43	11.80
Sucre	49.55	21.52	55.36	20.25	65.68	18.88
Magangué	44.79	37.10	50.49	35.51	63.34	30.64
Medellín	45.63	17.08	50.70	16.21	60.71	13.97
Antioquia	38.59	41.67	43.41	40.34	55.17	34.99
Chocó	35.70	51.53	40.47	50.03	52.35	44.58
Boyacá	43.41	21.07	49.02	18.95	58.58	16.96
Santander	44.21	29.91	50.14	27.70	64.16	20.67
Nte de Sant.	44.46	29.94	49.97	28.39	62.08	23.72
Caldas	41.47	39.61	47.05	37.68	60.16	31.69
Pereira	46.66	24.29	52.52	22.49	65.26	17.43
Quindío	47.06	27.00	53.18	24.97	65.77	20.43
Emcali	49.17	12.40	54.94	10.98	66.50	7.62
CVC	45.73	23.47	51.23	22.03	62.87	17.95
Tuluá	44.51	38.74	50.08	37.32	63.16	32.22
Cartago	40.59	43.13	46.04	41.32	59.47	35.02
Tolima	47.05	24.62	53.26	22.40	65.93	17.63
Huila	46.25	29.77	52.20	27.90	63.97	24.25
Caquetá	50.16	30.08	57.00	27.74	73.16	20.47
Cauca	37.90	48.24	42.87	46.75	54.75	41.69
Nariño	34.69	46.91	39.29	45.33	50.02	40.32
Celgac	51.40	16.38	57.35	15.16	67.30	14.62
Meta	56.84	14.46	63.82	12.67	78.23	8.21
Bogotá	52.24	13.40	57.19	13.78	69.62	10.00
National Total	**46.53**	**19.01**	**53.62**	**18.07**	**64.78**	**15.12**

Source: CREG

ANNEX 5

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

ECONOMIC PERSPECTIVES FOR COLOMBIA

Background

1. Colombia's population, 35.7 million according to the 1993 census, occupies an area of just over a million square kilometers with about three-quarters of the population living in urban areas. Colombia has plentiful natural resources and coasts on both the Atlantic and Pacific Oceans. Mountainous terrain, however, makes internal transportation costly and slows down physical and social integration. Solid growth of about 4.5 percent per year for the past four decades, combined with a drop in the population growth rate to 1.8 percent per year, have facilitated substantial improvement in social conditions. Rich physical resources, a literate and dependable work force, a robust private sector, competent macroeconomic management, and political stability are factors explaining Colombia's good record of economic development and social improvement over the last thirty years.

2. During the 1980s Colombia achieved one of the highest and most stable growth paths in Latin America. Its prudent and gradual approach to macroeconomic management yielded positive GDP per capita growth at a time of decline for most countries in the region. Productivity in most sectors, however, remained stagnant. Recognizing this shortfall, the Barco Administration launched in 1990 the Economic Modernization Program (EMP)--a set of structural reforms to improve efficiency of resource allocation and use.

3. **President Gaviria's Administration (1990-94)**. President Gaviria's election in March 1990, marked the entry of a new generation in government. During his tenure, which concluded in August, 1994, the Government implemented a large number of additional structural reforms and reoriented the role of the state to focus on the social sectors, infrastructure, and environmental protection, and set the framework for the private sector to be the main driving force in the economy. The centerpiece of the structural reforms was trade liberalization, but this was accompanied with reforms in the financial sector, tax system, foreign exchange market and regulations on direct foreign investment. Congress approved a new central bank law giving the monetary authorities greater autonomy. The labor regime was modified to reduce labor rigidities and facilitate industrial restructuring. Public monopolies were eliminated in sectors critical to trade flows, including railways, ports, shipping, and agricultural marketing. Most of the government's non-oil industrial holdings were divested, as were the five banks nationalized during the banking crisis of 1982-85. On the political front, the constitutional reform of 1991 advanced the process of decentralization mandating the delegation of both central government revenues and responsibilities for the provision of basic social services to subnational governments. International capital markets

have reacted positively to Colombia's development granting it one of the highest ratings in Latin America.

4. **President Samper's Administration (1994-98)**. The Samper Administration, inaugurated on August 7, 1994, put forward its policy agenda in the recently completed 1994-98 national development plan now being discussed in Congress. The four-year plan, which is known as the *Salto Social* (the Social Leap), focused on four critical areas of action: (i) social development; (ii) competitiveness of the economy; (iii) environment; and (iv) decentralization and institutional strengthening. All four elements of the strategy are to be pursued in tandem. Among the policy initiatives launched during the first six months of the Administration, probably the most important one was the negotiation of a social pact with labor unions and the business sector. The social pact, signed on December 9, 1994, was proposed to underpin the Government's effort to reduce inflation. Preliminary results are encouraging. Other policy initiatives of the new Administration were a series of measures to support agriculture--including increased protection through the introduction of domestic procurement agreements for key crops--and a proposal submitted to Congress to establish an oil stabilization fund to smooth the spending of oil revenues.

Recent Economic Development

5. Preliminary data indicate that output expanded by 5.7 percent in 1994 led by buoyant investment expenditures and a continued strong performance in the construction, commerce, finance, and transport sectors. With the buoyancy of economic activity, the unemployment rate dropped to 7.4 percent in the third quarter of 1994, the lowest rate observed in recent years. Inflation remained at the same level of 1993, with consumer prices rising by 22.9 percent in 1994.

6. The strength of economic activity and sustained private capital inflows--despite increased restrictions on external borrowing--sparked a rapid increase in imports (with equally strong growth of capital and consumer goods imports). Notwithstanding a 14 percent increase in export value--reflecting the surge in coffee export prices in the second half of the year--the external current account deficit remained wide at around 5 percent of GDP in 1994. Overall, there was a small decrease in net international reserves for the year as a whole of around US$330 million, bringing net reserves to US$7.5 billion, or nearly 6 months of imports of goods and services.

Medium Term Economic Perspectives

7. Colombia is starting to face an oil boom derived from the newly-discovered Cusiana and Cupiagua oil fields that could put the economy on a faster growth path--sustained GDP growth of almost 6 percent per year is within reach in the medium term. Overall oil production is expected to increase from approximately 480,000 bpd in 1993 to around 1,000,000 bpd in 1997 effectively doubling the participation of the oil sector in total GDP by the end of the

decade. The present value of the net income flows to be generated by the new oil discoveries between 1993 and 2005 amount to approximately US$15 billion, equivalent to 28% of GDP.

8. Colombia is expected to consolidate the gains of the structural reform of the past four years and accelerate the pace of economic growth. In response to the newly-created incentive structure, the implementation of an appropriate regulatory framework, and the foreign exchange revenues from higher oil exports, productivity is expected to improve and per capita GDP growth to rise above 3 percent per year. For the second half of this decade, private investment is expected to average 14 percent of GDP and public investment 9 percent of GDP, a combined average of more than 5 percentage points of GDP higher than the 1980s average.

Table 2 : COLOMBIA - Summary of National Accounts
(As percentage of GDP)

	1990	1991	1992	1993	1994p	1995p	1996p	1997p	2000p
I. Sources of Demand									
Total Consumption	**77.0%**	**78.0%**	**80.6%**	**82.8%**	**78.8%**	**77.5%**	**77.1%**	**77.0%**	**75.7%**
Private Consumption	67.5%	68.7%	71.1%	72.2%	67.0%	65.6%	65.3%	65.1%	63.9%
Public Consumption	9.4%	9.3%	9.5%	10.6%	11.8%	11.8%	11.8%	11.8%	11.8%
Investment	**18.5%**	**16.0%**	**17.2%**	**20.5%**	**24.1%**	**24.1%**	**23.8%**	**22.9%**	**25.4%**
Private	12.2%	9.4%	9.1%	11.1%	15.1%	14.6%	13.5%	12.1%	13.8%
Public	6.4%	6.5%	8.1%	9.4%	8.9%	9.5%	10.3%	10.8%	11.6%
Exports	**24.4%**	**22.1%**	**20.6%**	**19.0%**	**18.8%**	**20.0%**	**20.3%**	**21.0%**	**19.4%**
Imports	**19.9%**	**16.1%**	**18.4%**	**22.2%**	**21.7%**	**21.6%**	**21.2%**	**20.9%**	**20.4%**
II. Savings-Investment Balances									
Public Sector	0.4%	-0.4%	0.0%	0.0%	0.7%	1.0%	-0.7%	-0.7%	0.7%
Private Sector	1.2%	6.0%	1.6%	-4.2%	-5.1%	-4.9%	-2.5%	-1.5%	-4.2%
Current Account Balance	1.6%	5.6%	1.6%	-4.2%	-4.3%	-3.9%	-3.2%	-2.2%	-3.5%
Public Savings	6.8%	6.1%	8.2%	9.3%	9.7%	10.5%	9.6%	10.1%	12.3%
Private Savings	13.4%	15.4%	10.7%	6.9%	10.0%	9.7%	11.0%	10.6%	9.5%
Memorandum Items:									
Real GDP, % Change	4.3%	2.0%	3.8%	5.3%	5.3%	5.5%	5.5%	5.5%	6.0%
Real GDP Per Capita, % Change	2.4%	0.3%	2.1%	3.5%	3.5%	3.7%	3.7%	3.7%	4.2%
GDP in US$ (millions)	40,274	42,519	48,712	53,368	64,371	72,573	79,201	86,826	110,121
Real Private Consumption, % Change	2.3%	3.0%	-0.9%	6.0%	9.3%	3.6%	5.1%	5.3%	7.0%
Real Total Investment, % Change	-1.2%	-8.7%	39.0%	27.7%	-1.1%	6.3%	4.6%	2.3%	4.0%

p - projected

ANNEX 6

COLOMBIA
POWER MARKET DEVELOPMENT PROJECT

ELECTRICITY DEMAND

1. **Historical Data:** The electricity sector's historical net generation of electricity for the 1975-94 period is shown in Table 6-1. Net generation grew at an average rate of 6.4% per annum. However, the actual growth rate has been uneven: during 1975-80 it averaged 9.8%; during 1980-90 it averaged 5.8% and during 1990-94 it averaged 3.7% per annum. There have also been a number of atypical years characterized by negative or zero growth due to power rationing, such as 1981 and 1992/93. The latter explains the low growth rate during the last four years, the reason being that, after a period of significant power cuts, demand does not recuperate because substitution practices (including backup generation), as well as conservation habits, become permanent.

Table 6-1
COLOMBIA - Total Electricity Generation

	(Twh)	Growth (%)
1975	12.2	
1976	13.5	10.7
1977	14.2	5.2
1978	16.2	14.1
1979	17.9	10.5
1980	19.5	8.9
1981	19.5	0.0 (1)
1982	21.5	10.3
1983	23.1	7.4
1984	24.6	6.5
1985	25.7	4.5
1986	27.6	7.4
1987	29.5	6.9
1988	31.2	5.8
1989	32.6	4.5
1990	34.1	4.6
1991	35.1	2.9
1992	31.8	-9.4 (1)
1993	36.4	14.5 (1)
1994	39.5	8.5

(1) Values are atypical due to severe power rationing in 1981 and 1992-3.

2. **Market Structure:** Final demand for electricity has remained relatively stable during the past decade, with predominantly residential sales (48%), followed by the industrial (30%) and commercial (10%) subsectors, as shown in Table 6-2. Losses exhibited an increasing trend until 1988 when they reached a maximum of 24%. Since then there have been efforts to curb them, but they have only succeeded in reducing them to around 20%.

3. **Forecast of Future Power Sales.** The principal variables influencing power sector demand are:

- Population growth and service coverage;
- Economic growth
- Electricity prices and tariff policy
- The supply of substitutes

Regarding these factors, the outlook as of 1995 appears as follows:

(a) Service coverage by electricity utilities is estimated to be around 70-75%; this percentage is not expected to increase significantly in the near future as extending service to currently isolated communities is not economical (these areas may have electricity service from local generation);

(b) Economic growth is expected to fluctuate between 5% and 6.3% between 1995 and 2010;

(c) Prices for electricity are expected to increase, and current plans are to reach economic cost levels by 1997;

(d) Substitutes are expected to exert a major influence on electricity growth: on one hand, electricity price increases will induce its substitution by lower price and cost alternatives (LPG, natural gas) and, on the other, increases in the supply of natural gas and the construction of pipelines to major urban centers which have hitherto lacked this service will require the development of a significant market to justify these investments; this can be expected to lead to an aggressive marketing approach that would impact the electricity market;

(e) Expected reductions in losses will also exert a moderating influence in demand: by legalizing connections and detecting theft, consumers can be expected to moderate their consumption;

(f) Finally, energy conservation programs can also be expected to reduce demand growth

COLOMBIA
National Interconnected System
Table 6.-2: Electricity Supply and Demand

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
Total Generation	19448	19479	21511	23034	24558	25733	27548	29411	30973	32347	33839	35193	31847	36588	39455
Hydro	14308	14065	15024	15184	16850	18291	21087	23072	24217	26473	27456	27590	22039	27639	31841
Thermal	5140	5414	6487	7850	7708	7442	6461	6339	6756	5874	6383	7603	9808	8949	7614
Imports	33	40	38	39	30	5	3	82	179	226	241	213	337	303	144
Available Energy	19481	19519	21549	23073	24588	25738	27551	29493	31152	32573	34080	35406	32184	36891	39599
Exports	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand (GWh)	19481	19519	21549	23073	24588	25778	27551	29493	31152	32573	34080	35406	32184	36891	39599
Consumption sales	15159	15327	16466	17275	18252	19109	20420	21793	22958	24350	26048	27375	25209	27963	29939
Residential	7092	7224	7923	8272	8779	9293	9849	10378	11086	11809	12488	12962	11696	13173	14041
Commercial	1901	1853	1959	2043	2012	2112	2146	2244	2281	2450	2575	2695	2424	2756	3078
Industrial	4537	4519	4719	4901	5286	5449	6130	6679	7008	7482	7880	8389	8041	8871	9729
Government y A.P.	1390	1517	1562	1705	1793	1863	1945	2135	2203	2402	2565	2714	2573	1758	2007
Others	239	214	303	354	382	392	350	357	380	207	540	615	475	1405	1084
Utilities consumption	407	419	510	575	590	595	572	588	623	601	648	715	370	751	701
Transmission and Distribution Losses.	3915	3773	4574	5223	5746	6034	6559	7113	7571	7492	7384	7496	6405	8243	9102
Rationing		900											5183	973	172
% of losses	20.1	19.3	21.2	22.6	23.4	23.4	23.8	24.1	24.3	23	21.7	21.2	19.9	22.3	22.9
Maximum Demand (MW)	3568	3404	3855	4040	4230	4436	4838	5150	5443	5731	5915	6184	6098	6455	6896
Load factor	0.62	0.66	0.64	0.65	0.66	0.66	0.65	0.66	0.65	0.65	0.66	0.65	0.65	0.65	0.66

Source: ISA

4. The Policy Unit of the Ministry of Mines and Energy, UPME, has the responsibility for overseeing the energy sector's evolution. In order to structure the indicative expansion plan, it developed a sector-wide approach for structuring overall energy projections. The first phase of this study was executed during the first half of 1994; its methodology is based on econometric models together with analytic models which are combined to produce integrated energy projections.

5. Three scenarios were considered for projecting electricity demand during 1995-2007 which depend on (a) the degree of penetration of natural gas; (b) the adjustment of electricity prices; (c) economic development; and (d) energy conservation and demand management programs. Table 6-3 summarizes the assumptions and results obtained under the three demand scenarios.

Table 6-3
Electricity Demand Projections

Criteria	Low	Scenario Base	High
Electricity Substitution program by natural gas and LPG in residential Subsector	Maximum substitution until 2001, vegetative growth thereafter	Gradual substitution 1993-2010	Low substitution 1993-2010
Electricity prices			
residential	Average prices[1]	Average prices[1]	Low prices [2]
other [3]	constant prices	constant prices	constant prices
Energy conservation and savings program	Successful	Slow acceptance	Unsuccessful
GDP growth			
1995-2010	5.13%	5.13%	6.26%
1995-2000	5.35%	5.35%	6.29%
2000-2010	5.00%	5.50%	6.25%
Demand growth			
1993-2010	4.84%	6.10%	6.77%
1993-2000	3.63%	5.86%	6.39%
2000-2010	5.70%	6.28%	7.04%

[1] Average prices evolve as approved in 1995 by the social pact; cost levels are reached in 1998.
[2] Residential prices reach the target cost in 2000; thereafter they do not grow in real terms
[3] Other sub sectors have already reached the target cost level
[4] The change in the growth rate is explained by the change in pricing increases and a stabilization in natural gas growth.

6. The assumptions underlying the projections were analyzed during appraisal. The estimated growth rates for the economy largely coincide with the Bank's projections and the overall approach to estimating future demand is based on sound principles. The results yield higher growth rates than those observed during the last decade. On one hand, the strong expected economic performance will provide a demand-stimulating factor given that the income elasticity of demand is greater than unity; on the other hand, there is a major element of uncertainty related to the substitution of electricity by natural gas. The latter, characterized by its low cost and its environmentally friendly characteristics is likely to be widely sought after by consumers, even at the current price levels; this incentive is likely to intensify with the expected readjustment of electricity prices. The base case scenario assumes a gradual substitution of natural gas for electricity, and in this aspect is a conservative scenario.

ANNEX 7

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

INDICATIVE EXPANSION PLAN

Background

1. The Electricity Law approved in July, 1994 as well as the Domiciliary Public Services Law assign the Government the responsibility for assuring adequate supplies of electricity by taking measures to prevent major disruptions.

2. In the context of a market-driven development, this responsibility consists of foreseeing the generation and transmission requirements of the electricity sector, following-up the development of new facilities determining the need for additional incentives to the private sector and, ultimately, taking corrective action directly to prevent rationing on a large scale.

3. The objective of the indicative expansion plan is to respond to these requirements by (a) informing investors on desirable resources to be developed, including their location, size and timing, (b) informing Government of potential risks regarding supply disruptions; and (c) identifying the decision agenda regarding projects to be promoted through private sector investment as well as those that require decisions from Public Sector agencies.

4. The responsibility for developing the indicative expansion plan was assigned to the Policy Unit (UPME[2]). Given that this function had been executed in the past by Interconexión Eléctrica, and that the expertise regarding the structure of expansion plans was concentrated in that company, UPME delegated to ISA this responsibility in 1993; in the 1994/95 revision of the plan, ISA has continued to execute a major proportion of the plan with the help of UPME.

The 1993 Expansion Plan

5. The first plan executed under the new institutional arrangement can be briefly summarized as follows:

- It assumed a growth rate for electricity demand within the 4.2%-4.7% range (see annex 6 electricity demand);
- For 1995-2000 it identified the need for a total of 1950MW of new generation distributed between 750MW in gas-based plants, 450MW in coal plants and 750MW of hydro generation;

[2] Unidad de Planeacion Minero Energetica

- For 2001-2004 it identified 2050MW of which 1200MW would be gas-based, 150MW coal and 700MW hydro.

6. The plan exhibits the following progress:

- 742MW net additions of gas-based generation are under development with private sector participation (ABB and ENRON in Termobarranquilla and Termovalle, respectively);
- 150MW coal-based generation has been awarded to a private consortium (Paipa IV);
- The Porce II hydro project is under construction by EPM;
- The Urra I hydro is under construction and is expected to start operating towards the end of 1999;
- The Miel I hydro project was launched and a consortium was formed to build it.

The 1994/95 Update

7. The 1993 plan was updated in 1994/95 in order to (a) extend the planning horizon to 2007 and (b) take into account revised demand growth which is expected to be in the 5-6% range for the near and medium future.

8. Both the 1993 plan and the 1994/95 were structured in order to provide an energy supply reliability of 95%, i.e. the plan assures that the variations in runoff would lead to a disruption of supplies in 5% or less of the available hydrological simulation sequences. In order to accomplish this, the update confirms the need for reinforcing the thermal component of the system in order to manage possible drought conditions, and in particular those arising with the so-called "El Nino" phenomenon.

9. For the 1995-2000 period, the update recommends an additional 700MW in thermal plants which were identified as 400MW gas-based and 300MW coal-based (which corresponds to the Termocesar coal plant recommended in the previous plan). This plan was endorsed by CONPES in February, 1995. The principal action to be taken consists of identifying sponsors and investors for the 400MW thermal plants. The Termocesar plant feasibility is expected to be contracted by ISAGEN.

10. The private sector has so far responded aggressively to the new opportunities: there are at present 22 consortia which have expressed their interest in developing a total of 1700MW to 2600MW in thermal and hydro plants. The range of these proposals varies from 10MW in small hydro to 100-500MW proposals by both major energy companies and large industrial Colombian conglomerates.

11. For the longer term (2001-2007), the decision agenda calls for furthering studies related to five possible hydro plants; the hydro capacity to be installed during this period is on the order of 1200MW to 1500MW. Given the construction time required for these plants, further studies are required in order to make a decision to proceed with their construction and to initiate their promotion in 1996-97.

12. Regarding transmission expansion, the major developments include the reinforcements between the Central region and the Southwest and the new interconnection between the Atlantic region and the Northeast, i.e. the principal investment component of the project being financed by the Bank.

13. The cost of new projects in the proposed expansion plan for the 1995-2007 period has an expected present value of US$4.6 billion at December, 1994 price levels.

14. The plan was reviewed and its assumptions and conclusions were considered to be adequate by the Appraisal Mission.

ANNEX 8

COLOMBIA

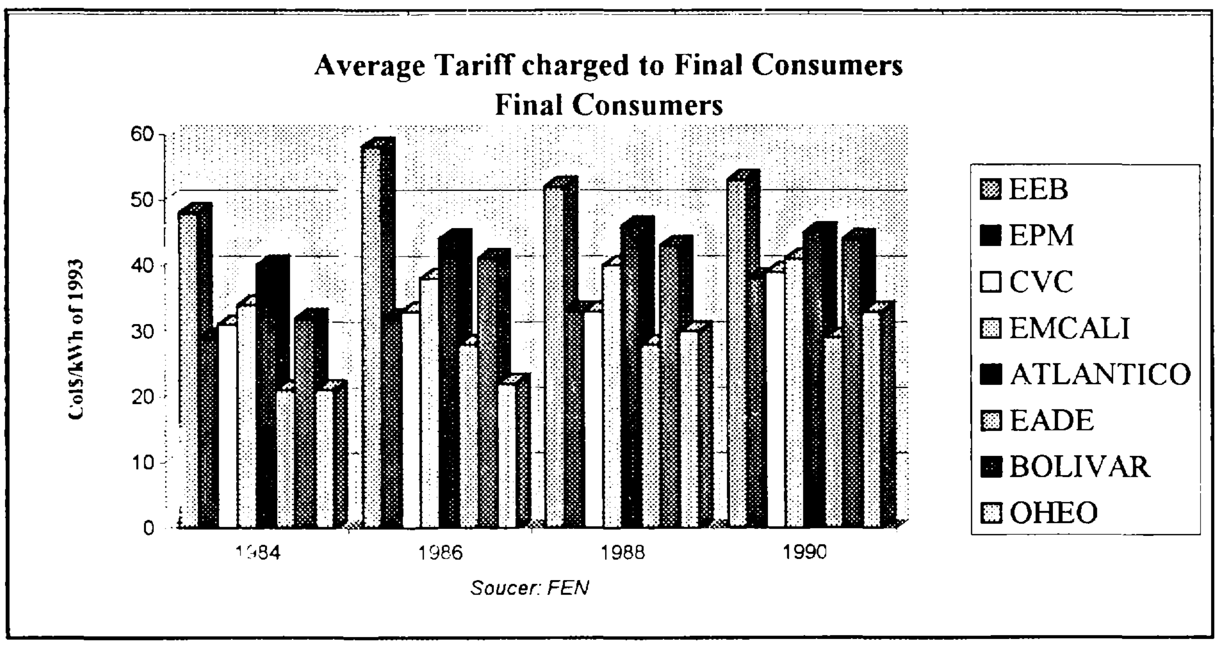
POWER MARKET DEVELOPMENT PROJECT

FINANCIAL PERFORMANCE OF THE POWER SECTOR

1. This annex analyzes the Colombian power sector's past financial performance and its expected performance during project implementation. Section A describes the financial situation of the power sector during 1984-1990, before the implementation of the power sector reform program. Section B summarizes the actions taken by the government during 1991-1994. Section C assesses the financial prospects of the power sector during 1995-2003.

A. Financial Performance During 1984-90

2. This period is characterized by a considerable deterioration of the sector's finances due to (a) slow tariff increases which did not keep up with inflation; (b) large increases in debt service due to plant overbuilding in the early 1980s; (c) periods of strong devaluation which further increased the already heavy burden of dollar-denominated debts; and (d) increased inefficiency due to administrative, financial, and commercial mismanagement.



3. Prior to 1984, the power sector was heavily subsidized and tariffs did not reflect costs. During 1980-84, average tariffs charged to final customers covered only about 50% to 60% of marginal costs and induced over consumption and waste. This low tariff level extended from the bulk level to the retail level during the 1984-90 period. In 1986, only 82% of average marginal costs were covered. Although the average tariff applied to final customers increased by 15% during the period, the retail tariff for each

utility was not uniform, and, depending on market composition, average prices varied considerably from one company to another, as shown in figure 8.1[3]. Most of the variation can be explained because the subsidized residential tariff was considerably below the overpriced commercial and industrial tariffs; consequently, distribution utilities with large numbers of residential customers were worse off than others. In 1990, the average tariff applied to final customers ranged between 3.7 and 6.8 UScent/kWh at 1993 price levels.

4. As a result of the rapid growth in power generation and distribution over the past twenty years, the power utilities incurred significant amounts of external debt to fund new investments as shown in Table 8.1. The consolidated indebtedness of the power sector amounted to about US$5.2 billion in 1990, of which US$2.9 billion was foreign debt and US$2.3 billion was internal debt. Consolidated internal cash generation of the power sector was insufficient to finance the corresponding debt service for 1990, which was partially financed with government contributions (see Table 8.2). In 1990, Government contributions were mainly used to finance guaranteed external debt totaling about US$130 million. It was also used to pay arrears from distributors due to energy purchased from ISA and to partially finance ICEL and CORELCA's investment program.

Table 8.1: EVOLUTION OF POWER SECTOR DEBT
(US$ million)

	Total Debt		External Debt		Local Debt	
Utility	**1986**	**1990**	**1986**	**1990**	**1986**	**1990**
ISA	1254	1232	812	732	442	500
Guavio	794	1066	727	943	67	123
CORELCA	523	568	327	172	196	396
EEB	607	496	461	247	146	249
CHB	400	476	268	163	132	313
EPM	534	465	424	358	110	107
ICEL	339	444	248	150	91	293
CVC	378	418	239	133	139	285
OTHERS	97	78	39	19	58	59
TOTAL	**4,926**	**5,243**	**3,545**	**2,918**	**1,381**	**2,325**

3 The utilities included in this figure cover over 75% of the retail market.

Table 8.2: CONSOLIDATED SOURCE AND APPLICATION OF FUNDS
(US$ million)

	1984	1987	1990
Gross Cash Generation	614	753	598
Gross revenue	894	948	1043
Cash operating expenses	-422	-350	-467
Depreciation and others	142	155	22
Debt Service	480	749	899
Amortization	320	469	509
Interest	160	280	390
Net Internal Cash Generation	134	4	(301)
Government contributions	69	125	148
Borrowings and others	1051	618	951
Total Sources	1254	748	815
Investment	1278	627	605
Other applications	(24)	121	210
Debt Service Coverage Ratio	1.3	1.0	0.7
Self Financing Ratio (%)	10.0	1.0	0.0

5. The rapid devaluation of the Colombian peso with respect to the dollar which took place between 1982 and 1986, together with low price levels which were not adjusted in line either with inflation or the devaluation, severely impacted the sector's financial position whose long-term debt was denominated in foreign currency.

