Reference Expansion Plan

Power Generation & Transmission 2004-2018

Plan de expansión de Referencia

Generación - Transmisión 2004 - 2018

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REPUBLICA DE COLOMBIA
MINISTERIO DE MINAS Y ENERGIA
UNIDAD DE PLANEACIÓN MINERO ENERGÉTICA

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Introduction

We are pleased to submit the 2004-2008 version of the Expansion Plan, as adopted by the Ministry of Mines and Energy by means of Resolution 181737 of December 2004. In the first place we would like to highlight that this is not an UPME exclusive product; it is the result of a consultation to agents and as such all entities and individuals who participated, either by preparing it or by providing their comments to the Plan's preliminary version or by directly participating in the CAPT Transmission's Planning Advisory Committee should be acknowledged.

Demand is the Basic supply to set up a Plan and in this sense we are optimistic that the country has regained a growth path that allowed us establishing a projection tunnel with the correct answers to the average scenario as regards real values of demand of less than one percent. This means that our commitment is stronger wherever we submit our generation expansion and transmission recommendations. The coordinated work carried out with the CND to maintain a demand projection group has been fundamental.

On the other hand the first year of operation of the TIEs layout between Colombia and Ecuador has been completed, proving real benefit to both countries. In this sense, the Unit has made its small contribution by developing a methodology that allowed it making an economic assessment of international interconnections and also establishing a procedure to apply such methodologies with the tools we have traditionally used. As a specific result, this Plan contains clear recommendations regarding the increase of the interconnection capacity between both countries, by implementing the double-circuit 230 kV Betania – Altamira – Mocoa – Pasto (Jamondino) – Pomasqui – Santa Rosa project; this project fulfills two needs: integrating Colombian South-West into the NTS on solid grounds and increasing the exchange of electric energy between both countries. The contribution of Ecuadorian authorities responsible for the transmission expansion is to be acknowledged, particularly that of CONELEC, CENACE and TRANSELECTRIC with which a joint work has been performed that made it possible to agree on the recommendations and to ensure a certain coordination that no doubt will result in the timely implementation of the projects.

As regards the generation expansion we are submitting our recommendations to ensure that the country not only be in the capacity to reliably serve the expected growth of demand; additionally the country should be prepared to go through economic growth shocks leading to large growth scenarios so as to overcome hydrological contingencies as those we have gone through in the recent past, to maintain a capacity margin that ensures a safety operation in the medium and long term, and to maintain our condition as a power exporting country. Even if the CREG has stated its commitment to maintain the payment of the capacity charge and a methodological proposal has been submitted to calculation and distribution thereof, it remains under discussion.

Situación Económica y Energética

Economic & Energy Situation

1. Economic and Power Situation

1.1 2002-2006 National Development Plan – Toward a Community State

The 2002-2006 National Development Plan was approved by means of Law 812 of 2003. Macroeconomic assumptions under which the Plan was developed are those shown in Table 1-1:

Table 1-1. Macroeconomic Assumptions

Macroeconomic Indicator	2003	2004	2005	2006
Real Growth (%)	2.0	3.3	3.7	3.9
PCI (%)	5.5	4.5	3.5	3.0
Cur Acct Deficit. (% of GDP)	-1.2	-1.5	-1.6	-2.0
Treasury Deficit (% of GDP)	2.5	-2.1	-2.0	-2.2
Debt/GDP ratio	51.5	52.1	51.7	51.4

Source NPD

As regards the provision of home public services, which include electricity, the following goals are set, among others:

- To promote private participation.
- To ensure energy offer and market strengthening
- To develope plans to determine the feasibility of providing the service in non-connected areas.
- To promote regional energy integration, particularly the integration of power transmission networks with Panama, Venezuela and Ecuador.

At present all electric energy chain activities have private participation; some mechanisms have been established towards solving the sector's financial crisis, particularly that of distribution and commercialization companies; in the short term the Country has enough installed capacity to satisfy its internal demand and export to neighboring countries; the process to attract investments is ongoing; mechanisms have been established to ensure provision of energy in non-connected regions and to enlarge service coverage in these regions as well as in the National Interconnected System area of influence through the FAER and FAZNI funds; also, a fund was structured to normalize the networks in subnormal neighborhoods.

As regards the regional power integration, several actions have been undertaken towards blending regulations together, particularly in the Andean Community of Nations. On the other hand, an agreement was reached with Panama to carry out the relevant research in order to achieve power interconnection particularly electrical.

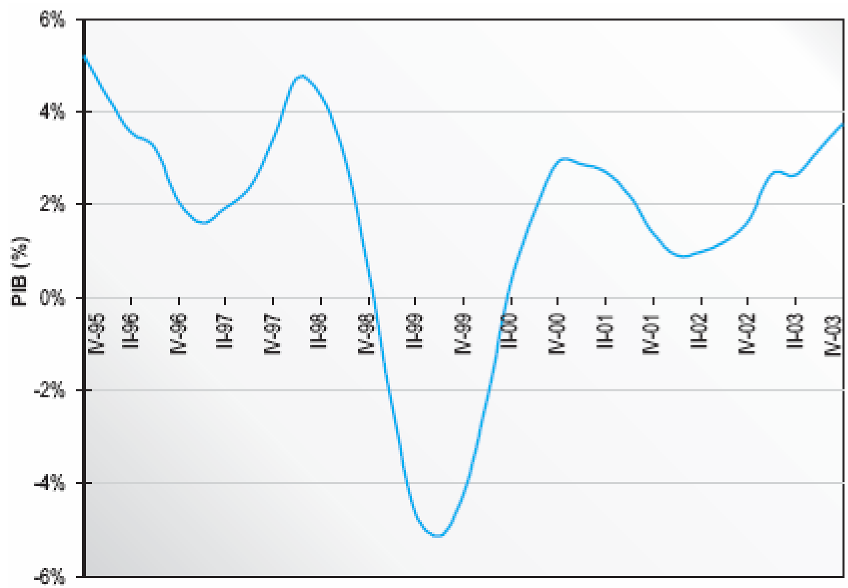
The project to interconnect with Panama creates a milestone in the development of regional power integration, wherein Colombia has a leading role, for it makes regional market interconnection possible: that of the Andean Community of Nations with the Central American market, boosted by SIEPAC project.

1.2 ECONOMIC INDICATORS

1.2.1 Economic growth

At the end of 2003 the Gross Domestic Product showed an annual growth of 3.74% in real terms as compared to the immediately prior year, this being the highest in the last five years as shown in Chart 1-1. In current values, the GDP reached Col$ 223.2 trillion[1]. Such an indicator exceeded the macroeconomic projections budget designed as part of the 2002-2006 National Development Plan, which was set at annual 2.0%.

Chart 1-1. GDP Growth

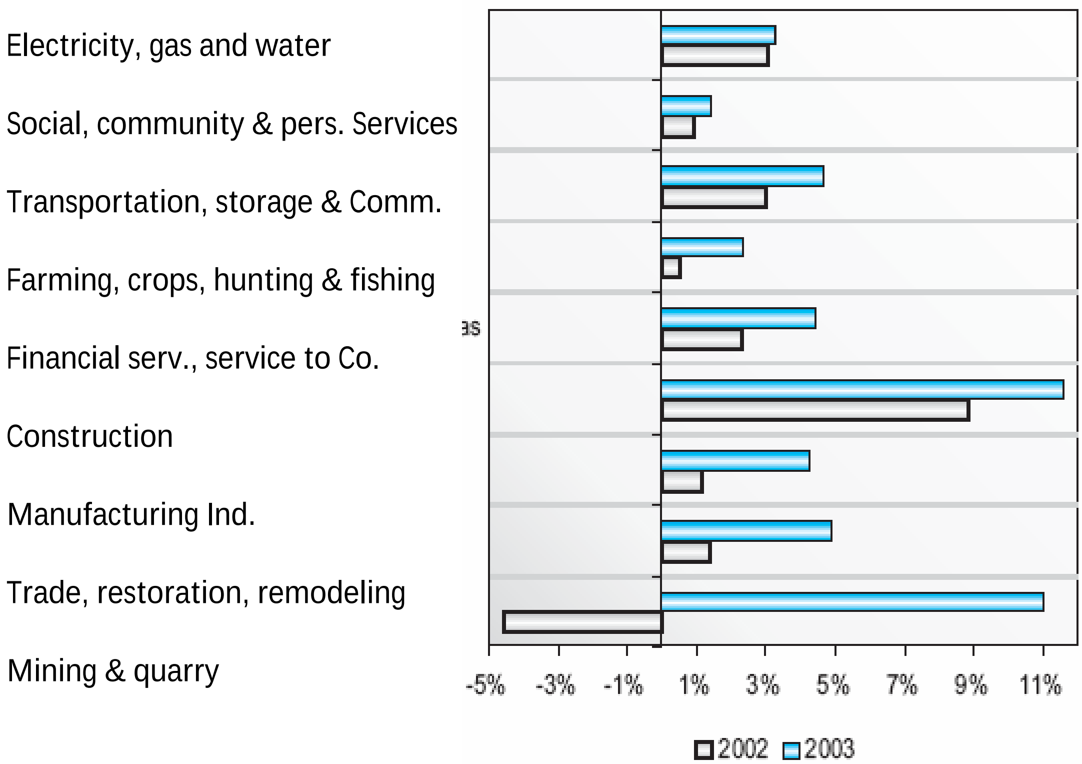


Source: DANE

[1] 2003 GDP, in 1994 constant peso,s is equivalent to 79,4 trillion

It is highlighted that all national economic activities grew during the 2002 to 2003 period, as shown in Chart 1-2. The activities with the more important growth during this period are construction (11,6%), exploitation of mines and quarries (11%) and import duties and charges (10,3%); other activities such as trade, transportation, communications, insurance and manufacturing showed moderate growth, between 4,2% and 4,9%. On the other hand, the aggregated of electricity, gas and water showed a 3,3% growth as compared with 2002, while agriculture and livestock, forestry, hunting and fishing grew by 2,4%.

Chart 1-2. Economic Activities

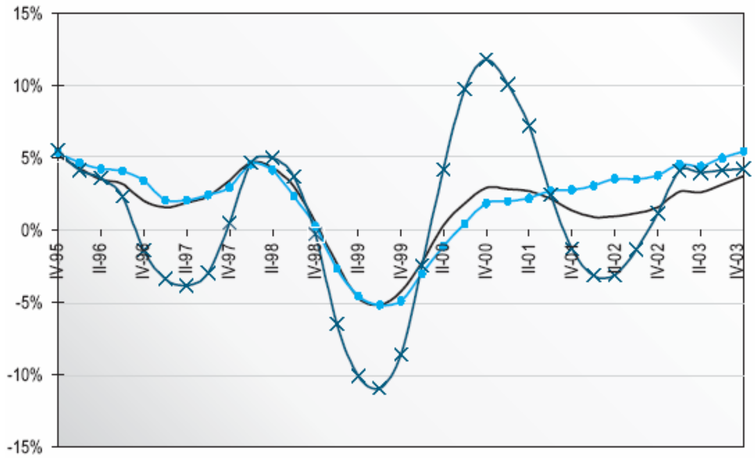


Exploitation of mines and quarries had the most important recovery in the GDP annual variation, going from -4,6% in 2002 to +11,0 in 2003, while the electricity, gas and water activity showed the lowest variation, going from 3,0% to 3,3%

The activities that contributed the most to the GDP in 2003 are, orderly, social, community and personal services, with a participation of 20.4%; financial institutions, insurance, real estate and services to companies, with 17.2%; manufacturing with a participation of 14.04%; and agriculture and livestock, forestry, hunting and fishing with 13.9%. On the contrary, the electricity, gas and water sector contributed the least to the GDP with 3.16%

Chart 1-3 compares the annual variation of GDP and electricity, gas and water sectors, against an electrical-intensive sector such as manufacturing. It can be noted that there is a strong correlation between GDP and electricity, gas and water sector, and that manufacturing greatly influences the behavior of GDP, being it comparable to the behavior of its economic cycles.

Chart 1-3. GDP and Power Sectors



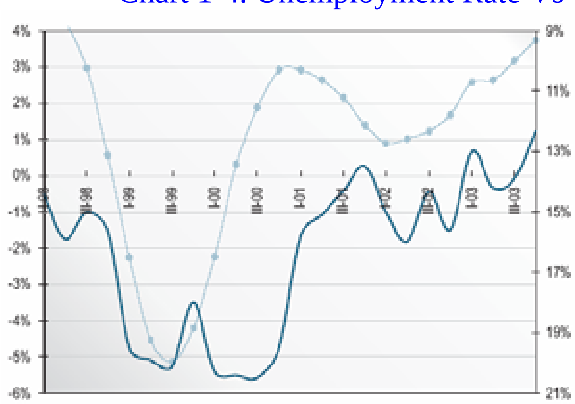
GDP --,>- Electricity, Gas and Water --X- Manufacturing

Source: DANE

1.2.2 Unemployment Rate

As shown in Chart 1-4 the unemployment rate at the national level decreased from 20.5% during the third quarter of 2000 to 12.3% at the end of 2003, being it worth mentioning that the methodology applied to make this calculation was changed. Unemployment rate in the thirteen main cities reached 14.7% of the economically active population during the fourth quarter of 2003.

Chart 1-4. Unemployment Rate Vs GDP



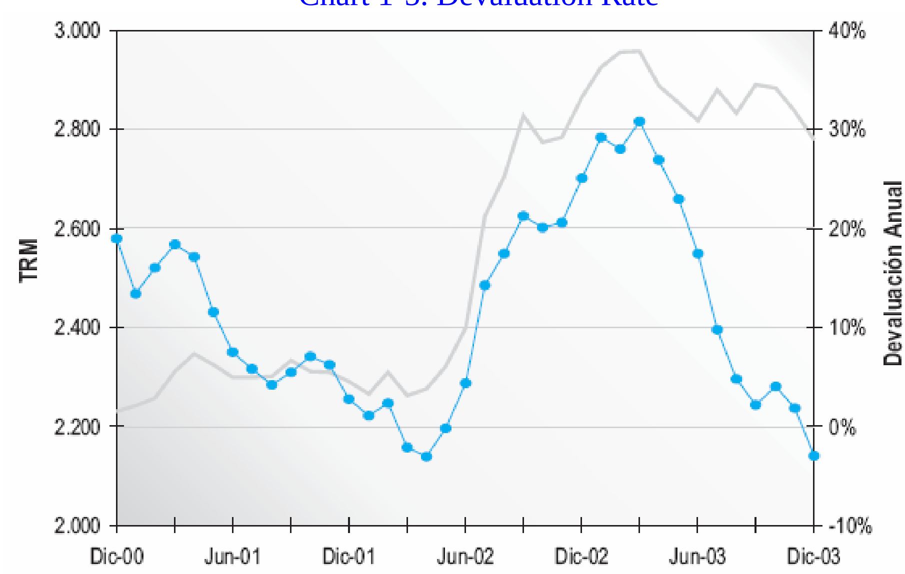
Source: DANE

Even though during the last two years the unemployment has shown an oscillating behavior, its trend is to decrease following the registered GDP increase behavior

1.2.3 Devaluation Rate

As shown in Chart 1-5, as from May 2002 and up to the first quarter of 2003, the local currency is heavily devalued as compared to the US dollar reaching 30.8% devaluation by March 2003 and a RMER (representative market exchange rate) of 2,958.25. As from that moment, the Colombian peso has been revalued to the dollar reaching Col$2,278.21 in December 2003 which is equivalent to an annual devaluation rate of minus three percent (-3%)

Chart 1-5. Devaluation Rate



RMER -w- Annual Devaluation

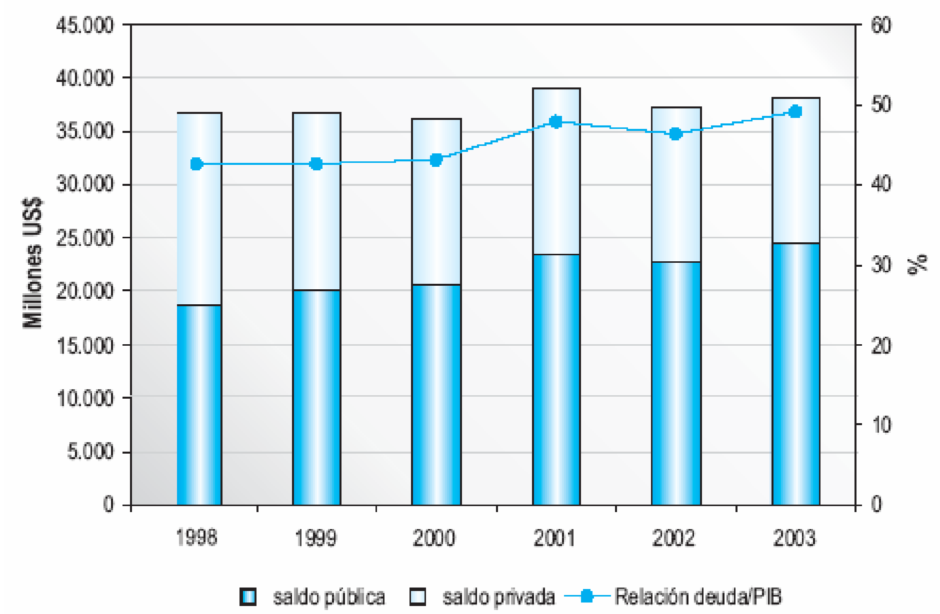
Source: DANE

1.2.4 Foreign Debt

Foreign debt increased from US$36,681 million in 1998 to US$38,163 million in 2003 as shown in Chart 1-6. This increase represents a variation of US$1,482 million during the period, or a 4% increase as compared to 1998 foreign debt; however, the Debt/GDP ratio shows a significant variation moving from 42.6% in 1998 to 49.2% in 2003.

During the last six years, the private debt component as regards the foreign debt total balance has decreased from 48.7% to 35.7%, which means that the public debt has increased from 51.8% in 1998 to 64.2% in 2003.

Chart 1-6. Foreign Debt

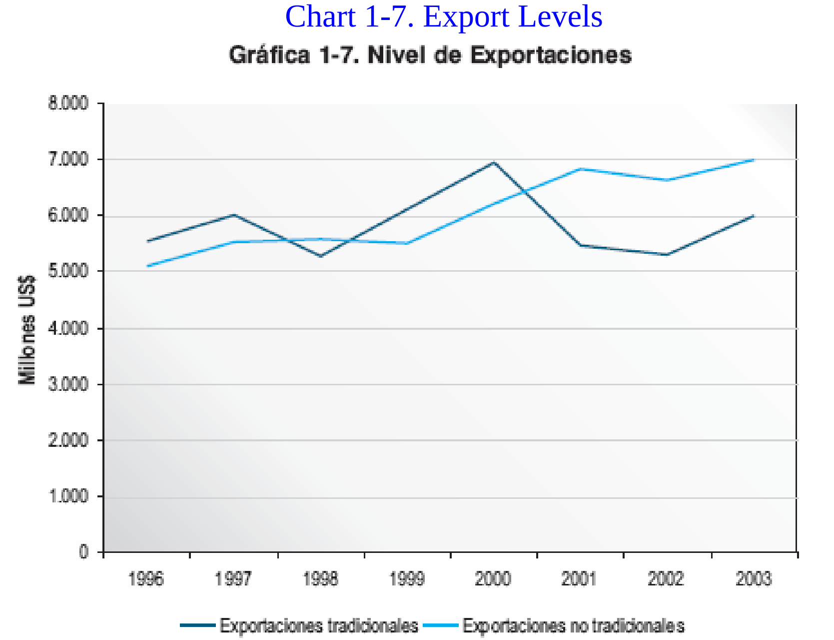


Source: DANE

1.3 FOREIGN SECTOR

As from 2000, traditional exports have declined, moving back to 1998 values as shown in Chart 1-7.