6. The lack of corporate accountability and autonomy in most of the utilities led to a deterioration of administrative, financial, and commercial practices. Power losses were out of control and ranged between 14% and 32% in 1990. Arrears of energy bills from distributors to generators, and from government agencies and private customers to distributors exceeded 6 months in most utilities.

7. Table 8.3 summarizes the financial performance of the utilities during 1984-90. The utilities have been grouped into three categories: (a) large companies (with total assets in excess of US$700 million), which include most of the generation utilities; (b) small power utilities, which were profitable and solvent at the end of 1990; and (c) small power utilities (mainly ICEL and CORELCA subsidiaries), which were unprofitable and insolvent at the end of 1990.

COLOMBIA
POWER MARKET DEVELOPMENT PROJECT
POWER SECTOR
Table 8.3: SUMMARY OF FINANCIAL PERFORMANCE - PERIOD 1984 - 1990

COMPANY		Cash Operating Ratio (%)			Debt Service Coverage			Debt/Assets (%)			Net Cash Generation (US$ million)			(US$ million)			GWh	Consumers	Employee	A/B
											1984	1987	1990	Total Assets	Gross Revenue	Net Income	Sold	A	B	
		1984	1987	1990	1984	1987	1990	1984	1987	1990				1990	1990	1990	1990	1990	1990	1990
LARGE COMPANIES														10,767	1,141	(105)	45,337	1,821,795	11,890	153
Empresa de Energía de Bogotá	EEB	55	35	51	1.8	1.4	0.7	47	74	59	71.0	58.5	8.2	3,255	317	67	6,057	1,023,206	4,374	234
Interconexión Eléctrica S..A.	ISA	36	26	26	0.9	0.8	0.7	45	69	56	23.5	(20.1)	(50.9)	2,630	240	10	14,527	7	1,387	
Corp. Electr. de la Costa Atlántica	CORELCA	59	46	61	0.7	0.6	0.6	42	64	64	(13.9)	(53.0)	(42.5)	1,121	129	(26)	4,869	10	1,621	
Empresas Públicas de Medellín	EPM	42	39	47	1.4	1.3	1.0	37	62	53	41.5	45.7	4.9	1,100	189	24	7,640	531,464	3,070	173
Instituto Colombiano de Energía Eléctrica	ICEL	91	90	98	0.3	0.6	0.1	38	51	81	(21.8)	(21.8)	(72.1)	1,026	108	(61)	5,331	13	369	
Corp. Autónoma Regional del Cauca	CVC	53	48	60	0.8	0.8	0.5	44	76	70	0.4	4.3	(0.0)	890	120	(43)	4,630	267,093	1,018	262
Central Hidroeléctrica de Betania	CHB	0	4	21	0.0	0.1	0.1	73	73	75	(0.0)	(29.0)	(83.7)	744	38	(74)	2,283	2	51	
SMALL, PROFITABLE, AND SOLVENT														976	302	30	5,739	1,797,381	7,806	230
Central Hidroeléctrica de Caldas S.A.	CHEC	90	99	91	0.8	1.2	1.8	23	26	26	(1.4)	(0.6)	2.9	193	39	3	1,273	234,689	1,438	163
Electrificadora de Santander S.A.	ESSA	>100	95	88	>2.0	>2.0	>2.0	17	15	24	6.7	3.2	9.8	171	33	2	828	261,644	1,249	209
Empresa Antioqueña de Energía	EADE	96	86	84	>2.0	>2.0	>2.0	6	9	12	2.7	3.8	4.7	154	34	3	1,169	293,189	1,290	227
Electrificadora de Boyacá S.A.	EBSA	77	70	73	>2.0	>2.0	>2.0	20	14	27	4.4	7.9	7.3	147	26	7	752	191,250	970	197
Empresas Municipales de Cali	EMCALI	91	87	94	0.8	>2.0	>2.0	55	48	28	(2.2)	17.5	12.3	127	102	11		315,121	787	400
Empresa Eléctrica de Cundinamarca S.A.	EEC	85	93	92	>2.0	>2.0	>2.0	52	46	36	2.4	2.5	3.0	64	20	2	445	110,618	609	182
C. Electr. del Norte de Santander S.A.	CENS	>100	93	100	0.0	>2.0	>2.0	32	28	41	(1.0)	2.8	1.7	45	22	1	599	166,520	536	311
Electrificadora del Huila S.A.		97	110	94	1.0	1.1	>2.0	22	26	44	0.3	0.2	2.0	45	13	1	319	119,347	485	246
Electrificadora del Meta S.A.		>100	>100	98	>2.0	>2.0	1.2	52	62	57	0.3	0.3	0.4	20	9	0	226	64,893	221	294
Electrificadora del Caquetá S.A.		>100	>100	93	0.9	>2.0	1.9	20	17	73	(0.0)	0.2	0.2	6	2	0	54	21,657	104	208
Electrificadora del Chocó S.A.		>100	84	87	0.0	>2.0	>2.0	29	19	59	(0.2)	0.3	0.2	5	2	0	74	18,453	117	158
SMALL, UNPROFITABLE, AND/OR INSOLVENT														728	215	(49)	5,189	1,161,929	6,904	168
Electrificadora del Atlántico S.A.		>100	>100	>100	2.0	1.1	0.0	46	73	63	2.4	0.7	(14.3)	204	72	(16)	1,623	251,026	1,531	164
Electrificadora del Tolima S.A.		>100	>100	>100	0.7	0.0	0.0	20	23	34	(0.6)	(2.9)	(247.0)	155	22	(5)	611	164,350	933	176
Electrificadora de Nariño S.A.	CEDENAR	>100	>100	>100	0.0	0.0	0.0	55	53	47	(3.2)	(2.2)	(3.8)	73	12	(5)	375	139,385	638	218
Electrificadora de Bolívar S.A.		>100	96	99	0.3	0.0	0.0	49	58	50	(1.9)	(1.1)	(2.1)	66	44	(4)	969	129,600	879	147
Centrales Eléctricas del Cauca S.A.	CEDELCA	>100	>100	>100	1.0	0.0	0.0	16	24	45	0.0	(1.0)	(0.7)	51	8	(2)	267	92,516	539	172
Electrificadora de Córdoba S.A.		>100	>100	>100	0.0	0.2	0.0	43	52	40	(1.5)	(0.8)	(1.9)	49	12	(5)	301	98,721	620	159
Electrificadora del Magdalena S.A.		>100	96	>100	0.0	0.0	0.0	97	93	64	(0.8)	(1.4)	(1.6)	33	16	(3)	386	96,772	523	185
Electrificadora del Sucre S.A.		>100	>100	>100	0.0	0.0	0.0	66	71	48	(1.0)	(0.6)	(0.3)	33	9	(1)	221	69,580	444	157
Electrificadora del Cesar S.A.		>100	>100	>100	0.0	0.0	0.0	58	77	41	(0.4)	(0.4)	(0.3)	25	9	(1)	212	70,441	302	233
Electrificadora de la Guajira S.A.		>100	>100	>100	0.0	0.0	0.0	64	110	80	(1.3)	(2.3)	(1.2)	17	6	(3)	145	40,120	294	136
Electrificadora de San Andrés		>100	>100	>100	0.0	0.0	0.0	20	20	18	(2.6)	(0.7)	(0.7)	22	5	(3)	79	9,418	201	47
TOTAL POWER SECTOR (CONSOLIDATED)		47	37	45	1.0	0.9	0.6	41	63	61	118.1	3.6	(265.6)	9,102	1,043	(127)	25,155	4,781.105	26,680	179

Note: Consolidated values for the total power sector do not always correspond to the sum of the vlaues for each company because of inter-company trade and the fact that a number of companies have participation in the equity of other power utilities.

8. The first group represents 81% of total power sector assets, and includes the main generation and distribution utilities. Of these, CORELCA, ICEL, CVC and CHB exhibit a deteriorating trend during 1984-1990. Net income was negative, debt service coverage was lower than 0.7, and the debt/assets ratio was higher than 60/40. ISA's net cash generation was also negative due to the heavy load of its debt service. The second group, which accounts for 11% of total power sector assets, had a satisfactory financial situation. The third group, with about 8% of the power sector assets, had an unsatisfactory financial situation. Net income and net cash generation were negative. Most of these distribution companies were more than 13 months in arrears in payment of the energy purchased from generation utilities. Their accounts receivable ranged between 66 days and 400 days; many of the clients in arrears were government agencies (water companies, hospitals, schools, government offices, etc.) whose debts are difficult to collect as power cannot be readily cut off without giving rise to social and political conflicts.

B. Financial Performance During 1991-94

9. As part of its 1991 adjustment program, the Government defined a long-term strategy to improve efficiency and to rehabilitate the power utilities' finances. This strategy aimed at: (a) establishing a rational tariff structure and rate level; (b) setting the utilities on a sound financial footing; and (c) increasing their efficiency.

10. **Tariff Adjustment.** Tariffs charged to final customers maintained an increasing trend during this period. This adjustment was particularly important in dollar terms as the rate of devaluation of the Colombian peso during 1991-94 was considerably lower than the rate of inflation (and lower than the rate of increase in electricity prices). During this period, the government made changes to the level and tariff structure in order to reflect economic costs and to reduce subsidies to residential customers. By the end of 1994, the average electricity price applied to final customers ranged between 6.0 and 10.0 UScent/kWh and the sector's average tariff was estimated to cover around 90% of LRMC.

11. **Financial Rehabilitation**. By far the most important step toward the implementation of the Government's strategy was the debt relief granted by the National Government to the large power utilities in exchange for assets and equity shares. This was made through a number of financial operations which consisted of:

(a) **A Debt/Equity Swap.** In October 1991, the Government increased its participation in Interconexión Eléctrica's equity, through capitalization of US$342.3 million owed by the utilities to Interconexión Eléctrica, and by US$318.5 million owed by Interconexión Eléctrica to the Government. As a result of this operation, debt service was reduced, and the Government became Interconexión Eléctrica's main stockholder. Table 8.4. summarizes the financial operation:

Table 8.4: Debt/Equity Swap
(US$ million)

Utility	Utilities' Debt to Interconexión Eléctrica	Interconexión Eléctrica's Debt to Government	Total Capitalized Debt
CORELCA	150.8	45.0	195.8
EEB	28.2	140.0	168.2
ICEL	134.1	9.7	143.8
CVC	27.6	92.5	120.1
EPM	.5	30.3	30.8
CHEC	1.1	0.9	2.0
Total	**342.3**	**318.5**	**660.8**

(b) **A Debt/Asset Swap.** In 1992, the Government implemented measures to improve the financial situation of CORELCA, CHB, ICEL, and CVC. The Government took charge of these utilities' foreign debt and canceled other debts amounting to about US$1.1 billion, as shown in Table 8.5. In return, the Government received operating assets for the same amount (Termocartagena - 220MW, Termotasajero - 150MW, and Termopalenque V - 20MW, among others).

Table 8.5 Actions Tken in large Government-Owned Utilities 1992
(US$ million)

Utility	Resolution	Debt Swaps:				
		Guaranteed foreign debt	Debts with Government	Internal debt	Bills owed Interconexión Eléctrica	Total
CORELCA	#124, dated 10.14.92	94.7	90.0			184.7
CHB	#111, dated 9.14.92	97.9	259.1			357.0
ICEL	#130, dated 11.14.92	112.9	50.2	215.5	96.0[4]	378.6
CVC	#137, dated 11.15.94	63.8	68.1			131.9
Total		**369.3**	**467.4**	**215.5**	**96**	**1052.2**

12. In 1992, the Government also defined a strategy to improve the financial situation of ICEL's and CORELCA's subsidiaries (electrificadoras). This strategy included the implementation of:

(a) a plan to alleviate the short- and medium-term financial situation of the electrificadoras. Arrears due to energy purchased by the electrificadoras to ICEL

[4] Resolutions #153 and #121, dated 11.4.93 and 10.13.94, respectively.

(US$76 million) and CORELCA (US$125 million) were refinanced through long-term debts, with a maturity between 20 and 30 years, 4 years grace period, and 5% and 10% interest rate;

(b) a mechanism to transfer subsidies to the electrificadoras through budget appropriations in order to cover the deficit resulting from the supply of electricity to low income residential users at below-cost tariffs. This budget allocation amounted to about US$89 million during 1992-94.

13. **Performance Contracts**. These contracts were signed between the Government (through the Consejo Superior de Política Fiscal and FEN), and all those utilities profiting from government loans and guarantees. The contracts set: (i) limits to the intervention of the Board in the utility; (ii) specific corporate targets; and (iii) administrative, commercial and financial performance targets to managers. In turn, the Government provides financial support through budget allocations. Lack of compliance with the committed objectives would cause disbursement suspension, credit accelerations, and firing of managers. 25 performance contracts[5] were signed during 1992 and 1993, and 20 of them induced a positive recovery, which resulted in net income and profit increases (see Table 8.6). Although these performance contracts will contribute to improve the utilities' financial situation, further actions are required to solve the problem and to improve management and ownership responsiveness.

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5 It does not include ICEL, which was re-structured and re-oriented, nor EADE, whose contract was amended in 1994.

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Table 8.5 Summary of Financial Performance - Year 1993

Company	1/	Major Shareholder Name	(%)	GWh Sold	Installed Capacity (MW)	Final Consumers	Employee	Energy Losses %	Assets US$ Million	Rate of Return %	Cash Operating Ratio %	Debt Serv. Coverage Ratio Times	Sel Financing Ratio (%)	Liability/ Total assets %	Productivity ratio Customer/per Employee	Market (% of G res. Com.)	
Large Companies				32,776	7,106	2,039,818	11,035		10,907.5								
Empresa de Energia de bogota	*	M. de Bogota	100	6,637	2,196	1,193,481	4,167	22.0	3,468.6	7.8	41.4	1.4	15.0	59	286	47.6	10.6
Interconexion Electrica S.A. -ISA	*	State	70	10,843	2,476		1,309	1.4	2,910.6		31.7			47			
Empresas Publicas de Medellin	*	M. de Medellin	100	4,632	1,500	595,701	3,075	20.5	1,692.2	9.9	56.7	1.8	95.0	31	184	34.3	7.0
Corporacion Electrica de la Costa Atlantica	*	State	100	5,700	818	10	1,409	22.0	1,131.8	4.4	75.3	1.4	65.0	47	638		
Corporacion Autonoma Regional del Cauca	*	State	100	2,840	116	250,626	1,075	17.3	1,016.3	5.8	59.2	0.9	<100	52	233	19.2	2.0
Central Hidroelectrica de Betania				2,124					688.0	6.2	12.8	0.5	<100	25			
Small, Solvent and Profitable				10,618	822	2,396,349	8,849		1,471.4								
Central Hidroelectrica de Caldas S.A.	*	State	50	943	198	264,776	1,291	23.6	278.7	8.3	70.4	>2.0	>100	15	205	58.1	8.8
Electrificadora del Atlantico S.A.	*	CORELCA	85	1,777	174	285,675	1,287	25.6	241.7	5.6	91.8	>2.0	>100	77	222	46.2	13.6
Electrificadora de Santander S.A.	*	State	52	907	194	307,714	1,114	15.7	198.8	2.6	84.2	>2.0	58.0	22	276	46.0	11.9
Electrificadora de Boyaca S.A.	*	State	87	814	181	218,473	973	13.0	163.4	4.1	85.5	>2.0	29.0	28	225	30.5	3.3
Empresas Municipales de Cali		M. de Cali		2,742		364,177	510	17.4	136.9		88.8	1.2	9.0	63	714	37.9	12.2
Centrales Electricas del Cauca S.A.	*	State	73	324	32	107,514	533	22.6	91.7	1.1	94.2	0.0	48.0	36	202	59.3	4.6
C. Electr. del Norte de Santander S.A.	*	State	82	664	29	185,366	610	19.2	70.8	11.7	84.5	>2.0	97.0	28	304	53.7	12.8
Electrificadora del Magdalena S.A.	*	CORELCA	89	470	1	113,781	506	27.5	61.1	10.5	93.3	>2.0	0.0	73	225	56.4	12.4
Electrificadora del Huila S.A.	*	State	83	346	7	137,640	426	17.6	43.7	3.5	91.9	>2.0	>100	43	323	60.1	11.1
Empresa de Energia de Pereira				361				21.4	40.9	28.3	75.3	>2.0	36.0	59			
Empresa de Energia del Quindio S.A.	*	ICEL	53	276	6	94,097	242	21.8	30.4	26.4	77.2	>2.0	>100	27	389	65.0	11.0
Electrificadora del Sucre S.A.	*	CORELCA	93	263	0	79,243	447	25.2	30.0	13.6	87.9	1.5	36.0	92	177	51.0	6.2
Electrificadora del Meta S.A.	*	State	56	237	0	79,324	228	21.5	28.6	7.1	90.8	0.0	54.0	74	348	53.9	14.0
Electrificadora del Cesar S.A.	*	CORELCA	60	263	0	83,830	332	23.9	25.7	15.7	89.9	>2.0	55.0	82	253	57.1	10.3
Electrificadora de la Guajira S.A.	*	CORELCA	90	173	0	49,191	267	29.7	18.9	20.5	83.6	>2.0	>100	16	184	65.9	11.0
Electrificadora del Caqueta S.A.	*	State	71	58	0	25,548	83	21.1	10.1	8.6	90.2	>2.0	64.0	33	308	53.6	17.5
Small, Insolvent and Unprofitable				4,136	183	1,097,402	4,531		568.0								
Empresa Antioqueña de Energia	*	Dpto. Antioquia	53	1,226	16	320,369	1,374	24.3	166.7	(5.8)	>100	0.0	32.0	24	233	72.0	7.1
Electrificadora del Tolima S.A.	*	ICEL	73	622	15	184,891	386	18.4	124.9	(17.0)	>100	0.0	<100	74	479	38.7	9.1
Electrificadora de Bolivar S.A.	*	CORELCA	89	966	47	146,051	896	17.2	100.5	0.5	98.5	1.1	13.0	68	163	38.9	11.0
Electrificadora de Nariño S.A.	*	State	94	394	47	152,392	559	32.0	67.7	0.4	98.0	0.0	(82.0)	91	273	71.1	5.6
Cia. de Electr. y Gas Cundinamarca S.A.	*	State	56	445	10	121,015	466	19.5	52.6	(7.4)	>100	0.0	(92.0)	66	260	47.6	8.4
Electrificadora de Cordoba S.A.	*	CORELCA	96	344	48	120,226	590	24.0	39.7	(3.0)	>100	2.6	>100	88	204	59.1	9.7
Electrificadora de Choco S.A.	*	State	79	77		20,692	125	30.7	9.6	(43.2)	>100	0.0	(62.0)	98	166	80.3	7.4
Electrificadora de Magangue S.A.	*	State		62		31,766	135		6.3	(12.9)	>100	0.0	0.0	68	235	82.4	17.0

1/ Utilities marked with * signed a performance contract with the government

C. Forecast Financial Situation for 1995-2003

14. As a result of the re-structuring reform initiated by the Government in 1991, the prospects for the power sector have changed radically:

- Bulk electricity prices have been deregulated, thereby introducing an element that will pressure final user prices to be adjusted accordingly;

- A regulatory commission is in charge of setting regulated prices; although the Commission has Government officials sitting on it, it also has independent regulators who outnumber the former and can prevent tariff erosion;

- The Domiciliary Public Services Law mandates that prices be adjusted to cost levels within the next five years, thereby pressuring the Government to maintain the real level of electricity prices; it also mandates that Government agencies include provisions in their budgets for paying public service bills, thereby helping to keep electricity companies' receivable under control;

- The Government has recognized that allowing the sector to deteriorate financially, as in the 1980s, leads ultimately to project delays, neglect in equipment maintenance, costly bailouts and, eventually, power cuts; and

- In accordance with the principles set out in the Public Services Law, the Government has effectively appropriated National Budget funds to finance the subsidies it awards certain categories of residential customers, thereby facing a tradeoff between allowing tariffs to be adjusted or imposing greater pressure on the Budget.

15. The financial performance of the power sector as whole for 1995-2003 is expected to be satisfactory. Table 8.7 summarizes the forecast financial performance of the utilities during 1994-2003. Projected tariffs were gradually adjusted to reflect economic costs, as indicated by the regulatory commission's guidelines and targets. Despite the overall satisfactory performance, the results are not uniform. In order to analyze them, the utilities have been grouped into four categories, as follows:

(a) **Large generation and distribution companies**. This group includes ISAGEN, EPM, EPSA, CHB, EEB, and CORELCA, whose projected financial performance is generally good, except for the last two utilities. EEB and CORELCA show a weak financial situation in the short and medium term, with a positive trend towards recuperation. EEB has a heavy debt service due to the construction of Guavio, which will become progressively lighter. CORELCA would need additional financing of about US$700 million (including the corresponding financial cost) to cover its debt service and investments due to the operation of new independent producers (such as PROELECTRICA and eventually the

Termocartagena and Las Flores plants if they are privatized) which would participate in the bulk power market, thereby displacing CORELCA's sales.

(b) **Small power utilities, which are expected to be profitable and solvent during the period**. These utilities present an improving financial trend during the period. Most of the utilities have a strong tariff structure and an acceptable administrative management. This group also includes some utilities (Magdalena, Cesar, and Guajira), which in spite of having had financial problems during 1984-90, are expected to recover during the period.

(c) **Small power utilities under financial recovery during the period.** This group includes utilities having financial difficulties only during the first three years. These companies, which account for about 4% of the sector's net fixed assets, deteriorated during 1991-94 with the exception of SUCRE (see Tables 8.3 and 8.6). The financial recovery of BOYACA, SUCRE and CAQUETA is partially due to the enforcement of a performance contract signed in 1992; EADE entered into a performance contract only in 1994.

(d) **Small power utilities with scarce hope of becoming either profitable or solvent.** This group includes utilities with a predominantly residential market structure of low income customers. They account for around 2% of the sector's net fixed assets and about 4% of total supply. Electrificadora de Bolívar recently lost most of its industrial customers to Proeléctrica, an independent private generator; Chocó, Nariño, and CEDELCA serve mainly rural customers.

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Table 8.7: SUMMARY OF FORECAST FINANCIAL PROJECTIONS - PERIOD 1994 - 2003

COMPANY	Net Fixed Assets in 1994 (US$million)	Rate of Return (%)				Debt Service Coverage (ratio)				Self-financing Ratio (%)				Liability Versus Total Assets (%)			
		1994	1997	2000	2003	1994	1997	2000	2003	1994	1997	2000	2003	1994	1997	2000	2003
LARGE COMPANIES	9 638,0																
EE. de Bogota - EEB	3 728,1	9,0	9,8	10,4	6,4	0,8	0,7	1,0	1,5	-90	<100	>100	>100	59	53	38	25
ISAGEN and ISA	1 812,0		7,4	6,4	5,3		1,7	>2.0	>2.0	>100	>100	>100	>100		22	21	28
E. P. de Medellin - EPM	1 810,5	13,8	15,8	14,6	17,5	0,1	>2.0	>2.0	>2.0	>100	56	>100	>100	26	26	22	19
E. E. del Pacifico - EPSA	863,5	9,5	15,3	18,6	24,7	0,5	1,1	1,3	>2.0	<100	46	>100	>100	35	37	32	23
C. H. de Betania - CHB	776,2	8,0	16,9	18,6	21,7	1,9	>2.0	>2.0	>2.0	not applicable				26	5	2	0
CORELCA	647,7	12,2	(9,6)	7,3	9,2	2,1	0,7	0,9	1,2	>100	-71	-25	50	44	56	55	50
SMALL, SOLVENT, AND PROFITABLE	1 055,4																
C.H. del Caldas - CHEC	292,3	5,4	7,3	9,8	10,7	>2.0	>2.0	>2.0	>2.0	55	>100	>100	>100	18	25	27	24
E. de Santander - ESSA	170,5	1,9	10,4	26,6	20,7	1,9	>2.0	>2.0	>2.0	>100	78	>100	>100	24	28	26	23
E. del Atlantico	170,0	(2,8)	8,1	15,3	13,1	0,1	1,1	1,2	1,1	-284	51	90	89	67	56	41	27
E. del Tolima	118,9	(6,8)	13,4	23,5	30,5	0,4	1,8	>2.0	>2.0	-163	>100	>100	>100	72	53	38	28
C.E. Norte Santander - CENS	82,1	7,4	28,9	45,3	46,5	>2.0	>2.0	>2.0	>2.0	33	>100	>100	>100	39	32	30	25
E. del Huila (1)	45,1	(4,5)	8,5	22,6	25,6		1,9	0,8	>2.0	-24	37	77	>100	44	46	36	24
E. E. de Cundinamarca - EEC	40,4	(4,9)	1,0	22,7	37,0	1,1	1,9	2,0	>2.0	0	66	>100	>100	62	77	78	70
E. P. de Pereira - EPP	37,7	22,0	21,5	12,4	12,0	1,8	>2.0	1,4	0,9	89	33	43	56	31	36	34	21
E. del Meta (1)	22,1	29,6	37,1	35,2	36,9	>2.0	>2.0	>2.0	>2.0	>100	>100	>100	>100	48	42	33	25
E del Magdalena (1)	24,6	8,1	32,7	41,0	41,7	1,4	2,7	2,1	>2.0	21	>100	>100	>100	73	60	42	31
E. del Quindio - EDEQ	23,9	7,6	18,6	25,0	24,7	>2.0	>2.0	2,0	>2.0	0	64	>100	>100	29	40	30	20
E. del Cesar (1)	18,3	(19,1)	11,2	26,0	28,0	0,0	>2.0	>2.0	1,8	-134	>100	>100	>100	86	76	71	71
E. de la Guajira (1)	9,5	3,4	25,8	34,0	32,0	>2.0	>2.0	>2.0	>2.0	119	>100	>100	>100	23	31	30	24
SMALL UNDER FINANCIAL RECOVERY	490,2																
E. E. Antioqueña - EADE (1)	186,6	0,2	(0,7)	15,3	15,9	2,3	0,3	0,8	0,9	27	18	11	9	28	63	58	45
E. de Boyaca - EBSA	161,3	15,4	3,0	15,6	17,5	>2.0	0,2	1,3	>2.0	101	-52	96	>100	19	30	25	20
EMCALI (1)	123,1	27,1	5,6	16,7	20,1	>2.0	0,8	0,9	0,7	51	-19	67	56	60	74	66	50
E. de Sucre (1)	12,7	10,8	16,9	19,6	20,0	0,8	0,7	0,8	0,9	-19	-12	27		89	76	58	37
E. del Caqueta (1)	6,5	(14,3)	0,6	33,2	38,3	0,0	0,5	1,0	>2.0	0	-39	>100	>100	36	52	39	26
SMALL, INSOLVENT, AND UNPROFITABLE	267,4																
CEDELCA	104,0	(5,9)	4,5	7,1	7,1	0,0	1,3	1,1	0,9	-47	13	10	-17	40	42	41	37
E. de Bolivar	73,7	0,9	(2,0)	4,5	4,3	0,5	0,4	0,6	0,0	-911	-46	-99	<100	46	68	73	95
E. de Nariño	62,7	(5,0)	0,6	7,7	7,1	0,2	0,6	0,8	0,7	-18	-18	-25	-69	87	90	89	87
E. de Córdoba	15,7	(33,1)	(6,9)	21,3	25,0	0,0	0,7	0,8	>2.0	0	-41	27	>100	96	124	112	97
E. del Chocó (1)	7,7	(8,1)	(1,8)	9,6	8,6	0,5	0,9	1,0	1,1	-8	-0	22	23	93	95	103	112
E. de Magangue (1)	3,6	11,2	(3,4)	3,3	6,2	>2.0	0,0	0,2	0,2	529	<100	<100	<100	63	84	>103	>100

16. **National Budget Appropriations.** The financial vulnerability of weak distribution companies is expected to persist as long as (a) the policy of subsidizing low income users is maintained and (b) their market structure in terms of residential/commercial/industrial users does not change. Therefore, they can be expected to require continued Government support. For 1995, the budgeted support for the sector amounts to Col$60 billion (US$70 million).

17. The issue consists of determining the appropriate amount of Government subsidy which is required by these companies; it can be examined under two alternative approaches:

- By quantifying subsidies (positive or negative) as the difference between prices and LRMC and by calculating the net subsidies for the sector and for each company; or
- By recognizing that equating prices and LRMC is a condition for efficiency but not a condition for financial equilibrium and by setting Government contributions at a level that compensates utilities according to the financial shortfall associated with residential subsidies.

18. The first approach provides an upper bound to the subsidies required by any given distribution company by comparing actual prices to the LRMC:

- Under the existing tariff schedules (1995), required subsidies amount to Col$ 240 billion, and cross subsidies generate Col$ 192 billion for a net requirement of Col$ 48 billion (US$176 million);

- Under the planned targeted subsidies, there would be a gross requirement of Col$ 47 billion and cross-subsidies of Col$ 60 billion for a net excess of Col$ 13 billion (US$15 million).

Consequently, under planned tariff adjustments, overall cross-subsidies are expected to exceed subsidies to lower income users. However the net position is positive for only six out of 29 distribution companies; as a consequence, 23 companies would still require support amounting to Col $ 47 billion (US$56 million). The financial subsidy required from Government once prices reach the level targeted by the regulatory commission is relatively modest and will amount to less than 5% of the sector's revenues.

19. The second approach recognizes that equating prices and LRMC is neither a necessary nor a sufficient condition of financial equilibrium; the existing average tariff level, on the order of 90% of LRMC, can generate sufficient funds for distribution companies to operate adequately, particularly when facing decreasing returns to scale.

20. Furthermore, many of the problems faced by the distribution utilities also originate in weak management; in this sense, the most pressing problem consists of controlling losses which amount to around 20% of generation. It is estimated that at least 10% correspond to unbilled consumption and reducing them should increase revenues significantly.

21. **Sensitivity Analysis.** The following scenarios were assumed:

(a) An increase of 3 and 1 percentage points in local and external inflation respectively, over the level of the base case. There is no appreciable effect in sector finance, due to the following factors: (i) revenues and most of the expenses are adjusted with inflation; (ii) external inflation has only an effect on large companies, whose investment programs have a foreign component, and who have the capacity to obtain new loans; (iii) smaller companies who only have distribution investments in local currency exhibit cash surpluses under this scenario;

(b) Local inflation identical to that used in the base case, and external inflation according to the Bank's OP 6.50 Annex B1 (October, 1994) (annual inflation increases of 1.5% in 1995, 1.8% in 1996, 2.6% in 1997, 2.5% in 1998-2001, 2.4% in 2002, and 2.1% in 2003). This scenario shows a decrease of about US$100 million in investment requirements due to the reduction of the foreign component of the investment program of large power utilities.

D. Assumptions For Power Sector Financial Projections

General

22. Financial projections for the period 1994-2003 have been prepared by FEN in current prices and are expressed in US$ million. Expected inflation and exchange rates are detailed in the following table:

Table 8.8: Financial Projection Assumptions

	1994	1995	1996	1997	1998-2003
Local inflation (%)	22.0	18.0	15.0	12.	10.0
External inflation (%)	5.5	3.8	3.5	3.5	3.5
Average exchange rate (Col $/US$)	814	876	979	1072	1150 in 1998, maintaining parity thereafter
Exchange rate at the end of the year (Col $/US$)	825	927	1030	1115	1185 in 1998, maintaining parity thereafter

23. The forecast was based on the following main assumptions:

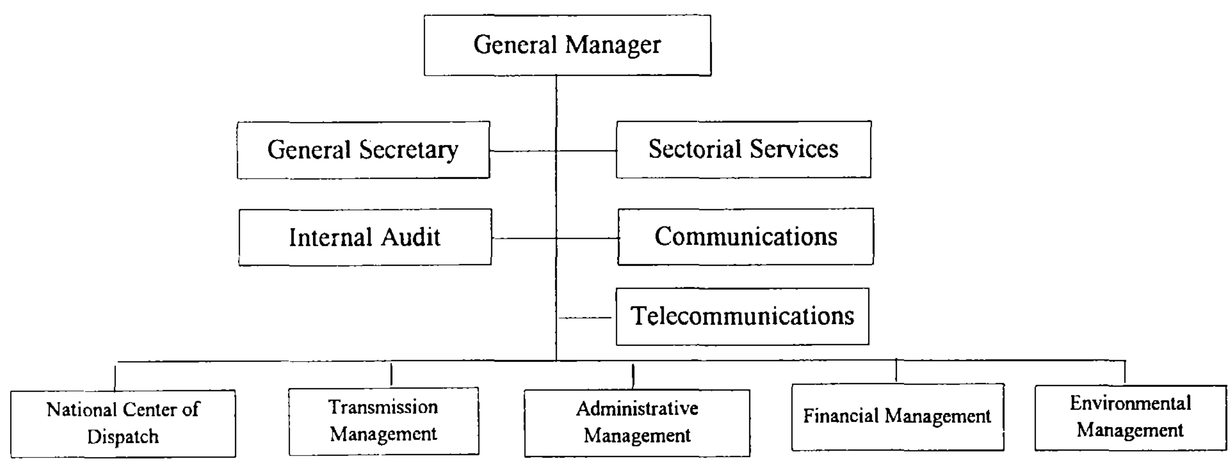
Item	Assumption
Energy Sales	Energy sales are based on the demand projections used in the Preference Generation and Transmission Expansion Plan of 1995. It considered an average 6.1% sales growth during the period, assuming a reduction of power losses from 23% in 1994 to 19% in 2000 over net power generation.
Power Sector Tariff	The power revenues of each utility are based on existing tariffs in 1993. Tariffs projected for the period were increased in accordance with the resolutions issued by JNT and ERC for 1994 and maintained constant in real terms. For 1995, sector tariff increases were set at 18% according to resolution #057 of December 1994, and take into account the policy set in the Pacto Social implemented by the current Government. Total increases in real terms during 1996-2000 for the four largest distribution companies in the sector were assumed as: EEB (2.3%), EPM (13%), EMCALI (7.9%) and Electrificadora del Atlántico (-2.8%); increases for the remaining distribution companies ranged between 10% and 20% with the exception of Magdalena (-6%) and Caquetá (57%).
Energy Purchased by the Distribution Utilities	Transmission tariffs are based on the ERC's resolution #001 and #004 of December 1994, which sets wheeling charges applied to distributors. These tariffs were maintained constant in real terms during the period. The tariff to be paid to the generators is based on ERC's resolutions #010 to #030, and was set as the average tariff paid the distributors less toll tariff.
Investment Program	New generation is assumed to be installed by the private sector. Current investment in generation only includes the completion of existing projects.

ANNEX 9

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

ISA's ORGANIZATION CHART



ANNEX 10

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

PROJECT DESCRIPTION, COSTS AND IMPLEMENTATION PLAN

A. Purpose

1. This Annex contains the Project Implementation Plan (PIP). The PIP details the project management and implementation arrangements, and is referenced in the loan documents. The PIP addresses the principal features of the project: scope and objectives, costs, implementation arrangements, implementation schedule and procurement and disbursement schedules. The PIP will be the basic reference for ISA's management for measuring progress and success in project implementation. The PIP will also provide the reference benchmarks for Bank supervision of the project's components.

2. Given the large number of components of the Project, the PIP is a summary of a more detailed document prepared by ISA and the Bank during project appraisal which is available in the project file (3 Project Implementation Plan, Spanish Version). This document details the above features for each of the sub-components of the Project and would be used for reference as appropriate, during project implementation.

B. Project Objectives and Description

3. The project's overall objective is to support power sector reform by facilitating the operation of a competitive bulk supply market for electricity. Specifically, the project seeks to lift transmission constraints that hinder an open access of publicly as well as privately owned power generators to the grid and to support ISA in its role as transmission network operator, system generation dispatcher and commercial transactions coordinator. The project will be a key component of the comprehensive power sector restructuring that is being put in place with Bank assistance.

4. The project consists of three components:

PART A: Energy Control Center (ECC) and Financial Settlement Center (FSC).

5. This component includes the upgrading of the data acquisition and control functions of ISA's existing ECC and the installation of a FSC. The project will finance the purchase of measurement, data acquisition, telecommunications, data processing equipment and software.

PART B: Expansion of the Interconnected Transmission System.

6. This component includes investments to strengthen and expand the national transmission system; the following is a summarized list of major elements:

(i) **San Carlos-San Marcos System**. (a) construction of a single circuit, 384 km, 500 kV transmission line interconnecting the East Antioquia hydroelectric complex to the Valle del Cauca Department; (b) construction of a single circuit, 30 km, 230 kV transmission line interconnecting the La Virginia and La Hermosa substations; (c) expansion of the San Marcos 500/230 kV substation; (d) construction of the La Virginia 500/230 kV substation; and (e) construction of the San Carlos 500/230 kV substation.

(ii) **Atlantic Coast System:** (a) reactive compensation for the Chinú substation; (b) expansion of the Cerromatoso 500/230 kV substation; (c) construction of the Urabá 230/115 kV substation; (d) construction of the double circuit, 80 km, 230 kV La Loma- El Copey transmission line; (e) expansion of the 500/115 kV Chinú substation; (f) expansion of the 500/230 kV Sabanalarga substation.

(iii) **Other Transmission Components:** (a) reactive compensation for the Caño Limón substation; (b) construction of the single circuit, 160 km, 230 kV transmission line between Paipa and Bucaramanga; (c) construction of the Paipa 230 kV substation; (d) construction of the Bucaramanga 230 kV substation; and (e) construction of a link between the San Felipe substation and the 230 kV Esmeralda-La Mesa transmission line;

PART C: Technical Assistance:

7. This part includes the provision of consulting services and training programs to assist ISA in the strengthening of its capabilities to assume its roles of: (i) transmission network operator, (ii) power dispatch coordinator and (iii) bulk electricity transaction clearing house. These activities will be agreed upon between ISA and the Bank subject to an annual plan to be approved by the Bank. An initial list of studies and training activities for the first year of execution is presented below:

Studies:

(a) Final design and technical specification for computing and data acquisition systems and the corresponding software for the ECC and the FSC;

(b) Determination and specification of methods to transmit data collected by remote meters to the ECC and the FSC;

(c) Identification of the characteristics of transmission power losses in ISA's network and specification of mechanisms for loss monitoring and control;

(d) Review and update of ISA's power substation design manual;

(e) Development of methodology for technical and economical assessment of width of corridors for transmission lines;

(f) Standardization of steel structures for single circuit 230 kV lines;

(g) Development of a comprehensive quality control data acquisition system;

(h) Evaluation of telecommunications infrastructure and equipment needs for power transmission projects;

(i) Development and acquisition of computer software to prepare construction budgets for power substations;

(j) Feasibility study of the application of synchronized operation of circuit breakers on ISA substations;

(k) Review of power transformer technical specifications used by ISA;

(l) Methodology for load curve forecast.

Subjects for Training:

(a) Operation of the interconnected power system, and recording and settlement of financial transactions among users of the power pool;

(b) Power system planning;

(c) Telecommunications;

(d) Environmental impact assessment and monitoring of power transmission lines;

(e) Marketing;

(f) Power transmission contract negotiation.

C. Project Cost

8. Two different sets of project costs were developed during appraisal: one, in accordance to Bank rules for presentation in SARs, the other based on ISA's accounting practices for easy follow up of the project execution. The differences are in the treatment of the foreign cost component, and the assumptions for estimating physical and price contingencies.

9. **Cost Estimate in Accordance with Bank Rules**. This cost estimate for the project is summarized in Table 1, and is identical to the one included in the main text of this report. The project's total cost including taxes, duties, physical contingencies, price contingencies and interest during construction is estimated at US$ 410.0 million, of which US$ 249.3 million (60%) corresponds to direct plus indirect foreign costs and US$ 170.1 million (40%) corresponds to local costs. Taxes and import duties are estimated at US$43.9 million. Cost estimates are in December 1994 prices.

10. Costs are based on ISA's estimates, which have been reviewed by the Bank and found acceptable. ISA maintains a database of transmission and substation costs with similar characteristics to those of the project; it was updated during project preparation on the basis of recent international bids for similar projects. Physical contingencies, which amount on average to 12%, were estimated based upon the type of project and the status of its design. Price contingencies assume: (a) a project execution period of six years based on the 1994 Bank standard disbursement schedule for power projects in LAC, and (b) escalation rates over and above base cost plus physical contingencies of 2.6% for 1995-2001.

TABLE 1
COLOMBIA - POWER MARKET DEVELOPMENT PROJECT
COST ESTIMATE
(US$ thousand; price level end 1994)

		SUBTOTAL FC	SUBTOTAL LC	TOTAL
	PART A: Energy Control Center and Financial Settlement Center			
1.	Engineering and Administration	6,323	2,380	8,703
1.1	Engineering	6,323	2,061	8,384
1.2	Administration	0	319	319
2.	Direct Construction Cost	10,096	1,686	11,782
	Subtotal	16,419	4,066	20,485
3.	Physical Contingencies	2,463	610	3,073
	SUBTOTAL PART A	**18,882**	**4,676**	**23,558**
	PART B: Expansion of the Interconnected Transmission System			
1.	Engineering and Administration	530	21,204	21,734
1.1	Engineering	530	14,887	15,417
1.2	Administration	0	6,317	6,317
2.	Direct Construction Cost	153,370	94,502	247,872
2.1	Land Purchase	0	6,507	6,507
2.2	Lines and Substations Construction	153,370	87,995	241,365
	Subtotal	153,900	115,706	269,606
3.	Physical Contingencies	23,085	17,356	40,441
	SUBTOTAL PART B	**176,985**	**133,062**	**310,047**
	PART C: Technical Assistance to ISA			
1.	Technical Assistance	1,927	1,021	2,948
1.1	Studies	964	443	1,407
1.2	Training	964	578	1,542
	Subtotal	1,927	1,021	2,948
3.	Physical Contingencies	289	153	442
	SUBTOTAL PART C	**2,216**	**1,175**	**3,391**
	Total A+B+C			
1.	Engineering, Administration and Technical Assistance	8,780	24,606	33,386
2.	Direct Construction Cost	163,466	96,188	259,654
	Subtotal	172,246	120,794	293,040
3.	Physical Contingencies	25,837	18,119	43,956
	SUBTOTAL A+B+C	**198,083**	**138,913**	**336,996**
	Escalation	14,460	6,807	21,267
	Subtotal (Including Escalation)	212,544	145,719	358,263
	Interests During Construction	36,770	15,009	51,779
	TOTAL PROJECT INCLUDING TAXES AND DUTIES	**249,314**	**160,729**	**410,042**
	Taxes and Duties	0	43,908	43,908
	TOTAL PROJECT WITHOUT TAXES AND DUTIES	**249,314**	**116,821**	**366,134**

11. **Project Cost Adjustment for Purposes of Supervision**. For purposes of project implementation, the appraisal team and ISA worked on the basis of costs estimates which can be easily supervised and monitored during project implementation. Such data should be consistent with ISA accounting procedures, which include as foreign component only direct imports of materials, equipment and consulting and contractor services, (expenditures directly done by ISA in foreign currency), while the table presented in the SAR considers foreign component also the indirect foreign costs (the import component embodied in goods and services which are provided domestically). On the above basis, the project's total cost, including duties, taxes, price

contingencies and interest during construction is estimated at US$ 397.4 million, of which US$ 236.7 million corresponds to **direct only** foreign costs and US$ 160.7 million corresponds to local costs. Physical contingencies weighting, in average 10% has been estimated by ISA in accordance with its own internal procedures. Price contingencies assume: (a) a project execution based on ISA's detailed schedule for each one of the components of the project, and (b) escalation rates over and above base cost plus physical contingencies in accordance with guidelines provided to ISA by DNP. It was assumed that the exchange rate variations would compensate for the difference between the local and international inflation rates. Total project cost is summarized in Table 2.

COLOMBIA - POWER MARKET DEVELOPMENT PROJECT
Table 2 - COST ESTIMATE
AND BUDGET EXECUTION SCHEDULE
(US$ thousand)

		UP TO 1994		19 95		19 96		19 97		19 98		19 99		SUBTOTAL		TOTAL
		FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	
	Part A															
1.	Engineering and Administration	0	702	4149	690	1817	476	0	0	0	0	0	0	5965	1868	7833
1.1	Engineering		581	4149	600	1817	386							5965	1567	7532
1.2	Administration		120		90		90							0	301	301
2.	Construction Direct Costs	0	167	4879	850	4645	813	0	0	0	0	0	0	9525	1830	11355
2.2	Equipment		167	4879	850	4645	813							9525	1830	11355
	Subtotal	0	869	9028	1541	6462	1289	0	0	0	0	0	0	15490	3699	19188
3.	Physical Contingencies	0	13	531	93	516	90							1047	196	1243
	Subtotal	0	882	9559	1634	6978	1380	0	0	0	0	0	0	16537	3895	20432
4.	Price Contingencies		148	458	336	586	342							1044	826	1870
	Subtotal Part A	0	1030	10017	1970	7564	1722	0	0	0	0	0	0	17581	4721	22302
	VAT (Engineering)		81		84		54							0	219	219
	Import Duties (Equipment)				611		581							0	1192	1192
	Total Taxes	0	81	0	695	0	635	0	0	0	0	0	0	0	1412	1412
	Subtotal Part A w/o Taxes	0	948	10017	1274	7564	1087	0	0	0	0	0	0	17581	3309	20890
	Part B															
1.	Engineering and Administration	0	3552	0	4689	250	3006	250	5947	0	3617	0	992	500	21802	22302
1.1	Engineering	0	2577	0	3712	250	2056	250	4415	0	2552	0	530	500	15841	16341
1.2	Administration	0	975	0	977	0	950	0	1532	0	1065	0	462	0	5960	5960
2.	Construction Direct Costs	93	785	8520	4579	21115	16789	44159	33755	59727	42861	2113	3360	135727	102128	237854
2.1	Infrastructure	0	755	0	2354	0	2759	0	271	0	0	0	0	0	6139	6139
2.2	Equipment	93	30	8512	2077	19371	7814	40426	19817	56707	30597	0	0	125108	60335	185444
2.3	Construction And Erection	0	0	7	148	1744	6216	3733	13666	3020	12264	2113	3360	10618	35654	46272
	Subtotal	93	4336	8520	9267	21365	19795	44409	39701	59727	46478	2113	4351	136227	123929	260156
3.	Physical Contingencies	9	116	852	567	2089	2055	4641	4116	6065	4783	317	504	13974	12141	26115
	Subtotal	102	4453	9372	9834	23453	21850	49051	43817	65792	51261	2430	4855	150200	136070	286271
4.	Price Contingencies	2	52	449	449	1971	1792	6096	5428	11152	8666	466	876	20136	17263	37399
	Subtotal Part B	104	4505	9821	10283	25424	23642	55147	49245	76944	59927	2896	5731	170336	153333	323670
	VAT (Engineering)	0	315	0	446	0	238	0	546	0	313	0	65	0	1923	1923
	VAT (Civil Works)	0	0	0	3	0	121	0	256	0	239	0	7	0	626	626
	VAT (Materials And Equipment)	0	13	0	660	0	3215	0	6967	0	9670	0	0	0	20525	20525
	VAT (Erection)	0	0	0	0	0	2	0	130	0	260	0	299	0	691	691
	Total Vat	0	328	0	1109	0	3576	0	7899	0	10482	0	371	0	23765	23765
	Import Duties	0	12	0	601	0	2982	0	6244	0	8766	0	0	0	18604	18604
	Total Taxes	0	340	0	1710	0	6557	0	14143	0	19248	0	371	0	42369	42369
	Subtotal Part B w/o Taxes	104	4165	9821	8573	25424	17085	55147	35103	76944	40679	2896	5360	170336	110964	281301
	Part C															
1.	Technical Assistance	0	0	455	227	909	455	455	227	0	0	0	0	1818	909	2727
1.1	Studies			227	114	455	227	227	114					909	455	1364
1.2	Training			227	114	455	227	227	114					909	455	1364
	Sub-Total	0	0	455	227	909	455	455	227	0	0	0	0	1818	909	2727
3.	Physical Contingencies			45	23	91	45	45	23					182	91	273
	Sub-Total	0	0	500	250	1000	500	500	250	0	0	0	0	2000	1000	3000
4.	Price Contingencies													0	0	0
	Subtotal Part C	0	0	500	250	1000	500	500	250	0	0	0	0	2000	1000	3000
	VAT (Technical Assistance)				32		64		32					0	127	127
	Total Taxes	0	0	0	32	0	64	0	32	0	0	0	0	0	127	127
	Subtotal Part C w/o Taxes	0	0	500	218	1000	436	500	218	0	0	0	0	2000	873	2872
	Total Project															
1.	Engineering and Administration	0	4253	4603	5606	2976	3937	705	6174	0	3617	0	992	8283	24579	32862
1.1	Engineering	0	3158	4603	4539	2976	2897	705	4642	0	2552	0	530	8283	18318	26601
1.2	Administration	0	1095	0	1067	0	1040	0	1532	0	1065	0	462	0	6261	6261
2.	Direct Construction Costs	93	952	13399	5429	25760	17602	44159	33755	59727	42861	2113	3360	145251	103958	249209
2.1	Infrastructure	0	755	0	2354	0	2759	0	271	0	0	0	0	0	6139	6139
2.2	Equipment	93	197	13392	2927	24016	8627	40426	19817	56707	30597	0	0	134633	62166	196799

... continued

COLOMBIA - POWER MARKET DEVELOPMENT PROJECT
Table 2 - COST ESTIMATE
AND BUDGET EXECUTION SCHEDULE
(US$ thousand)

		UP TO 1994		19 95		19 96		19 97		19 98		19 99		SUBTOTAL		TOTAL
		FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	FC	LC	
2.3	Construction and Erection	0	0	7	148	1744	6216	3733	13666	3020	12264	2113	3360	10618	35654	46272
	Sub-Total	93	5205	18002	11035	28735	21539	44864	39929	59727	46478	2113	4351	153534	128537	282071
3.	Physical Contingencies	9	129	1429	682	2696	2191	4687	4139	6065	4783	317	504	15203	12428	27631
	Subtotal	102	5334	19431	11718	31431	23730	49551	44067	65792	51261	2430	4855	168737	140965	309702
4.	Price Contingencies	2	200	907	785	2557	2134	6096	5428	11152	8666	466	876	21180	18089	39269
	Total Project	104	5534	20338	12503	33988	25864	55647	49495	76944	59927	2896	5731	189917	159054	348971
	Interests during Implementation			2764	155	4895	572	9472	440	15107	316	14544	185	46782	1668	48450
	Total Project Financial Required	**104**	**5534**	**23102**	**12658**	**38883**	**26436**	**65119**	**49935**	**92051**	**60243**	**17440**	**5916**	**236699**	**160722**	**397421**
	Taxes Break-down															
	VAT Engineering	0	396	0	562	0	356	0	578	0	313	0	65	0	2270	2270
	VAT Civil Works	0	0	0	3	0	121	0	256	0	239	0	7	0	626	626
	VAT Materials And Equipment	0	13	0	1271	0	3796	0	6967	0	9670	0	0	0	21717	21717
	VAT Erection	0	0	0	0	0	2	0	130	0	260	0	299	0	691	691
	Total Vat	0	409	0	1836	0	4274	0	7931	0	10482	0	371	0	25304	25304
	Import Duties	0	12	0	601	0	2982	0	6244	0	8766	0	0	0	18604	18604
	Total Taxes	0	421	0	2437	0	7256	0	14175	0	19248	0	371	0	43908	43908
	Total Project Cost w/o Taxes	**104**	**5113**	**23102**	**10221**	**38883**	**19180**	**65119**	**35761**	**92051**	**40995**	**17440**	**5545**	**236699**	**116814**	**353513**

D. Financing

On the basis of Table 1, total required financing is estimated at US$ 410.0 million. A Bank loan of US$ 249.3 million is proposed to cover the foreign currency component. Local financing, amounting at US$ 160.7 million, would be provided by ISA's own cash generation (see Financial Analysis).

Financing Plan
(US$ million)

	LC	**FC**	**TOTAL**
IBRD	0	249.3	249.3
ISA	160.7	0	160.7
TOTAL	160.7	249.3	410.0

E. Implementation Arrangements

12. The project will be implemented by ISA. ISA has long experience and has performed well in implementing Bank financed projects. Implementation of the project would be the responsibility of a Project Executing Unit (PEU) under the Transmission Directorate. The PEU is well staffed with experienced professionals and has enough resources and autonomy to seek consultant support whenever this is needed. The Project Execution Unit has successfully carried out several projects financed by loans from the Bank and IDB and has proven good implementation capabilities.

13. ISA will require support from specialized consultants for developing specific tasks, as follows: **Part A of the Project**: ISA has procured and will finance with its own resources the

participation of a specialized consulting firm for completing the feasibility study and the preparation of bidding documents for the implementation of the ECC and the FSC. **Part B of the Project**: ISA will procure, in accordance with the procurement schedule, several contracts for design and supervision during construction for lines and substations to be implemented under this component. Most of consultant contracts will be locally procured and financed with ISA's own funds. **Part C of the Project**. Under the TA component of the Project, ISA will contract under procedures acceptable to the Bank and with bank financing several consultant contracts as indicated in the procurement schedule.

14. The PEU's specific activities covers the following:

- preparation of terms of reference, solicitation of proposals, contractual arrangements and supervision of consultant work for studies, design and inspection of works (manufacturer's tests for equipment and supervision of construction and erection of lines and substations),

- preparation and solicitation of bids for procurement of equipment and materials,

- preparation and solicitation of proposals for construction of civil works and for the erection of electromechanical equipment,

- organization and procurement of certification of acceptance tests and commissioning,

- follow up of Project budget and management of disbursement applications,

- internal reporting to ISA's management and to ISA's internal audit system,

- follow up of implementation of environmental programs,

- external reporting (IDB, IBRD, FEN, MME, others).