Chart 1-7. Export Levels



(Traditional Exports – Non-traditional Exports)

Source: DANE

Diagnostics

2. Diagnotics

2.1 INSTALLED CAPACITY

The effective net installed capacity of the national interconnection system as of December 31, 2003 was 13,200 MW, out of which 12,847 MW (or 97.32%) are centralized dispatches and 353 MW (or 2.68%) are non-centralized dispatches.

Out of the effective net capacity centrally dispatched 8,549 MW (or 66.54%) come from hydroelectric power stations, 3,606 (or 28.07%) from plants on natural gas and 692 MW (or 5.38%) from plants on coal.

Out of the effective net capacity not centrally dispatched 299 MW (or 84.70%) come from hydroelectric power stations, 35 MW (or 9.91%) from plants on natural gas and 19 MW (or 5.39%) from joint sources of energy and auto-generators.

2.1.1 Availability of electricity generating plants

Daily average availability of electricity generating plants in 2003 was 12,994.2 MW, of which 9,729.74 MW came from plants with centralized dispatches and 3,264.46 from plants not centrally dispatched.

Minimum availability in 2003 was 10,881.830 MW which took place in April 2003 and maximum was 12,985.720 MW in January 2003.

2.1.2 Availability of hydric resources

Total contributions during 2003 amounted to 47,442.6 GWh, being February and July the months with the lowest and highest level of medium contributions (1,941.5 GWh and 5,452.6 GWh, respectively).

Chart 2-1 shows the level of contributions corresponding to the historical average for years 1992, 1998 and 2003. As it can be noted, 2003 historical average contributions were higher than those for 1992 and higher than those for the first half of 1998.

Aggregate reservoir level at the end of December 2003 was13,188.2 GWh, that is to say 80.71% of its maximum capacity. Reservoir maximum and minimum levels were reached during March and November at 46.53% and 83.62% of its full capacity2, respectively. Chart 2-2 shows the evolution of reservoirs for 1992, 1998 and 2003.
2 During the months January to July the maximum reservoir capacity was 15,892.9 GWh

Chart 2-1. Evolution of hydric contribution

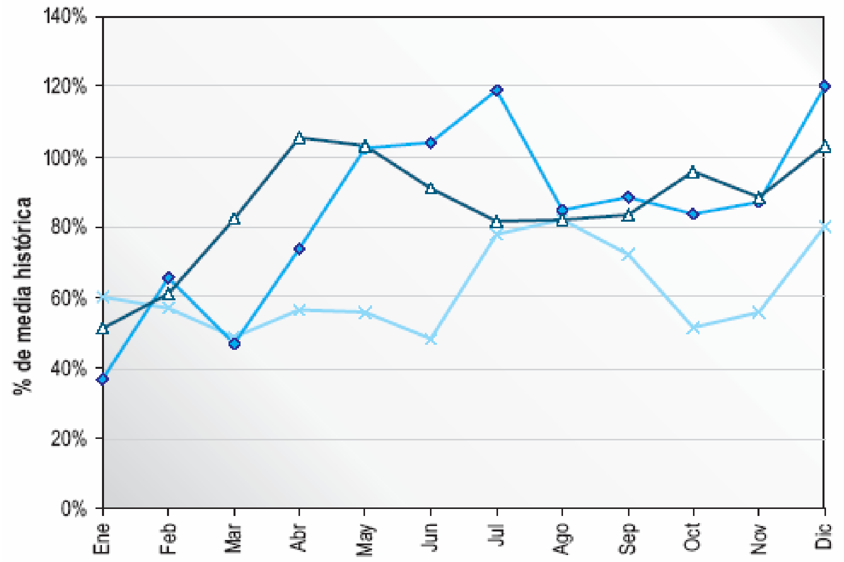
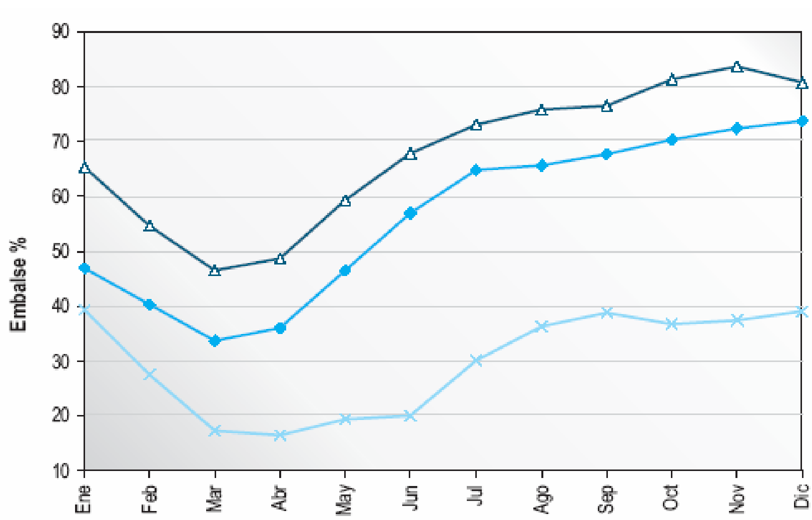


Chart 2-2. Evolution of aggregate reservoir



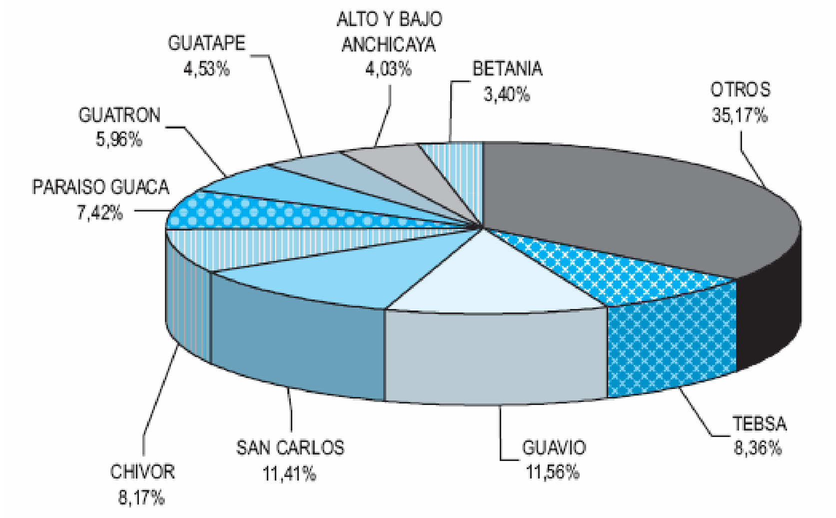
The flows at the various system reservoirs amounted to 472.14 million M3, being Betania the reservoir with the largest flows.

2.1.3 Generation of electric energy

During 2003 the National Interconnected System generated3 46,734.19 GWh exclusive of OXY's generation or electric energy international transfers. Out of such generation, 76.9% came for hydric resources, 14.5% from natural gas operated plants, 5.7% from coal operated plants, 2.7% from minor plants and the remaining 0.2% from auto-generators and joint-generators.

The plant that most contributed to the generation of electric energy in 2003 was Guavio, which generated 11.6% of system's generation, followed by San Carlos plant with 11.41% and Tebsa with 8.36%. Out of these plants' generation, only Tebsa generated a large amount of energy via restrictions, whilst the other plants did on their own. Chart 2-3 shows the percentage participation of plants as regards electric energy generation in 2003.

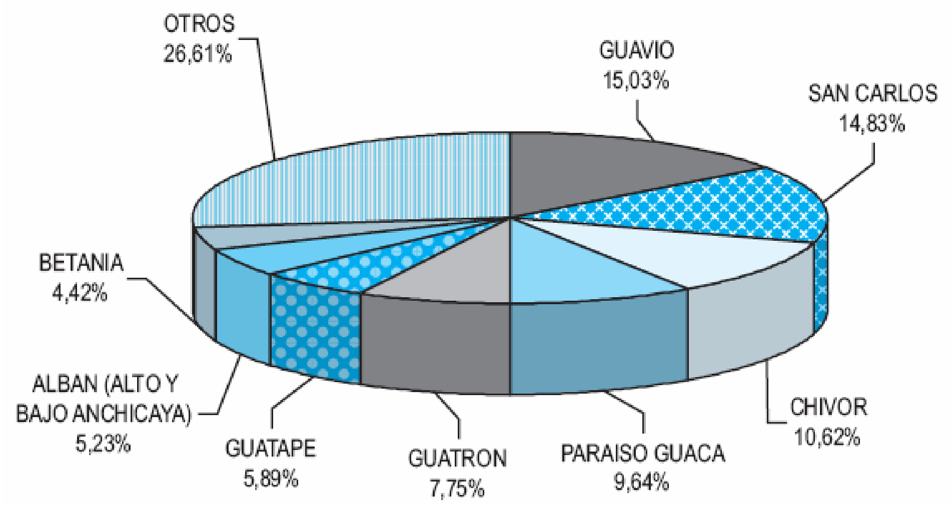
Chart 2-3. Plant contribution to electric energy generation in 2003



2.1.3.1 Hydraulic Plants

Power generated with hydraulic resources was 35,958.19 GWh, of which Guavio participated with 15% followed by San Carlos and Chivor plants with 14.8% and 10.6%, respectively. A large portion of hydraulic generation corresponds to plants with high dispatch levels. Chart 2-4 shows the generation percentage of the various hydraulic generation plants in 2003.

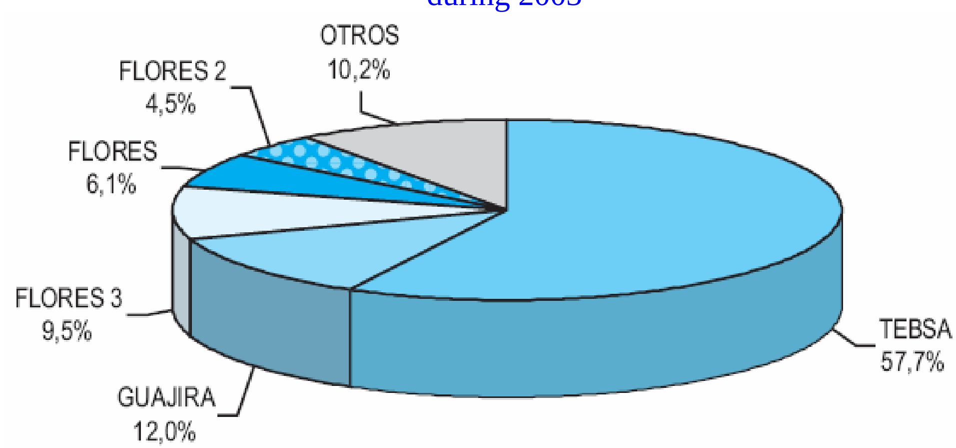
Chart 2-4. Participation percentage in hydraulic plant generation in 2003



2.1.3.2 Natural Gas

During 2003 the generation of electric energy from natural gas operated plants was 6.769.93 GWh, out of which 57.7% was served by Tebsa plant, 6.1% by Flores 1 plant, 9.5% by Flores 3 plant and 12% by Termoguajira. Chart 2-5 shows the participation of various natural gas operated plants in the generation during 2003.

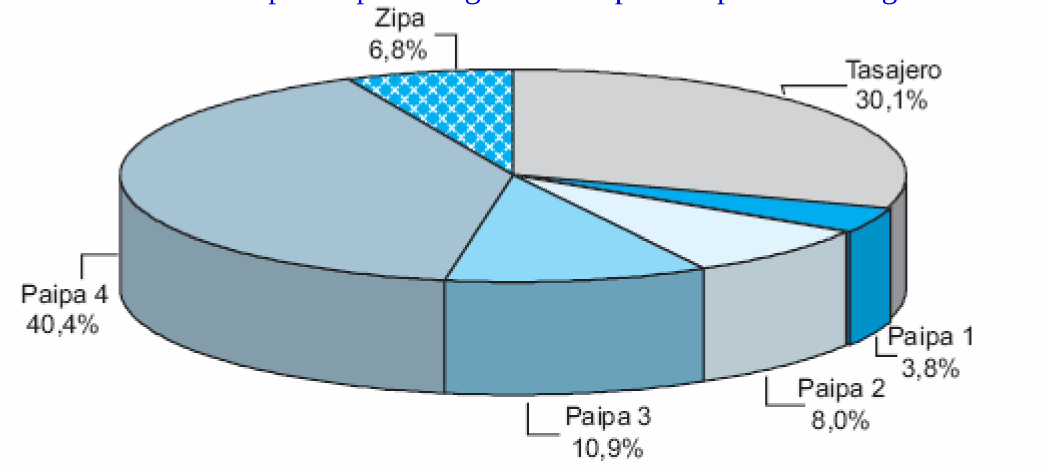
Chart 2-5. Participation percentage of natural gas operated plants in the generation during 2003



2.1.3.3 Coal

During 2003 the generation from coal operated plants was2.631,8 GWh, out of which 40.4% was served by Paipa 4, 30.1% by Tasajero plant and 10.9% by Paipa 3. Chart 2-6 shows the participation of the various coal operated plants in the generation of power.

Chart 2-6. Participation percentage of coal operated plants in the generation during 2003



2.2.1 Description of the National Transmission System

Actual National Transmission System (NTS) is made of a network comprising 10,999 km at 230 kV and 1,449 km at 500 kV, of which ISA owns 68.5%. NTS's transformation capacity is around 3960 MVA and transformation capacity at Network Operators' connection points with the NTS is 12031 MVA.

2.2.2 Expansion of the National Transmission System

Colombia –Ecuador interconnection operation was implemented in 2003 by means of a double circuit between Jamondino 230 kV (Colombia) and Pomasqui 230 kV (Ecuador) substations. Colombian portion is owned by ISA and has a length of 75 kms.

On the other hand, during 2003 a public bid screening process was carried out to perform the following projects: Costa 500 kV, Bogotá 500 kV, compensation 75 MVAr in Northeast substation 115kV and compensation 60 MVAr in Cúcuta 115 kV.

Bogotá and Costa 500 kV were awarded to ISA with a joint proposal of 294.8 MUS$. Compensations in Bogotá and Cúcuta were awarded to EEB with proposals of 0.85 MUS$ and 1.65 MUS$, respectively.

Additionally, UPME issued its opinion on connection researches as shown in Table 2-1.

Table 2-1. Connection opinions

Connection Site	Typer of Project	Description	Connection site Owner	Connection site Applicant	Concept date
S/E Tunal 230 Kv	Reliability Bogotá area	Connection of Tunal 230/115 kV-168MVA third transformer	EEB	CODENSA	14/03/2003

S/E Canoas 115 kV	Generation	Connection of Charquito hydroelectric power plant 19.4MW	CODENSA	EMGESA	27/06/2003
S/E Salto 2 115 kV	Generation	Connection of San Antonio hydroelectric power plant 19.4MW	CODENSA	EMGESA	27/06/2003
S/E Laguneta 115 kV	Generation	Connection of El Limonar hydroelectric power plant 18MW	CODENSA	EMGESA	08/10/2003
S/E Colegio 115 kV	Generation	Connection of La tinta hydroelectric power plant 19.4MW	CODENSA	EMGESA	22/10/2003
S/E Candelaria 220 kV	Generation	Expansion of the capacity assigned to Termocandelaria, from 300 MW to 314MW	TERMOCANDELARIA	TERMOCANDELARIA	23/10/2003
S/E Salto 1 115 kV	Generation	Connection of Tequendama hydroelectric power plant 19.4MW	CODENSA	EMGESA	31/10/2003
S/E Cartagena 220 kV	Generation	Expansion of the capacity assigned to Termocartagena, from 178 MW to 187 MW.	TRANSELCA	TERMOCARTAGENA	31/10/2003
S/E Cuestecitas 220 kV	Generation	Connection of Jepirachi eolian power plant 19.5MW	TRANSELCA	CARBONES DEL CERREJON LLC	31/10/2003
S/E Caño Limón 230 Kv	Demand	Increased demand. Instalation new	ISA	OXY	19/12/2003

		50 MVA transformer and OXY auto-generation capacityexpansion			
S/E Reforma 220 kV	Reliability Meta area	150 MVA Transformation expansion at Reforma Substation	ISA	EMSA	19/12/2003
S/E Paipa 230 kV	Reliabiility Boyacá area	Paipa 230/115 kV-180MVA transformer connection	EBSA	EBSA	10/02/2004
S/E Flores 110 kV	Generation	Expansion of the capacity assigned to Flores 2, from 100MWa to 112MW	TERMOFLORES	TERMOFLORES	18/03/2004
S/E Flores 220 kV	Generation	Expansion of the capacity assigned to Flores 3, from 150MW to 175MW	TERMOFLORES	TERMOFLORES	18/03/2004
S/E Yopal 115 kV	Generation	Conexión de la planta Termoyopal 46MW	EBSA	TERMOYOPAL	03/05/2004
S/E Comuneros 230 kV	Generation	Expansion of the capacity assigned to Meriléctrica from 154.5 MW to 186.5MW	ISA	MERILÉCTRICA	07/07/2004

Table 2-2 shows UPME opinions issued in application of Resolution CREG 082 of 2002, which sets forth that "wherever new assets using tension 4 or NTS connection assets become operative during the tariff period, the annual cost arising from the use of tension 4 level assets or the annual cost of NTS connection assets may be reviewed by the commission, under the following conditions:

That NTS connection projects have been approved by the UPME and the relevant connection agreement has been executed, in compliance with legal regulations in force…"

That the projects related with assets using Tension 4 Level, requested by an OR, have been approved by the UPME.

Table 2-2. New Assets Using Level 4

Project Description	Connection Site Owner	Approval Applicant	Concept date
Connection Tunal third transformer. 230/115KV-168 MVA	EEB	CODENSA	10/06/2003
Connection Paipa transformer 230/115 kV - 180 MVA	EBSA	EBSA	10/02/2004
Construction of 115 kV La Insula substation. .	CENS	CENS	11/03/2004
Construction of 115 kV Paipa - Tunja - Chiquinquirá line	EBSA	EBSA	03/05/2004

2.2.3 NTS regulated income

Commercializing agencies paid 837. 5 thousand million Colombian pesos at June 2004 value in respect of the NTS Regulated Income. Such value was paid in monthly installments averaging 69.8 thousand million Colombian pesos.

Chart 2-7 shows the net Regulated Income flow4 in respect of NTS and the monthly compensation variance arising from the non-availability of NTS assets.

Additionally, the chart shows that the level of compensations arising from the non-availability of NTS assets increased to 0.060% of Regulated Income during May 2004. Table 2-3 shows the proportion in which Regulated Income is distributed among the various national transmitters.

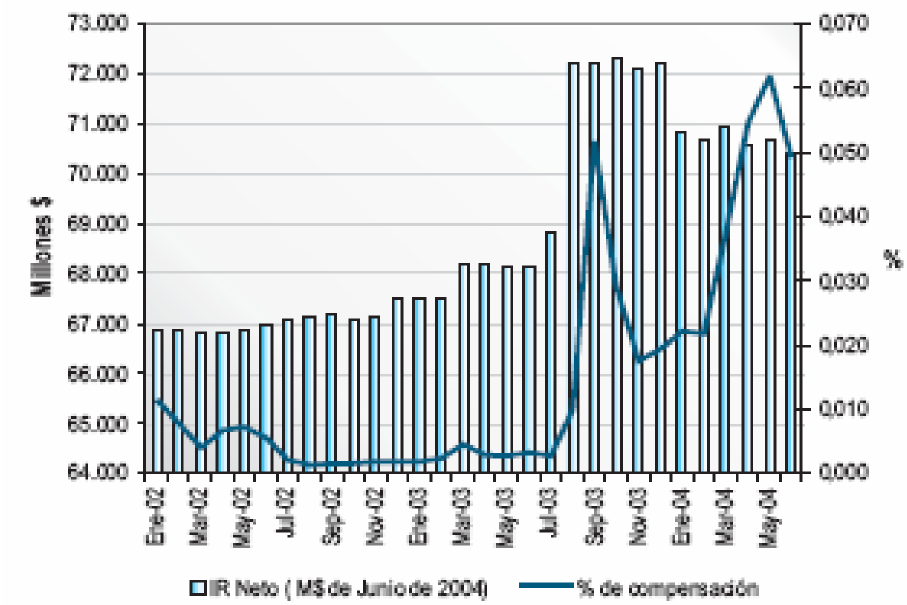


Table 2-3 . Distribution of Regulated Income among National Transmitters

National transmitting Agent	Participation Percentage
CENS	0,2
CHB	0,3
CORELCA	0,3
DISTASA	0,4
EBSA	0,2
EEB	7,3
EEPPM	7,9
EPSA	3,1
ESSA	1,5
ISA	68,5
TRANSELCA	10,3

2.3 DISTRIBUTION – COMMERCIALIZATION OF ELECTRIC ENERGY

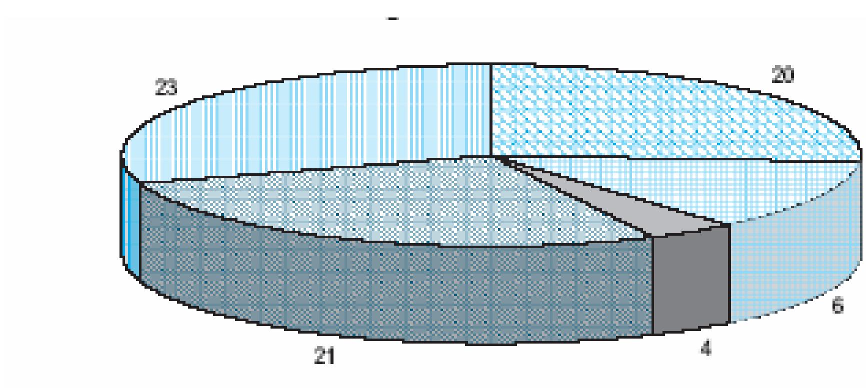
Below there is a general description of the market being operated by the largest companies which simultaneously commercialize and distribute electric energy, as part of the National Interconnected System.

As part of the National Interconnected System there are approximately 30 companies which simultaneously perform commercialization and distribution activities. Coverage areas of the various electrification companies in principle arise from the country's political division, which in most cases relate to departmental divisions, however there are some regional companies covering various departments e.g. the electrification companies serving the northern (Caribbean) region

There are companies serving highly concentrated markets, with majority of urban users, being the most important those serving the cities of Bogotá, Cali and Medellín. Most of departmental and regional electrification companies have medium market concentration levels, combining high market concentration urban areas and high dispersion rural areas. Some distribution companies serve low concentration markets as is the case for those providing power to Chocó and Caquetá Departments and to the Southern region of the country.

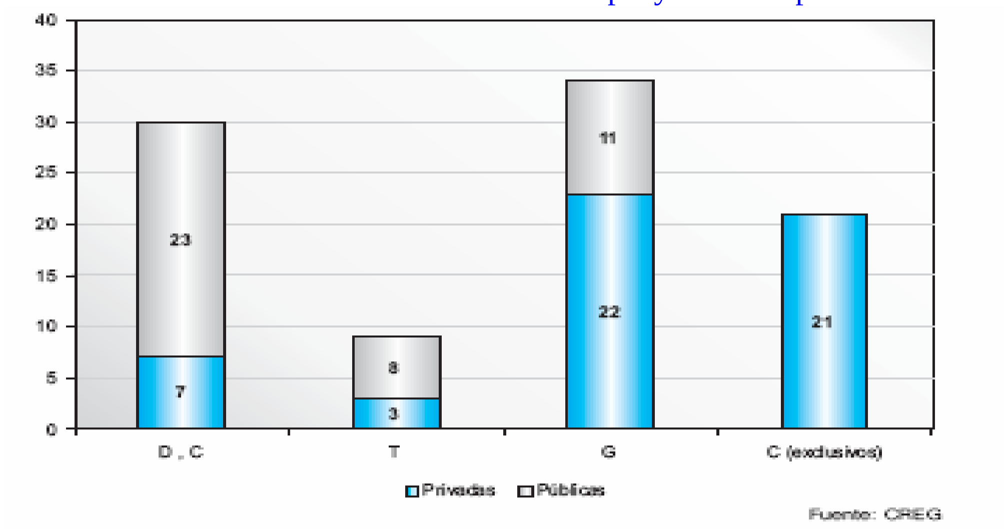
Electricity Law (143 of 1994) allows independently performing electric energy commercialization activities and provides that such companies incorporated after this Law coming into force cannot carry out more than one activity, except that the commercializing companies may simultaneously carry out other activity, namely generation or distribution. Companies incorporated prior to the law coming into effect are allowed to vertically integrate their activities.Out of a group of 30 distribution-commercialization companies operating in the NIS, 7 are private companies and the remaining 23 are public companies, 10 carry out generation activities simultaneously and there are four companies, ESSA, EBSA, EPSA y EEPPM, which have vertically integrated all four activities: generation, transmission, distribution and commercialization.

Chart 2-8 Vertical integration of activities



11 transmitters operate in total, out of which three are private companies and the remaining are public companies. Out of 33 generating companies, 22 are private companies and 11 are public companies. Companies exclusively devoted to commercialization are all private.

Chart 2-9 Company ownership



C (exclusive) Source: CREG

Distribution – Commercialization companies are grouped in the following six zones:

Table 2-4 Companies grouped by zone

Area	Companies
Caribe	Electrificadora de la Costa Atlántica Electrificadora del Caribe
Andina Norte	Centrales Eléctricas de Norte de Santander Electrificadora de Santander Empresa de Energía de Arauca Empresa de Energía de Boyacá
Andina centro	Empresa de Energía de Cundinamarca Codensa Electrificadora del Tolima Electrificadora del Huila Electrificadora del Meta Electrificadora del Caquetá
Viejo Caldas	Central Hydroelectric de Caldas Empresa de Energía de Pereira Empresa de Energía del Quindio
Antioquia and Chocó	Empresa Antioqueña de Energía Empresas Públicas de Medellín Distribuidora del Pacífico
Andina South	Empresas Municipales de Cali Empresa de Energía del Pacífico Empresas Municipales de Cartago Compañía de Electricidad de Tulua Centrales Eléctricas del Cauca

	Centrales Eléctricas de Nariño Empresas Municipales de Energía Eléctrica Empresa de Energía del PutuMay Empresa de Energía del Valle del Sibundoy Empresa de Energía del Low PutuMay

The number of regulated users located in the National Interconnected System in 2003 amounted to approximately 8.8 million, of which 91.6% were residential users, 6.8% were commercial users, 0.8% were industrial users and the remaining percentage were distributed among official, special charges and street lightning.

Table 2-5 Number of regulated users by sector

Regulated Users by Sector		(%)
RESIDENTIAL	8.095.057	91,6%
COMMERCIAL	603.362	6,8%
INDUSTRIAL	72.963	0,8%
OFFICIAL	58.268	0,7%
OTHERS	2.970	0,03%
TOTAL USERS	**8.832.620**	**100,0%**

The distribution of the residential sector by social strata can be seen in Chart 2-10. Total strata 1 and 2 users represent approximately 62% of total users, whilst strata 5 and 6 users are approximately 5%.

Chart 2-10 Percentage distribution of residential users by social strata

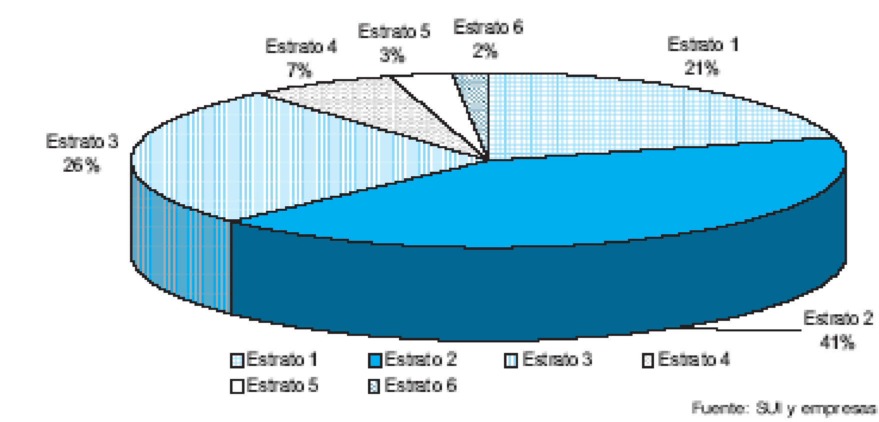
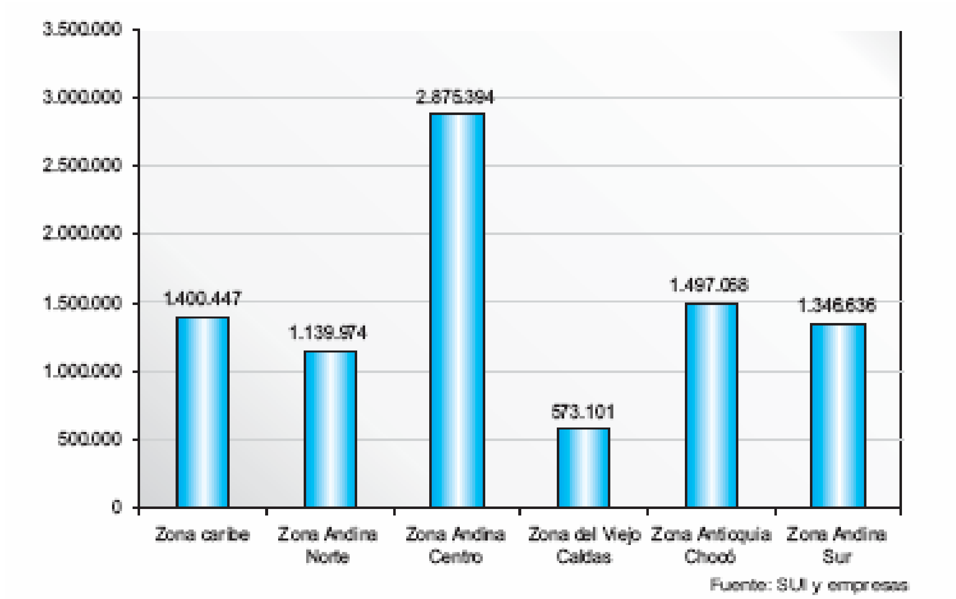


Chart 2-11 shows the approximate distribution of regulated users by region. The Andean Central region concentrates approximately 32.6% of total SIN's regulated users, followed by Antioquia-Chocó region with 16.9% and the Caribbean region with 15.9%.

Chart 2-11 Regulated users by region



Power consumption of regulated users of the largest distribution companies connected to the NIS in 2003 amounted approximately to 24 TWh- year, distributed pursuant to Table 2-6.

Table 2-6 Consumption (GWh – year) regulated users (2003)

Consumption billed per sector- **Regulated user**		
	(GWh-year)	%
Nation Interconnected System		
Total	24.032	100,0%
RESIDENTIAL	14.016	58,3%
COMMERCIAL	4.381	18,2%
INDUSTRIAL	3.587	14,9%
OFFICIAL	1.230	5,1%
OTHERS	818	3,4%

Out of this consumption, the region with the highest participation is the Andean Central region, representing 27.3% of the total, followed by Caribbean and Antioquia-Chocó regions with 22.8% and 17%, respectively. Andeal South region represents 16.3%, Andean North 10.7% and Viejo Caldas 6.1%

Tariff aspects are ruled by laws 142 and 143 of 1994 and the National Political Constitution, which section 367 provides that it is a duty of the Law to set forth the competencies and responsibilities relevant to the provision of public services and to determine the tariffs, on the grounds of efficiency, neutrality, solidarity and income redistribution, financial self-satisfaction, simplicity and public accountability principles.

Pursuant to legal regulations in force, the charges for using the regional transmission system and local distribution are in effect for five years. Regulatory frame for the present tariff period was defined by resolution CREG 082 of 2002.

Regulations define tour tension levels at a distribution level, as follows: level I, less than 1 kV; level II, equal or higher than 1 kV and lower than 30 kV; level III equal or higher than 30 kV and lower than 57.5 kV; and level IV, for tensions equal or higher than 57.5 kV and lower than 220 kV. Tariff applied at a distribution level remunerates for replacement-to-new costs of distribution assets as from constructive unit costs plus AOM costs and recognized losses.

The methodology to define the tariff applicable on regulated users depends on the tension level of the connection. Level IV tariff is defined as a stamp charge that remunerates an efficient infrastructure at a regional level. Levels II and III tariff is calculated as from the replacement to brand new of the assets of each particular distributor and by applying an efficiency marking at a national level. Level I tariff is determined from valuating an ideal network. The difference in valuation of rural and urban networks and aerial and underground networks is acknowledged during the actual tariff period

Discount rate granted to remunerate investments is 14.06% before taxes for tension IV level assets, and 16.06% before taxes for lower tension level assets. hart 2-13 shows the behavior of the average Unit Cost (UC) for tension I level during 2003 (annual variation 14%) and the variation of the various tariff elements. It can be noted that along 2003 elements G and T had increases of 12%. Elements D and C varied by 16% and 5.8%, respectively. The element with the highest growth in percentage terms was “other charges” with 37%, moving from 7040 $/kWh in January to 10.16 $/kWh
For both Caribbean region electrification companies the UC is similar and close to the national average. In the Andean North region, the UC approved for CENS is 18% lower than EBSA’s . In the Andean Central region extreme UCs are those of CODENSA and EEC with a 42% difference. In the Antioquia-Chocó region, EPM’s UC is 35% lower than EADE’s. In Andean South region the difference in percentage terms between the lowest UC (EPSA) and the highest UC (CEDELCA) is 58.4%
Chart 2-15 shows the average UC at the end of 2003 in each of the regions. As an average, the Andean North region had the highest tariff at the end of 2003 with an UC of 264.32 $/kWh; on the contrary, Antioquia-Chocó region had the lowest UC among all the regions under study, at 211 $/kWh. The same chart shows the composition of unit costs at the end of 2003 for each of the regions under consideration.

As an average, the charge for using distribution networks is approximately 37.8% of the UC for tension I level; the generation element (including acknowledged losses) is 39.2%;

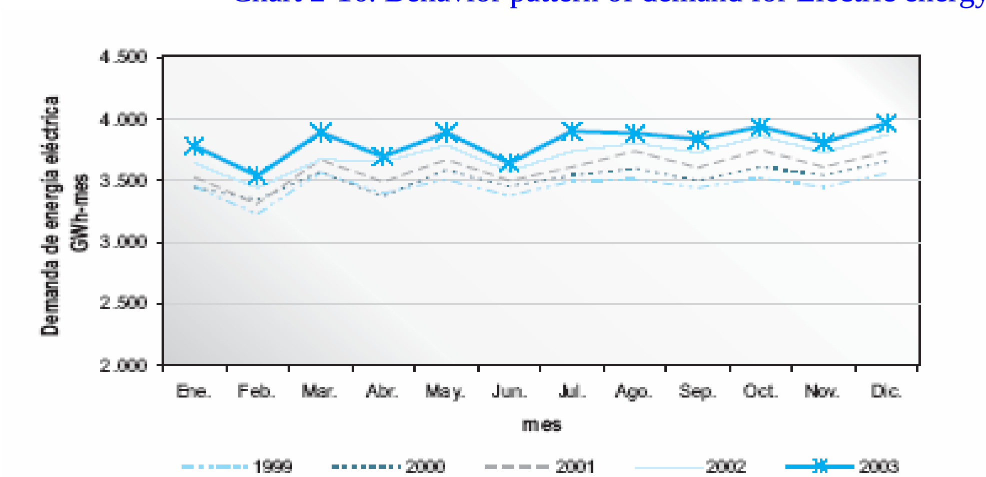
transmission (losses included) aresent 9.2nd commercialization elements rep% and 9.4% and other charges element is 4.4%.