15. The PEU is organized along functional groups as shown in Schedule 1.

F. Implementation Schedule

16. In accordance with the aggregate schedule of the various components of the project, execution is expected to be completed by the end 1999. ISA's official execution schedule is presented in Schedule 2.

17. **Procurement** arrangements for the proposed project are summarized in Table 2 [1]. Purchase of goods and equipment and contracting of construction works to be financed with

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[1] ISA is exempted from application of Law 80, which regulates contracts involving public entities, in respect to all aspects of Project execution, including procurement. (See Annex 1, Electricity Law.)

proceeds of the loan would be carried out in accordance with the Bank procurement guidelines, **Bank Guidelines for Procurement under IBRD Loans and IDA Credits** (January 1995). Purchases of goods and equipment for transmission lines and substations for a total of US$129.0 million would be procured under International Competitive Bidding (ICB). Computers and other electronic equipment for implementing the ECC and FSC for a total amount of US$ 12.3 million would be procured through Limited International Bidding (LIB) because there is only a limited number of potential suppliers. Works for construction of transmission lines and substations for a total of US$31.0 would be procured under ICB. Equipment and installation services for substations and transmission lines for a total amount of US$50.0 million would be procured under ICB. Procurement of consultant services for a total amount of US$5.0 million will be carried out in accordance with the **Bank Guidelines for the Use of Consultants** (August 1981). An aggregate amount of US$1.0 million would be used to reimburse foreign expenditures incurred by ISA in its training abroad of ISA staff, such as tuition fees and travel expenses for attending courses and seminars. Bank issued standard bidding documents would be used for all procurement of goods and works. For complex time-based consulting assignments Bank issued standard form of contract for consulting services will be used. To expedite procurement, an initial list of procurement packages was agreed with ISA and is presented as Attachment 3 (Procurement Schedule). Procurement packages under ICB arrangements would be about 30 with an average cost of about US$ 7.4 million, a minimum cost of US$ 1.0 million and a maximum cost of about US$ 38 million. There would also be about 50 locally procured packages not financed by the Bank with an average cost of about US$500,000; these packages are not likely to attract foreign bidders and local procurement is considered to be the most efficient procedure. Goods and services not financed with proceeds of the loan would be procured locally under ISA's established procurement practices, which have been reviewed by the Bank and found to be satisfactory.

Table 2: Procurement Arrangements

(US$ million)

A. Procurement Method[1]	ICB[2]	NCB	OTHER	NBF[6]	TOTAL
Equipment	129.0		12.3 [3]	50.0	191.3
	(113.6)		(10.0)		(123.6)
Works	31.6			12.5	43.4
	(25.0)				(25.0)
Equipment and installation	50.0			34.6	84.5
	(43.0)				(43.0)
Consultant services			28.6[4]	8.4	37.0
			(5.0)		(5.0)
Training courses			1.9[5]		1.9
			(1.0)		(1.0)
Total	210.0		42.8	105.4	358.3
	(181.6)		(16.0)		(197.5)

(1) Figures in parentheses are amounts financed by the proposed Bank Loan, including contingencies. Table does not include US$ 51.8 million of interest during construction .
(2) Goods and services to be procured by International Competitive Bidding in accordance with Bank guidelines
(3) Limited International Bidding
(4) Contracting of Consultants in accordance to Bank guidelines.
(5) Training: reimbursement of foreign currency expenses.
(6) Not Bank financed. To be procured locally under ISA's established procurement practices.

18. **Prior Review**. All contracts for goods and works under ICB and all contracts related to training (other than consultant services) equal or exceeding US$ 300,000 would be subject to the Bank's prior review. The provisions of the Consultant Guidelines requiring prior Bank review or approval of budgets, short lists, selection procedures, letters of invitation, proposals, evaluation reports and contracts, shall not apply to: (a) contracts for the employment of consulting firms estimated to cost less than US$100,000 equivalent each; or (b) contracts for the employment of individuals estimated to cost less than US$50,000 equivalent each. However, said exceptions to prior Bank review shall not apply to: (a) the terms of reference for such contracts; (b) single-source selection of consulting firms; (c) assignments of a critical nature, as reasonably determined by the Bank; (d) amendments to contracts for the employment of consulting firms raising the contract value to US$100,000 equivalent or above; or (e) amendments to contracts for the employment of individual consultants raising the contract value to US$50,000 equivalent or above. Contracts subject to prior review would cover about 85% of Bank financed goods and services. The balance of contracts would be subject to ex-post review by the Bank after contracts are awarded. When evaluating bids for goods, qualified domestic manufacturers would be eligible for a 15% margin of preference, or the import duty, whichever is lower.

19. **Disbursements.** ISA expects to substantially complete project implementation in four years, but the disbursements period should extend to six years. ISA expects to complete project implementation in four years. However, under the 1994 standard disbursement profile for power projects implemented in the LAC region, the loans would be disbursed over a seven years period. The disbursement schedule is attached in Annex 10. Proceeds from the loans would be applied to finance following estimated amounts of project expenditures:

(a) 90% of expenditures for works (US $25.0 million);

(b) 100% of foreign expenditures and 90% of local expenditures (ex-factory cost) for the purchase of goods (US$ 10.0 million for part A of the Project and US$ 103.6 million for parts B and C of the Project);

(c) 95% of expenditures for contracts for the supply of equipment and installation thereof (US$ 43.0 million);

(d) 100% of foreign expenditures for consultant services (US$ 0.5 million for part A of the Project and US$ 4.5 million for parts B and C of the Project);

(e) 100% of foreign expenditures for training of ISA staff abroad and training fees (US$ 1.0 million); and

(f) interest and other charges under the Bank loan, (US$ 36.8 million);

(g) unallocated expenditures (US$ 24.9 million).

20. Disbursements against statement of expenses (SOE) will be made in respect of training service contracts costing less than US$ 300,000 and for consultant services not subject to prior review. Retroactive financing of up to US$ 10 million for eligible expenditures (made after March 31, 1995, but no more than 12 months before signing) would be provided for under each loan. Eligible expenditures would have to follow procurement procedures acceptable to the Bank. The Project is expected to be substantially completed by 2001 with a closing date of December 31, 2002.

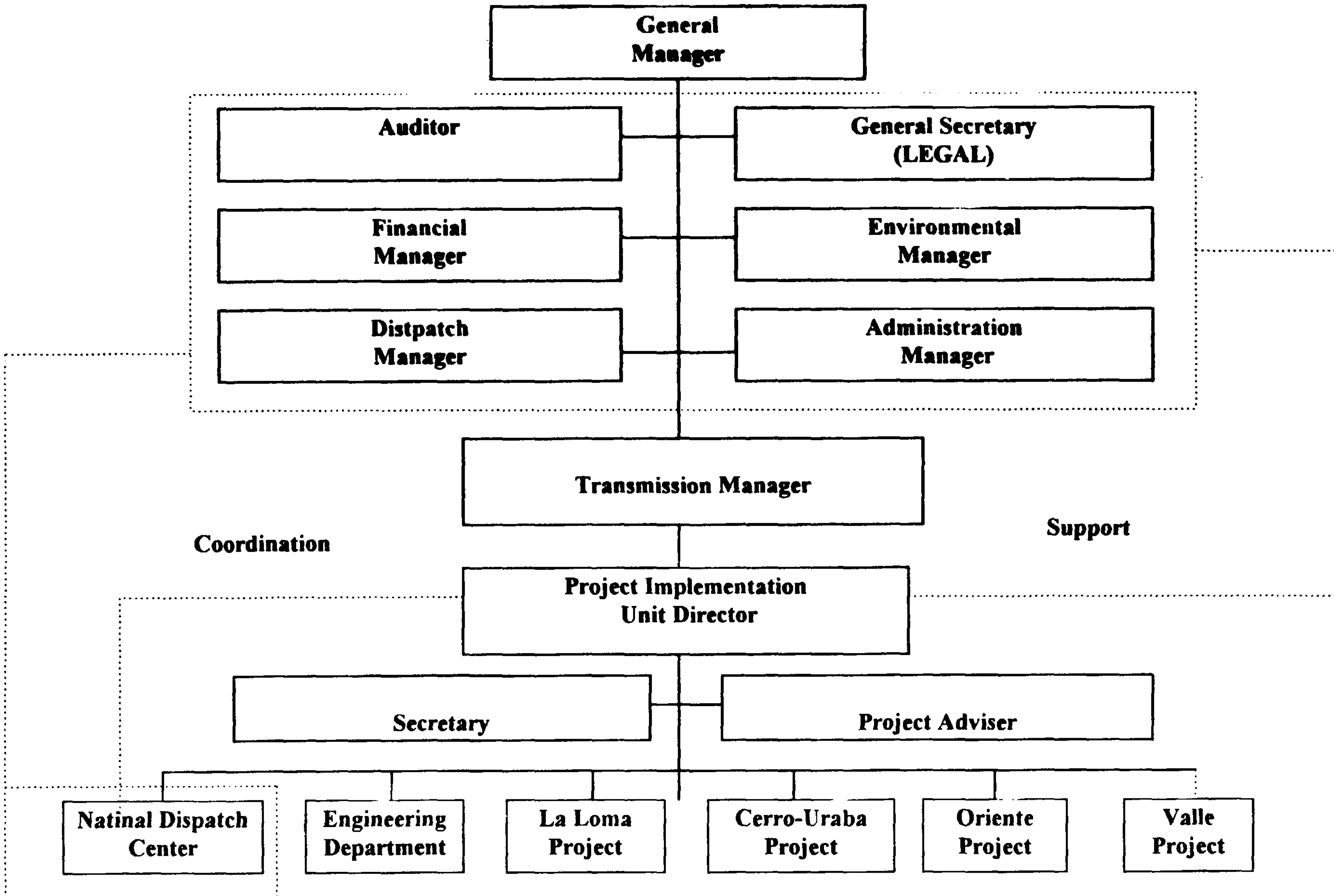
21. The Borrower would establish for each loan Special Accounts in US dollars with a commercial bank acceptable to the Bank to cover eligible Bank expenditures under the loan. The authorized allocation to the Special Accounts would be US$8 million for each loan. However, they should not exceed US$4 million during the start-up of the project. The balance could be requested when the total amount disbursed from each loan account plus outstanding commitments has reached US$20 million. Subsequent replenishment by the Bank into the Special Accounts would follow the procedures by which Bank funds are disbursed against actual expenditures.

22. Disbursements from the loan, in accordance with LAC's standard profile would be as follow:

Estimated Disbursements (Bank FY)
(US $ million)

Calendar Year	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**
Annual	14.9	39.9	69.8	69.9	49.8	5.0
Cumulative	14.9	54.8	124.6	194.5	244.3	249.3

Project Execution Unit Organization chart



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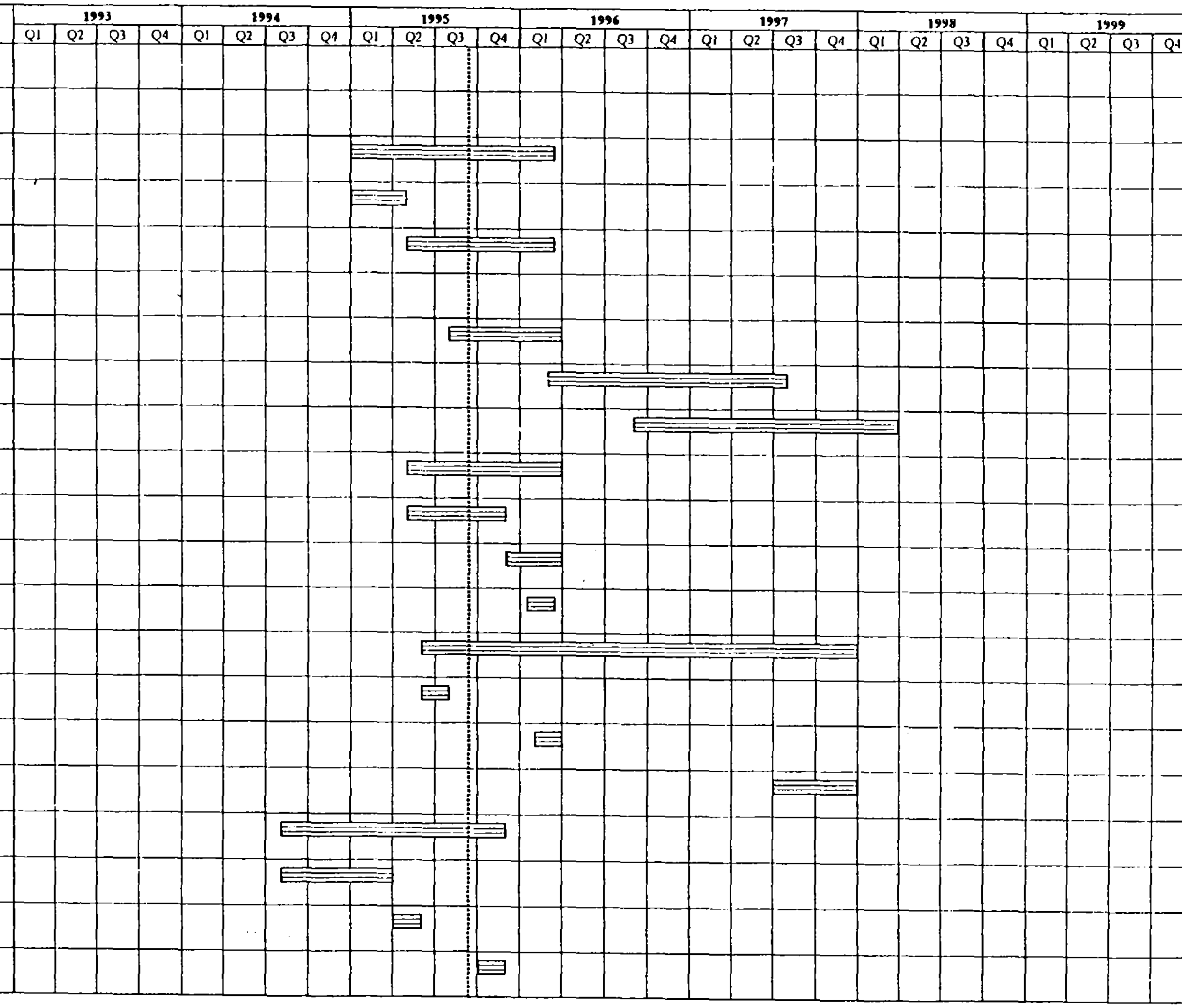
ANNEX 10 - ATTACHMENT 2
COLOMBIA - POWER MARKET DEVELOPMENT PROJECT
EXECUTION SCHEDULE

Code	Activity
1	PART A
2	ENERGY CONTROL CENT. AND FINANCIAL SETTL. CENT.
3	CONSULTANT WORKS
4	Contractual Arrangements
5	Execution of Studies
6	IMPLEMENTATION OF PHYSICAL FACILITIES
7	Procurement
8	SCADA/AGC System
9	Applications Development
10	DATA ACQUISITION SYSTEM
11	Procurement
12	Manufacturing and Delivering
13	Tests and Commissioning
14	NETWORK ANALYSIS SOFTWARE
15	Definition of Requirements
16	Plan Preparation
17	Plan Implementation
18	FINANCIAL SETTLEMENT CENTER
19	Requirements Definition
20	Accounting Administration System
21	Telemetering Systems



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Schedule 2

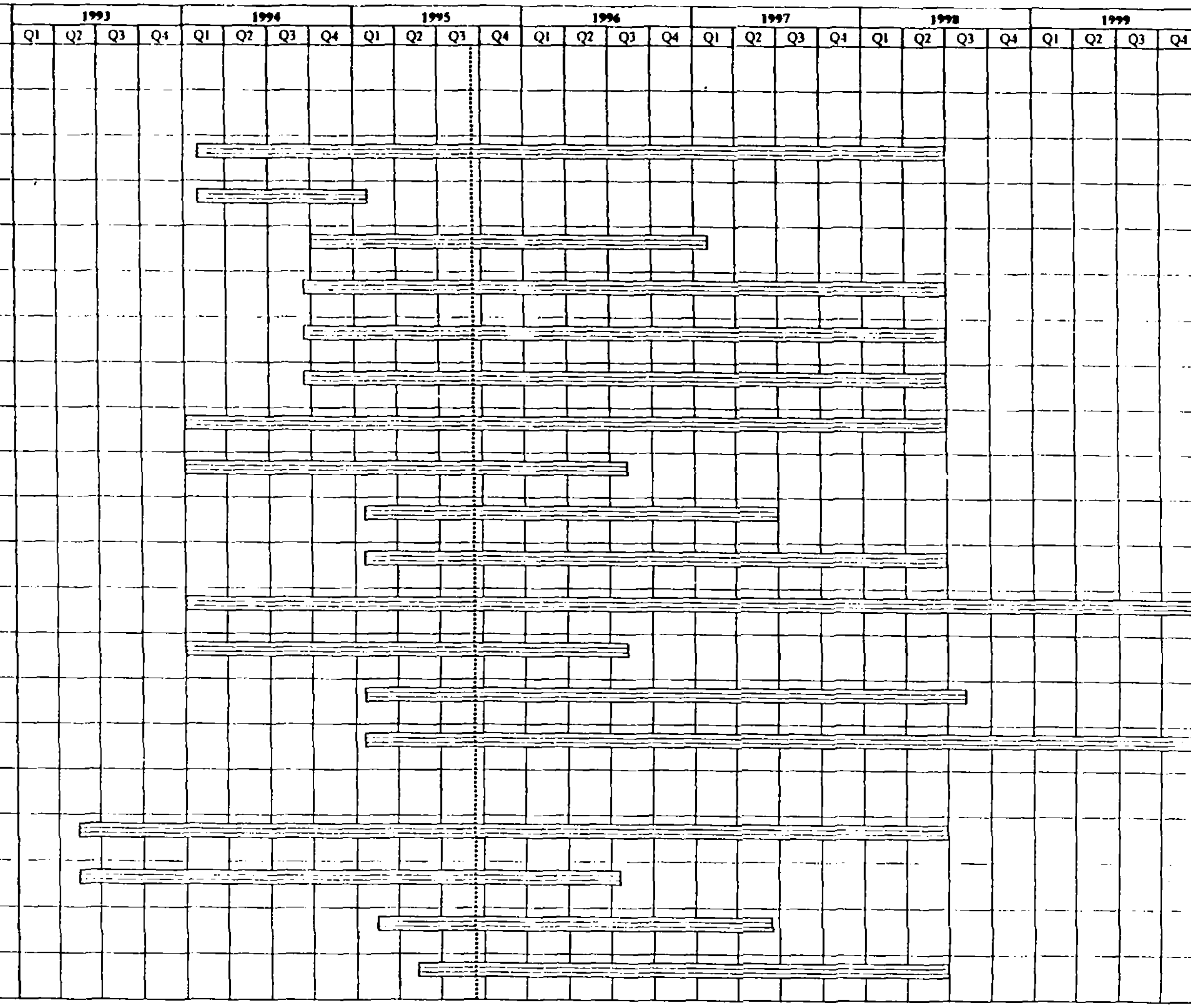
ANNEX 10 - ATTACHMENT 2

COLOMBIA - POWER MARKET DEVELOPMENT PROJECT

EXECUTION SCHEDULE

9/11/95

Code	Activity
22	**PART B**
23	**SAN CARLOS - SAN MARCOS SYSTEM**
24	**LINE SAN CARLOS - LA VIRGINIA - SAN MARCOS**
25	Design
26	Procurement of Material and Equipment
27	Construction, Erection and Tests
28	**LINE LA VIRGINIA - LA HERMOSA**
29	Design, Procurement, Construction, Erection and Tests
30	**SUBSTATION SAN MARCOS, SAN CARLOS, LA VIRGINIA 230 kV**
31	Design
32	Procurement of Material and equipment
33	Construction, Erection and Tests
34	**SUBSTATION SAN MARCOS, SAN CARLOS, LA VIRGINIA 500 kV**
35	Design
36	Acquisition of Material and Equipment
37	Construction, Erection and Tests
38	**SYSTEM COSTA ATLANTICA**
39	**SUBSTATION CERROMATOSO Y URABA**
40	Design
41	Acquisition of Material and Equipment
42	Construction, Erection and Tests



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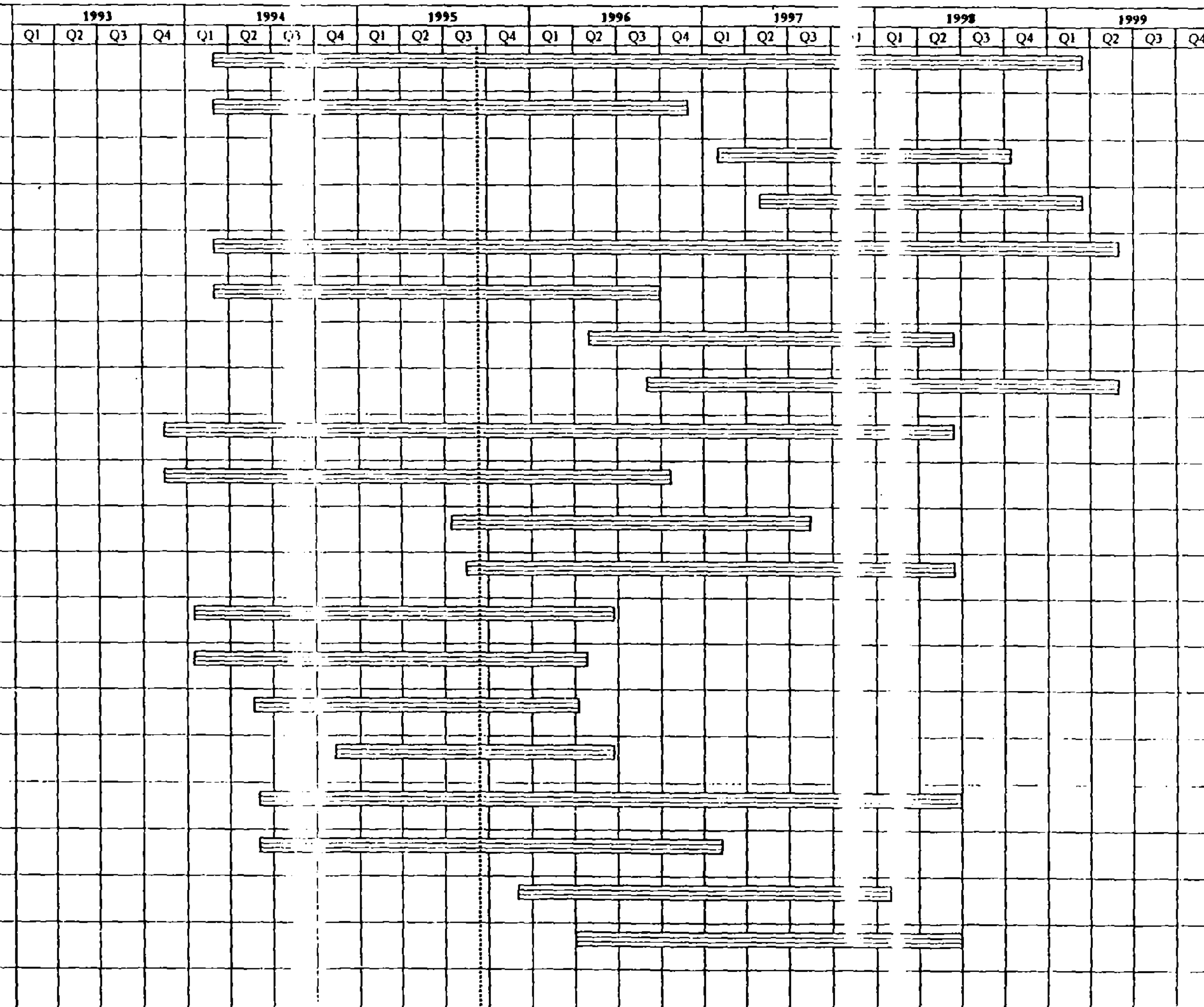
Schedule 2

9/11/95

ANNEX 10 - ATTACHMENT 2
COLOMBIA - POWER MARKET DEVELOPMENT PROJECT
EXECUTION SCHEDULE

Code	Activity
43	**LINE LA LOMA - EL COPEY**
44	Design
45	Acquisition of Material and Equipment
46	Construction, Erection and Tests
47	**SUBSTATION LA LOMA Y EL COPEY**
48	Design
49	Acquisition of material and Equipment
50	Construction, Erection and Tests
51	**REACTIVE COMPENSACION SUBSATION CHINU**
52	Design
53	Acquisition of Material and Equipment
54	Construction, Erection and Tests
55	**EXPANSION OF SUBSTATION CHINU**
56	Design
57	Acquisition of material and Equipment
58	Construction, Erection and Tests
59	**SUBSTATION SABANALARGA**
60	Design
61	Acquisition of material and equipment
62	Construction, Erection and Tests
63	**MISCELLANEOUS WORKS**



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Schedule 2

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ANNEX 10 - ATTACHMENT 2
COLOMBIA - POWER MARKET DEVELOPMENT PROJECT
EXECUTION SCHEDULE

9/11/95

Code	Activity
64	**REACTIVE COMPENSATION SUBSTATION CANO LIMON**
65	Design
66	Acquisition of material and Equipment
67	Construction, Erection and Tests
68	**LINE PAIPA - BUCARAMANGA**
69	Design
70	Acquisition of material and equipment
71	Construction, Erection and Tests
72	**SUBSTATION PAIPA - BUCARAMANGA**
73	Design
74	Acquisition of Material and equipment
75	Construction, Erection and Tests
76	**INTERCONNECTION SUBSTATIO SAN FELIPE**
77	Design
78	Acquisition of Material and Equipment
79	Construction, Erection and Tests
80	**PART C**
81	**TECHNICAL ASSISTANCE**
82	Final design for the ECC & the FSC
83	Methods to transmit data to ECC and FSC
84	Identification of the characteristics of transmission power losses in ISA

Timeline columns: 1993 – 1999, Q1 Q2 Q3 Q4 for each year.