2.4 EVOLUTION OF ELECTRIC ENERGY DEMAND IN 2003

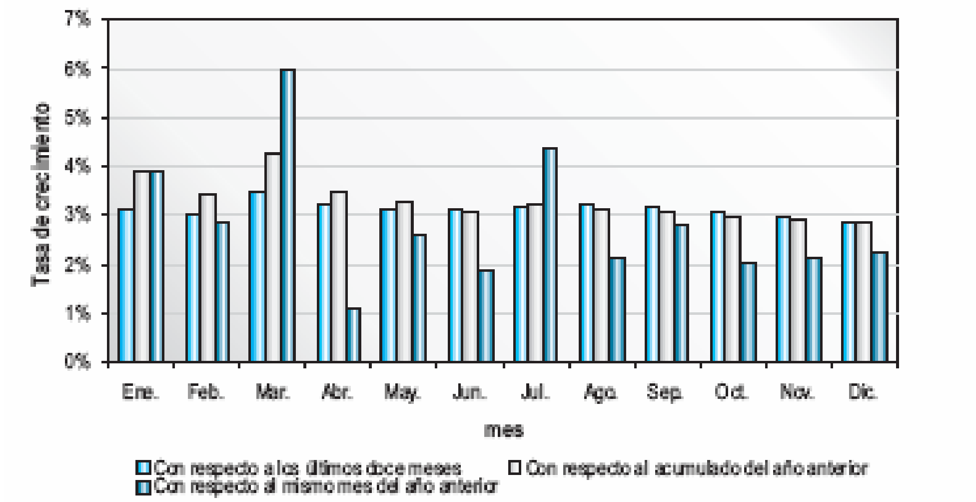
During 2003 demand amounted to 45771 GWh, equivalent to a 2.8% growth as compared to 2002.The relevant monthly behavior of demand is shown in table 2-7 and Chart 2-16

Month	Energy (GWh)
January	3783,0
February	3538,9
March	3891,0
April	3693,8
May	3887,2
June	3642,1
July	3902,6
August	3885,6
September	3833,6
October	3940,2
November	3809,4
December	3963,5
Total	45770,9

Chart 2-16. Behavior pattern of demand for Electric energy



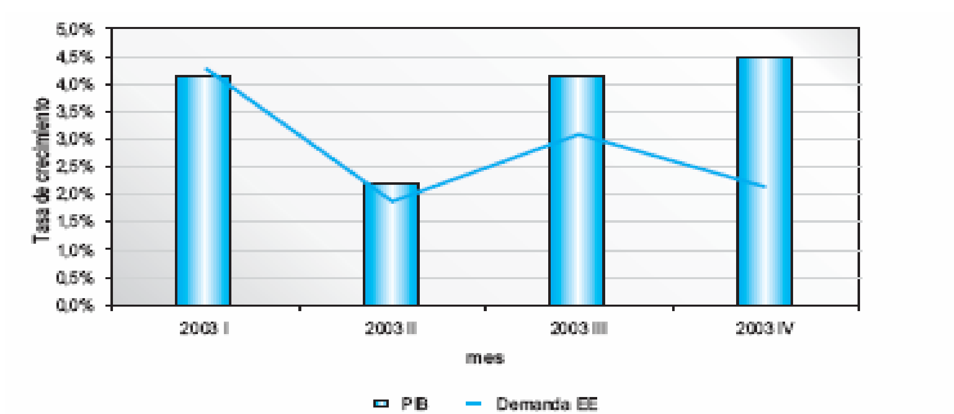
In general it can be noted that the behavior of the demand for electric energy during 2003 is similar to the historical record as shown in Chart 2-17



If the evolution of monthly demand were to be analyzed on the grounds of growth rates, (see Chart 2-17) it is possible to identify some variations as compared to 2002, namely: the effects of the Holy Week which affect the months of March and April; mid-year vacation term which affects the months of June-July combined with the effect of the holidays during those two months (In June 2002 there were 2 holidays and in 2003 there were4, resulting in a lower growth rate, contrary to July which in 2002 had two holidays and none in 2003, resulting in a higher growth rate).

When analyzing the growth trend in annual sales of electric energy and GDP growth rates it can be noted that even if there is a slowing down in the growth of demand during the last quarter of 2003 as compared to the GDP, in general there is a strong co-relation between them. Chart 2-18 shows the trend on a quarterly basis.

Chart 2-18. Evolution of demand for electric energy and GDP



On comparing 2003 predictions to the actual demand for electric energy, even though the behavior of demand tended to be lower that the average scenario expected, table 2-8 shows an important prediction adjustment as regards the average scenario, at all times far below acceptable error. The higher deviation appeared during May, October and December; in the first case mainly due to the effect of terrorist attacks, in October due to election days and in December (which effects blend with those seen for January 2004), due to year-end long weekends and possibly to tourist convoys.

Table 2-8. Deviation of average scenario vs. demand for electric energy

Energy	Prognosys Deviation
January	0,8%
February	0,3%
March	0,4%
April	-0,8%
May	-1,3%
June	-1,0%
July	0,0%
August	-0,8%
September	-0,7%
October	-1,2%
November	-0,5%
December	-2,5%

With all that mentioned above, the prediction average deviation for the average scenario as compared to actual demand proved to be 0.6% higher than actually observed.
As regards power, during 2003 a peak of 8257MW was reached in December which meant a growth of 2.2% as compared to 2002.

Table 2-9 shows the behavior of power demand for 2003; it should be noted that different from 2002 when the peak was reached at 8 p.m., in 2003 it was reached at 7:00 p.m. during the last three months.

Table 2-9. Power behavior (MW) in 2003

Month	Power MW	Date	Period
January	7484	Jueves 30	20
February	7872	Lunes 24	20
March	7704	Martes 4	20
April	7696	Martes 8	20
May	7535	Lunes 5	20
June	7494	Miércoles 25	20
July	7516	Martes 29	20
August	7483	Lunes 11	20
September	7691	Jueves 11	20
October	7786	Martes 7	19
November	7899	Miércoles 19	19
December	8257	Martes 9	19

Proyecciones de Demanda de Energía Eléctrica y Potencia

Electric Energy & Power Demand Forecasts

3. Forecast Demand for Electric Energy and Power

3.1 METHODOLOGY

The behavior of demand for electric energy depends mainly on the macroeconomic trend (GDP), the behavior of tariffs and population growth, being it possible to predict such behavior when relating such variables' historical time series using econometric models. Collision models that allow simulating important investments at a regional level are used to model particular events, and dynamic models are used to take climatic effects such as El Niño into consideration.

The models result in electric energy domestic sales; to obtain the demand for electric energy it is necessary to externally add energy losses at the distribution, sub-transmission and transmission levels. Demand for special industrial charges (OXY, Cerrejón and Cerromatoso) are added as well as other known effects, and in such a way the total domestic demand is obtained.

Up to here annual forecasted demand for energy has been obtained. Historical distributions and a methodology based on ARIMA models and the Best Conditional Forecast, which allows tuning the first prediction year, are used to split it along the twelve months in a year.

Starting from the total monthly domestic demand for electric energy, charge factors are added to each of the months on the grounds of what happened during the last three years, which results in the domestic monthly peak power values that allow defining the annual peak power value.

3.2 MARCH 2004 ASSUMPTIONS

The following are the assumptions applied on the scenario review carried out in March 2004.

3.2.1 GDP

Assumptions used to build the scenarios showing the growth of the Gross Domestic Product –GDP variable have changed as regards those used on the November 2003 review. The National Planning Department (NPD) made official new high, medium and low GDP growth scenarios, among them an optimistic scenario where the country growths at 4.5% and a pessimistic scenario which includes oil production movements. Chart 3-1 and Table 3-1 show such scenarios.

Chart 3-1. GDP growth scenarios

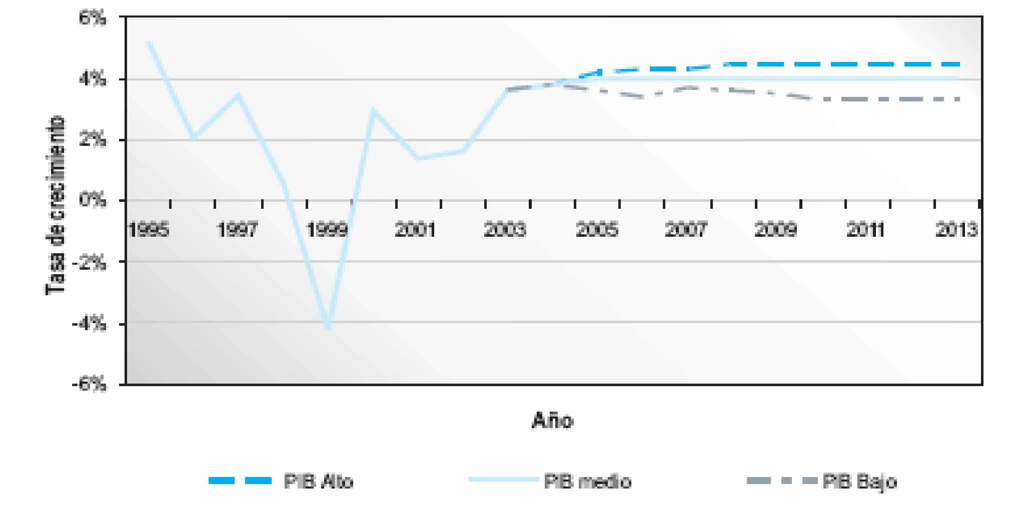


Table 3-1 GDP growth rates

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
GNP High	3,80%	4,20%	4,30%	4,30%	4,50%	4,50%	4,50%	4,50%	4,50%	4,50%
GNP Medium	3,80%	4,00%	4,00%	4,00%	4,00%	4,00%	4,00%	4,00%	4,00%	4,00%
GNP Low	3,80%	3,60%	3,40%	3,70%	3,60%	3,50%	3,30%	3,30%	3,30%	3,30%

It should be noted that for 2004 only one GDP value is available, reason why the short-term model reliability rank was used to build the projection tunnel in 2004.

3.2.2 Loss of Electric Energy in NTS

The loss of electric energy associated with the National Transmission System maintains its historical behavior, reaching an average 2.42% of total forecasted electric energy sales. This value is maintained along the prediction horizon.

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3.2.3 Loss of Electric Energy in the distribution system

The loss of electric energy in the distribution system is the aggregate of technical and non-technical losses incurred in this tension level.

Unique loss scenario is maintained for all prediction scenarios. This scenario was built on the grounds of historical information, data provided by some network operators and assumptions regarding present companies' economic conditions to forecast potential investments in loss recovery plans.

Table 3-2. Percentage of losses applied to the distribution system

Year	Loss
2003	23,7%
2004	23,1%
2005	22,6%
2006	22,1%
2007	21,6%
2008	21,1%
2009	20,6%
2010	20,2%
2011	19,7%
2012	19,7%
2013	19,7%

Such percentages of losses in the distribution systems are applied to the sales values obtained from the models; the remaining values are considered as a recovered demand that become a part of sales lagging behind for one year. Thus it is being considered that the loss recovery of the distribution system is mainly achieved on non-technical losses and that it has relevant effects on the sales for the next year.

.2.4 Special charges

On reason of their particular characteristics, special charges are considered external to the sales projection model and as such are added at the very end. For March 2004 review, the "special charges" used in November 2003 are kept, corresponding to OXY, Cerrejón and Cerromatoso, so for 2004 the expected aggregate of such be 1921 GWh/month and for 2005 1924 GWh/ month, being the latest value maintained along the remaining prediction horizon.

3.3 RESULTS OF THE FORECASTED DEMAND FOR ELECTRIC ENERGY AND POWER

The forecasted demand for electric energy for the period 2204-2013 was obtained on the grounds of the above assumptions, and is shown on Table 3-3 and on Chart 3-2. It should be noted that a long-term demand prediction is included in the Table for the period 2014-2018.

Table 3-3. Forecasted scenarios of demand for electric energy Likewise Table 3-4 shows power growth predictions for each of the scenarios. Also, a long-term 2014-2018 forecast is included as regards potential evolution thereto.

Year	High		Mid		Low	
	GWh-year	**Rate**	**GWh-year**	**Rate**	**GWh-year**	**Rate**
2003	45771		45771		45771	
2004	47556	3,9%	47094	2,9%	46633	1,9%

2005	49378	3,8%	48836	3,7%	48232	3,4%
2006	51288	3,9%	50625	3,7%	49803	3,3%
2007	53260	3,8%	52468	3,6%	51512	3,4%
2008	55490	4,2%	54486	3,8%	53353	3,6%
2009	57554	3,7%	56321	3,4%	54964	3,0%
2010	59817	3,9%	58336	3,6%	56664	3,1%
2011	62160	3,9%	60413	3,6%	58404	3,1%
2012	64693	4,1%	62661	3,7%	60291	3,2%
2013	67056	3,7%	64716	3,3%	61962	2,8%
2014	69731	4,0%	66971	3,5%	63808	3,0%
2015	72598	4,1%	69300	3,5%	65702	3,0%
2016	75236	3,6%	71835	3,7%	67774	3,2%
2017	77995	3,7%	74188	3,3%	69636	2,7%
2018	80995	3,8%	76754	3,5%	71680	2,9%

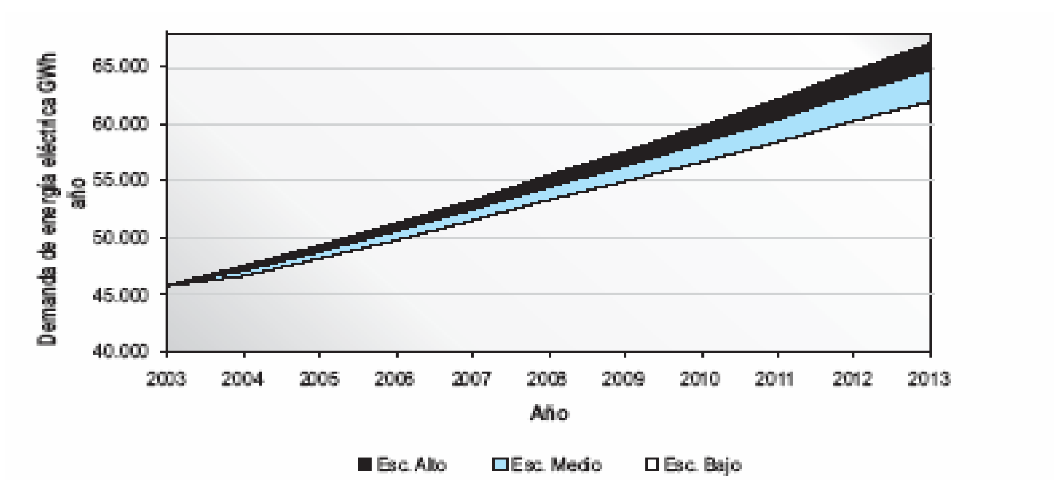


Table 3-4

Year	High		Mid		Low	
	MW	**Rate**	**MW**	**Rate**	**MW**	**Rate**
2003	8257		8257		8257	2.2%
2004	8506	3.0%	8423	2.0%	8341	1.0%
2005	8820	3.7%	8723	3.6%	8616	3.3%
2006	9161	3.9%	9043	3.7%	8896	3.3%
2007	9514	3.8%	9372	3.6%	9201	3.4%
2008	9952	4.6%	9771	4.3%	9568	4.0%
2009	10344	3.9%	10123	3.6%	9879	3.3%
2010	10751	3.9%	10485	3.6%	10184	3.1%
2011	11172	3.9%	10858	3.6%	10497	3.1%
2012	11604	3.9%	11239	3.5%	10813	3.0%

2013	12052	3.9%	11631	3.5%	11136	3.0%
2014	12704	5.4%	12037	3.5%	11468	3.0%
2015	12999	2.3%	12455	3.5%	11809	3.0%
2016	13499	3.8%	12888	3.5%	12158	3.0%
2017	14018	3.8%	13334	3.5%	12516	2.9%
2018	14557	3.8%	13795	3.5%	12883	2.9%

Disponibilidad de Recursos y Proyección de Precios

Resource Availability & Price Forecast

4. Availability of Resources and Pricing forecast

4.1 AVAILABILITY OF RESOURCES 4.1.1 Coal

Measured coal reserves in the country as of 31 December 2003 were 6304. 5 million tons.

Out of measured reserves, 91% (5759.5 million tons) are located on the Atlantic Coast, and 61% of these, that is, 3535.9 million tons are in the department of Guajira.

On the other hand, the reserves in central Colombia reached 614.3 million tons, 9.7% of the national total, with 38% of such concentrated in the department of Cundinamarca.

4.1.2 Natural Gas

25 GPC of commercial gas were added to country's reserves during 2003; however, after deducting period production and pursuant to Resolution 180397 of April 6, 2004 issued by the Ministry of Mines and Energy, Proven Reserves of natural gas as of 31 December 2003 amounted to 4039.5 GPC, 4.4% lower than reserves on the same date of 2002. Such reserves did not include 2296 GPC that correspond to those consumed during the operation and those that fail to have a commercialization program.

4.2 PRICING FORECAST

4.2.1 Coal

Pricing forecast for the coal to be used in coal-powered electric plants all over the country starts with the recollection of coal prices carried out by UPME each year in October by means of which each of the companies having coal-powered thermal plants is requested to provide information on the prices it has paid for the coal used as fuel in order to calculate the Cost by Capacity.

Such pricing forecast considers two scenarios, one called Base scenario and other called High scenario. Figures are shown in constant pesos in both scenarios. The Base scenario does not take any real increase into consideration and consequently its value is the same in all years, while the High scenario considers actual increases which for each case are as follows: Termotasajero 2,80% per year, Termopaipa 2,35% per year, Termozipa 2,21% per year and Termoguajira 2,45% per year.

Prices forecasted as of June 2004 for each of the scenarios are as follows:

Table 4-1. Projection of the annual average purchase price of coal at coal-powered electric plants Base scenario (June $ / Ton)

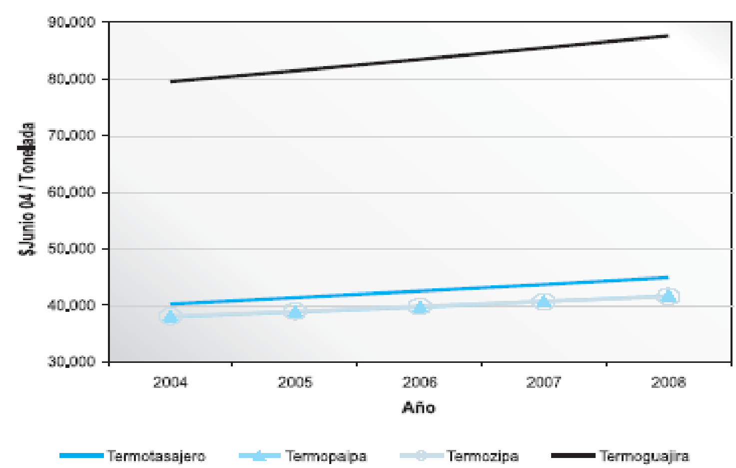
	2004	2005	2006	2007	2008
TermoRatejero	39078	39078	39078	39078	39078
Termopaipa	37033	37033	37033	37033	37033
Termozipa	37218	37218	37218	37218	37218
Termoguajira	77550	77550	77550	77550	77550

Table 4-2. Projection of the annual average purchase price of coal at coal-powered electric plants
High scenario (June /2004 $ / Ton)

	2004	2005	2006	2007	2008
TermoRatejero	40170	41293	42447	43634	44853
Termopaipa	37904	38795	39707	40640	41595
Termozipa	38041	38883	39743	40622	41521
Termoguajira	79452	81401	83397	85443	87538

The following chart shows price projection in the High scenario.

Chart 4-1. Projection of the annual average purchase price of coal at coal-powered electric plants, high scenario



Prices of Colombian coal in the United States during 2004 started at US$49 per ton, maintaining such a price until May, month during which it started increasing to reach US$65 per ton by the end of June. This fast increase of prices resulted from the high demand of coal by China.

4.2.2 Natural Gas

The projection of the highest price for natural gas delivered at thermal plants corresponds to an exercise carried out by the UPME during March 2004. Despite different price scenarios were considered, a decision was made to maintain this high-price scenario since for the purpose of valuating generation system marginal costs as part of the expansion plan, this might be a critical case.

Macroeconomic assumptions applied are those of current year's 26 January scenario, of National Planning Department's Office of Economic Studies.

4.2.2.1 Highest price of natural gas delivered at the entrance gates to transportation systems.

To determine the highest price of natural gas delivered at the entrance gates to transportation systems during forecasted period (2004-2014), two time horizons were considered: from 2004 to 2005 and from 2006 onwards.
2004 – 2005 horizon.
Regulations in force for the first semester of 2004 and highest prices at entrance gates to transportation systems were applied, as follows:

* Resolution CPPGN1 039/75: 1,5288 USD/KPC, final value from February 10, 2004 to August 9, 2004.