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Schedule 2

9/11/95

ANNEX 10 - ATTACHMENT 2
COLOMBIA - POWER MARKET DEVELOPMENT PROJECT
EXECUTION SCHEDULE

Code	Activity
85	Review and update of ISA's power substation design manual
86	Width of power line corridors
87	Standarization of steel structures for single circuit 230 kV lines
88	Development of a comprehensive quality control data acquisition system
89	Evaluation of telecommunications needs for power transmission projects
90	Power stations construction budget software
91	Feasibility study of synchronized operation of circuit breakers
92	Review of power transformer technical specifications used by ISA
93	Methodology for load curve forecast

1993 Q1 Q2 Q3 Q4 · 1994 Q1 Q2 Q3 Q4 · 1995 Q1 Q2 Q3 Q4 · 1996 Q1 Q2 Q3 Q4 · 1997 Q1 Q2 Q3 Q4 · 1998 Q1 Q2 Q3 Q4 · 1999 Q1 Q2 Q3 Q1

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Procurement Schedule

(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
PART A								
	ECC Consultant Technology Update	385	756	1141		385	756	1141
(International)	Shopping	385	756	1141	World Bank	385		385
					ISA		756	756
	Purchase Of Rtus, Expansion Of Ecc Coverage	1961	343	2304		1961	343	2304
(International)	Competitive Bidding	1961	343	2304	World Bank	1498		1498
					ISA	463	343	806
	Restructuring Of Ecc Information Network	191	33	224		191	33	224
(International)	Shopping	191	33	224	World Bank	146		146
					ISA	45	33	78
	Update Of Scada / Agc /Ems System	12359	2572	14931		12359	2572	14931
(International)	Competitive Bidding	12359	2572	14931	World Bank	7701		7701
					ISA	4658	2572	7230
	Financial Settlement Center	150	191	341		150	191	341
(National)	Shopping	150	191	341	World Bank	119		119
					ISA	31	191	222
	Methodology, Training And Assistance	1491	0	1491		1491	0	1491
(International)	Shopping	1491		1491	World Bank	969		969
					ISA	522		522
	Total Procedures	16537	3895	20432		16537	3895	20432
					World Bank	10818	0	10818
					ISA	5719	3895	9614
	Indexing	1044	827	1871		1044	827	1871
					World Bank			0
					ISA	1044	827	1871
	Total	17581	4722	22303		17581	4722	22303
					World Bank	10818	0	10818
					ISA	6763	4722	11485
					World Bank	0	0	0
					ISA	0	0	0
PART B								
	San Carlos - San Marcos System							
	San Carlos - San Marcos Line							
TPL-501	Supply Of San-Carlos-	13640	4911	18551		13640	4911	18551

Procurement Schedule

(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
(International)	San Marcos 500-kV Line							
	Insulators, Ancillary Equipment	13640	4911	18551	World Bank	13640	682	14323
					ISA		4229	4229
TPL-502	Supply Of 500-kV Line	13443	4839	18282		13443	4839	18282
(International)	San Carlos - San Marcos							
	Cables, Including Lightning Protector Cable	13443	4839	18282	World Bank	13443	672	14115
					ISA		4167	4167
TPL-571	Construction And Erection Of	16497	18479	34976		16497	18478	34975
(International)	San Carlos-San Marcos 500-kV Line							
	Structures, Construction And Erection	16497	18479	34976	World Bank	16497	14837	31334
					ISA		3641	3641
	- Structures	11747	4229	15976				
	-Construction And Erection	4750	14250	19000				
T-004	External Supervision	0	3315	3315		0	3315	3315
(National)	San Carlos-San Marcos 500-kV Line							
	External Supervision Of Construction And Erection		3315	3315	ISA		3315	3315
T-003	Design Of San Carlos-San Marcos	0	1790	1790		0	1790	1790
(National)	500-kV Line							
	Design		1790	1790	ISA		1790	1790
	Land And Easements Land And Easements	0	4000	4000		0	4000	4000
			4000	4000	ISA	0	4000	4000
	La Virginia - La Hermosa Line							
TPL-201	Supply And Construction Of	1585	1692	3277		1585	1692	3277
(International)	La Virginia-La Hermosa Line							
	Design, Materials Supply	1585	1692	3277	World Bank	1492	1088	2580
	Construction And Erection				ISA	93	604	697
T-015	External Supervision	0	201	201		0	201	201
(National)								
	External Supervision Of Construction And Erection	0	201	201	ISA	0	201	201
							92	92
	Land And Easements	0	92	92		0		

Procurement Schedule
(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
	Land And Easements		92	92	ISA	0	92	92
	San Carlos, La Virginia, San Marcos (Phase Ii) Substations							
TPS-202 (International)	Supply S.Marcos (Phase Ii), La Virginia AND SAN CARLOS 230-kV SUBSTATIONS	8468	5203	13671		8468	5204	13672
	Supply Of Equipment	7927	5203	13130	World Bank	8468	355	8823
	Supervision Of Erection	541		541	ISA		4849	4849
TPS-262 (National)	Civil Engineering S. Macros (Phase Ii), La Virginia And San Carlos 230-kV Substations	0	1084	1084		0	1083	1083
	Civil Engineering, Substations:	0	1084	1084	ISA	0	1083	1083
	-Construction (1)	0	87	87				
	-Construction (2)	0	910	910				
	-Construction (3)	0	87	87				
TPS-282 (International)	Erection S.Marcos (Phase Ii), La Virginia And San Carlos 230-kV Substations	180	541	721		180	541	721
	Erection Of Substations:	180	541	721	World Bank	180	541	721
	- Erection (1)	15	44	58				
	- Erection (2)	151	454	605				
	- Erection (3)	15	44	58				
T-006 (National)	External Supervision S. Marcos (Phase Ii), La Virginia And San Carlos 230-kV Substations	0	371	371		0	371	371
	External Supervision Of Construction And Erection	0	371	371	ISA	0	371	371
T-005 (National)	Design And Consultancy S. Marcos (Phase Ii), La Virginia And San Carlos 230-kV Substations	0	688	688		0	688	688
	Design And Consultancy	0	688	688	ISA	0	688	688
	Infrastructure	0	755	755		0	755	755
	Infrastructure		755	755	ISA	0	755	755
	San Carlos, La Virginia, San Marcos (Phase III) Susbstations							
TPS-502 (International)	Supply S.Marcos (Phase III), La Virginia And San Carlos Substations 500	26305	12958	39263		26304	12958	39262

Procurement Schedule

(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
	kV							
	Supply Of Equipment	24758	12958	37716	World Bank	26304	1105	27409
	Supervision Of Erection	1547		1547	ISA	0	11853	11853
TPS-562 (National)	Civil Engineering S.Marcos (Phase Iii), La Virginia And San Carlos 500-kV Substations	0	3094	3094		0	3094	3094
	Substation Civil Engineering	0	3094	3094	ISA	0	3094	3094
	-Construction (1)	0	922	922				
	-Construction (2)	0	1517	1517				
	-Construction (3)	0	655	655				
TPS-582 (International)	Erection S.Marcos (Phase Iii), La Virginia And San Carlos 500-kV Substations	514	1543	2057		514	1543	2057
	Erection Of Substations	514	1543	2057	World Bank	514	1543	2057
	-Erection (1)	153	460	613				
	-Erection (2)	252	757	1009				
	-Erection (3)	109	326	435				
T-014 (National)	External Supervision	0	1003	1003		0	1003	1003
	External Supervision Of Construction And Erection	0	1003	1003	Recuros ISA	0	1003	1003
T-005 (National)	Design And Consultancy S Marcos (Phase Ii), La Virginia And San Carlos 500-kV Susbstations	0	1861	1861		0	1861	1861
	Design And Consultancy	0	1861	1861	ISA	0	1861	1861
	Chinu Compensation Substation							
TPS-504 (International)	Supply Of Substation	12657	4959	17616		12657	4959	17616
	Materials And Equipment	11983	4959	16942	World Bank	12657	617	13274
	Supervision Of Erection	674		674	ISA		4342	4342
TPS-584	Erection Of Substation	0	896	896		0	896	896
	Erection		896	896	World Bank		896	896
TPS-564 (National)	Substation Civil Engineering	0	1348	1348		0	1348	1348
	Construction		1348	1348	ISA		1348	1348

Procurement Schedule
(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
T-010 (National)	External Supervision	0	511	511		0	511	511
	External Supervision		511	511	ISA		511	511
T-009 (National)	Design And Consultancy	0	1111	1111		0	1111	1111
	Design And Consultancy		1111	1111	ISA		1111	1111
	Cerromatoso Substation							
TPS-203 (International)	Supply Of Substation	5478	3043	8521		5478	3043	8521
	Materials And Equipment	5142	3043	8185	World Bank	5478	865	6343
	Supervision Of Erection	336		336	ISA		2178	2178
(International)								
	Erection		446	446	World Bank		446	446
TPS-263 (National)	Substation Civil Engineering	0	671	671		0	671	671
	Construction		671	671	ISA		671	671
T-008 (National)	External Supervision	0	248	248		0	248	248
	External Supervision		248	248	ISA		248	248
T-007 (National)	Design And Consultancy	0	461	461		0	461	461
	Design And Consultancy		461	461	ISA		461	461
	Uraba Substation							
TPS-203	Supply Of Substation	1151	757	1908		1151	757	1908
(International)	Materials And Equipment	1075	757	1832	World Bank	1151	282	1433
	Supervision Of Erection	76		76	ISA		475	475
TPS-283 (International)	Erection Of Substation	0	101	101		0	101	101

Procurement Schedule
(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
	Erection		101	101	World Bank		101	101
TPS-263 (National)	Substation Civil Engineering	0	318	318		0	318	318
	Construction		318	318	ISA		318	318
T-008 (National)	External Supervision	0	61	61		0	61	61
	External Supervision		61	61	ISA		61	61
T-007 (National)	Design And Consultancy	0	113	113		0	113	113
	Design And Consultancy		113	113	ISA		113	113
	La Loma- El Copey Line							
LLL-201 (International)	Cables	2303	806	3109		2303	806	3109
	Cables	2060	721	2781	World Bank	2303	115	2418
	Lightning Protector Cable	243	85	328	ISA		691	691
LLL-202 (International)	Insulators And Accessories	977	342	1319		976	342	1318
	Insulators	357	125	482	World Bank	976	49	1025
	Accessories	292	102	395	ISA		293	293
	Accessories And Grounding Equipment		114	441				
LLL-271 (International)	Structures, Construction And Erection	1964	2118	4082		1964	2118	4082
	Structures	1424	498	1922	World Bank	1964	1691	3655
	Construction And Erection	540	1620	2160	ISA		427	427
L-001 (National)	Design And Impact Assessment El Copey - La Loma - Ocaña Line	0	396	396		0	396	396
	-Design And Impact Assessment		396	396	ISA		396	396
L-002 (National)	External Supervision Of Line Works	0	264	264		0	264	264
	-External Supervision		264	264	ISA		264	264

Procurement Schedule
(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
	Land And Easements	0	160	160		0	160	160
	Land And Easements		160	160	ISA	0	160	160
	La Loma And El Copey Substations							
LLS-201 (International)	Materials And Equipment	3791	2444	6235		3790	2444	6234
	La Loma Substation	1264	814	2078	World Bank	3790	872	4662
					ISA		1572	1572
	Bay Equipment	696	251	947				
	Structures		109	109				
	Miscellaneous Equipment	540	454	994				
	Supervision Of Erection	28		28				
	El Copey Substation	2527	1630	4157				
	Bay Equipment	1391	502	1893				
	Structures		219	219				
	Miscellaneous Equipment	1080	909	1989				
	Supervision Of Erection	56		56				
LLS-261 (International)	Civil Engineering	265	795	1060		265	795	1060
	Civil Engineering La Loma Substation	88	265	353	World Bank	265		265
	Civil Engineering El Copey Substation	177	530	707	ISA		795	795
LLS-281 (National)	Erection	0	254	254		0	254	254
	Erection Of La Loma Substation		85	85	ISA		254	254
	Erection Of El Copey Substation		169	169				
L-003 (National)	Design	0	323	323		0	323	323
	-Design Of La Loma Substation		109	109	ISA		323	323
	-Design Of El Copey Substation		214	214				
L-004 (National)	External Supervision	0	174	174		0	174	174
	-External Supervision Of La Loma Substation		59	59	ISA		174	174
	-External Supervision Of El Copey Substation		115	115				

Procurement Schedule
(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
	Infrastructure	0	72	72		0	72	72
	Infrastructure		72	72	ISA	0	72	72
	Expansion Of Chinu Substation Transformation Capacity							
CHS-501 (International)	Materials And Equipment	1895	1373	3268		1895	1373	3268
	-Bay Equipment	875	317	1192	ISA	1895	1373	3268
	-Structures, Cables And Connection Equipment	0	720	720				
	-Transformers	931	336	1267				
	-Supervision	89	0	89				
CHS-561 (National)	Civil Engineering	0	133	133		0	133	133
	Civil Engineering		133	133	ISA		133	133
CHS-581 (National)	Erection	0	101	101		0	101	101
	Erection		101	101	ISA		101	101
CD (National)	Design	0	47	47		0	47	47
	Design		47	47	ISA		47	47
C-001 (National)	Engineering And Consultancy	0	25	25		0	25	25
	Engineering And Consultancy		25	25	ISA		25	25
C-002 (National)	External Supervision	0	39	39		0	39	39
	External Supervision		39	39	ISA		39	39
	Transformation Capacity, Sabana							
TPS-504 (International)	Substation Supply	4454	2713	7167		4454	2713	7167

Procurement Schedule
(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
	Materials And Equipment	4169	2713	6882	World Bank	4454	289	4743
	Supervision Of Erection	285		285	ISA		2424	2424
TPS-585 (National)	Substation Erection	0	379	379		0	379	379
	Erection		379	379	ISA		379	379
TPS-565 (National)	Civil Engineering, Substation	0	570	570		0	570	570
	Construction		570	570	ISA		570	570
T-012 (National)	External Supervision	0	217	217		0	217	217
	External Supervision		217	217	ISA		217	217
T-010 (National)	Design And Consultancy	0	404	404		0	404	404
	Design And Consultancy		404	404	ISA		404	404
	Infrastructure	0	250	250		0	250	250
	Infrastructure		250	250	ISA	0	250	250
	Misc. Transmission Works							
	Caño Limon Substation							
TPS-204 (International)	Substation Supply	415	142	557		415	142	557
	Materials And Equipment	394	142	536	World Bank	415	20	435
	Supervision Of Erection	21		21	ISA		122	122
TPS-284	Substation Erection	0	28	28		0	28	28
	Erection		28	28	World Bank		28	28
(International)								
TPS-264 (National)	Civil Engineering, Substation	0	42	42		0	42	42
	Construction		42	42	ISA		42	42
T-010	External Supervision	0	16	16		0	16	16

Procurement Schedule

(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
(National)								
	External Supervision		16	16	ISA		16	16
T-009 (National)	Design And Consultancy	0	30	30		0	30	30
	Design And Consultancy		30	30	ISA		30	30
	Paipa - Bucaramanga Line							
P68-L210 (International)	Structures, Construction And Erection	3638	3451	7089		3638	3451	7089
	-Structures	2318	811	3129	World Bank	3638	2756	6394
	-Construction And Erection	1320	2640	3960	ISA		695	695
P68-L220 (International)	Cables, Including Lightning Protector Cable	2619	917	3536		2619	917	3536
	-Cables, Including Lightning Protector Cable	2619	917	3536	World Bank	2619	131	2750
					ISA		786	786
P68-L230 (International)	Insulators And Accessories	1210	423	1633		1210	423	1633
	- Insulators And Accessories	1210	423	1633	World Bank	1210	60	1270
					ISA		363	363
P68-L121 (National)	External Supervision	0	558	558		0	558	558
	External Supervision		558	558	ISA		558	558
P68-L120 (National)	Design And Consultancy	0	300	300		0	300	300
	Design And Consultancy		300	300	ISA		300	300
	Land And Easements	0	360	360		0	360	360
	Land And Easements		360	360	ISA	0	360	360
	Paipa And Bucaramanga 230-kV Substations							
P68-L310	Supply Of Paipa And Bucaramanga	7413	4233	11646		7413	4233	11646

Procurement Schedule
(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
	Substations							
(International)								
	Paipa Substation Bay Equipment	2435	879	3314	World Bank	1253	37	1290
	Paipa Substation Misc. Equipment	1889	1590	3479	ISA	6160	4196	10356
	Buacaramanga Substation Bay Equipment	1739	628	2367				
	Bucaramanga Substation Misc. Equipment	1350	1136	2486				
P68-L350 (National)	Erection Of Paipa And Bucaramanga Substations	0	677	677		0	677	677
	Erection Of Paipa Substation		395	395	ISA		677	677
	Erection Of Bucaramanga Substation		282	282				
P68-L410 (International)	Communications	1300	1450	2750		1300	1451	2751
	Communications Equipment	1300	1450	2750	World Bank	1300		1300
					ISA		1451	1451
P68-L340 (National)	Supply Of Paipa And Bucaramanga Substations	0	657	657		0	657	657
	Paipa Substation Structures		383	383	ISA		657	657
	Bucaramanga Substation Structures		274	274				
P68-L360 (National)	Paipa And Bucaramanga Substations Civil Engineering	0	2120	2120		0	2120	2120
	Paipa Substation Civil Engineering		1237	1237	ISA		2120	2120
	Bucaramanga Substation Civil Engineering		883	883				
P68-L131 (National)	External Supervision	0	350	350		0	350	350
	External Supervision		350	350	ISA		350	350
P68-L130 (National)	Design And Consultancy	0	649	649		0	649	649
	Design And Consultancy		649	649	ISA		649	649

Procurement Schedule
(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
	Infrastructure	0	200	200		0	200	200
	Infrastructure		200	200	ISA	0	200	200
	Connection Between San Felipe Substation And La Esmeralda - La Mesa Line							
TPS-205 (International)	Supply Of Substation	1262	956	2218		1262	956	2218
	Materials And Equipment	1172	956	2128	World Bank	1262	188	1450
	Supervision Of Erection	90		90	ISA		768	768
TPS-285 (National)	Substation Erection	0	119	119		0	119	119
	Erection		119	119	ISA		119	119
TPS-265 (National)	San Felipe Substation Civil Engineering	0	179	179		0	179	179
	Construction		179	179	ISA		179	179
T-020 (National)	External Supervision	0	73	73		0	73	73
	External Supervision		73	73	ISA		73	73
T-011 (National)	Design And Consultancy	0	136	136		0	136	136
	Design And Consultancy		136	136	ISA		136	136
	Infrastructure	0	250	250		0	250	250
	Infrastructure		250	250	ISA	0	250	250
	Transportation Equipment	1500	600	2100		1500	600	2100
	Transportation Equipment	1500	600	2100	World Bank	1500		1500
					ISA		600	600
	Computer Equipment	1500	500	2000		1500	500	2000

Procurement Schedule

(US$ thousand)

Code	Description	FC	LC	Total	Financing	FC	LC	Total
	Computer Equipment	1500	500	2000	World Bank	1500		1500
	STUDIES							
					ISA		500	500
		500	0	500		500	0	500
	Studies	500		500	World Bank	500		500
	Management		5960	5960	ISA		5960	5960
	Contingencies	13974	12141	26115		13973	12140	26113
					World Bank	12995	3982	16977
					ISA	978	8158	9136
	Indexing	20136	17263	37399		20135	17264	37399
					World Bank	18899	4740	23639
					ISA	1236	12524	13760
	Financial Costs	46782	1668	48450		46782	1668	48450
					World Bank	39526		39526
					ISA	7256	1668	8924
	Total Procedures Part B	217815	154311	372126		217811	154311	372122
					World Bank	200193	38988	239181
					ISA	17618	115323	132941
	Revision Part B, Erection San Marcos, La Virginia, San Carlos Substations	694				694		
	Revised Total	217121	155005	372126		217117	155005	37 2122
	Total Without Financial Costs	170339	153337	323676	World Bank	199499	39682	239181
					ISA	17618	115323	132941
PARTE C								
		2000	1000	3000		2000	1000	3000
	Technical Assistance	2000	1000	3000	World Bank	2000		2000
					ISA		1000	1000

ANNEX 11

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

PROJECT ECONOMIC ANALYSIS

1. The proposed project consists of three components: (a) Control Center upgrading to support the sector's new institutional structure; (b) Expansion of the interconnected system to allow ISA to accomplish its role of supporting a competitive generation-level market by allowing energy transactions between generators and suppliers to take place; and (c) Technical Assistance to ensure a good start and smooth operation of ISA in its new role.

2. The economic analysis consists of:

- A **cost-effectiveness** analysis to verify that: (i) the project as a whole is part of the sector least cost expansion plan, and (ii) its components are the least cost alternative for accomplishing their objective; and

- An **economic analysis** which verifies that the resources used in the proposed investments provide an acceptable economic rate of return.

Cost-effectiveness Analysis

3. **Expansion Plan.** The Government recently approved a strategy for the 1995-2007 expansion of the power subsector[1]. The strategy is based on an updated expansion plan prepared by MME and ISA in February, 1995; economic growth for 1995-2010 is assumed to vary within the 5.13%-6.3% range depending on the scenario being examined, i.e. roughly within current Bank projections which are in the 5.5%-6% range; electricity demand for these years is expected to grow correspondingly at rates which range between 4.8% and 6.77% per annum. The transmission lines and substations included in the project are part of the least cost expansion plan and all components are needed in order to meet the desired reliability criteria.

4. The following analysis verifies that the proposed investments are indeed the least cost solution by comparing their costs and benefits with those of the next best alternatives. This analysis was performed for the transmission components of the project (the San Carlos-San Marcos System, and the La Loma-Copey and Paipa-Bucaramanga System) which account for the bulk of the proposed investments. The Control Center and Technical Assistance components are required for the power market to develop; without such new equipment and the requisite training, the existing dispatch center, which is based on equipment that is substantially out of date, will be unable to operate the network efficiently or to create proper financial accounting for the

[1] "Estrategias para el Desarrollo y la Expansion del Sector Eléctrico 1995-2007", Documento CONPES 2763, 15 February 1995.

settlements required under the new commercial rules. For these two components of the project there does not appear to be a second-best alternative against which they can be compared.

5. From the purely technical standpoint the second-best alternative to the transmission components could consist of a different design, e.g. a lower or higher voltage for the transmission lines and a different combination of 230/500kV lines. ISA's technical analyses provide assurance that alternative designs are not economical. Furthermore, it should be noted that the expansion plan is designed within a joint generation/transmission optimization perspective, including an optimized sitting of future gas plants.

6. Adopting a more global approach, the next-best alternatives used to verify the cost-effectiveness of the project consist of studying alternatives whereby the proposed transmission reinforcements (including any design variations) are substituted by installing generating capacity to provide equivalent service. In practical terms, within the context of the generation and transmission expansion plan, this would require relocating new generating facilities. The generating facilities identified in the plan are:

- 1995-2000:
  - 747MW repowering of gas-based plants on the Atlantic Coast (commissioned) which will add 507MW net to the system;
  - 232MW gas-based generation in the Southwest (commissioned)
  - 400MW gas-based generation in the Central region;
  - 1100MW hydro generation;
  - 450MW coal-based (150MW commissioned, 300MW on the Atlantic Coast).

- 2001-2007:
  - 3700MW gas-based plants
  - 2068MW hydro plants

7. **San Carlos-San Marcos System.** The lines and substations included in this component are a necessary reinforcement to supply the demand for power in the Southwestern area of the country. This region is relatively energy-poor and has fewer generation resources compared to other areas; its supply is particularly vulnerable during the dry months as it lacks significant storage facilities in its hydro plants.

8. Although substantial thermal generation is planned to be located in the region (232MW in the 1995-2000 period), a second best alternative to the proposed transmission reinforcements would consist of relocating around 400MW of gas-based generation to the Southwest in the 1995-2000 period, and a further 100MW around 2001. Consequently, given the equivalence in overall capacity (and assuming that dispatch conditions are roughly similar), the least cost tradeoff consists of transporting electricity through the proposed transmission facilities or transporting gas through a gas pipeline in order to feed the relocated plant. There would be no cost differences regarding generation investments.

9. The cash flows associated with the project are shown in Table 11-1. They consist of:

- Investment Costs;
- Operation and maintenance (O&M) costs of the project, estimated to be 2% of investment per year, which corresponds to ISA's previous experience with transmission facilities;
- Savings due to lower losses with the project; and
- Savings associated with the reduction of incremental gas transportation costs for supplying the relocated plant.

10. The savings in gas transport were based on a heat rate of 9544 Btu/kWh for the relocated plant, against 9733 Btu/kWh for the original plant (due to lower ambient temperatures prevailing in Cali). The energy delivered by the plant corresponds to the energy originally supplied by the thermal plant before relocation, with an average plant factor of 50%. The incremental transportation cost is based on the price quoted by ECOPETROL for transporting gas to the Cali area (US$2.4/MBtu) less the price for transporting gas to the original location in the central region (US$1.0/MBtu). Taking into account the efficiency difference, the incremental transportation cost is equivalent to savings on the order of US$13/MWh.

11. At a 12% discount rate, the present value of the investment and incremental operational and maintenance (O&M) costs of the proposed San Carlos-San Marcos reinforcements amounts to US$106 million. The present value of project benefits, quantified as savings due to reduced losses and reduced gas transportation costs, amounts to US$171million. Consequently the project yields a net present value of US$65 million and a Benefit/Cost (B/C) ratio of 1.6. The Equalizing Discount Rate (EDR), i.e. the discount rate that yields a B/C ratio of 1.0, amounts to 20%, which exceeds the acceptable rate of return (12%), thereby justifying the project as part of the least cost plan.

12. Regarding the timing of the San Carlos-San Marcos component, its benefits could be reduced due to lower demand in the Cali area. Under a low demand growth scenario (on the order of 4.3% p.a.), the project would yield no benefits for the first two years of operation; in this case, the EDR would decrease to 15%, which is still above the benchmark discount rate of 12%.

13. **La Loma-Copey and Paipa-Bucaramanga System**. The purpose of this system is to (a) connect the 300MW Cesar coal plant to the Atlantic Coast and Central Region systems and (b) to increase the transmission system reliability by creating an additional interconnection between the Atlantic Coast and Central Region systems.

14. The 300MW coal plant was decided on the basis of fuel diversification and to reduce the risk of supply shortfall. Consequently, a second best alternative in this case would consist of an equivalent coal plant (in order to preserve the fuel diversification policy dictated by existing

constraints on gas supply), located at a site where the proposed transmission reinforcement is no longer needed.

15. Two possible alternatives to the La Loma-Copey and Paipa-Bucaramanga System were identified:

- Tasajero II (300MW) located in the general area served by the Paipa-Bucaramanga line; or
- Tasajero II (150MW) and Cartagena IV (150MW), the latter being located in the Atlantic Coast region.

16. The base case comparison is shown in Table 11-4. The alternatives were analyzed by comparing the total generation and transmission costs (including fuel costs) associated with the proposed project and the second best alternatives:

- Investment costs are lower for the proposed project (Cesar-Loma-Copey);
- There are slightly lower fuel costs associated with the second-best alternative consisting of Tasajero II 150MW and Cartagena IV 150MW.

17. The overall result shows a cost ratio of 1.04 whereby the second-best alternative exceeds the proposed project costs at 12% discount (the fuel savings do not compensate for the extra investment cost). The equalizing discount rate whereby the fuel savings are enough to justify the second-best alternative is over 50%.

18. **Sensitivity Analysis**. The previous results were subjected to the following sensitivity tests:

- A: 10% increase in investment costs;
- B: 10% decrease in gas transportation costs for the San Carlos-San Marcos transmission project;
- C: 10% decrease in coal costs for the Loma-Copey project and its second-best alternatives;
- D: discount rates of 10% and 14%

19. The sensitivity results are shown in Tables 11-2 and 11-3 (San Carlos-San Marcos) and 11-5 and 11-6 (Loma-Copey); they are summarized as follows:

San Carlos-San Marcos Project

Sensitivity Case	EDR	B/C ratio
Base Case	20%	1.6
+10% Investment Costs	18%	1.5
-10% Gas Transportation	18%	1.5
10% Discount Rate	N.A.	1.8
14% Discount Rate	N.A.	1.4

Loma-Copey and Paipa-Bucaramanga Project

Sensitivity Case	EDR	B/C ratio
Base Case	>50%	1.04
+10% Investment Costs	-----	1.04
-10% Coal Costs	-----	1.04
10% Discount Rate	N.A.	1.04
14% Discount Rate	N.A.	1.04

The results show that the projects' cost-effectiveness characteristics are robust in relation with changes in the underlying assumptions.