* Resolution CPPGN 061/83: (i) 1,866 USD/MBTU, final value for the first semester of 2004, applicable on the North Coast and Mid Magdalena Valley non-associated natural gas. (ii) 2,065 USD/MBTU, final value for the first semester of 2004, applicable on the Eastern and Offshore regions non-associated natural gas.

* Resolution CREG 050/02: 1,405 USD/MBTU, final value for the first semester of 2004.

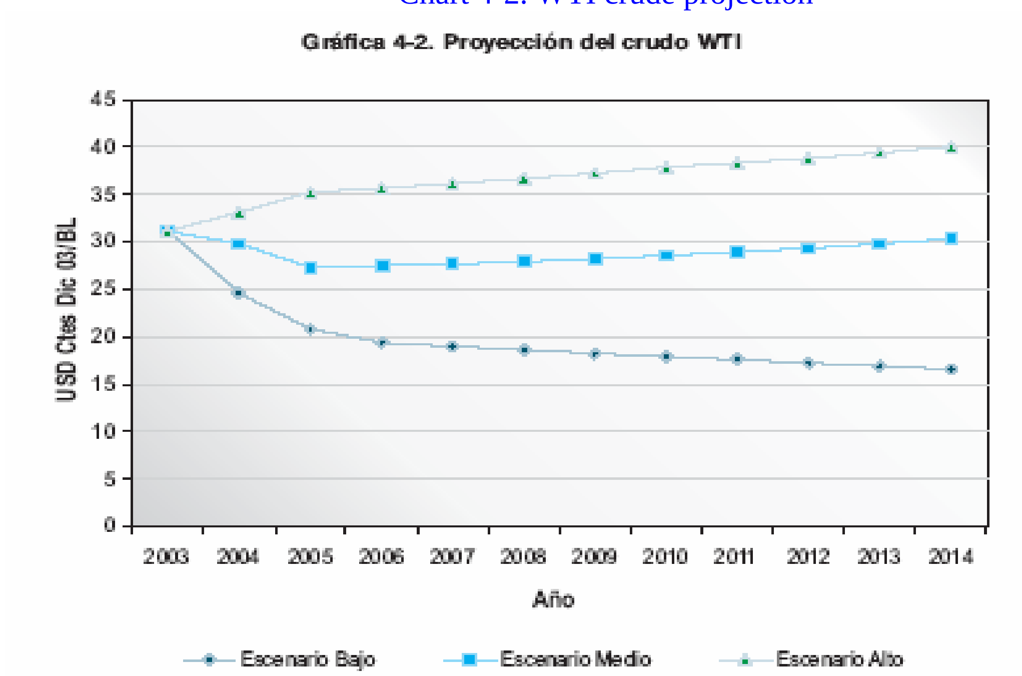
As from the second semester of 2004, and considering that in order to implement the half-yearly pride updating resolutions 039/75 and 061/83 take into account the behavior of the exportation fuel oil price FOB Colombia, an econometric ratio was applied between FOB price and the reference crude oil price (West Texas Intermediate – WTI), so as to reflect the international market variance on the prices.

Consequently it is necessary to set projection scenarios for the WTI reference crude oil.

Being aware of the difficulty of performing such an exercise given that multiple factors have an incidence on the evolution of prices, some of which are non-predictable, it has been decided to use international referents. Considering that information provided by the Energy Information Administration – EIA and the U.S. Department of Energy – DOE is public and can be easily monitored, the UPME uses such agencies medium and high scenarios and low price scenario which source is the CONFIS6. Nevertheless, it should be made clear that there are other outstanding international sources of information which are also valid.

The following chart shows the trends in the reference crude price under the above-mentioned scenarios:

Chart 4-2. WTI crude projection



Low Scenario f Medium Scenario A, High Scenario

The following are some considerations as regards the projections herein: (i) Among other macroeconomic variables, the high scenario considered a U.S. average GDP of 3.5% / year, and a strong penetration in the market of alternative energy sources which might be economically feasible at such crude price levels; (ii) The medium scenario applied a U.S. GDP of 3.0%; and (iii) in the short term all three scenarios projected an increase in the crude supply in international markets resulting from the entrance of additional amounts from Iraq.

2006-onwards horizon.

Due to the actual uncertainty as regards the application of Resolution CREG 023 of 2000, the exercise to set the price of natural gas at the well hole as from 2006 consisted in the application of econometric models on the WTI price projections to find export Fuel Oil values and, by applying regulations in force, a country-average price was determined for the natural gas at the well hole.

4.2.2.2 Highest price of natural gas delivered at the entrance gates to transportation systems

Resolutions in force issued by the CREG and applicable to gas pipelines of interest upon performing this exercise were taken into consideration to determine the highest transportation price via gas pipeline:

- Resolution Creg 070/03: By means of which a decision is made on the request to review Regulated Charges of Promigas S.A. ESP's Transportation System.

- Resolution Creg 0125/04: By means of which a decision is made as regards Motions to Dismiss filed against Resolution CREG 013 of 2003 (Regulated charges for Ecogás transportation system)

- Resolution Creg 076/02: By means of which regulated charges for Cusiana-El Porvenir gas pipeline are set.

- Resolution Creg 016/01: By means of which regulated charges for Transoriente transportation system are set.

Assumption was made, additionally, of a pair of regulated charges, fixed charge / variable charge, 50% / 50% during all projected period.

Finally some particular considerations made to forecast both the highest price of natural gas at the well hole and the highest transportation fees for thermal plants in central country were:

Contribution from Cusiana to supply the natural gas demand in central country.

For Barranca and Palenque thermal plants, supply was assumed out of Payoa field up to 2009, and from 2010 onwards out of Guajira. The above considering the ration reserves / production for Payoa field.

For Termovalle, supply was assumed out of Opón field up to 2005, and from 2006 onwards out of Guajira and Cusiana.

Due to the fact that it was assumed that Cusiana contributes additional natural gas supply to serve the demand in central country, the following central country transportation

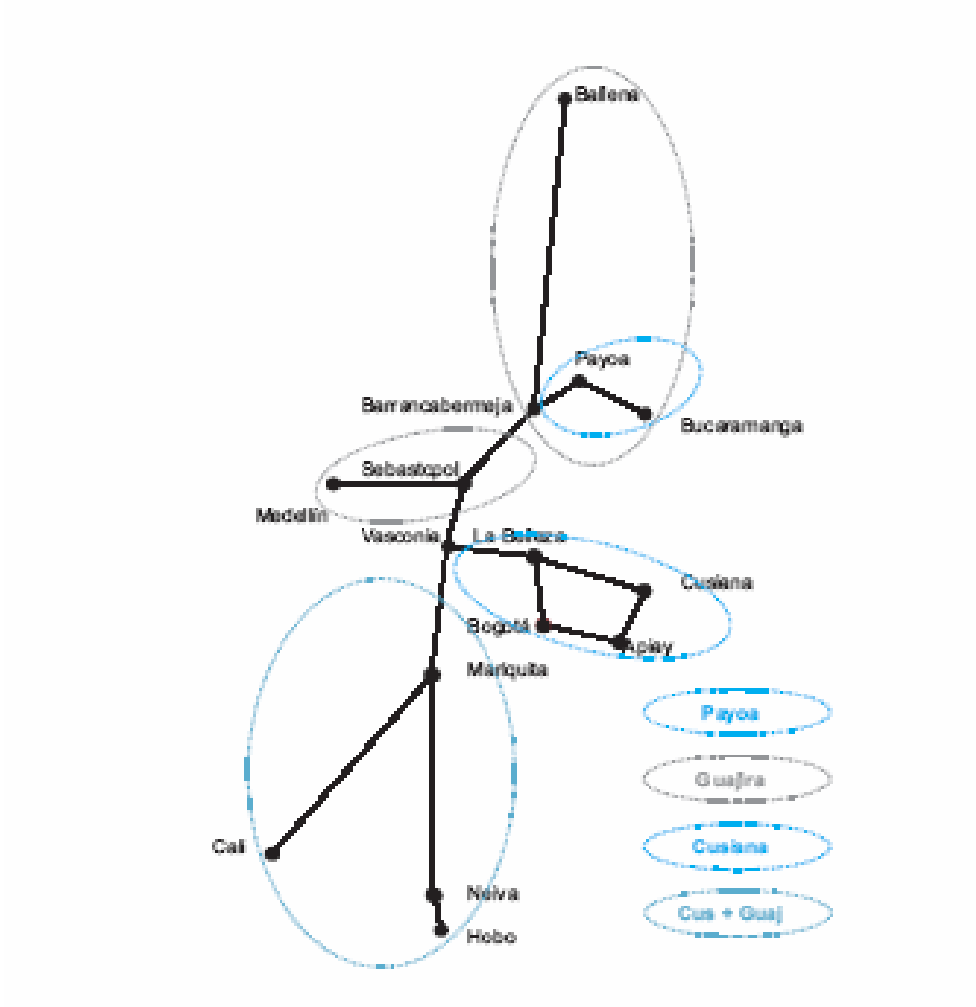
system simplified chart shows the gas source assumed to the effects of the calculations carried out.
* From Guajira to Vasconia it is supplied out of Guajira during the entire forecast horizon.

* Department of Santander is supplied out of Payoa up to 2009, and from 2010 onwards it is supplied out of Guajira.

* Cusiana and Guajira supply the Cundinamrca-Boyacá High Plain up to 2005, and Cusiana does from then on.

* From Vasconia to the South of the country supply is made out of Guajira up to 2005, and afterwards natural gas will be supplied out of Guajira and Cusiana, in different proportion depending on each of the sources' production levels.

* Chart 4-3. Natural gas supply nodes areas of influence



Alternativas y Estrategias de la Expansión de la Generación

Alternatives & Strategies for Power Generation Expansion

5. Alternatives and Strategies toward an Expansion of Energy Generation

Short term alternatives and long term strategies seek to strengthen the country's demand for energy under different scenarios. Analyses performed look at the actual status of energy generation in Colombia, assessing country's requirements, if it were not interconnected to Ecuador, Panama and Venezuela.

Other analyses that include energy exchanges with Ecuador and Panama are performed in the various short term alternatives and long term strategies. One first scenario intends to show the behavior of Colombia and Ecuador interconnected systems considering a 250 MW link up to the end of the fourth quarter 2006 and from then on increasing such capacity by 250 MW, that is to say that by the end of the fourth quarter 2006 Colombia-Ecuador interconnection is foreseen as having a capacity of 500 MW and Ecuador-Colombia 200 MW. A second scenario foresees the entry of an 80MW hydraulic project in the short term and enlarging the capacity toward Ecuador up to 500 MW by the end of the fourth quarter of 2006 and interconnection with Panama as from 2008 foreseeing a capacity of exchange with the latter of 300 MW from Colombia and 300MW from Panama. Planning horizon foreseen over the short term includes the period 2004-2008 and the long term includes the period 2009-2013. Likewise, a prospective of the energy generation required to serve the demand for energy up to 2018 was developed. Criterion applied to develop the different scenarios was the lowest cost.

On the other hand, three sensitivity tests were performed as regards the short and long term analyses; one of them considered hydrologies with low level of contributions to the system, another with delays in the entry of generation projects both in Colombia and in Ecuador in the long term, and a third one foreseeing a high demand scenario in the Colombian case taking the interconnection with Ecuador into consideration.

5.1 GENERATION ANALYSES ASSUMPTIONS

Basic assumptions foreseen in short term alternatives as well as in the long term are as follows:

5.1.1 Colombian Case

* Hydrologies from January 1975 to December 2003.
* November 2003 non-availability rates taken into consideration to calculate capacity charge
* Projects filed with UPME registration.
* March 2004 demand for medium and high energy and power projections
* Characteristics of hydraulic and thermal plants as of May 2004
* Natural gas and coal price projections in December 2003 constant USdollars

* Minimum operative capacity in force as of May 2004.
* No limitations on the supply of natural gas were considered.
* Generation indicative costs as well as fixed and variable costs as determined by IPME.

5.1.2 Ecuadorian Case

* Hydrologies from January 1975 to December 2003
* May 2004 non-availability rates available at CND
* Projects filed with CONELEC
* CONELEC's demand for energy and power projections
* Characteristics of hydraulic and thermal plants as of May 2004
* Radial Ecuador-Peru interconnection as from October 2004
* Fuel oil price projections, CENACE website
* Generation variable costs and other costs as determined by CENACE

5.1.3 Panamanian Case

* Hydrologies from January 1975 to December 1998.
* Non-availability rates provided by ETESA
* ETESA'S projections on demand for energy and power.
* Characteristics of hydraulic and thermal plants as of May 2004
* Fuel Oil price projections, ETESA
* Generation variable costs and other costs as determined by ETESA

5.2 PROJECTS TO EXPAND GENERATION IN COLOMBIA

At present, the UPME has a Project register with approximately 12,200 MW, most of which are under research. Filed projects are shown in Table 5-1.

Some outstanding steps in developing such projects updated as of October are:

* Porce III: this project is under construction; at present negotiations are carried out to acquire the lands and the legalization to build the project's access roads is under way. Estimated entry date June 2010.
* Transferring Calderas river to Punchiná reservoir which provides 267 GWh / year. Estimated entry date February 2006.

* Transferring Guarinó river to Miel I reservoir, which will allow this project to have approximately 268 GWh/year availability. Estimated entry date November 2007.

* Transferring Manso river to Miel I reservoir, which will allow this project to have energy contributions of around 179 GWh/year. Estimated entry date June 2008.

* Amoyá, hydraulic project with a capacity of 78 MW. Its financial closing is being carried out at present.

* Hidrosogamoso has re-defined the dam size changing its previous capacity from 1,035 MW to 840 MW. It has been granted an environmental license but fails to have a financial closing.

* Termoyopal 1 and 2: natural gas powered project located in the department of Casanare with a capacity of 46 MW, which went commercial in July 2004.

* Termoyopal 3, changed its name to Central Térmica El Morro: natural gas powered project located in the department of Casanare with a capacity of 40 MW, which is expected to go commercial during the second quarter of 2005.

* Enlarging the capacity of Flores 2 and Flores 3 plants in 12 MW and 25 MW, respectively. This capacity enlarging is available in the system as from September 2004.

* La Herradura y La Vuelta: hydraulic plants owned by EEPPM; due to their capacity they are deemed to be small plants in the wholesale energy market, These plants have a capacity of 19.7 MW and 11.8 MW respectively. Available in the system as from October 2004.

* Meriléctrica: This plant will expand its capacity in 14 MW, being it foreseen that it may contribute total 168 MW to the system. Opinion as regards the point to connect with the national transmission system has been requested and approved.

Table 5-1. Generation projects filed with UPME

PROJECT	CAPACITY (MW)	TECHNOLOGY	LOCATION (municipio y departamento)		POSIBLE Delivery	PROMOTOR	PHASE
		Thermal-gas	Capacity		Registered::	2.226 MW	
TermoYopal 3	36	Open cycle	Yopal	Casanare	II SeMonthtre 2005	TERMOYOPAL S.A	1
TermoBiblis	1000	Combined cycle	Cartagena	Bolívar	Unconfirmed	ELECTROENERGIA Flores III Ltda. & Cía.	1
TermoFlores IV	150	Combined cycle	Barranquilla	Atlántico	Unconfirmed	SCA ESP	1
Térmica del	215	Open cycle	Yopal	Casanare	Unconfir	Prom. Térmica	1

Café					med	del Café S.C.A.	
Termo Upar	300	Open cycle	La Paz	Cesar	Unconfir med	ISAGEN S.A. E.S.P.	1
Termo Lumbí	300	Combined cycle	Mariquit a	Tolima	Unconfir med	ISAGEN S.A. E.S.P.	1
Termo Yarigüies	225	Combined cycle	Barranca bermeja	Santander	Unconfir med	ISAGEN S.A. E.S.P.	1
Térmico de Carbón. Capacity Registered: 317.5 MW							
TermoCauca	100	Fuidizided bed	Santande r de Quilichao	Cauca	Unconfir med	TERMOCAUCA S.A.	2
GenerCauca	160	Conventional	Puerto Tejada	Cauca	Unconfir med	GENERCAUCA S.A.	1
TermoSabana	7.5	Conventional - Cogen.	Cajicá	Cundinam arca	Unconfir med	Gestión & Desarrollo	1
T. San Bernardino	50	Fluidizaded	San Bernardi no	Cauca	Unconfir med	Somos Energy del Cauca S.A.	1
Fuel Oil – Other- Capacity Registered: 300 MW							
Petrosur	150	Fuel Oil – Steam	Guachuc al	Nariño	Unconfir med	PETROSUR S.A.	2
Geotermia	150	Geothermia	Villamarí a	Caldas	Unconfir med	GEOTERMIA ANDINA	1
Hydroelectric (Reservoir) Capacity Registered: 8,730 MW							
Porce 3	660	Turbine Francis	Anorí - Amalfi	Antioquia	Jun-10	EEPPM	2
Nechí	645	Turbine Pelton	Anorí (others)	Antioquia	Unconfir med	EEPPM	2
Sogamoso	840	Turbine Francis	Río Sogamos o	Santander	Unconfir med	HIDROSOGAMOSO S.A.	2
Guaico	136	Turbine	Abejorral	Antioquia	Unconfir	EEPPM	1

		Francis			med		
Guamues PMG – I	428	Turbine Pelton	Pasto	Nariño	Unconfir med	Empresa PMG S.A. E.S.P.	1
Guamues PMG – II	605	Turbine Pelton	Pasto	Nariño	Unconfir med	Empresa PMG S.A. E.S.P.	1
PMG – Patía I	880	Turbine Francis	Pasto	Nariño	Unconfir med	Empresa PMG S.A. E.S.P.	1
PMG – Patía II	911	Turbine Francis	Pasto	Nariño	Unconfir med	Empresa PMG S.A. E.S.	1
Cabrera	600	Turbine Francis	Río Suarez	Santander	Unconfir med	ISAGEN S.A. E.S.P.	1
Fonce	520	Turbine Pelton	San Gil	Santander	Unconfir med	ISAGEN S.A. E.S.P.	1
Andaquí	705	Turbine Francis	-	Cauca y PutuMay	Unconfir med	ISAGEN S.A. E.S.P.	1
Pescadero-Ituango	1800	Turbine Francis	Ituango	Antioquia	Unconfir med	Hidroeléc. Pescadero–Ituango S.A.	1
Hydroelectric (Mediana y Pequeña Central) Capacity Registered: 578.3 MW							
La Herradura	19.7	Turbine Pelton	Cañasgordas, Frontino	Antioquia	Oct-04	EEPPM	1
La Vuelta	11.8	Turbine Pelton	Frontino, Abriaquí	Antioquia	Oct-04	EEPPM	1
PCH Las Cascadas	8.6	-	--- San Roque	Antioquia	Jun-05	INVERSIONES JG VILLEGAS	1
PCH de Neusa	2.9	-	Cogua - Tausa	C/marca	Jan-06	INGAMEG	1
Río Amoyá	78	Turbine Pelton	Chaparral	Tolima	Unconfirmed	GENERADORA UNIÓN S.A.	1
Agua Fresca	4	Turbine Pelton	Jericó	Antioquia	Unconfirmed	GENERADORA UNIÓN S.A.	1
Montañitas	24.5	Turbine Pelton	Don Matías - Sta. Rosa	Antioquia	Unconfirmed	GENERADORA UNIÓN S.A.	2
Cañaveral	68	Turbine Pelton	Caldas	Antioquia	Unconfirmed	ISAGEN S.A. E.S.P.	2

Encimadas	94	Turbine Pelton	Caldas	Antioquia	Unconfirmed	ISAGEN S.A. E.S.P.	2
Central del Río Palo	35	Turbine Francis	Caloto	Tolima	Unconfirmed	CIA. DE ELECTR. DE TULUA	1
Alejandría	16.3	Sin Información	Alejandría	Antioquia	Unconfirmed	EADE S.A. E.S.P.	1
Aures	24.9	Turbine Pelton	Sonsón, Abejorral	Antioquia	Unconfirmed	EADE S.A. E.S.P.	1
Caracolí	14.6	Turbine Pelton	Caracolí	Antioquia	Unconfirmed	EADE S.A. E.S.P.	1
Cocorná	29.7	Sin Información	Cocorná	Antioquia	Unconfirmed	EADE S.A. E.S.P.	1
Río Frío	8.5	Turbine Pelton	TáMonthis	Antioquia	Unconfirmed	EADE S.A. E.S.P.	1
Santa Rita (Rehab.)	1	Turbine Pelton	Andes	Antioquia	Unconfirmed	EADE S.A. E.S.P.	1
Cucuana	88	Turbine Francis	Roncesvalles	Tolima	Unconfirmed	ELECTRIF. DEL TOLIMA	1
Coello 1, 2, 3	3.8	Turbine Kaplan	Chicoral	Tolima	Unconfirmed	HIDROESTUDIOS	1
Río Ambeima	45	Turbine Pelton	Chaparral	Tolima	Unconfirmed	GENERADORA UNIÓN S.A.	1

The following are the projects taken into consideration as part of the expansion analyses, in the short term and in the long term (see Table 5-2).