20. Shifts in some of the key variables were identified which would lead to preferring the second-best alternatives to the proposed project components. For the San Carlos-San Marcos component, the transportation cost to Cali would need to decrease to around Col $1.7/MBtu for the EDR to become 12%; this would imply a 29% decrease in the gas transport cost. Similarly, a break-even fuel cost is obtained for the Loma-Copey component when fuel costs for the Cesar coal plant increase by 35%.

Economic Analysis

21. The economic analysis consists of evaluating the rate of return for ISA's overall investment plan. Although most of the components for the Third Transmission Plan are part of the Bank-financed project, the analysis includes a small number of additional investments which are not part of the project.

22. **Costs** consist of the investment costs for the 1994-99 period, together with O&M costs associated with these investments until year 2022. **Benefits** are calculated by comparing the operating conditions with and without the proposed investment program:

- Without the program, demand growth leads to a progressive saturation of ISA's network at which point demand and operating conditions are kept constant;

- With the program, additional energy and capacity are delivered through the network until network saturation occurs, at which point demand and operating conditions are again kept constant.

23. The benefits attributable to the investment program are then valued as follows:

- The difference in operating costs with and without the program are benefits attributable to the lower cost dispatch (due to the lifting of transmission bottlenecks) made possible by network reinforcements; and

- The difference in energy supplied to consumers with and without the program is valued according to a proxy for their willingness to pay.

24. The additional revenue generated by sales to final consumers, less the required subtransmission and distribution costs incurred to deliver the energy, was used as a proxy for the willingness to pay. (The cost of the incremental energy delivered is included when the net operating benefits of the project are computed.) The incremental revenue serves as a lower bound for the willingness to pay of final consumers located at the lower voltage level, as it ignores the consumer surplus over and above the cash revenues associated with incremental sales.

25. The O&M costs associated with the program were calculated as 2% of the investment cost, which is consistent with ISA's past experience.

26. The capacity and energy delivered through the network were calculated through a Monte Carlo generation-transmission simulation program; the operating costs were obtained using the Hydrothermal Dispatch module of the SUPER/OLADE-BID program. These dispatch costs are calculated on the basis of a losses interconnection network, and therefore require an adjustment to take into account the loss increase or decrease associated with the program.

27. The results are summarized in Table 11-7. Most of the benefits associated with the investment program relate to the decrease in operating costs (i.e. savings in thermal generation) made possible through the proposed interconnection reinforcements. Without the project, the operating cost of the system increases because of a more intensive use of high-cost thermal plants due to transmission constraints as well as higher network losses. This confirms the project's overall objective which seeks to lift transmission bottlenecks in order to facilitate the operation of the bulk energy market.

28. The analysis yields the following benchmark values:

- Net Present Value of Costs (12% discount rate): US$186 million
- Net Present Value of Benefits: US$250 million
- B/C ratio 1.34
- Economic Internal Rate of Return (EIRR): 27%

29. **Sensitivity Analysis**. The economic analysis was subjected to the following sensitivity variations:

A- First and Second year reduction of benefits. These benefits are associated with short term network reinforcements (such as compensation equipment in the San Marcos substation);

B- Increase of 10% in investment program costs;

C- Decrease of 10% in operating benefits; and

D- Lower demand growth rates; this case was calculated assuming a 4.3% per annum average growth rate for electricity demand.

30. The sensitivity cases are shown in Tables 11-8 to 11-11; they yield the following results:

Sensitivity Analysis
(US$ million)

Sensitivity Case	NPV of Costs	NPV of Benefits	EIRR	B/C ratio
Base	186	250	27	1.34
A	186	200	13	1.08
B	204	250	19	1.23
C	186	226	19	1.22
D	186	214	18	1.15

31. The results show that the investment program provides an adequate rate of return under conservative evaluation conditions: (a) as only energy-related benefits were quantified, and capacity-related benefits were disregarded due to the analytical difficulties associated with their evaluation; and (b) the net consumer surplus associated with the additional supplies enabled by the program was not quantified due to the uncertainty associated with parameters such as the price elasticity of demand.

32. The sensitivity analysis allows the identification of shifts in the principal variables which could reduce the benefits of the project. The principal source of benefits consists of fuel savings and loss reduction which can be achieved with the transmission investment program. If these are reduced by around 27%, the net present value of the project at 12% discount becomes zero. Similarly, an increase in program costs on the order of 35% with respect to the budgeted values would also lead to a zero net present value. These "safety margins" are unlikely to be consistently exceeded during the program's lifetime (benefits) or during its construction phase (investment costs).

Table 11-1
Cost Comparison San Carlos - San Marcos and AternativeProject
BASE CASE

Costs (US$ thousand)				Benefits (US$ thousand)		Difference
Year	Investment	O&M	Total Cost	Loss Reduction Savings	Savings from Gas Transp.	
1994	3573	0	3573	0	0	-3573
1995	8428	0	8428	0	0	-8428
1996	33129	0	33129	0	0	-33129
1997	53277	0	53277	0	0	-53277
1998	40406	1977	42383	595	23078	-18710
1999	5341	2883	8758	3395	23078	18250
2000		2883	2883	4581	23078	24776
2001		2883	2883	8070	28848	34035
2002		2883	2883	9845	28848	35810
2003		2883	2883	9048	28848	35013
2004		2883	2883	9370	28848	35335
2005		2883	2883	9370	28848	35335
2006		2883	2883	9370	28848	35335
2007		2883	2883	9370	28848	35335
2008		2883	2883	9370	28848	35335
2009		2883	2883	9370	28848	35335
2010		2883	2883	9370	28848	35335
2011		2883	2883	9370	28848	35335
2012		2883	2883	9370	28848	35335
2013		2883	2883	9370	28848	35335
2014		2883	2883	9370	28848	35335
2015		2883	2883	9370	28848	35335
2016		2883	2883	9370	28848	35335
2017		2883	2883	9370	28848	35335
2018		2883	2883	9370	28848	35335
2019		2883	2883	9370	28848	35335
2020		2883	2883	9370	28848	35335
2021		2883	2883	9370	28848	35335
2022		2883	2883	9370	28848	35335
Discount Rate	**PRESENT VALUE**					**B/C Ratio**
14%	86944	11262	98205	28540	109461	1.41
10%	99596	17312	116909	46285	169050	1.84
12%	92981	13857	106838	36075	134985	1.60
16%	80435	8957	89392	21980	86844	1.22

Equalizing IRR **18%**

NOTE: Evaluation in constant Dec'93 dollars
Present Values as of Dec'93

Table 11-2
Cost Comparison San Carlos - San Marcos and Alternative Project
INCREASE IN INVESTMENT COSTS
10%

Costs (US$ thousand)				Benefits (US$ thousand)		Difference
Year	Investment	O&M	Total Cost	Loss Reductions Savings	Savings from Gas Transp.	
1994	3930	0	3930	0	0	-3930
1995	9271	0	9271	0	0	-9271
1996	36442	0	36442	0	0	-36442
1997	58605	0	58605	0	0	-58605
1998	44447	1977	46424	595	23078	-22751
1999	5875	2883	8758	3395	23078	17716
2000		2883	2883	4581	23078	24776
2001		2883	2883	8070	28848	34035
2002		2883	2883	9845	28848	35810
2003		2883	2883	9048	28848	35013
2004		2883	2883	9370	28848	35335
2005		2883	2883	9370	28848	35335
2006		2883	2883	9370	28848	35335
2007		2883	2883	9370	28848	35335
2008		2883	2883	9370	28848	35335
2009		2883	2883	9370	28848	35335
2010		2883	2883	9370	28848	35335
2011		2883	2883	9370	28848	35335
2012		2883	2883	9370	28848	35335
2013		2883	2883	9370	28848	35335
2014		2883	2883	9370	28848	35335
2015		2883	2883	9370	28848	35335
2016		2883	2883	9370	28848	35335
2017		2883	2883	9370	28848	35335
2018		2883	2883	9370	28848	35335
2019		2883	2883	9370	28848	35335
2020		2883	2883	9370	28848	35335
2021		2883	2883	9370	28848	35335
2022		2883	2883	9370	28848	35335
Discount Rate	**PRESENT VALUE**					**B/C Ratio**
8%	117544	22005	139549	60375	215420	1.98
10%	109556	17312	126868	46285	169050	1.70
12%	102279	13857	116136	36075	134985	1.47
15%	92860	10312	103171	25819	100133	1.22

Equalizing IRR 18%

NOTE: Evaluation in constant Dec'93 dollars
Present Values as of Dec'93

TABLE 11-3
Cost Comparison San Carlos - San Marcos Project
REDUCTION IN GAS TRANSPORT COSTS
-10%

	Costs (US$ thousand)			**Benefits** (US$ thousand)		**Difference**
Year	Investment	O&M	Total Cost	Loss Reduction Savings	Savings From Gas Transp. Costs	
1994	3573	0	3573	0	0	-3573
1995	8428	0	8428	0	0	-8428
1996	33129	0	33129	0	0	-33129
1997	53277	0	53277	0	0	-53277
1998	40406	1977	42383	595	20771	-21018
1999	5341	2883	8224	3395	20771	15942
2000		2883	2883	4581	20771	22468
2001		2883	2883	8070	25963	31151
2002		2883	2883	9845	25963	32925
2003		2883	2883	9048	25963	32128
2004		2883	2883	9370	25963	32450
2005		2883	2883	9370	25963	32450
2006		2883	2883	9370	25963	32450
2007		2883	2883	9370	25963	32450
2008		2883	2883	9370	25963	32450
2009		2883	2883	9370	25963	32450
2010		2883	2883	9370	25963	32450
2011		2883	2883	9370	25963	32450
2012		2883	2883	9370	25963	32450
2013		2883	2883	9370	25963	32450
2014		2883	2883	9370	25963	32450
2015		2883	2883	9370	25963	32450
2016		2883	2883	9370	25963	32450
2017		2883	2883	9370	25963	32450
2018		2883	2883	9370	25963	32450
2019		2883	2883	9370	25963	32450
2020		2883	2883	9370	25963	32450
2021		2883	2883	9370	25963	32450
2022		2883	2883	9370	25963	32450
Discount Rate	**PRESENT VALUE**					**B/C Ratio**
8%	106858	22005	128864	60375	193878	1.97
10%	99596	17312	116909	46285	152145	1.70
12%	92981	13857	106838	36075	121486	1.47
15%	84072	10188	94260	25465	89022	1.21

Equalizing IRR **18.4%**

NOTE: Evaluation in constant Dec'93 dollars
Present Values as of Dec'93

Table 11-4:
Cost Comparison La Loma-Copey And Alternative Projects
(US$ millions Dec'93, Present Values)
10% DISCOUNT RATE

Projects	Generation				Transmission			TOTAL	Cost Ratio
	Invest.	Fuel	O&M	Total.	Invest.	O&M	Total		
La Loma -Copey and Paipa-Bucaramanga(1)	251.5	66.0	77.6	395.1	31.5	6.0	37.5	432.6	
Tasajero II (2)	265.8	60.4	85.9	412.2	32.8	6.2	39.0	451.2	1.043
TASAJERO I And	137.1	30.6	43.1	210.7	27.6	5.3	32.9	243.6	
Cartagena IV (3)	136.0	29.5	33.9	199.3	5.8	1.0	6.8	206.1	
Total	273.1	60.0	76.9	410.0	33.4	6.3	39.7	449.7	1.040

12% DISCOUNT RATE

Projects	Generation				Transmission			TOTAL	Cost Ratio
	Invest.	Fuel	O&M	Total	Invest.	O&M	Total		
La Loma -Copey and Paipa-Bucaramanga(1)	233.4	52.3	61.4	347.0	29.0	4.8	33.7	380.8	
Tasajero II (2)	245.8	48.0	68.0	361.8	30.3	4.9	35.2	396.9	1.042
Tasajero I and	126.7	24.3	34.1	185.0	25.5	4.2	29.6	214.6	
Cartagena IV (3)	125.7	23.2	26.7	175.6	5.3	0.8	6.1	181.7	
Total	252.3	47.5	60.8	360.6	30.8	5.0	35.7	396.4	1.041

14% DISCOUNT RATE

Projects	Geneneration				Transmission			TOTAL	Cost Ratio
	Invest.	Fuel	O&M	Total	Inv.	O&M	Total		
La Loma -Copey and Paipa-Bucaramanga(1)	216.9	42.0	49.2	308.1	7.8	0.3	8.2	316.3	
Tasajero II (2)	227.6	38.6	54.6	320.8	8.3	0.4	8.7	329.4	1.04
Tasajero I and	117.2	19.5	27.4	164.1	7.0	0.3	7.3	171.4	
Cartagena IV (3)	116.3	18.5	21.4	156.2	1.4	0.05	1.4	157.7	
Total	233.5	38.0	48.7	320.3	8.4	0.4	8.8	329.1	1.04

(1) Transmission includes the Loma-Copey and Paipa - Bucaramanga project

(2) Transmission includes the Palos - Tasajero (double circuit) and Paipa - Bucaramanga projects

(3) Transmission includes the Palos - Tasajero (one circuit), Paipa - Bucaramanga and Cartagena - Sabanalarga lines

TABLE 11-5:
SENSITIVITY ANALYSIS
LOMA - COPEY AND PAIPA - BUCARAMANGA PROJECT
10% INCREASE IN INVESTMENT COSTS
(US$ millions Dec'93)
12% DISCOUNT RATE

Projects	Generation				Transmission			TOTAL	Cost Ratio
	Invest.	Fuel	O&M	Total	Invest.	O&M	Total		
La Loma -Copey and Paipa-Bucaramanga(1)	256.7	52.3	61.4	370.4	31.9	4.8	36.6	407.0	
Tasajero II (2)	270.4	48.0	68.0	386.3	33.3	4.9	38.2	424.5	1.043
Tasajero I and	139.3	24.3	34.1	197.7	28.0	4.2	32.2	229.9	
Cartagena IV (3)	138.3	23.2	26.7	188.2	5.8	0.8	6.6	194.8	
Total	277.6	47.5	60.8	385.8	33.8	5.0	38.8	424.7	1.043

(1) Transmission includes the Loma-Copey and Paipa - Bucaramanga project

(2) Transmission includes the Palos - Tasajero (double circuit) and Paipa - Bucaramanga projects

(3) Transmission includes the Palos - Tasajero (one circuit), Paipa - Bucaramanga and Cartagena - Sabanalarga lines

TABLE 11-6: SENSITIVITY ANALYSIS
LOMA - COPEY AND PAIPA - BUCARAMANGA PROJECT
10 % DECREASE IN FUEL COSTS
(US$ million Dec'93)
12% DISCOUNT RATE

Projects	Generation				Transmission			TOTAL	Cost Ratio
	Invest.	Fuel	O&M	Total	Inv.	O&M	Total		
La Loma -Copey and Paipa-Bucaramanga(1)	233.4	47.0	61.4	341.8	29.0	4.8	33.7	375.6	
Tasajero II (2)	245.8	43.2	68.0	357.0	30.3	4.9	35.2	392.1	1.044
Tasajero I and	126.7	21.8	34.1	182.6	25.5	4.2	29.6	212.2	
Cartagena IV(3)	125.7	20.9	26.7	173.3	5.3	0.8	6.1	179.4	
Total	252.3	42.7	60.8	355.9	30.8	5.0	35.7	391.6	1.043

(1) Transmission includes the Loma-Copey and Paipa - Bucaramanga project

(2) Transmission includes the Palos - Tasajero (double circuit) and Paipa - Bucaramanga projects

(3) Transmission includes the Palos - Tasajero (one circuit), Paipa - Bucaramanga and Cartagena - Sabanalarga lines

TABLE 11-7
BASE CASE EVALUATION OF INVESTMENT PROGRAM

	Program Costs (M $)			BENEFITS: THERMAL ENERGY SAVINGS			BENEFITS: INCREMENTAL ENERGY SUPPLY						
				Cost of Thermal Generation (M US$)									
Year	Investment	O&M	Total Cost	W/O Program	W/ Program	Total Operating Savings (M $)	Gross Incremental Energy (GWh)	Net Incremental Energy (GWh)	Gross Incremental Benefit (M $)	Incremental Distribution Costs (M $)	Net Incremental Benefits (M $)	Total Benefits (M $)	Net Cash Flow (M $)
1993				$ -	$ -	$ -						$ -	$ -
1994	4.8		4.8	$ 46	$ 14	$ 32						$ 32	$ 27
1995	14.0	0.4	14.4	$ 54	$ 28	$ 27	1	0.6	0.04	0.02	0.03	$ 27	$ 12
1996	37.9	1.1	39.0	$ 61	$ 41	$ 19	3	2.5	0.18	0.06	0.1	$ 19	$ (20)
1997	83.1	2.8	85.9	$ 79	$ 56	$ 24	0	0.0	0.00	0.00	0.0	$ 24	$ (62)
1998	104.1	4.9	109.0	$ 98	$ 73	$ 25	3	2.5	0.18	0.06	0.1	$ 25	$ (84)
1999	7.8	5.0	12.8	$ 120	$ 95	$ 22	8	7.1	0.49	0.18	0.3	$ 22	$ 10
2000		5.0	5.0	$ 143	$ 117	$ 20	6	5.2	0.36	0.13	0.2	$ 21	$ 16
2001		5.0	5.0	$ 157	$ 124	$ 29	133	122.0	8.54	3.05	5.5	$ 34	$ 29
2002		5.0	5.0	$ 185	$ 147	$ 39	242	222.7	15.59	5.57	10.0	$ 49	$ 44
2003		5.0	5.0	$ 240	$ 198	$ 42	42	38.4	2.69	0.96	1.7	$ 44	$ 39
2004		5.0	5.0	$ 258	$ 213	$ 37	55	50.4	3.53	1.26	2.3	$ 40	$ 35
2005		5.0	5.0									$ 40	$ 35
2006		5.0	5.0									$ 40	$ 35
2007		5.0	5.0									$ 40	$ 35
2008		5.0	5.0									$ 40	$ 35
2009		5.0	5.0									$ 40	$ 35
2010		5.0	5.0									$ 40	$ 35
2011		5.0	5.0									$ 40	$ 35
2012		5.0	5.0									$ 40	$ 35
2013		5.0	5.0									$ 40	$ 35
2014		5.0	5.0									$ 40	$ 35
2015		5.0	5.0									$ 40	$ 35
2016		5.0	5.0									$ 40	$ 35
2017		5.0	5.0									$ 40	$ 35
2018		5.0	5.0									$ 40	$ 35
2019		5.0	5.0									$ 40	$ 35
2020		5.0	5.0									$ 40	$ 35
	12%	NPV:	$186			$163					$8.37	$250	$64
												IRR =	27%

W/O = Without Program

W/ = With Program

Total Operating Benefits = Thermal Costs W/Program - Thermal Costs W/O Program + Adjustment for lower losses

Net Incremental Energy = Gross Incremental Energy - Distribution Losses

Gross Incremental Benefit = Net Incremental Energy * Price

Net Incremental Benefit = Gross Incr. Benefit - Incr. Distribution Costs

Total Benefits = Total Operating Benefits + Net Incremental Benefits

Distribution Losses (%) = 8

Average Price ($/MWh) = 70

Incremental Dist. Cost ($/MWh) = 25

TABLE 11-8
SENSITIVITY ANALYSIS OF INVESTMENT PROGRAM: REDUCED INITIAL YEAR BENEFITS

				BENEFITS											
				THERMAL ENERGY SAVINGS					INCREMENTAL ENERGY SUPPLY						
	Program Costs (M$)			Cost of Thermal Generation (MUS$)		Loss Adjustment		Total Operating Savings (M$)	Gross Incremental Energy (GWh)	Net Incremental Energy (GWh)	Gross Incremental Benefit (M$)	Incremental Distribution Costs (M$)	Net Incremental Benefits (M$)	Total Benefits (M$)	Net Cash Flow (M$)
Year	Investment	O&M	Total Cost	W/O Pro	W/ Progra	GWh	M$								
1993				$ -	$ -			$ -						$ -	$ -
1994	4.8		4.8	$ 46	$ 14			$ -						$ -	$ (5)
1995	14.0	0.4	14.4	$ 54	$ 28			$ -	1	0.6	0.04	0.02	0.03	$ 0	$ (14)
1996	37.9	1.1	39.0	$ 61	$ 41			$ 19	3	2.5	0.18	0.06	0.1	$ 19	$ (20)
1997	83.1	2.8	85.9	$ 79	$ 56			$ 24	0	0.0	0.00	0.00	0.0	$ 24	$ (62)
1998	104.1	4.9	109.0	$ 98	$ 73	4	0.1	$ 25	3	2.5	0.18	0.06	0.1	$ 25	$ (84)
1999	7.8	5.0	12.8	$ 120	$ 95	73	2.4	$ 22	8	7.1	0.49	0.18	0.3	$ 22	$ 10
2000		5.0	5.0	$ 143	$ 117	181	5.9	$ 20	6	5.2	0.36	0.13	0.2	$ 21	$ 16
2001		5.0	5.0	$ 157	$ 124	135	4.4	$ 29	133	122.0	8.54	3.05	5.5	$ 34	$ 29
2002		5.0	5.0	$ 185	$ 147	-13	-0.4	$ 39	242	222.7	15.59	5.57	10.0	$ 49	$ 44
2003		5.0	5.0	$ 240	$ 198	4	0.1	$ 42	42	38.4	2.69	0.96	1.7	$ 44	$ 39
2004		5.0	5.0	$ 258	$ 213	224	7.3	$ 37	55	50.4	3.53	1.26	2.3	$ 40	$ 35
2005		5.0	5.0											$ 40	$ 35
2006		5.0	5.0											$ 40	$ 35
2007		5.0	5.0											$ 40	$ 35
2008		5.0	5.0											$ 40	$ 35
2009		5.0	5.0											$ 40	$ 35
2010		5.0	5.0											$ 40	$ 35
2011		5.0	5.0											$ 40	$ 35
2012		5.0	5.0											$ 40	$ 35
2013		5.0	5.0											$ 40	$ 35
2014		5.0	5.0											$ 40	$ 35
2015		5.0	5.0											$ 40	$ 35
2016		5.0	5.0											$ 40	$ 35
2017		5.0	5.0											$ 40	$ 35
2018		5.0	5.0											$ 40	$ 35
2019		5.0	5.0											$ 40	$ 35
2020		5.0	5.0											$ 40	$ 35
	12%	NPV:	$186					$113					$8.37	$200	$15
														IRR=	13%

W/O= Without Program
W/= With Program
Total Operating Benefits=Thermal Costs W/Program - Thermal Costs W/O Program +Adjustment for lower losses
Net Incremental Energy=Gross Incremental Energy - Distribution Losses
Gross Incremental Benefit= Net Incremental Energy * Price
Net Incremental Benefit= Gross Incr. Benefit - Incr. Distribution Costs
Total Benefits= Total Operating Benefits + Net Incremental Benefits

Distribution Losses (%) 8
Average Price ($/MWh) 70
Incremental Dist. Cost ($/MWh)= 25

TABLE 11-9
SENSITIVITY ANALYSIS OF INVESTMENT PROGRAM
10% INCREASE IN INVESTMENT COSTS

				BENEFITS									
				THERMAL ENERGY SAVINGS			INCREMENTAL ENERGY SUPPLY						
	Program Costs (M$)			Cost of Thermal Generation (MUS$)		Total Operating	Gross Incremental Energy	Net Incremental Energy	Gross Incremental Benefit	Incremental Distribution Costs	Net Incremental Benefits	Total Benefits	Net Cash Flow
Year	Investment	O&M	Total Cost	W/O Program	W/ Program	Savings (M$)	(GWh)	(GWh)	(M$)	(M$)	(M$)	(M$)	(M$)
1993				$ -	$ -	$ -						$ -	$ -
1994	4.8		4.8	$ 46	$ 14	$ 32						$ 32	$ 27
1995	14.0	0.4	14.4	$ 54	$ 28	$ 27	1	0.6	0.04	0.02	0.03	$ 27	$ 12
1996	37.9	1.1	39.0	$ 61	$ 41	$ 19	3	2.5	0.18	0.06	0.1	$ 19	$ (20)
1997	83.1	2.8	85.9	$ 79	$ 56	$ 24	0	0.0	0.00	0.00	0.0	$ 24	$ (62)
1998	104.1	4.9	109.0	$ 98	$ 73	$ 25	3	2.5	0.18	0.06	0.1	$ 25	$ (84)
1999	7.8	5.0	12.8	$ 120	$ 95	$ 22	8	7.1	0.49	0.18	0.3	$ 22	$ 10
2000	0.0	5.0	5.0	$ 143	$ 117	$ 20	6	5.2	0.36	0.13	0.2	$ 21	$ 16
2001	0.0	5.0	5.0	$ 157	$ 124	$ 29	133	122.0	8.54	3.05	5.5	$ 34	$ 29
2002	0.0	5.0	5.0	$ 185	$ 147	$ 39	242	222.7	15.59	5.57	10.0	$ 49	$ 44
2003	0.0	5.0	5.0	$ 240	$ 198	$ 42	42	38.4	2.69	0.96	1.7	$ 44	$ 39
2004	0.0	5.0	5.0	$ 258	$ 213	$ 37	55	50.4	3.53	1.26	2.3	$ 40	$ 35
2005	0.0	5.0	5.0									$ 40	$ 35
2006	0.0	5.0	5.0									$ 40	$ 35
2007	0.0	5.0	5.0									$ 40	$ 35
2008	0.0	5.0	5.0									$ 40	$ 35
2009	0.0	5.0	5.0									$ 40	$ 35
2010	0.0	5.0	5.0									$ 40	$ 35
2011	0.0	5.0	5.0									$ 40	$ 35
2012	0.0	5.0	5.0									$ 40	$ 35
2013	0.0	5.0	5.0									$ 40	$ 35
2014	0.0	5.0	5.0									$ 40	$ 35
2015	0.0	5.0	5.0									$ 40	$ 35
2016	0.0	5.0	5.0									$ 40	$ 35
2017	0.0	5.0	5.0									$ 40	$ 35
2018	0.0	5.0	5.0									$ 40	$ 35
2019	0.0	5.0	5.0									$ 40	$ 35
2020	0.0	5.0	5.0									$ 40	$ 35
	12%	NPV:	$186			$163					$8.37	$250	$64
												IRR=	27%

W/O= Without Program
W/= With Program
Total Operating Benefits=Thermal Costs W/Program - Thermal Costs W/O Program +Adjustment for lower losses
Net Incremental Energy=Gross Incremental Energy - Distribution Loss   Distribution Losses (%)= 8
Gross Incremental Benefit= Net Incremental Energy * Price   Average Price ($/MWh)= 70
Net Incremental Benefit= Gross Incr. Benefit - Incr. Distribution Costs   Incremental Dist. Cost ($/MWh)= 25
Total Benefits= Total Operating Benefits + Net Incremental Benefits