Table 5-2. Ongoing projects in Colombia

Plant	Units	Capacity Mw	Date
Jepirachi	15	19.5	Apr-04
Menor Tequendama	1	19.4	Apr-04
Termoyopal 1	1	18	Jun-04
Termoyopal 2	1	28	Jun-04
Flores 2	-	12	Jul-04

Flores 3	-	25	Jul-04
Merilectrica	1	14	Ago-04
La Vuelta	1	11.8	Sep-04
La Herradura	2	19.7	Sep-04
Termoyopal 3	1	36	Nov-05
Calderas	1	26	Feb-06
Porce 3	4	660	Jun-10
Total - MW		889.4	

5.3 PROJECTS TO EXPAND GENERATION IN ECUADOR

Ecuador has a potential capacity of 1,700 MW which may be operated on different energetic resources; approximately 1,100 MW are under concession agreements and the remaining 600 MW are under concession certificates.

Projects having a higher possibility of being constructed in Ecuador are those under concession agreements. Out of the 1100 MW of projects under concession agreements, 77% is made of five projects which are described in summary hereunder.

* San Francisco Project, is a 230 MW capacity project, with two 115 MW units with Francis engines. The project will take advantage of the water discharge of Agoyan power plant. This project's medium energy contribution is estimated at 1,403 GWh/year. The project will be located in the Tungurahua province, and is under construction at present.

* Mazar Project, is an hydraulic project with an approximate capacity of 190 MW arranged in two generation units of 95 MW each and two Francis engines. Medium energy contributions are estimated at 871 GWh /year. This project will take advantage of hydric contributions of Paute River and will be located in Azuay province. On May 14, 2003, CONELEC and Hidropaute S.A. entered into a concession agreement to construct and operate Mazar. At present access roads are under construction and the process has been undertaken to appoint managerial staff and to construct civil works thereto.

* Termoriente Project, is a thermal project which will use inner combustion engines to reach a capacity of 270 MW; main source of fuel is refinery waste. Medium energy contribution of project is estimated at 2,010 GWh/year and it will be located at Sucumbíos province.

* Machala Power Projects (EDC2), this project is a combined cycle powered by natural gas with a capacity of 95 MW and a medium energy of 666 GWh/year. The project will be located at El Oro province.

* Machala Power Projects (EDC3), this project is a combined cycle powered by natural gas with a capacity of 65 MW and a medium energy of 610 GWh/year. The project will be located at El Oro province.

Table 5-3 below shows the estimated entry date of the projects considered in the expansion analyses, both in the short and long term, for Ecuador.

Table 5-3. Projects included in Ecuador's Expansion Plan

Plant	Type	Capacity MW	Date
Perlabi	HYDRO	2.8	Jul-04
Sibimbe	HYDRO	15.2	Dec-04
Posa Honda	HYDRO	3.0	Jan-05
Esmeralda	MCI	50	Oct-05
La Esperanza	HYDRO	6.0	Jan-06
Salinas	EOLIAN	10	Jan-06
Ocaña	HYDRO	26	Nov-06
Termoriente	MCI	270	Jul-07
Edc 2	GAS	95	Sep-07
San Francisco	HYDRO	230	Apr-08
Edc 3	GAS	65	Sep-08
Mazar	HYDRO	180	Dec-08
Total - MW		**953**	

5.4 PROJECTS TO EXPAND GENERATION IN PANAMÁ

ETESA previous research has identified a potential of 1,300 hydroelectric MW, and out of these, 900 MW may be technically potential and financially available to be implemented up to 2015. In the immediate future the Panamanian system foresees the development of 30 MW-Bonvic, 158 MW-Changuinola 75 and 132 MW-Changuinola 140 hydroelectric projects, located in Bocas del Toro province.

Panamanian projects included in the Colombian system expansion analysis wherein Panama interconnection is foreseen, are shown in Table 5-4.

Table 5-4. Expansion projects in Panama

Plant	Type	Capacity MW	Date
Low Mina	HYDRO	51	Jan-07
Bonyic	HYDRO	30	Jan-07
Gaulaca	HYDRO	24	Jan-07
Chan 75	HYDRO	158	Jan-09
Santa María	HYDRO	30.5	Jan-10
Chan 140	HYDRO	132	Jan-12
Mmv 50-1	--	100	Jan-12
Pando	HYDRO	32	Jan-12
Total -MW		**557.5**	

On the other hand, the generation analyses for the Panamanian system considered the withdrawal of 220 MW in thermal plants by mid 2010.

5.5 GENERATION REFERENCE COSTS

Generation costs represent the amounts incurred by a generator, they are referential values and as such they correspond to an approximation as regards actual costs incurred to install and operate a generation project. It should be highlighted that costs applied to these analyses are deemed a type technology and do not consider the start-ups and stops incurred by the various generation units in the Colombian system.

As regards the plants required for expansion, the costs include the generation unit cost as well as approximate transportation costs from manufacturing place, as well as direct costs such as FOB costs at loading port, CIF costs in Colombian ports, CIF at the plant site with taxes. Likewise, some indirect costs have been estimated, e.g. project's engineering and administration expenses.

On the other hand for the plants actually being operated only its variable cost was considered. As part of variable costs at thermal plants the cost of fuels was estimated both for natural gas and for coal, which include, in the natural gas case, the well hole and transportation (fixed and variable) costs incurred as defined in section 4.2.2; also, coal costs shown under section 4.2.1 were considered.

It is worth mentioning that the costs do not include additional costs to be incurred when financing the project. A 10% discount rate was considered for the different types of analyses.

Reference costs are shown in Attachment A and can be found in a constant dollar data base dated December 2003.

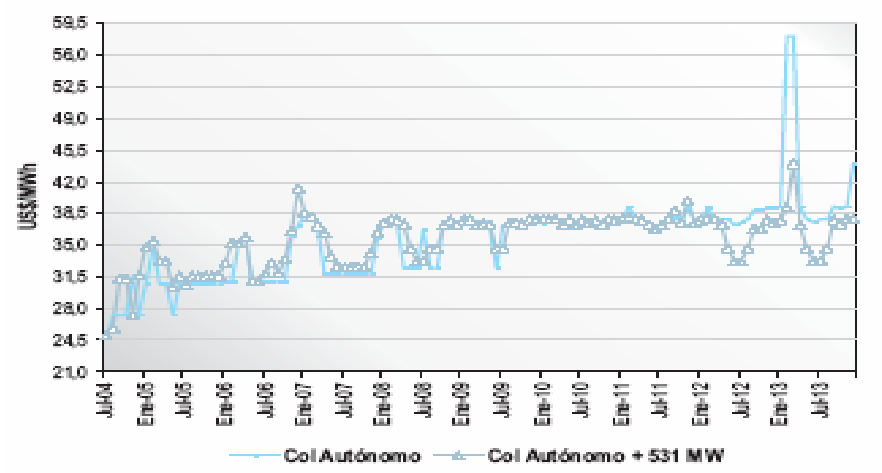
5.6 STATUS OF ENERGY GENERATION IN COLOMBIA IN THE SHORT AND LONG TERM

In order to assess Colombia's energy requirements at the request of the Transmission Planning Advisory Committee, a case was evaluated wherein the Colombian system were not interconnected with the neighboring countries (Ecuador, Panama and Venezuela). In this sense, such a case seeks to independently serve Colombia's demand for energy in the short term and in the long term, to which effect the assumptions mentioned under 5.1.1 were applied as well as the generation projects entry schedule pursuant to Table 5-2. Additionally the energy contributions of transferring Calderas to Punchiná reservoir and Guarinó and Manso rivers to Miel I reservoir as from November 2007 and June 2008, respectively, were taken into consideration. Analyses show that in the short term, period 2004-2008, the Colombian system does not require installing generation sources additional to those currently in operation and construction.

In the long term, period 2009-2013, a shortage of energy is foreseen in March 2013, which corresponds to two hydrological series that produce a failure in serving the demand for energy of 634 GWh; after that month and until December 2013 no cases of unsupplied demand for energy are foreseen. In order to avoid this potential deficit in the system, it is necessary to install 531 MW which may be added by the end of 2012 and beginning of 2013. Such a capacity may be provided with the closure of natural gas powered combined cycles at plants with present open cycle operations.

Chart 5-1 below shows two curves reflecting the potential behavior of marginal cost. One of them represents the system's average marginal cost not considering the installation of additional capacity other than that under construction at present, and the second one represents the average marginal cost with addition of 531 MW to the capacity actually in construction in 2013. Results are expressed in December 31, 2003 constant dollars and take CERE, FAZNI and Law 99 of 1993 costs into consideration.

Chart 5-1. Colombian system average marginal cost excluding interconnections



5.7 SHORT TERM ALTERNATIVES

Short term alternatives were analyzed for a five-year period and include 2004 to 2008. Three short term alternatives were considered; one seeking to establish Colombian system's generation requirements with consideration of the interconnection with Ecuador expanded to 500 MW; other considering the entry of a 80 MW hydraulic project in 2008 and interconnection with Ecuador up to 500 MW; and a third one that considers the joint interconnection of Colombia, Ecuador and Panama.

5.7.1 ST Alternative – 1

This alternative seeks to satisfy Colombia and Ecuador demand in a coordinated way, for which purpose in addition to the above-mentioned assumptions, the entry schedule of Colombia generation projects shown in Table 5-2 and the transferring of Calderas, Guarinó and Manso Rivers were taken into consideration.

For the Ecuadorian case the expansion shown in Table 5-3 was used. Likewise a 250 MW capacity of interconnection with Ecuador was assumed until the end of the fourth quarter of 2006, period as from which the interconnection capacity was expanded by 250 MW which resulted in a link capacity of 500 MW by the end of fourth quarter 2006. The results show that the Colombian system, when interconnected to the Ecuadorian system, does not require additional capacity other than that actually installed and under construction.

5.7.2 ST Alternative – 2

This alternative seeks to satisfy Colombia and Ecuador demand for energy in a coordinated way, for which purpose in addition to the above-mentioned assumptions, the entry schedule of Colombia generation projects shown in Table 5-2 and the transferring of Calderas, Guarinó and Manso Rivers were taken into consideration. Additionally, the entry of a hydraulic project in 2008 with capacity of 78 MW was considered. For the Ecuadorian case the expansion shown in Table 5-3 was used. Likewise a 250 MW capacity of interconnection with Ecuador was assumed until the end of the fourth quarter of 2006, period as from which the interconnection capacity was expanded by 250 MW which resulted in a link capacity of 500 MW by the end of fourth quarter 2006. The results show that the Colombian system, when interconnected to the Ecuadorian system, does not require additional capacity other than that actually installed and under construction

5.7.3 ST Alternative – 3

This alternative seeks to satisfy Colombia and Ecuador demand for energy in a coordinated way, for which purpose in addition to the above-mentioned assumptions, the entry schedule of Colombia generation projects shown in Table 5-2 and the transferring of Calderas, Guarinó and Manso Rivers were taken into consideration. For the Ecuadorian case the expansion shown in Table 5-3 was used. Likewise a 250 MW capacity of interconnection with Ecuador was assumed until the end of the fourth quarter of 2006, period as from which the interconnection capacity was expanded by 250 MW which resulted in a link capacity of 500 MW by the end of fourth quarter 2006. Also, consideration was give to interconnecting the Colombian system to the Panamanian system for which purpose it was proposed that as from 2008 both systems were to have a 300 MW interconnection. The results show that the Colombian system, when interconnected to the Ecuadorian system, does not require additional capacity other than that actually installed and under construction

5.7.4 Reliability in the short term

Reliability analyses were applied on the various short term alternatives8 and results are shown in table 5-5. It can be noticed that none of them has a deficit in serving the demand for energy.

Table 5-5. Short term reliability limits in Colombia

Period	Number of Cases			VEREC %			VERE		
	LP 1	LP 2	LP 3	LP 1	LP 2	LP 3	LP 1	LP 2	LP 3
Dec 04 – Apr 05	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
Dec 05 – Apr 06	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
Dec 06 – Apr 07	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
Dec 07 – Apr 08	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0

5.8 LONG TERM STRATEGIES

Long term strategies seek to determine the generation requirements in the long term for the period 2009-2013, necessary to supply energy demand under a minimum cost criterion, taking potential energy exchange between Colombia, Ecuador and Panama into consideration.

5.8.1 Long Term Strategy LT-1

The generation system for the period 2009-2013 was assessed, taking Colombia-Ecuador integration into consideration, based on short term alternative ST-1. That is to say, that the interconnection with Ecuador will have a capacity of 500 MW as from December 2006. In addition, for the Colombian case the analysis includes the entry of a 660 MW hydraulic project in 2010.

As it can be seen in Table 5-6, the system does not require additional capacity other than the 660 hydraulic MW considered for 2010. Should Ecuador generation projects fail to entry on the dates mentioned in the Ecuadorian expansion plan, it is necessary for the Colombian system to install additional capacity, as can be seen in the sensitivity analyses hereunder.

5.8.2 Long Term Strategy LT – 2

This strategy includes an analysis of energy requirements using alternative ST-2 in the short term, which considers the entry of a 78 MW hydraulic project, as well as the expansion of the interconnection with Ecuador up to 500 MW as from December 2006. As it can be seen in Table 5-6, Colombian system does require installing 660 MW, which are under construction. Same as the previous alternative, should Ecuador fail to fulfill the expansion plan shown in Table 5-3, Colombia requires capacity additional to the 660 MW actually under construction at the end of the analysis horizon. Such requirement can be seen in the sensitivity analyses hereunder

5.8.3 Long Term Strategy LT – 3

This strategy includes an analysis of energy requirements using alternative ST-3 in the short term, which considers an expansion of the interconnection capacity with Ecuador as from December 2006 up to 500 MW and interconnection with Panama up to 300 MW as from 2008. Additionally, in the Colombian case the analysis includes the entry of a 660 MW hydraulic project in 2010. As it can be seen in Table 5-6, the system requires 500 MW in addition to the 660 hydraulic MW considered for 2010.

Table 5-6 Summarizes the generation capacity required by the Colombian system for the various strategies.

Table 5-6. Long term energy generation expansion requirements

Period	LP 1			LP2			LP 3		
	H	G	C	H	G	C	H	G	C
2009									
2010	660			660			660		
2011								170	
2012								180	
2013								150	
Subtotal – MW	660			660			660	500	
Total – MW	**660**			**660**			**1,160**		

5.8.4 Reliability in the long term

Reliability assessment is carried out in order to establish the energy reliability limit values, set by means of resolution CREG 025 of 19959, in each of the proposed long term alternatives.

Table 5-7 shows the reliability limits obtained for the various energy generation strategies in the long term.

Table 5-7. Long term reliability limits in Colombia

Period	Number of Cases			VEREC %			VERE		
	LP 1	**LP 2**	**LP 3**	**LP 1**	**LP 2**	**LP 3**	**LP 1**	**LP 2**	**LP 3**
Dec 09 – Apr 10	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
Dec 10 – Apr 11	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
Dec 11 – Apr 12	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
Dec 12 – Apr 13	1	1	0	0.8	0.5	0.0	0.0	0.0	0.0

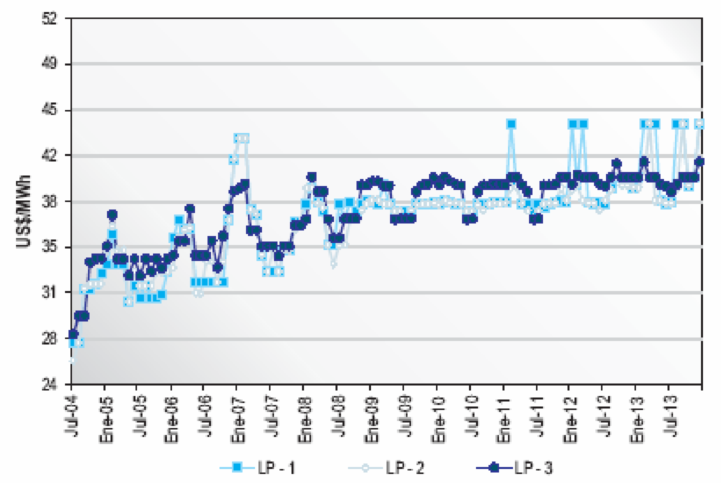
As it can be noticed, some deficits appear for the summer commencing in December 2012 and ending in April 2013; nevertheless, they fall within the limits set by resolution CREG 025 of 1995.

5.9 MARGINAL COST OF ENERGY IN THE SHORT TERM AND IN THE LONG TERM

The average marginal cost of energy was established for the various short term and long term alternatives and strategies. Based on results obtained, energy exchanges show and increase in the marginal cost for Colombia which may range between 25 and 37 US$/MWh in the short term and 38 and 40 US$/MWh in the long term.

It is worth mentioning that even if this means an increase in the marginal cost of energy and consequently an increase in price in energy markets for Colombian users, the county will benefit from the monies received via hi-end rates. Chart 5-2 shows the marginal cost of energy in the short term and in the long term, in December 31, 2003 constant dollars and takes CERE, FAZNI and Law 99 of 1993 into consideration.

Chart 5-2. Colombia marginal cost in the short term and in the long term

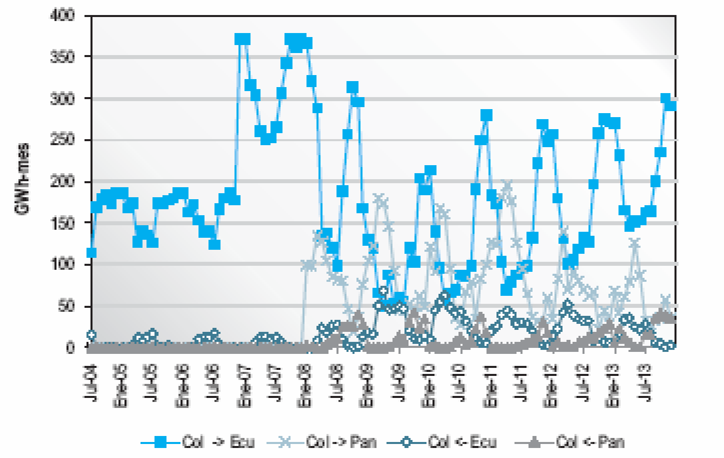


5.10 ENERGY EXCHANGES

Energy exchanges with Ecuador and Panama for alternative ST-3 and strategy LT-3 show that Colombia is in condition of exporting energy to these countries. In such a sense, as from the expansion of export capacity to Ecuador up to 500 MW, that country might have up to 370 GWh/month available from Colombia between years 2007 and 2008. After these years exports might reach values ranging between 100 and 270 GWh/month. Chart 5-3 shows the behavior of exports and imports between countries.

In the case of Panama, the exports of energy from Colombia might fluctuate between 50 and 200 GWh/month as an average, with the latter value being reached by 2011.

Chart 5-3. Energy exchange MWh



On the other hand exports from Panama and Ecuador to Colombia are minimal. These values reach 50 GWh/month as an average along the horizon.

5.11 LONG TERM SENSITIVITY

Three sensitivity cases were analyzed, all of them regarding the interconnection of Colombia and Ecuador. These cases maintain some of the assumptions in alternative ST-1 and strategy LT-1. The first sensitivity case foresees dry hydrologies similar to those that appeared in the 90's. The second case was based on a year's delay in the entry of projects for Colombia and Ecuador, and finally the third case foresaw a high demand for energy in Colombia.

5.11.1Sensitivity Case 1 – S1

This sensitivity consisted of evaluating the energy generation requirements in Colombia, considering the assumptions mentioned in section 5.1 but using a series of historical water flows from 1990 to 2003 to obtain the 100 series of random hydrologies. Even if the historical series is quite short in time, it includes two critical hydrology periods, which allow evaluating the system behavior under critical hydrology conditions. Also, it is worth mentioning that this case included the interconnection with Ecuador and the entry of projects in this country pursuant to Table 5-3 as well as the expansion of linking capacity up to 500 MW by the end of the fourth quarter of 2006. Generation requirements are 850 MW additional to the 600 MW of the hydraulic project, which are shown in Table 5-8.

5.11.2 Sensitivity Case 2 – S2

This case foresees a delay in the entry of projects in the long term both for Colombia and Ecuador and the expansion of interconnection capacity with Ecuador in 250 MW to reach a 500 MW link capacity by the end of the fourth quarter in 2006.

In the Colombian case the 660 MW hydric project was delayed by one year, that is to say, the forecasted entry in operation is June 2001. Likewise for the Ecuadorian case Mazar (180 MW), and San Francisco (230 MW) projects were delayed one year, and Termoriente (270 MW) was delayed two years. Generation requirements are shown in Table 5-8.

5.11.3 Sensitivity Case 3 – S3

This case assumes a high demand for energy scenario in Colombia and a medium scenario in Ecuador; all other assumptions are those used in alternative LT-1 and strategy LT-1. Having analyzed the results it can be noticed that in order to comply with reliability criteria for the Colombian case 500 MW are required between 2011 and 2013, additional to the 660 hydraulic MW. This sensitivity case considered expanding the capacity of electric interconnection with Ecuador to 500 MW as from December 2006.

Results obtained for the various sensitivity cases are included in Table 5-8 wherein the various Colombian system energy generation requirements are shown.

Table 5-8. Long term expansion requirements – Sensitivity cases

Period									
	H	**G**	**C**	**H**	**G**	**C**	**H**	**G**	**C**
2009									
2010	660						660		
2011		170		660	170			170	
2012		180			180			180	
2013		500						150	
Subtotal – MW	660	850		660	350		660	500	
Total – MW		**1,510**			**1,010**			**1,160**	

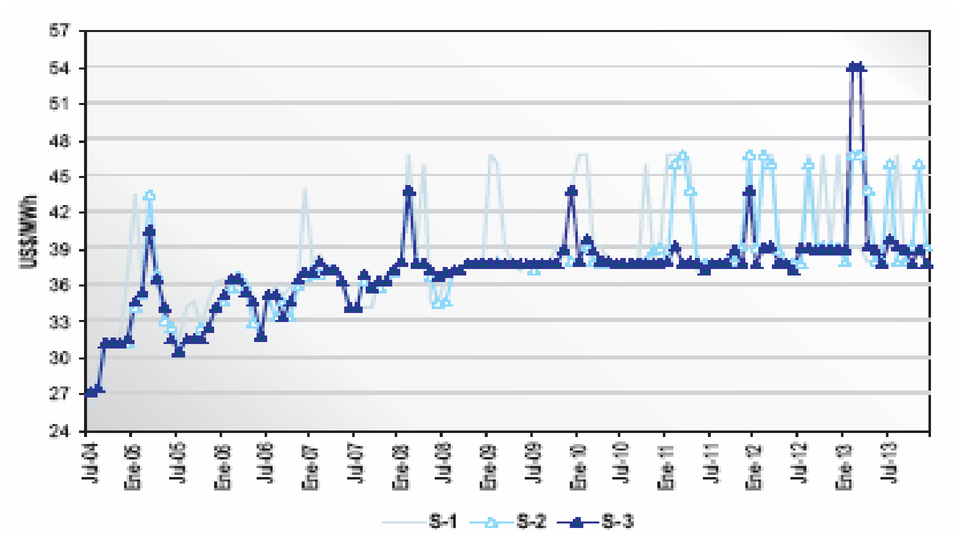
Reliability limits for the long term can be seen in Table 5-9

Table 5-9. Long term reliability limits in Colombia – sensitivity cases

Period	Number of Cases			VEREC %			VERE		
	S1	**S2**	**S3**	**S1**	**S2**	**S3**	**S1**	**S2**	**S3**
Dec 09 – Apr 10	0	0	0	0.0	0.0	0.0	0.0	0.0	0.0
Dec 10 – Apr 11	4	1	0	3.0	2.7	0.0	0.1	0.0	0.0
Dec 11 – Apr 12	2	1	0	2.8	1.0	0.0	0.1	0.0	0.0
Dec 12 – Apr 13	0	2	0	0.0	1.4	0.0	0.0	1.9	0.0

Marginal cost for the various sensitivity cases is shown in Chart 5-4; it can be noticed that if any of the three situation should happen, the price of energy for Colombia might reach values ranking between 38 US$/MWh and 45 US$/MWh at the end of horizon.

Chart 5-4. Marginal cost in sensitivity cases US$/MWh



5.11.4 Summary

The various Long Term scenarios analyzed establish that except for LT3, no additional expansion is required. However, the results of extreme situation analyses show that the system does require additional capacity to be installed between the years 2010 and 2013 to overcome such conditions. A climatic contingency is the most critical situation, in which a higher increase of installed capacity is required (additional 850 MW to Porce III).

On the other hand, in analyzing the evolution of the system capacity margin reserve it is found that the actual power demand to installed capacity ratio is 1.61, that is to say that the system has a gross reserve of 61%. For the high demand scenario in 2012 the ratio demand to installed capacity shall be reduced to 1.21 and to 1.16 in the following year, situation not recommended given that from an operations viewpoint it should have a 10% margin on demand for frequency control.

In an expansion scenario covering the hydrological events system, conditions of high demand and delay in expansion projects, 850 MW are required. In this scenario, and foreseeing the entry of this additional capacity as shown in Table 5-8, the ratio demand to installed capacity is 1.23, which represents a more appropriate power fringe.

A final consideration that brings light on the entry dates of projects is determined by the projects delay scenario, for which additional 350 MW are required between 2010 and

2013. Coverage against such a risk would have an effect closer to reality if this additional generation is available by 2010. Consequently, this situation should be further studied.

5.12 2014-2018 ENERGY GENERATION PERSPECTIVE

In order to observe a future behavior of the generation system beyond 2013, the potential generation requirements for the period between 2014 and 2018 were evaluated. The analyses consider that Colombia is interconnected with Ecuador.

The country's energy requirements reach 1,800 MW, of which approximately 600 MW would correspond to natural gas cycle closures which are at present open and in operation in the system. Likewise to the incorporation of 900 MW in hydraulic resources and the remaining 300 MW in coal-powered plants by the end of such period.

5.13 CONCLUSIONS AND RECOMMENDATIONS

The following are the conclusions presented for generation requirements in the short term and in the long term:

* In the analyses carried out for the short term, period 2204-2008, it can be noted that in the autonomous Colombian case no additional capacity is required other than that in operation and under construction.

* The cases in which generation requirements for the Colombian system interconnected with the Ecuadorian and Panamanian systems are analyzed in the long term period 2009 – 2013, it can be noted that the Colombian system requires additional capacity other than the 600 MW foreseen in 2010.

* The analysis for the long term period 2009-2013 show that for the system it is a must to install the hydraulic 660 MW in 2010 and that any variation in its entry shall entail increase in the marginal cost of energy and potential requirements for additional generation.

* Results obtained show that the marginal cost of the system in the long term would be placed between 38 US$/MWh and 40 US$/MWh.

* Based on the analyses carried out, the UPME considers it necessary that the Colombian system should have a generation expansion of 850 MW as shown in Table 5-8, in addition to the projects that are under construction at present, in such a way that it may face extreme situations like those in the sensitivity cases. Therefore, it is necessary to consider these additional requirements when establishing the system's reliability remuneration methodology.

Expansión de la Transmisión

Transmission Expansion

6. Expansion of the Transmission System

Law 143 of 1994 assigned the UPME with the duty of carrying out the Expansion Plan of the National Interconnected System following technical and economic criteria, as well as the duty of evaluating the economic and social profitability of the export of energetic resources. Criteria to be applied to produce the Expansion Plan were established by the Ministry of Mines and Energy pursuant to Resolution 181313 of 2002. Additionally, in furtherance of regulations, the CREG has established criteria to perform the Plan, which has been so far applied by the UPME in performing the Expansion Plan.

On the other hand, CREG Resolution 04 of 2003 amended by CREG Resolution 014 of 2004, sets forth that the UPME will plan the expansion of international links jointly with planning authorities of the Andean Community country members or countries sharing electricity market integration.

6.1 PLAN REVIEW ANALYSIS APPROACH

In order to establish the required reference to define the expansion to be performed in the short term and medium term, this version of the Plan includes a long term analysis – year 2018- to identify the recurrence of the problems encountered in the different areas and the consistency of potential solutions over a 15-year horizon.

The objective of the Plan in the short and medium term is to submit additional projects as required by the National Transmission System, including international interconnection projects. Methodology developed by the UPME during 2004 and discussed with the CAPT is applied to that purpose.

Additionally, this version of the Plan continues analyzing the regional sub-transmission systems. For the case of the expansion projects under regional transmission systems it is the intention to give signals that allow involved agents further studying their expansion needs and incorporating the required investment in their budgets.

6.2 BASIC INFORMATION

Information regarding electric energy demand projections, availability of resources, fuel prices and short and long term generation scenarios as described in the previous chapters makes the Basic information to carry out the analyses hereunder.

Network modeling takes into consideration Colombian and Ecuadorian National Transmission System (NTS), Level IV Regional Transmission Systems, and generation units at the relevant operation tension levels including their individual control systems.

Topology information and system's electrical parameters were provided by the different agents and supplemented with that available at the CND.

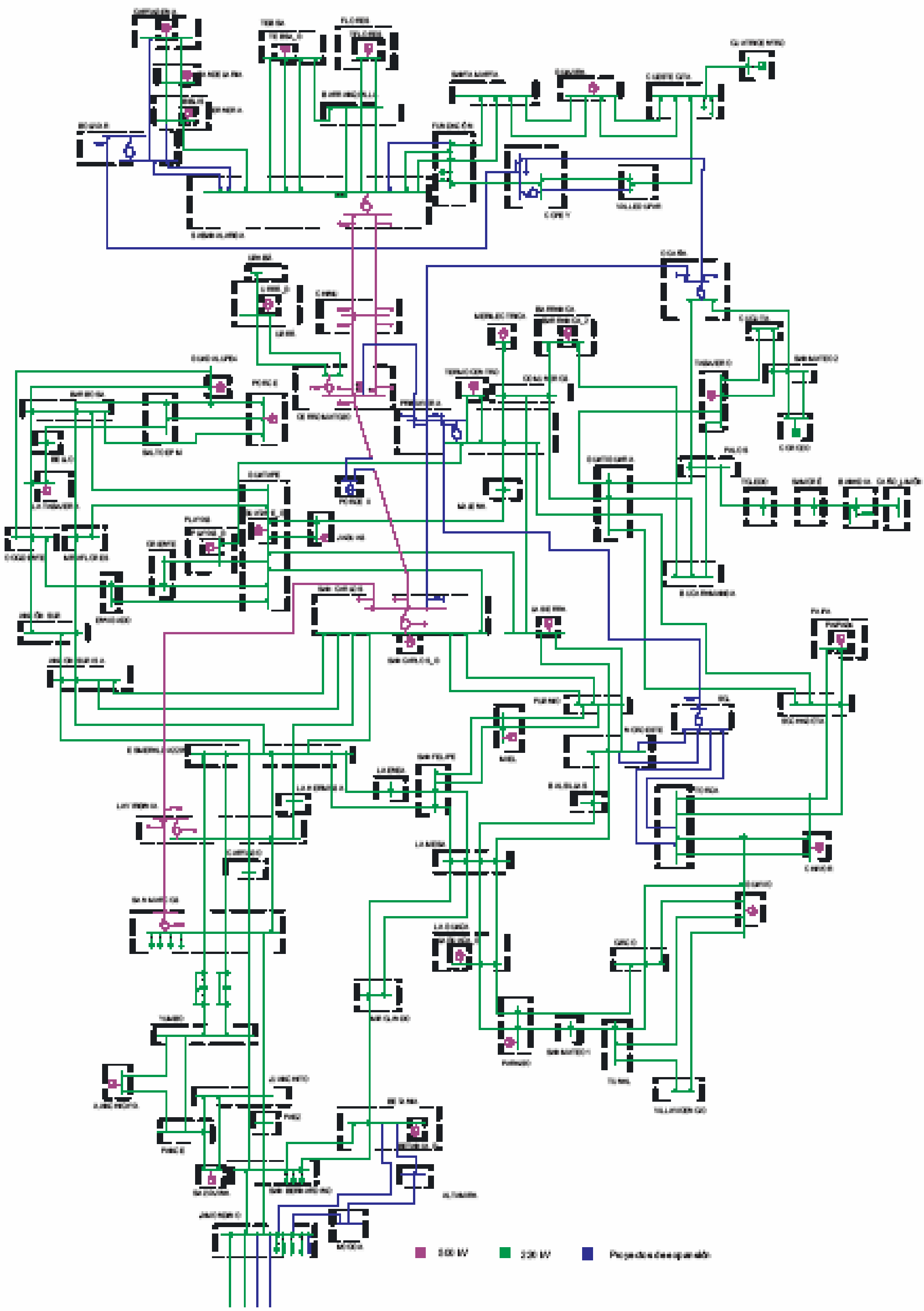
As regards NTS expansion works as defined in the above-mentioned plans, assumption is made on the operation entry dates pursuant to Table 6-1 as follows:

Table 6-1. Expansion Projects

Project	Date Entered in Operation
Capacity Compensation 75MVAr in Noroeste 115 kV	1 of June 2005
Capacity Compensation 60MVAr in Nordeste115 kV	1 of December 2004
Tercer circuito Sabanalarga – Fundación a 220 kV	January 1, 2005
Capacity Compensation 2*75MVAr in Tunal 115 kV	December 1, 2005
Project Bolívar –Copey – Ocaña – Primavera – Bacatá a 500 kV	October 1, 2007
Transformador 500/115 kV in Bacatá	October 1, 2007

Chart 6-1 Shows NTS's single-fiber diagram with expansion works foreseen up to 2012.

Gráfica 6-1. STN con proyectos de expansión hasta el año 2012



As regards regional distribution systems, expansion projects were included as foreseen in the network operators' plans, as shown in Attachment B.

Non-availability information used is that included in the record of electrical subsystem events managed by the CND in compliance with CREG Resolution 062 of 2000. Attachment C includes a description of the events of non-availability related with electrical subsystems defined as from NTS lines, use and connection transformers, for the period December 2002 to December 2003.

6.3 LONG TERM ANALYSIS

Load flow electrical analyses were performed for 2018 on the grounds of energy demand increase up to 2018 obtained from a UPME internal exercise and the generation expansion defined until 2013. The foregoing in order to obtain signals as regards the location of generation projects and the need to reinforce the NTS and Regional Transmission Systems.

The long term analyses results should be reconciled to the medium and short term results in such a way as to undertake an integrated optimization over time.

Even though as a vision for 2018 Colombia will be interconnected with neighboring Ecuador, Venezuela and Panama, networks and exchanges with these countries were not included to the effects of the 2018 steady status analysis, considering rapprochement to the planning thereof.

The results of the steady status analysis show that the most critical areas in 2018 are North Eastern, Bogotá and South Western. Possible solutions to the problems encountered at each of these areas are as follows:

6.3.1 Analysis of Bogotá Area

Bogotá area will not be in the capacity to supply its demand in 2013 with current network and generation. For this reason, joint solutions are submitted as regards the entry of generation projects in the area and reinforcement of transmission and sub transmission networks.

Even if it is technically impossible to connect generation in 230kV Tunal and 115 kV Concordia, these alternatives are submitted in order to identify the most sensitive spots from an electricity viewpoint

As regards works at a transmission level the following are being considered: second 500 kV Primavera-Bacatá circuit, expansion of transformation capacity to 500 kV, entry of Tunal substation to 500 kV, 500 kV Bacatá-Tunal line, 450 MVA 500/230 kV transformations and 450 MVA 500/115 kV transformation.

The following are further considered: entry of Mesa sub station at 115 kV with 90 MVA

230/115 kV transformations and a second 168 MVA 230/115 kV transformer in La Guaca; this seems to be an interesting alternative to study in further detail to face potential future problems in Balsillas area.