TABLE 11-10
BASE CASE EVALUATION OF INVESTMENT PROGRAM
10% DECREASE IN OPERATING BENEFITS

				BENEFITS									
				THERMAL ENERGY SAVINGS			INCREMENTAL ENERGY SUPPLY						
	Program Costs (M$)			Cost of Thermal Generation (MUS$)		Total Operating Savings (M$)	Gross Incremental Energy (GWh)	Net Incremental Energy (GWh)	Gross Incremental Benefit (M$)	Incremental Distribution Costs (M$)	Net Incremental Benefits (M$)	Total Benefits (M$)	Net Cash Flow (M$)
Year	**Investment**	**O&M**	**Total Cost**	W/O Program	W/ Program								
1993				$ -	$ -	$ -						$ -	$ -
1994	4.8		4.8	$ 46	$ 14	$ 29						$ 29	$ 24
1995	14.0	0.4	14.4	$ 54	$ 28	$ 24	1	0.6	0.04	0.02	0.03	$ 24	$ 10
1996	37.9	1.1	39.0	$ 61	$ 41	$ 17	3	2.5	0.18	0.06	0.1	$ 17	$ (22)
1997	83.1	2.8	85.9	$ 79	$ 56	$ 21	0	0.0	0.00	0.00	0.0	$ 21	$ (65)
1998	104.1	4.9	109.0	$ 98	$ 73	$ 22	3	2.5	0.18	0.06	0.1	$ 23	$ (86)
1999	7.8	5.0	12.8	$ 120	$ 95	$ 20	8	7.1	0.49	0.18	0.3	$ 20	$ 7
2000		5.0	5.0	$ 143	$ 117	$ 18	6	5.2	0.36	0.13	0.2	$ 19	$ 14
2001		5.0	5.0	$ 157	$ 124	$ 26	133	122.0	8.54	3.05	5.5	$ 32	$ 27
2002		5.0	5.0	$ 185	$ 147	$ 35	242	222.7	15.59	5.57	10.0	$ 45	$ 40
2003		5.0	5.0	$ 240	$ 198	$ 38	42	38.4	2.69	0.96	1.7	$ 39	$ 34
2004		5.0	5.0	$ 258	$ 213	$ 34	55	50.4	3.53	1.26	2.3	$ 36	$ 31
2005		5.0	5.0			$ -						$ 36	$ 31
2006		5.0	5.0			$ -						$ 36	$ 31
2007		5.0	5.0			$ -						$ 36	$ 31
2008		5.0	5.0			$ -						$ 36	$ 31
2009		5.0	5.0			$ -						$ 36	$ 31
2010		5.0	5.0			$ -						$ 36	$ 31
2011		5.0	5.0			$ -						$ 36	$ 31
2012		5.0	5.0			$ -						$ 36	$ 31
2013		5.0	5.0			$ -						$ 36	$ 31
2014		5.0	5.0			$ -						$ 36	$ 31
2015		5.0	5.0			$ -						$ 36	$ 31
2016		5.0	5.0			$ -						$ 36	$ 31
2017		5.0	5.0			$ -						$ 36	$ 31
2018		5.0	5.0			$ -						$ 36	$ 31
2019		5.0	5.0			$ -						$ 36	$ 31
2020		5.0	5.0			$ -						$ 36	$ 31
	12%	NPV:	$186			$147					$8.37	$226	$40
												IRR=	**19%**

W/O= Without Program
W/= With Program
Total Operating Benefits=Thermal Costs W/Program - Thermal Costs W/O Program +Adjustment for lower losses
Net Incremental Energy=Gross Incremental Energy - Distribution Loss Distribution Losses (%)= 8
Gross Incremental Benefit= Net Incremental Energy * Price Average Price ($/MWh)= 70
Net Incremental Benefit= Gross Incr. Benefit - Incr. Distribution Costs Incremental Dist. Cost ($/MWh)= 25
Total Benefits= Total Operating Benefits + Net Incremental Benefits

TABLE 11-11
OVERALL INVESTMENT PROGRAM: SENSIVITY TO LOWER DEMAND SCENARIO
10% DECREASE IN OPERATING BENEFITS

				BENEFITS									
				THERMAL ENERGY SAVINGS			INCREMENTAL ENERGY SUPPLY						
	Program Costs (M$)			Cost of Thermal Generation (MUS$)		Total Operating Savings (M$)	Gross Incremental Energy (GWh)	Net Incremental Energy (GWh)	Gross Incremental Benefit (M$)	Incremental Distribution Costs (M$)	Net Incremental Benefits (M$)	Total Benefits (M$)	Net Cash Flow (M$)
Year	Investment	O&M	Total Cost	W/O Program	W/ Program								
1993				$ -	$ -	$ -						$ -	$ -
1994	4.8		4.8	$ 41	$ 10	$ 31						$ 31	$ 26
1995	14.0	0.4	14.4	$ 48	$ 19	$ 29	0	0.0	0.00	0.00	0.0	$ 29	$ 15
1996	37.9	1.1	39.0	$ 50	$ 30	$ 20	0	0.1	0.01	0.00	0.0	$ 20	$ (19)
1997	83.1	2.8	85.9	$ 61	$ 40	$ 21	1	0.7	0.05	0.02	0.0	$ 21	$ (65)
1998	104.1	4.9	109.0	$ 74	$ 51	$ 23	2	1.4	0.10	0.03	0.1	$ 23	$ (86)
1999	7.8	5.0	12.8	$ 94	$ 69	$ 23	3	2.9	0.21	0.07	0.1	$ 23	$ 10
2000		5.0	5.0	$ 104	$ 84	$ 14	0	0.3	0.02	0.01	0.0	$ 14	$ 9
2001		5.0	5.0	$ 117	$ 84	$ 29	39	36.0	2.52	0.90	1.6	$ 30	$ 25
2002		5.0	5.0	$ 135	$ 100	$ 35	79	72.5	5.07	1.81	3.3	$ 39	$ 34
2003		5.0	5.0	$ 152	$ 117	$ 35	28	25.5	1.78	0.64	1.1	$ 36	$ 31
2004		5.0	5.0	$ 169	$ 134	$ 28	38	35.1	2.46	0.88	1.6	$ 29	$ 24
2005		5.0	5.0			$ -						$ 29	$ 24
2006		5.0	5.0			$ -						$ 29	$ 24
2007		5.0	5.0			$ -						$ 29	$ 24
2008		5.0	5.0			$ -						$ 29	$ 24
2009		5.0	5.0			$ -						$ 29	$ 24
2010		5.0	5.0			$ -						$ 29	$ 24
2011		5.0	5.0			$ -						$ 29	$ 24
2012		5.0	5.0			$ -						$ 29	$ 24
2013		5.0	5.0			$ -						$ 29	$ 24
2014		5.0	5.0			$ -						$ 29	$ 24
2015		5.0	5.0			$ -						$ 29	$ 24
2016		5.0	5.0			$ -						$ 29	$ 24
2017		5.0	5.0			$ -						$ 29	$ 24
2018		5.0	5.0			$ -						$ 29	$ 24
2019		5.0	5.0			$ -						$ 29	$ 24
2020		5.0	5.0			$ -						$ 29	$ 24
	12%	NPV:	$186			$153					$3.12	$214	$28
												IRR=	18%

W/O= Without Program
W/= With Program
Total Operating Benefits=Thermal Costs W/Program - Thermal Costs W/O Program +Adjustment for lower losses (not shown)
Net Incremental Energy=Gross Incremental Energy - Distribution Losses   Distribution Losses (%)= 8
Gross Incremental Benefit= Net Incremental Energy * Price   Average Price ($/MWh)= 70
Net incremental Benefit= Gross Incr. Benefit - Incr Distribution Costs   Incremental Dist. Cost ($/MWh)= 25
Total Benefits = Total Operating Benefits + Net Incremental Benefits

ANNEX 12

COLOMBIA
POWER MARKET DEVELOPMENT PROJECT

Assumptions For ISA's Financial Projections

General

1. Financial projections for 1995-2004 were prepared by ISA in current prices and are expressed in millions of Colombian pesos (Col $ million). Expected inflation rates and exchange rates used are detailed in the following table:

Table 1

	1994	1995	1996	1997	1998	1999-2004
Local Inflation (%)	22.5	17.0	16.0	15.0	14.0	13.5 in 1999 and 13.0 from 2000 onwards
External Inflation %)	3.0	1.5	1.8	2.6	2.5	2.5% for 1999-2001, 2.4% for 2002, and 2.1% from 2003 onwards
Average Exchange Rate (Col $/US$)	814	895	1025	1158	1292	1434 form 1999 onwards parity remains constant
Exchange Rate at the end of the year (Col $/US$)	831	958	1092	1224	1361	Col $1507 from 1999 onwards parity remains constant

The other main assumptions adopted to prepare the financial projections are summarized in Table 2:

Table 2

Item	Assumption
INCOME FORECAST	
Transmission Revenues	See para. 3 below.
Operations and Maintenance	Estimated at 1.5% of gross fixed assets in operation.
Administrative and General Expenses	Estimated at 0.5% of gross fixed assets in operation.
Depreciation	In accordance with the current accounting standards, ISA applies a 6.6% accelerated depreciation.
Taxes	ISA pays custom duties and VAT taxes. In accordance with Law #142, dated July 11, 94, ISA pays income tax (37.5%). Starting in 1996, ISA will pay in advance income taxes as follows: 25% in 1996, 50% in 1997, and 75% from 1998 onwards. VAT paid for capital expenditures is discounted from the income tax at the commissioning year.
Other Non-operational Income (expenses)	Include interest earned on deposits.
Dividend Payment.	No dividend payments are considered, so net income is capitalized.
FLOW of FUNDS	
Investment Program	MME prepared demand projections dated January, 1995. They consider an average 6.1% sales growth during the period, assuming and average 3.7% transmission losses over net power generation. The investment program is based on the Indicative Generation and Transmission Expansion Plan approved by CONPES for the period 1995-2007.

Item	Assumption
Financing of Investment Program	See Table 12.4 and Annex 10 - Project Description, Costs, and Implementation Plan. Reasonable availability of external financing from international institutions, commercial banks - through FEN or directly - and from suppliers of foreign components of the investment program have been assumed. No local credits have been considered.
BALANCE STATEMENT	
Revaluation of Assets	Fixed assets are revalued with internal inflation, taking into account the useful life of the installation.
Accounts Receivable	Are based on sixty days of billing for distribution utilities and other direct customers.
Inventory	Projected as 0.5% of fixed assets in operation.
Accounts payable	Are estimated as percentage of cash operating expenses, and local costs of the investment program.

2. **Calculation of Transmission revenues**. The transmission revenues are composed of: (a) usage of the transmission system wheeling charges and (b) connection fees, and are based on the regulated rates defined in the Public Service Law and rules #001 through #004, issued by the ERC in 11.02.94

3. Wheeling Charges. ISA transmission revenues due to the use of the system are defined in accordance with the following formulae:

ISA Revenue= $a*M_t$
$M_t = R_t + K_t$
and $R_t = R_{t-1}*[(IPP_t/IPP_{t-1}) + (X/100)]$
where,

M_t = regulated revenue due for the whole of the transmission system during year t;
R_o = Regulated revenue in 1994 equal to Col $138,595 million (at September 1994 prices);
IPP = Wholesale Price Index;
X = growth factor of the regulated revenues. Currently fixed at 5% for the next 5 years. (This factor is revised every five years).
K_t = Correction factor (positive or negative) applied to the regulated revenues, depending on the actual variation of the IPP.
a = 72.7% of the transmission system assigned to ISA during 1995-1997, and 72.5% from 1998 onwards.

4. **Connection fees**. Calculated taking into account the inventory of assets connected to the distribution utilities, valued at replacement cost and adjusted according to the variation of the power sector cost index. The assets included in this calculation correspond to a transformation module at 230/500 kV and 230/500 kV power transformers. Connection fees are estimated to amount to US$ 15 million at June 1993 prices.

COLOMBIA
Table 12-1 ISA's Financial Projections
Actual and Forecast Income Statements
(Col$ billion)

	1995 (1)	1996	1997	1998	1999	2000	2001	2002	2003	2004
Gross Operating Revenues	**129.8**	**166.7**	**201.0**	**239.6**	**288.3**	**354.2**	**418.2**	**493.9**	**583.5**	**689.5**
Operating Expenses	**88.1**	**105.4**	**124.1**	**149.1**	**186.0**	**233.6**	**255.2**	**278.4**	**299.6**	**328.4**
O & M Expenses	17.7	21.8	26.0	35.1	40.4	51.3	58.5	66.6	76.0	86.6
Venezuelan Transm. Line Charges	3.2	3.5	3.8	4.0	4.2	4.4	4.5	4.6	0.0	0.0
Administration and General Expenses	5.9	7.3	8.7	11.7	13.5	17.1	19.5	22.2	25.3	28.9
Depreciation (general assets)	0.4	0.5	0.7	0.9	1.2	1.5	1.8	2.2	2.6	3.2
Depreciation (assets in operation)	60.9	72.3	84.9	97.4	126.7	159.3	170.9	182.8	195.7	209.7
Operating Income	**41.7**	**61.3**	**76.9**	**90.5**	**102.3**	**120.6**	**163.0**	**215.5**	**283.9**	**361.1**
Non-operating Income (net)	-1.8	1.7	4.2	-2.0	-2.8	-3.5	9.2	-4.5	-5.1	-5.7
Income before Interest	39.9	63.0	81.1	88.5	99.5	117.1	172.2	211.0	278.8	355.4
Interest charged to Operation	20.3	25.7	30.2	32.2	43.6	58.5	56.9	54.5	51.2	48.4
Monetary Correction	5.8	6.4	14.5	21.6	24.7	29.2	26.4	37.2	44.8	51.1
Income Tax	9.0	16.0	24.5	29.2	30.2	32.9	53.2	72.6	102.2	134.3
NET INCOME	**16.4**	**27.7**	**40.9**	**48.7**	**50.4**	**54.8**	**88.5**	**121.1**	**170.2**	**223.8**
Financial Indicators										
Rate of Return										
With accelerated depreciation	4.9%	6.1%	6.6%	6.2%	5.9%	5.9%	6.9%	8.6%	10.6%	12.5%
With linear depreciation	8.3%	8.9%	9.2%	8.2%	8.0%	8.0%	8.4%	9.3%	10.5%	11.7%
Cash Operation Ratio	20.7%	19.6%	19.2%	21.2%	20.2%	20.6%	19.7%	18.9%	17.4%	16.8%

(1) It includes the estimate for the whole year, although the ISA was legally split in May 1, 1995.

COLOMBIA
Table 12-2 ISA's Financial Projections
Source and Application of Funds Statement
(Col$ billion)

	1995[1]	1996	1997	1998	1999	2000	2001	2002	2003	2004
Gross Internal Cash Generation	**104.8**	**140.0**	**171.5**	**192.3**	**233.6**	**284.9**	**352.9**	**405.0**	**487.3**	**579.7**
Income before Interest	39.9	63.0	81.1	88.4	99.5	117.1	172.3	211.0	278.8	355.5
Depreciation	61.3	72.8	85.6	98.4	127.9	160.8	172.7	185.0	198.4	212.8
Other non-Cash Expenses	3.6	4.2	4.8	5.5	6.2	7.0	7.9	9.0	10.1	11.4
Less: Net debt service	**56.7**	**70.5**	**82.7**	**75.6**	**91.6**	**144.8**	**151.9**	**158.7**	**172.8**	**182.9**
Amortization	36.4	44.8	52.5	43.4	48.0	86.3	95.0	104.2	121.6	134.6
Interest Charges	26.3	33.5	39.1	48.6	57.0	58.5	66.6	74.1	87.6	102.8
Total Debt Service	62.7	78.3	91.6	92.0	105.0	144.8	161.6	178.3	209.2	237.4
Less: Interest during Construction	6.0	7.8	8.9	16.4	13.4	0.0	9.7	19.6	36.4	54.5
Net Internal Cash Generation	**48.1**	**69.5**	**88.8**	**116.7**	**142.0**	**140.1**	**201.0**	**246.3**	**314.5**	**396.8**
Borrowings	**93.9**	**59.3**	**107.7**	**165.1**	**15.9**	**0.0**	**116.8**	**109.1**	**316.5**	**69.5**
IBRD	16.1	42.4	80.7	115.7	15.9	0.0	0.0	0.0	0.0	0.0
Existing Loans in FC	74.3	15.4	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing Local Loans in LC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Future Loans in FC	0.0	1.1	24.9	49.4	0.0	0.0	116.8	109.1	316.5	69.5
Future Local loans in LC	3.5	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Sources	**142.0**	**128.8**	**196.5**	**281.8**	**157.9**	**140.1**	**317.8**	**355.4**	**631.0**	**466.3**
Applications										
Investment Program	**84.9**	**107.9**	**182.2**	**272.8**	**78.6**	**52.4**	**321.2**	**318.9**	**502.4**	**320.1**
Construction Program[2]	78.9	100.1	173.3	256.4	65.2	52.4	311.5	299.3	466.0	265.6
Foreign Component	41.6	52.9	93.8	154.9	21.4	35.0	153.0	128.2	218.9	96.1
Local Component	35.7	45.3	77.4	99.1	41.0	14.3	155.0	167.1	242.6	164.4
Other Investment	1.6	1.9	2.1	2.4	2.8	3.1	3.5	4.0	4.5	5.1
Interest during Construction	6.0	7.8	8.9	16.4	13.4	0.0	9.7	19.6	36.4	54.5
Variation in Working Capital	**57.1**	**21.0**	**14.1**	**8.9**	**79.4**	**87.7**	**(3.4)**	**36.5**	**128.6**	**146.3**
Other Applications	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Total applications	**142.0**	**128.9**	**196.3**	**281.7**	**158.0**	**140.1**	**317.8**	**355.4**	**631.0**	**466.4**
Financial Indicators										
Debt service Coverage (times)	1.7	1.8	1.9	2.1	2.2	2.0	2.2	2.3	2.3	2.4
Self-financing Ratio %	34	75	30	30	110	224	54	48	37	79

Includes the whole year, although ISA was split in May 1, 1995.

It does not include VAT

COLOMBIA
ISA'S FINANCIAL PROJECTIONS
Table 12-3 Balance Sheet
(Col$ billion)

ASSETS		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
Net Fixed Assets		1,025.1	1,232.8	1,528.0	1,935.6	2,152.9	2,336.1	2,809.1	3,328.8	4,098.2	4,759.0
	Fixed Assets in Operation	1,179.5	1,453.6	1,735.7	2,341.9	2,695.1	3,418.7	3,897.2	4,442.4	5,063.5	5,770.9
	Less: Accumulated Depreciation	249.3	361.5	500.6	668.1	885.0	1,151.1	1,471.6	1,845.8	2,281.4	2,787.7
	Net Fixed Assets in Operation	930.1	1,092.1	1,235.0	1,673.8	1,810.1	2,267.6	2,425.6	2,596.6	2,782.0	2,983.2
	Work in Progress	88.1	131.2	280.5	245.9	323.0	44.3	354.2	697.1	1,274.4	1,726.2
	Fixed General Assets	7.4	10.6	14.5	19.2	24.7	31.2	39.1	48.4	59.5	72.7
	Less: Accumulated Depreciation	0.5	1.2	2.1	3.3	4.9	7.1	9.8	13.3	17.7	23.1
	Net Fixed General Assets	6.9	9.5	12.5	15.9	19.8	24.2	29.3	35.1	41.8	49.6
Current Assets		94.8	117.6	123.9	145.5	163.6	225.0	222.7	210.2	264.5	325.7
	Cash and Banks	6.4	8.0	8.4	6.6	4.5	5.7	9.9	10.0	11.9	14.1
	Temporary surplus	14.8	45.6	25.2	2.2	28.2	92.0	57.4	0.0	0.0	0.0
	Accounts Receivable	21.6	27.8	33.5	39.9	48.1	59.0	69.7	82.3	97.3	114.9
	Advance income tax payment	12.0	20.8	38.8	75.5	58.4	38.9	52.3	80.0	112.3	147.8
	Inventories	5.9	7.3	8.7	11.7	13.5	17.1	19.5	22.2	25.3	28.9
	Other	34.1	8.1	9.3	9.6	10.9	12.3	13.9	15.7	17.7	20.0
Other Assets		8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0
TOTAL ASSETS		1,127.9	1,358.4	1,659.9	2,089.1	2,324.5	2,569.1	3,039.8	3,547.0	4,370.7	5,092.7

... continued

ISA'S FINANCIAL PROJECTIONS
Table 12-3 Balance Sheet
(Col$ billion)

LIABILITIES AND EQUITY		1995	1996	1997	1998	1999	2000	2001	2002	2003	2204
Equity		727.4	871.5	1,043.0	1,237.8	1,455.2	1,699.3	2,008.8	2,391.0	2,872.1	3,469.4
	Capital	99.1	99.1	99.1	99.1	99.1	99.1	99.1	99.1	99.1	99.1
	Legal Reserve	10.4	12.0	14.8	18.9	23.7	28.8	34.3	43.1	55.2	72.3
	Contributions	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4	17.4
	Retained Earnings	40.1	66.2	104.2	148.8	194.3	244.2	327.3	439.5	597.7	804.5
	Capital Revaluation	560.4	676.8	807.5	953.6	1,120.7	1,309.8	1,530.7	1,791.9	2,102.7	2,476.1
Long Term Debt		312.5	369.2	486.2	668.8	675.0	653.6	744.1	820.1	1,112.4	1,175.8
Current Liabilities		70.0	95.3	103.8	150.1	155.4	170.4	233.3	273.3	313.7	363.4
	Short term Debt	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Current portion of Long Term Debt	41.9	49.5	41.1	45.6	82.1	90.4	99.0	115.4	127.8	128.4
	Accounts Payable	1.1	8.4	13.5	42.4	10.1	10.7	39.9	39.0	30.7	40.2
	Income Tax	9.0	16.0	24.5	29.2	30.2	32.9	53.2	72.6	102.2	134.3
	Other	18.0	21.4	24.7	32.9	33.0	36.4	41.2	46.3	53.0	60.5
Other Liabilities		18.0	22.1	26.9	32.4	38.6	45.6	53.5	62.5	72.6	84.0
TOTAL LIABILITIES AND EQUITY		1,127.9	1,358.1	1,659.9	2,089.1	2,324.2	2,568.9	3,039.7	3,546.9	4,370.8	5,092.6
FINANCIAL INDICATORS		1,995	1,996	1,997	1,998	1,999	2,000	2,001	2,002	2,003	2,004
	Debt/Equity Ratio	33	32	34	37	34	30	30	28	30	27
	Liability/Assets	36	36	37	41	37	34	34	33	34	32

COLOMBIA

POWER MARKET DEVELOPMENT PROJECT

Table 12-4 ISA: LONG-TERM DEBT SCHEDULE

Lender	Project	Signing Date		Original Amount (Currency thousand)	Notes	Grace Period (year)	Re-payment Period (month/year)	Interest (%)	Commit-ment Fee (%)	Outstanding Debt (US$ thousand) Total	Current Portion
EXISTING LOANS											
(As of December 31, 1994)											
External Debt											
IDB Loan 195	Transmission reinforcement	December 86	US$	115,80	(1/)	6	06/95 - 12/0	Variabl	1.25	130,97	11,38
IDB Loan 242	Transmission reinforcement	December 87	US$	86,60		4	12/91 - 12/9	Variabl	0.50	39,96	13,32
Ansaldo	Transmission reinforcement	January 90	Li	35,233,00		5	12/95 - 06/1	1.7	0.00	17,41	86
Export Development Corp.	Arauca-Bucaramanga T. Line	November 87	Can$	45,00		2 1/2	06/90 - 12/9	8.7	0.50	15,80	3,16
Credit Lyonnais Canada	Arauca-Bucaramanga T. Line	November 87	US$	16,00		3 1/2	05/91 - 11/9	L+1+	0.50	3,20	3,20
Local Debt in Foreign Currency											
FEN FCH-009	Debt Service	August 90	US$	30,77		4 1/2	03/95 - 09/0	L+7/8+3/4		30,79	2,79
FEN-Eximbank FEX-003	Venezuela Interconnection Line	February 92	US$	80,00	(5)/	3Years+ 10months	07/93 - 01/0	JPR+0.75%	0.50	43,76	4,30
	San Marcos S/S - 1st. stage										
	Cerromatoso - Uraba Transm. Line										
	Betania-Mirolindo T.Line										
	Transmission System Reinforcement										
	Second Transmission Plan										
IDB Loan 687	San Marcos S/S and	December 92	US$	69,70	(4/)	3Years+ 2months	08/97 - 08/1	Variabl	0.75	7,69	
	Lines: Cerromatoso-Uraba										
	Betania- Mirolindo										
FEX -006	Bucaramanga-Ocaña-Cucuta T.Line	June 92	Yen	1,538,56	(2/)		07/95 - 01/0	JPR+0.7		15,40	1,30

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POWER MARKET DEVELOPMENT PROJECT

Table 12-4 ISA: LONG-TERM DEBT SCHEDULE

Lender	Project	Signing Date		Original Amount (currency thousand)	Notes	Grace Period (year)	Re-payment Period (month/year)	Interest (%)	Commit-ment Fee (%)	Outstanding debt (US$ thousand) Total	Current Portion
Local Debt in Local Currency											
FONADE -702	Second Transmission Plan	February 91	C$	50,00		2Years+ 4months	06/93 - 03/9	23.0	1.5		
FONADE -703	Second Transmission Plan	February 91	C$	39,00		4months	06/92 - 03/9	23.0	1.5	1	1
FONADE -704	Second Transmission Plan	February 91	C$	133,00		4months	06/92 - 03/9	23.0	1.5	2	1
FEN -87	Transmission reinforcement	October 87	C$	1,500,00		1	04/89 - 04/9	27.0	0.5	15	15
FEN -88	Transmission reinforcement	January 88	C$	1,700,00		1	04/90 - 01/9	29.0	0.5	72	20
	Second Transmission Plan & Studies										
FUTURE LOANS											
IBRD Proposed	Power market development Project	under preparation	US$	230,00		5		7.3	0.25		
Commercial Credit (several)	Fourth Transmission Plan	To be contracted	US$	80,00	(3)			8.7	0.5		
Multilateral loans (several)	Future expansion	To be contracted	US$	421,00	(3)			8.5	1 25		
									TOTAL	305,93	40,73

Notes:
(1) US$ 250,000 were canceled
(2) This loan was transferred from ICEL to ISA
(3) Total amount to be contracted corresponds to the financing requirement during the period
(4) Last Disbursement expected in March, 97
(5) Japanese Preferential Rate

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Table 12- 5 Financial Sensitivity Analysis
(Current US$ Million)

	Base Case		Case A		Case B		Case C		Case D	
	Period		Period		Period		Period		Year 1997	
Financial indicators	(95- 99)	(2000-04)	(95-99)	(2000-04)	(95-99)	(2000-04)	(95-99)	(2000-04)	DI	DII
Operating Revenues	868	1286	865	1222	865	1222	878	1301	174	174
Operating Expenses	554	718	554	718	554	718	575	784	107	107
Net Income	314	568	312	504	312	504	302	517	67	67
Gross Internal Cash Generation	714	1067	711	1004	683	954	714	1067	153	153
Debt Service (excludes IDC)	325	420	326	413	328	517	327	443	71	71
Internal Cash Generation	388	647	385	591	355	437	387	624	82	82
Borrowings	395	302	395	351	395	351	413	414	93	93
Investment (Includes IDC)	624	754	623	767	623	767	639	831	158	158
Average Rate of Return (%)	8.5	9.6	8.5	8.7	8.5	8.7	8.3	8.6	9.1	9.1
Average Cash Operating Ratio (%)	20.2	18.5	20.2	19.5	20.2	19.5	20.7	20.0	19.0	19.0
Average Debt Service Ratio	1.9	2.2	1.9	2.1	1.8	1.9	1.9	2.1	1.9	1.9
Average Self-Financing Ratio (%)	37	58	37	54	35	47	35	50	16	16
debt plus equity	34	29	34	32	34	31	34	31	34	34

CASE A: Tariffs are not adjusted to take into account increase of investment needs after 1999.

CASE B: Same as case A plus delay in execution o investment program, which obliges ISA to pay penalty charges, plus a 10% increase in energy losses.

CASE C: Same as case A plus higher local (+3%) and external inflation (+1%) than that used in the base case.

CASE DI: Assumes that "small and unsolvent utilities" (see Annex 8, Table 8-7) delay payments.

DII: Case DII assumes that in addition to the arrears supposed in DI "small and under recovery utilities" also delay payments, resulting in a shortfall of 20% of ISA's revenues

ANNEX 13

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POWER MARKET DEVELOPMENT PROJECT

ENVIRONMENTAL EVALUATION

Main Environmental Issues Associated with the Three Transmission Lines

1. Over the past years, ISA has demonstrated a noteworthy commitment to incorporating environmental issues within the decision making process to select optimal transmission projects. Since 1992, ISA has being developing the "Metodología para el Estudio de Restricciones Ambientales y Selección de Alternativas de Ruta". The methodology combines a Geographical Information System (ILWIS) for data gathering as well as photo interpretation, field work, and secondary data. It was applied to the San Carlos-San Marcos (500 kV) Transmission Line. The methodology represents a significant advance in environmental assessment starting with the earliest stage of the transmission project cycle. It permits selection of the corridor by weighting socio-economic, cultural, political and physic-biotic factors with electrical, technical and economic objectives. The main environmental restrictions are automatically incorporated within the designs, thereby assuring that highly complex environmental effects will be avoided.

2. ISA prepared and submitted to the Bank the report "Estudio de Restricciones Ambientales - Tercer Plan de Transmision", which identifies the main environmental and social constraints that are being used to select the optimal corridor and to be taken into account within the design of the three transmission lines. This report also contains the sequence of steps followed by ISA to incorporate environmental and social considerations within the entire project cycle. The report was approved by the Bank. Based on lessons learned in construction and operation of the present national interconnected system, the following environmental issues have been analyzed:

(a) **Abiotic Environment**: geomorphology, erosion, soil alteration and destabilization of slopes as a consequence of construction of roads; mining activities and current and potential morphodynamic processes resulting from human intervention.

(b) **Biotic Environment**: unique ecosystems of high biodiversity or high fragility; natural resources affected (especially water); loss of vegetative cover, effects on protected areas (e.g., national parks, natural reserves and areas with special jurisdiction).

(c) **Socio-economic and Socio-cultural Environment**: restriction to the right-of-way derived from indigenous reserves or national minorities settlements;

special cultural and archaeological regions; highly populated areas; economic activities; land tenure; conflict related to the use of scarce natural resources; socio-political conflict in the area of influence of the transmission line.

San Carlos-San Marcos. Main Environmental Restrictions

3. This 500 kV line (380 km; 24 meter right-of-way) will be developed to supply energy to the southwest region of the interconnected system. For this line, several alternatives were assessed. The alignment selected is expected to generate low environmental impacts mainly related to vegetation clearance, access paths and use of sensitive terrain (e.g., river crossings). Impacts on human settlements, cultivated lands, critical wildlife habitat, sites of archaeological interest, human health and visual landscape have been rated low. Special care of avoiding negative impacts on sugar cane plantations were taken during corridor selection. The designs will be finalized during the first quarter in 1995. Consultoría Colombiana, the firm in charge of the designs, is carrying out, in parallel, a project-specific environmental report containing the environmental mitigation plan.

4. A plan for the identification of potential archaeological sites that can be affected by the construction of the towers, and the sequential rescue of the archaeological heritage has been scheduled to start prior to construction and will be extended until excavations in tower-sitting and paths are finished.

La Loma-Copey and Paipa-Bucaramanga. Main Environmental Restrictions

5. According to the current expansion plan and demand scenario, the two lines are required to start operating after 1997. The specific Study of Environmental Impacts will be undertaken by a consultant firm during 1995-96. Detailed mitigation measures and a monitoring system will be prepared while detailed engineering, definitive route alignment and field surveys are carried out prior to 1996. The preliminary studies for these 230 kV lines have identified some critical environmental aspects in a 4 km wide corridor. They are: (a) potential effects on a forestry reserve a native forest known as "Robledales" in the Virolin region, the status of which is currently being reviewed; and (b) impacts on the urban population living around the final substation in Bucaramanga. To avoid impacts on the Robledales forest ISA will use the existing corridor that was opened for the 500 kV line. ISA is also contemplating alternatives to avoid undesirable impacts on the neighborhood located around the substation in Bucaramanga. Other constraints are related to the socio-political conflicts in Santander. The Bank will carefully review the study when available to ensure conformity with Bank environmental guidelines and will supervise the environmental performance during the implementation of the two mentioned lines.

Environmental Management Plan

6. Along with the current scheme to assess environmental impacts associated with transmission lines, a complete Environmental Management Plan to mitigate and compensate undesirable effects on human and natural systems is being prepared. It

embraces programs dealing with social communication and negotiation with affected and benefited communities; compensation for physical losses; reforestation or grass-planting; archaeological rescue; resettlement of displaced population; rural electrification, policy on local employment and supplies for contractor camps; creation of preserved areas; mitigation of impacts derived from access construction; path maintenance; monitoring of migratory species; and micro-basin management and environmental monitoring. ISA will prepare project-specific environmental reports satisfactory to the Bank for each of the project's transmission lines before the bidding process. In addition, general procedures to incorporate environmental standards and safeguards have been included within the bidding documents for contractors of main civil works.

Resettlement

7. Relocation from transmission lines is usually much simpler compared to other kinds of infrastructure construction due to the fact that houses and assets can be displaced just a few meters away from the corridor and in many cases land can be utilized for agriculture or grazing (except for forestry and tall fruit trees). The three lines do not affect concentrated communities. In 1991, the Colombian Electric Power Sector prepared and approved an official Resettlement Policy which is consistent with World Bank resettlement policy. ISA has undertaken successful experiences in applying a participative approach to resettlement of scattered populations living along the right-of-way of the lines of the existing interconnected system. Individual solutions for housing, land and economic activities restoration have been designed and implemented in conjunction with each affected family.

8. In the case of the San Carlos-San Marcos transmission line, the population to be displaced along the corridor comprises 42 families (176 persons). Due to the small size of the right-of-way that is necessary to raise the towers, many affected families will be able to remain on their lots and will be given a new house. Regardless of the small number of people that will be displaced by these lines, the borrower will prepare a resettlement plan for Bank approval before opening the bidding process. The ISA social team has already contacted the affected families to inform them about the project, the expected environmental and social effects, the ISA's resettlement policy, and their rights in terms of compensation and indemnization. The families' expectations and preferences are being included in the resettlement plan.

9. In the case of the transmission lines foreseen to reinforce the Atlantic Coast Region, design is scheduled to start in 1996 and construction will begin in 1998. Therefore, definite figures for displacement of population will not be available until detailed engineering designs are finished. Moreover, the final centerline can be changed even during the construction phase. Although the selected corridors avoid human settlements, a small number of families living within the right-of-way corridor might be displaced. Regardless the number of people that will be displaced by these lines, the borrower will prepare a resettlement plan for Bank approval and will follow the same procedures agreed for the San Carlos-San Marcos transmission line.

Institutional Capacity for Environmental Assessment and Management

10. The recent institutional reforms in the Colombian Electric Power Sector and the restructuring of ISA as an independent transmission company, emphasize ISA's role in planning, implementation and operation of the existing and planned expansion of the national transmission system. Therefore, ISA is responsible for implementing environmental management plans for the current and new transmission lines and for directly monitoring compliance with national and sectoral environmental norms and proposed mitigation measures. Monitoring and evaluation is to be undertaken by the Dirección de Proyectos de la Gerencia de Transmisión de ISA.

11. Gradually moving from corrective to preventive management is improving ISA's institutional capacity. The studies of alternative alignments and environmental constraints are carried out by an interdisciplinary team comprising ecologists, anthropologists, sociologists, economists, geologists, and environmental engineers. The interdisciplinary team works in conjunction with the electric and civil engineers in charge of project design, in order to achieve the optimal electrical, technical, economic and environmental decisions. Occasionally other environmental specialists can be brought in as needed. Finally, the recently created Ministry of Environment is responsible for providing the environmental licenses once ISA presents the Report on Environmental Impact for each transmission line and fulfills all requirements to demonstrate their environmental feasibility.

Legal Framework

12. In recent years, the government has been making a significant effort to strengthen the regulatory framework in order to promote an environmentally sustainable development in the Electric Power Sector. Since the creation of the Ministry of Environment (ME) and the approval of the National Environmental Law (NEL)[2], specific regulations for environmental assessment and licensing for electric power projects have been established.

13. The recently approved National Environmental Law establishes a new procedure according to which an Environmental Diagnosis of Alternatives (EDA) should be presented to the ME. The EDA should present several alternatives for each project and assess their advantages and drawbacks. The ME will select the optimal alternative and will request a detailed Environmental Assessment before providing the corresponding permit to build the project. The new legal procedure is intended to ensure optimal decisions in selecting environmentally sound projects.

14. The new Electricity Law approved by Congress in July 1994 explicitly establishes the adequate protection of the environment, consultation with affected communities and relevant social groups involved in all operations of the electric power sector (See Chapter X: de la Conservación del Medio Ambiente, art. 50 to 53). Sound environmental planning, execution and operation of the transmission lines is widely recognized as a condition for privatization of the electric power facilities. In addition, the regulation of the recently approved NEL explicitly

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[2] Ley 99 de Diciembre de 1993

requires an Environmental Assessment of alternatives for transmission lines among other projects (see Chapter IV art. 17 to 20 of Law 99/93: Diagnóstico Ambiental de Alternativas). The NEL also establishes the new processes for clearance and environmental licensing.

15. Non-governmental organizations, both at the local and national levels, as well as private consulting firms, have participated in the environmental assessment and design of the planned transmission system. Active discussions on methodologies to incorporate environmental considerations since the earliest stage in the planning process, have been put in place at both the regional and sectoral level.

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TERMS OF REFERENCE FOR TECHNICAL ASSISTANCE

Part C of the project includes the provision of consulting services to assist ISA in the strengthening of its capabilities to assume its roles of: (i) transmission network operator, (ii) power dispatch coordinator and (iii) bulk electricity transaction clearing house. These activities will be agreed upon between ISA and the Bank subject to an annual plan to be approved by the Bank. A summary of the terms of reference for technical assistance studies to be started in 1996 is presented below. The corresponding implementation timetable is in Annex 10, together with the Project's Execution Schedule. The terms of reference presented by ISA are in the project files.

(a) **Final design and technical specification for computing and data acquisition systems and the corresponding software for the ECC and the FSC**. Objective: improve performance of ISA's ECC and FSC. Scope: design and specify the hardware and software necessary for the effective functioning of the ECC and the FSC. Product: bidding documents for the international competitive bidding for the supply of hardware and software.

(b) **Determination and specification of methods to transmit data collected by remote meters to the ECC and the FSC**. Objective: improve performance of ISA's ECC and FSC. Scope: identify a practical and reliable mean for the transmission of data between remote meters and the ECC. Product: specification of the hardware and software needed.

(c) **Identification of the characteristics of transmission power losses in ISA's network and specification of mechanisms for loss monitoring and control.** Objective: reduce ISA's power losses to economic levels. Scope: prepare a diagnose of electricity transmission losses during typical demand pattern cycles that occur during the year. Product: a power loss reduction plan.

(d) **Review and update of ISA's power substation design manual**. Objective: improve the design of power substations with the ultimate objective of reducing costs and improving reliability. Scope: review existing manual to include new technology in the areas of compensation, transformer overload protection and telecommunications; extend manual to cover 500 kV substations. Product: updated manual.

(e) **Development of methodology for technical and economical assessment of width of corridors for transmission lines**. Objective: reduce costs of transmission line construction and insure public safety. Scope: review existing literature on the subject, and evaluate existing software; if necessary adapt methodology for ISA's use. Product: adequate methodology and software to determine the width of corridors for transmission lines.

(f) **Standardization of steel structures for single circuit 230 kV lines**. Objective: reduce costs of construction and maintenance of single circuit 230 kV lines. Scope: update ISA's metereological data base and normalize the dimension of transmission towers. Product: set of standard blueprints for transmission towers adequate to Colombian topology and meteorology.

(g) **Development of a comprehensive quality control data acquisition system**. Objective: improve power transmission reliability. Scope: diagnose of existing quality control system, design upgraded system, draft technical specifications for metering equipment and software for analysis of failures. Product: plan to improve ISA's power transmission reliability and bidding documents for the purchase of the necessary equipment.

(h) **Evaluation of telecommunications infrastructure and equipment needs for power transmission projects**. Objective: improve power transmission reliability and minimize construction costs. Scope: prepare a manual on telecommunication infrastructure requirements with the specifications and costs of the necessary equipment. Product: manual on telecommunications requirement for power transmission projects.

(i) **Development and acquisition of computer software to prepare construction budgets for power substations**. Objective: reduce time and cost of preparing construction budgets. Scope: develop a cost data base and computer software to prepare budgets for the construction of substations. Product: substation components cost data base and computer software.

(j) **Feasibility study of the application of synchronized operation of circuit breakers on ISA substations**. Objective: reduce transmission losses and improve transmission system reliability. Scope: specification of schemes for the synchronized operation of circuit breakers. Products: (i) report identifying which nodes of ISA's transmission network require breakers synchronized operation, and description of the appropriate operation technique in each case; and (ii) bidding documents for the purchase of the required equipment.

(k) **Review of power transformer technical specifications used by ISA**. Objective: reduce power transformation costs and increase system reliability. Scope: evaluate the adequacy to Colombian conditions of the use of new power transformation technology. Product: report specifying which types of transformers should be used in ISA's substations, their technical specifications and cost curves.

(l) **Methodology for load curve forecast**. Objective: improve power plant economic dispatch and increase system reliability. Scope: review ISA's load curve forecast techniques and recommend which set of forecasting tools (e.g. time series forecast techniques combined to energy end-use models) are most suitable to ISA; specify the required software to be implemented. Product: Report prescribing load curve forecast methods and corresponding software.

ANNEX 15

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ISA - MONITORING INDICATORS

1. **Indicators**: The following indicators would be used during project supervision to monitor ISA performance:

(a) **Weighted Average Frequency of Interruption (Fi)**

Fi = (Σ Pi) / CEM

Pi = Interrupted power in MW
CEM = Average capacity of the transmission network in MW

(b) **Weighted Average Length of Interruptions (Di)**

Di = Σ (Pi x DHi) / Σ P

Pi = Interrupted power in MW
DHi = Length of interruption in hours.

(c) **Average Interruption Time (TEI)**

TEI = Σ (Pix DHI)/CEM

Pi: Interrupted power in MW
DHi: Length of interruption in hours
CEM: Average capacity of the transmission network in MW

(d) **Reliability Index (IC)**

IC = 1 - (TEI/T)

TEI = Average interruption time
T = 8760 hrs

(e) **Total Transmission Losses (Loss):** defined as the ratio:
Loss = (NG-DG)/NG (%) where
NG = Net energy supplied to ISA's grid
DG = Energy delivered by ISA to its clients

(f) **Cash Operating Ratio**: defined as the ratio between total cash operating expenses and total gross revenues. Total cash operating expenses refers to all expenses related to operations, including operation, maintenance and administrative expenses, taxes and payments in lieu of taxes, but excluding provision for depreciation, income taxes, and other non-cash operating charges, interest and other charges on debts. Gross operating revenue refers to revenues from all sources related to operations;

(g) **Self-Financing Ratio**: defined as the ratio between funds from internal sources and capital expenditures. Funds from internal sources are the difference between the sum of revenues from all sources, excluding borrowing, and the sum of all expenses related to operations, debt service requirements, income taxes, all cash dividends, transfers to the Treasury, and variation in working capital other than cash excluding provision for depreciation and other non-cash operating charges. Capital expenditures means the sum of all expenditures incurred on account of fixed assets, including interest charged to construction;

(h) **Debt Service Coverage**: defined as the ratio between gross internal cash generation (excluding customer contribution and consumer deposits) and total debt service requirements.

2. Monitoring: Attachment 1 shows the expected evolution of these indicators.

Attachment 1

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MONITORING INDICATORS - EXPECTED VALUES

Indicator	1995	1996	1997	1998	1999	2000	2001	2002	2003
Weighted Average frequency of Interruption	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0	<2.0
Weighted Average Length of Interruptions (hrs.)	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0	<1.0
Average Interruption time (hrs.)	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Reliability Index (%)	98.6	98.6	98.7	98.8	98.8	98.8	98.8	98.8	98.8
Total Transmission Losses (%)	<2.5	<2.5	<2.5	<2.5	<2.5	<2.5	<2.5	<2.5	<2.5
Debt Service Coverage [1]	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
Cash operating ratio[1] (%)	20	20	20	20	20	20	20	20	20
Self-financing Ratio [1] (%)	30	30	30	30	30	30	30	30	30
Accounts Receivable (days)	60	60	60	60	60	60	60	60	60

[1] Indicator covered by legal covenant. (The cash operating ratio agreed in the covenant ratio is 23%).

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ENVIRONMENTAL MONITORING INDICATORS

Indicators	1995	1996	1997	1998	1999	2000	2001	2003
1. Completion of Environmental Assessment (EA) for each transmission line before inviting bids for construction.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
2. Preparation of an Environmental Project Implementation Manual for Transmission Lines [1]		100%						
3. Execution of all actions determined in the Environmental Management Plan (EMP)		Yes	Yes	Yes	Yes	Yes	Yes	Yes
4. Ratio families relocated/displaced		100%	100%	100%	100%	100%	100%	100%

[1] The Project Implementation Manual should be prepared prior to starting construction of the San Carlos-San Marcos transmission lines.

ANNEX 16

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SUPERVISION PLAN

Approx. Dates (Month/ Year)	Special Activity in the Supervision Mission	Skill Requirements	Staff Input (SW)
Jan/96	Project Launch	Power Engineer, Financial Analyst, Environmental Specialist	6
Apr/96	Annual Formal Review Meeting Review Project Implementation Program	Power Engineer, Financial Analyst, Environmental Specialist	5
Oct/96	Review Procurement Plan Review TA development	Power Engineer, Financial Analyst, Environmental Specialist	5
Apr/97	Annual Formal Review Meeting Review Project Implementation Program	Power Engineer, Financial Analyst, Environmental Specialist	5
Oct/97	Review Project Implementation Review TA development	Power Engineer, Financial Analyst, Environmental Specialist	5
Apr/98	Mid-term Review Meeting Review Procurement Plan	Power Engineer, Financial Analyst, Environmental Specialist	5
Oct/98	Review Project Implementation Review TA Development	Power Engineer, Financial Analyst, Environmental Specialist	5
Apr/99	Annual Formal Review Meeting Review Project Implementation	Power Engineer, Financial Analyst, Environmental Specialist	5
Oct/99	Review Project Implementation Review TA Development	Power Engineer, Financial Analyst, Environmental Specialist	5
Apr/2000	Annual Formal Review Meeting Project Implementation	Power Engineer, Financial Analyst, Environmental Specialist	5
Oct/2000	Review Project Implementation	Power Engineer, Financial Analyst, Environmental Specialist	5
Apr/01	Annual formal Review Meeting Project Implementation	Power Engineer, Financial Analyst, Environmental Specialist	5
Oct/01	Review Project Implementation	Power Engineer, Financial Analyst, Environmental Specialist	5

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Allocation of Loan Proceeds

The proposed disbursement categories, the allocation of loan funds for each of the fixed and floating rate single currency loans, and the disbursement percentages are as follows:

Category	Floating Rate Loan		Currency Pool Loan		Total	% Expenditure to be Financed
	(US$ million)					
Works	24.0	17%	1.0	1%	25.0	90%
Goods (Part A)[1]	0.1	0.1%	9.9	9%	10.0	100% of foreign exp. and 90% of local ex-factory
Goods (except Part A)	60.0	41%	43.6	42%	103.6	100% of foreign exp. and 90% of local ex-factory[2]
Equipment and Instalation	25.0	17%	18.0	17%	43.0	95% of foreign exp.
Consultant Services (Part A)	0.1	0.1%	0.4	0.5%	0.5	100% of foreign exp.
Consultant Services (except Part A)	0.1	0.1%	4.4	4%	4.5	100% of foreign exp.
Training	0.1	0.1%	0.9	1%	1.0	100% of foreign exp.
Interest and other changes under the Bank loans	21.4	14.8%	15.4	15%	36.8	100%
Unallocated	14.2	9.8%	10.7	11%	24.9	
TOTAL	145.0	100%	104.3	100%	249.3	

(1) Part A: Energy Control Center and Financial Settlement Center
(2) Except equipment.

ANNEX 18

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SELECTED DOCUMENTS AND DATE AVAILABLE IN THE PROJECT FILES

1 PEN - Plano Energético Nacional, Unidad de Planeación Minero Energética - mayo de 1994

2 ISA - Informe Anual 1993; Informe Anual 1994

3 Sistema Eléctrico Colombiano - Balance Energético Histórico 1977-92, ISA - junio de 1994

4 Estrategias para el Desarrollo y la Expansión del Sector Eléctrico 1995-2007, documento COMPES - 2763, febrero de 1995

5 Plan de Expansión de Referencia Generación y Transmisión1995-2004, MME-1993

6 Informe de Restricciones Ambientales - Tercer Plan de Transmisión y Proyecto La Loma, ISA, abril de 1994

7 Evaluación Sectorial Ambiental - Sector Eléctrico Colombiano, ISA-MME - 1994

8 Metodología para la Previsión de la Demanda de Energía Eléctrica, Documento UPME-E-004/95 -enero de 1995

9 Estrategia Tarifaria de Energía Eléctrica - Objetivos a mediano y corto plazo, documento JNT-1215, mayo de l993

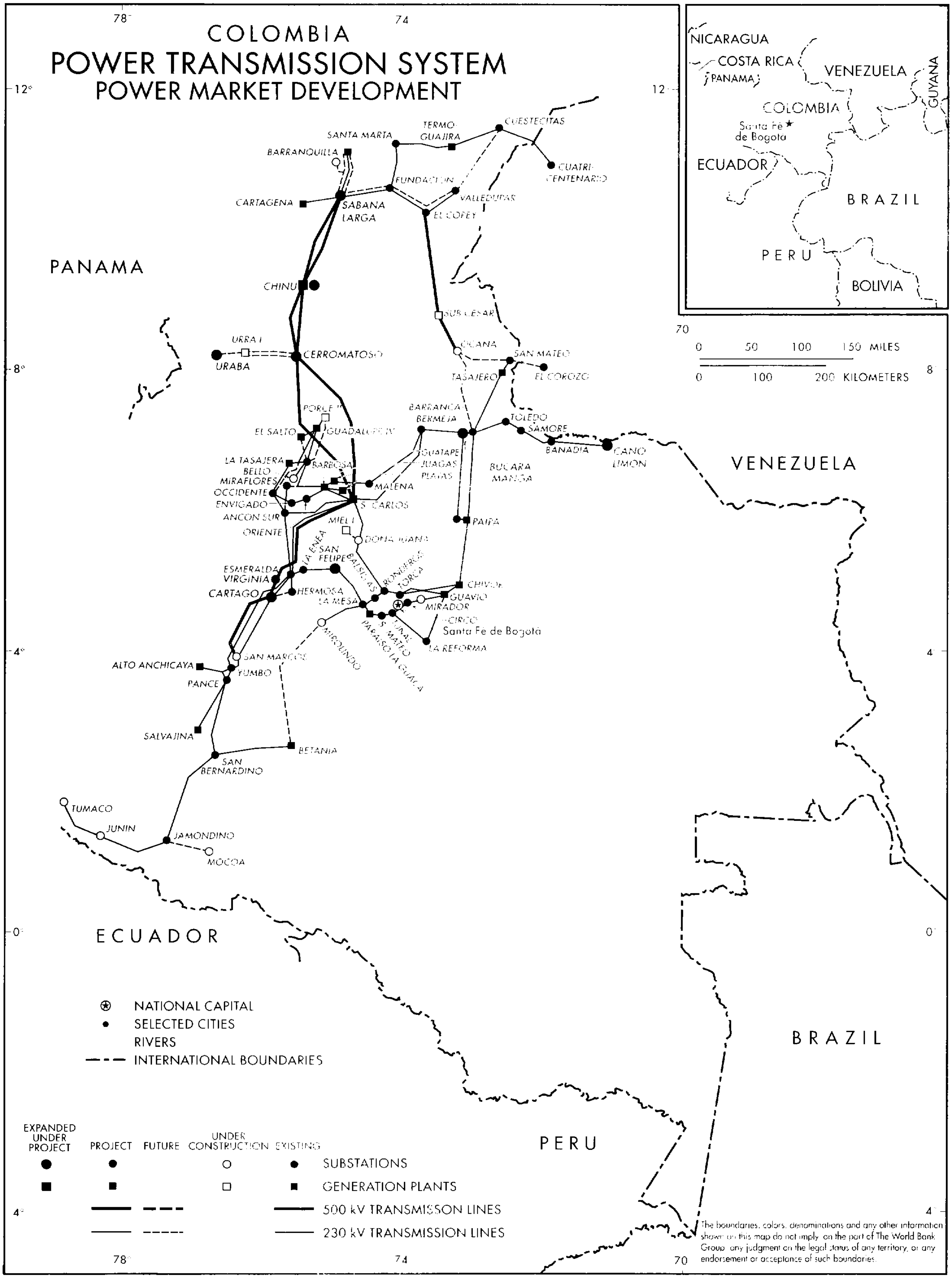
10 COLOMBIA - The Financial Conditions of the Electric Sector and Actions Needed to Reach Creditworthiness, Xavier Nogales (consultant), November, 1993

11 PIP - Project Implementation Plan - Plan de Implementación del Proyecto de Expansión de la Transmisión, ISA - mayo de 1995

12 Desarrollo de las Medidas Tomadas por el Gobierno en el Sector Eléctrico Colombiano Durante los Ultimos Años, MHCP - septiembre de 1994.

13 Terms of Reference for technical assistance.

IBRD 26929



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