6.3.2 Analysis of North Eastern Area

Even if due to space limitations it is not possible to turn Bucaramanga substation into 500 kV, from an electricity viewpoint it represents a solution to the North Eastern area problems and consequently the alternative is that Nueva Bucaramanga substation becomes a 500 kV substation. However, in order for this alternative to be a solution it is necessary to study the possibility of turning Nueva Bucaramanga into a load substation, since at present it is only a transmission substation.
Once the 500 kV is defined, the 500 kV Ocaña-Primavera line –which will start operating in 2007 will be reconfigured. The will be the entry point to the 500 kV Ocaña-Primavera line and 500 kV Bucaramanga-Primavera, and also to the 360 MVA 500/230 kV transformer.

As regards connection spots, the expansion of transformation in Bucaramanga is included with two additional 150 MVA 230/115 kV transformers, a second 90 MVA 230/115 kV transformer in Barranca, and a second 150 MVA 230/115 kV transformer in San Mateo.

Entry of the Bucaramanga-Realminas 115 kV second circuit is also included.

6.3.3 Analysis of CQR (Caldas – Quindío – Risaralda) Area

Tensions under 0.9 p.u. at the 115 kV level are foreseen for this year, as well as overloads on 115 kV La Hermosa-Regivit and Armenia-Regivit lines, and on Hermosa and Esmeralda transformers.

As alternative towards solving these problems, consideration is given to expanding in 90 MVA the actual Esmeralda transformation capacity, expanding the transformation capacity in Hermosa, 115 kV Hermosa-Regivit second circuit and 115 kV Armenia-Regivit second circuit. It is considered that actual 115 kV Regivit-Cajamarca and 115 kV Papeles Nacionales-Dosquebradas links operate normally closed.

Another potential alternative is the construction of 230 kV Armenia substation with 90 MVA 230/115 kV transformation, which would prevent from expanding the transportation capacity of the 115 kV Armenia-Regivit and Hermosa-Regivit lines. It is noticed, however, that it is necessary to expand the transformation capacity in Hermosa and Esmeralda. This alternative makes it possible to foresee a 103.4% load ability in 230/115 kV Armenia transformer under regular operation.

An alternative submitted by the area NO is to turn the 34.5kV Pavas substation into 115 kV and connect it to 115 kV Virginia substation and with 115 kV Dosquebradas substation with approximate lengths of 12 kms and 10 kms respectively. Results show that with this alternative and without the 230 kV Armenia alternative, the 230/115 kV Virginia transformer has a load ability of 101% under regular operation and the Hermosa-Regivit line has a load ability of 103% under regular operation.

If both of the foregoing alternatives were jointly analyzed, a load ability of 96% and 79% of 230/115 kV Armenia and 230/115 kV Virginia transformers, respectively, is to be seen under regular operation results

According with the foregoing, it is important to analyze the area problems jointly with the Network Operators (NO) so as to find the best technical and economic alternative.

6.3.4 Analysis of EEPPM Area

Overloads under regular operation are found in the 115 kV Bello-Castilla line and in 230/115 kV Envigado and 230/115 kV Bello transformers. Consequently, the expansion of the line's transportation capacity and of transformers is being considered.

6.3.5 Analysis of EPSA Area

Overload problems are found in this area at TNS connection spots. Entry of 230/115 kV San Marcos second transformer and entry of 230 kV San Marcos-Pance line are put forward as joint solution alternatives.

Entry of 230 kV Aguablanca substation with two 90 MVA 230/115 kV transformers and reshaping of 230 kV Pance-Juanchito line into 230 kV Pance-Aguablanca-Juanchito are additionally put forward, as well as:

- Entry of Sub220 substation with two 90 MVA 230/115 kV transformers and reshaping of 230 kV Pance-Yumbo line into 230 kV Pance-Sub220-Yumbo.
- Entry of 230 kV Pailón substation with a 90 MVA 230/115 kV transformer and 230 kV Alto Anchicayá-Pailón line.
- Finally, entry of 500/230/34.5 kV Virginia second transformer is under consideration.

6.3.6 Analysis of Tolima-Huila-Caquetá Area

For the current year overloads are found in Mirolindo 230/115 kV transformer and 115 kV Mirolindo – Papayo line, 115 kV Betania-Altamira and tension problems at Altamira and Florencia substations

Seeking to solve these problems, the following is put forward: entry of 230 kV Altamira substation with 90 MVA 230/115 kV transformers, 230 kV Betania-Altamira line. Additionally, there is also the expansion of transformation capacity at Mirolindo and expansion of transportation capacity of 115 kV Mirolindo-Papayo line.

On the other hand, operation of 115 kV Cajamarca-Regivit and 115 kV Gualanday-Flandes, normally closed, is under consideration.

6.3.7 Analysis of Cauca – Nariño Area

In 2018 it will be necessary to have the 230/115 kV Pasto second transformer, 230/115 kV Popayán second transformer and one of the alternatives, e.g. 230 kV Altamira-Mocoa-Pasto or 230 kV Popayán-Pasto third circuit.

6.3.8 Analysis of Bolívar Area

In addition to the expansion plan submitted by the NO, the entry of 110 kV Candelaria-Zaragocilla second circuit is under consideration for this year.

6.3.9 Analysis of Guajira-Cesar-Magdalena Area

Expanding the capacity of 220/115 kV transformers is being considered in Fundación and Copey.

Additionally, overloads are found in Valledupar 110/34.5 kV transformer, in 34.5 kV Valledupar-Guatapu lines and in Valledupar 220/34.5 kV transformer.

6.3.10 Analysis of Chinú Area

Entry of the 500/110 kV Chinú third transformer, 220 kV Urrá-Montería line and two 90 MVA 220/110kjV Montería transformers is foreseen for 2018.

6.3.11 Analysis of Cerromatoso Area

Overload is found in the 115 kV Urabá-Apartadó line in this area, and it is therefore necessary to expand this line’s transportation capacity.

6.4 SHORT TERM AND MEDIUM TERN ANALYSIS

Electrical surveys carried out in the 2004-2012 horizon include steady status, load flows and reliability analysis.
Energy generation strategies used to perform both short term and medium term analysis refer to the base cases referred to in Chapter 5.

Out of generation deliveries obtained from energetic simulations, extreme cases were selected by area (lowest and peak deliveries), so as to simulate critical exchanges among the different areas.
On the other hand, 250 MW exchanges between Colombia and Ecuador are considered under peak demand conditions and the behavior of the System facing an increase in 500 MW exchanges is analyzed.

6.4.1 Expansion of Colombia-Ecuador Interconnection

Presently, Colombia is interconnected with Ecuador via a double circuit between 230 kV Pasto-Pomasqui substations and one 138 kV between Ipiales-Tulcán. The exchange limit through these interconnections is 250 MW under peak demand conditions.

The Preliminary Version of the Expansion Plan contained the technical and economic assessment of the expansion of the Colombia-Ecuador interconnection from 250 MW to 350 MW and two expansion alternatives at the single circuit line level of 230 kV Popayán-Pasto-Pomasqui and single circuit line Altamira-Mocoa-Pasto-Pomasqui; these alternatives share a portion of the 230 kV Betania Altamira line, since this project is indeed necessary regardless of the expansion of actual interconnection between Colombia and Ecuador.

According with results obtained, in the Preliminary Version of the Plan the UPME recommended to carry out the Betania-Altamira-Mocoa-Pasto-Pomasqui alternative, for it resulted in benefit additional to that obtained from the Popayán-Pasto-Pomasqui alternative, such as the possibility of expanding coverage at the Huila, Caquetá and Putumayo departments; the development of generation projects such as Andaquí in Caquetá; the development of the Amazonas frontier zone; the feasibility of interconnecting with Ecuadorian Lago Agrio oil and gas zone and reinforcement of Huila and Caquetá connections to the SIN.

In reply to one of the comments to the Plan's Preliminary Version submitted by the agents, relating to the UPME's request of evaluating the expansion of the Colombia-Ecuador interconnection from 250 MW to 500 MW, below you will find such expansion's technical and economical evaluation.

The methodology Developer by the UPME during 2004 and discussed at the CAPT is applied to evaluate the interconnection expansion. Particularly for the economic evaluation chapter 5 "Economical Evaluation of international electrical interconnections" is applied, wherein the following criteria were set to define an interconnection:

* There should be a positive net benefit for the group of countries.
* There should be a positive net benefit for each of the countries.

The methodology is divided in two stages; the first one refers to the energetic survey and the second relates to the analysis of the Transmission component analysis. This way the impact on producer and consumer is obtained, as well as the variance in peak rates, so as to obtain the total impact on the country.

Energetic analysis for Colombia is carried out in its capacity as exporter and in its capacity as importer; by way of the simulation relevant to the operation of Colombia and Ecuador systems the amounts of energy transacted between the countries and their prices is determined, given the TIEs model. These results are first obtained for a 250 MW exchange limit and further extended to 500 MW.

Seeking to assess average and extreme conditions, out of one hundred hydrological series three possible flow scenarios are considered: medium, peak and lowest.
To analyze the impact on the Transmission component, consideration is made of the effect on use charges arising from the energy increase that compensates for the use of the NTS. On the other hand, the cost of the investment in the expansion project as previously defined to expand the interconnection capacity is included. Such alternative and the relevant costs are described herein below:

Betania - Altamira – Mocoa – Pasto – Pomasqui – Santa Rosa
As shown in Chart 6-2, this alternative consists of a 230 kV double circuit line between Betania-Altamira substations, 85 kms, and Altamira-Mocoa, 134 kms; a single circuit between Mocoa-Pasto substation, 76 kms; electrification of the existing Mocoa-Pasto line at 230 kV; and a double circuit between Pasto substation and the Colombia-Ecuador frontier, 75 kms. Additionally, the respective line modules at 230 kV are required, taking into consideration that the second circuit will only connect at Betania and Pasto substations.

Chart 6-2. Altamira – Mocoa – Pasto – Pomasqui Alternative

Chart 6-2 Shows the valuation of this alternative, with costs of constructive units

Table 6-2. Cost detail

Item	Cantidad	Costo Unitario MUSD/02	Costo Total MUSD/02
Common Module 220 kV	2	2,7	5,3
Reactive Compensation 37.5 MVAr 220 kV	1	2,7	2,7
Bay Reactor 220 kV	1	0,9	0,9
Line 220 kV double circuit	294	0,17	50,1
Líne 220 kV double circuit	76	0,11	8,3
Lione Module	10	1,2	11,7
Bay transference	2	1,7	3,5

Approximate cost of this alternative is 87.7 Million Dollars of 2002, which correspond to investment in assets, financial costs and AOM costs.

Below there are the results obtained, such as the valuation of the economic impact on each of the agents (producer and consumer) and country net figures. These results refer to the difference of results obtained with the 500 MW exchange limit and the 250 MW exchange limit.

6.4.1.1 Peak flow

Chart 6-3 shows the impact that expanding the interconnection capacity has on Colombian consumers, resulting from the variation in stock exchange prices. These results show that the interconnection expansion has differences to actual condition, that is when Colombia acts as an exporter country.

Consequently, as regards the energetic analysis, it is found that the net effect on consumers arising from expanding the interconnection capacity is negative.

Chart 6-3. Benefit to Consumers – Peak flows

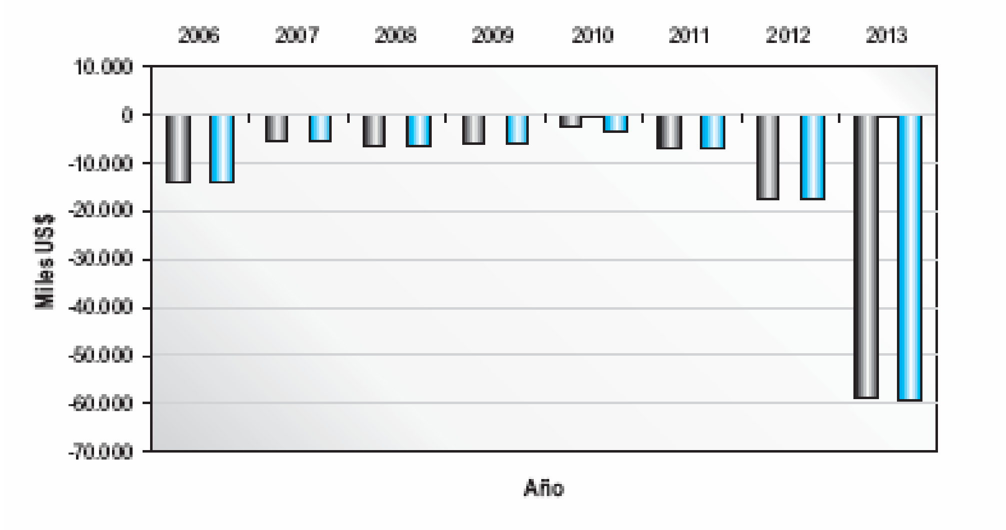


Chart 6-4 shows the impact that expanding the interconnection capacity has on Colombian producers, resulting from the increase of transacted energy and the variation in the interconnection capacity, arising from the increase of transacted energy and the variation in stock exchange prices. Results show that producers obtain a positive net benefit, which almost in total relates to the transfer of local consumers to local producers and in a lower extent to the increase in transacted demand.

Chart 6-4 . Benefit to Producers- Peak flows

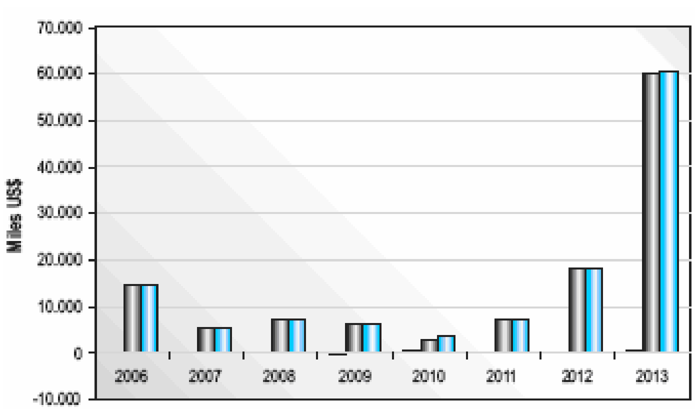
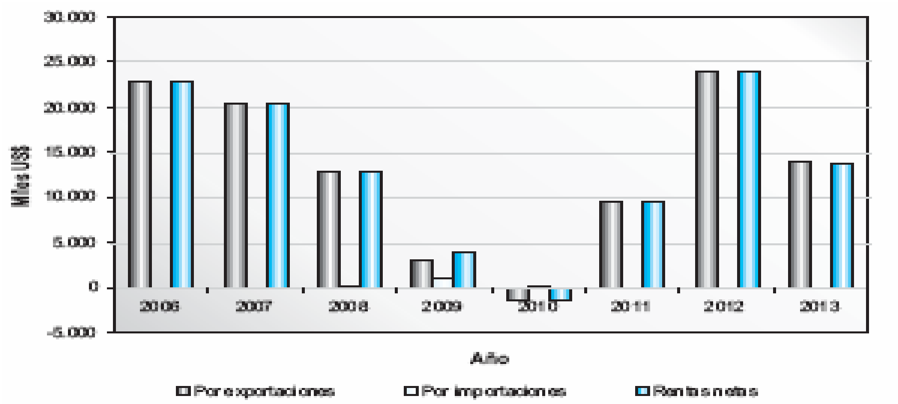


Chart 6-5 shows the impact that expanding the interconnection capacity has on the peak rates, resulting from the differential stock exchange prices of countries and transacted energy; these values include changes as regards the allotment of peak rates set by means of CREG Resolution 060 of 2004.

Chart 6-5. Rates for Peak Flows



By aggregating the above results the first part of the county balance is obtained, which corresponds to energy component. Chart 6-6 shows country benefit.

Chart 6-6. Country benefit peak flows

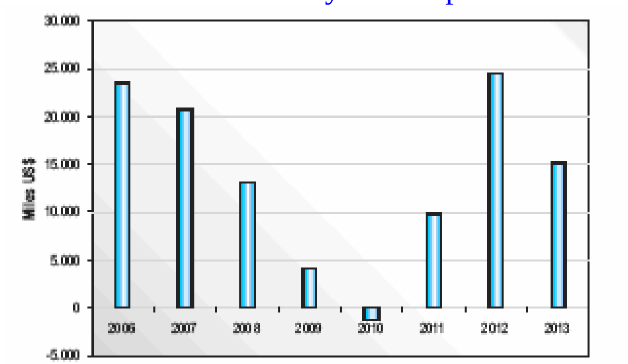
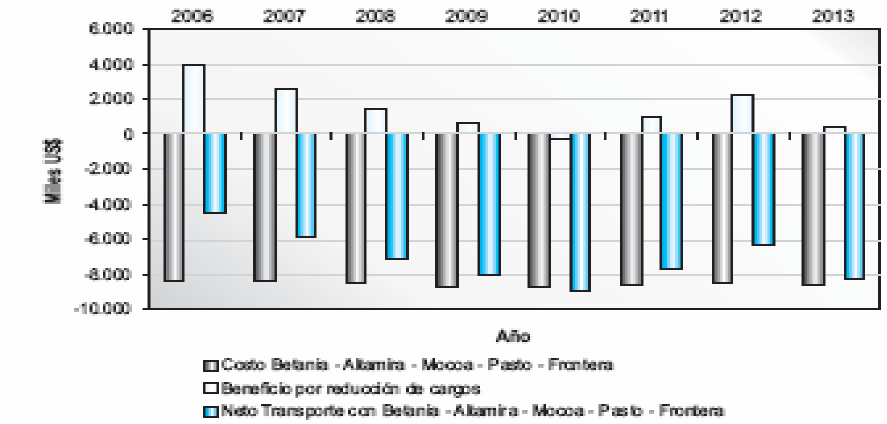


Chart 6-7 shows the impact that Transmission component has on Colombian users; such an impact is divided into the cost of each annuity to remunerate investment under the expansion alternative10 and the benefit obtained from the reduction of NTS charges resulting from a largest amount of energy transported by the NTS.

10 Total cost of each Project is taken and analyzed over a 25 year period, at a rate of 9%. Additionally, the payment of this annuity is distributed between local demand and exports.

Chart 6-7. Impact on Transmission component peak flows



There are further benefits from expanding interconnection capacity which correspond to the reduction in payment of the availability charge, reduction in payment of restrictions and reduction in payment of losses, since these charges are allotted between domestic demand and exports. Additionally, there is the benefit from collecting the contribution to FAER and FAZNI. Chart 6-8 shows the impact that such reductions have on Colombian consumer.

Chart 6-8. Benefit arising from the reduction in payments - peak flows

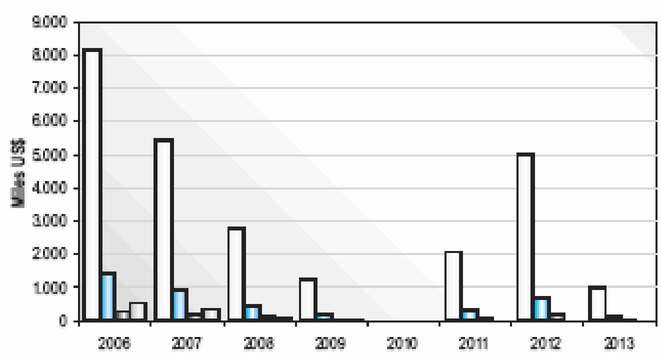
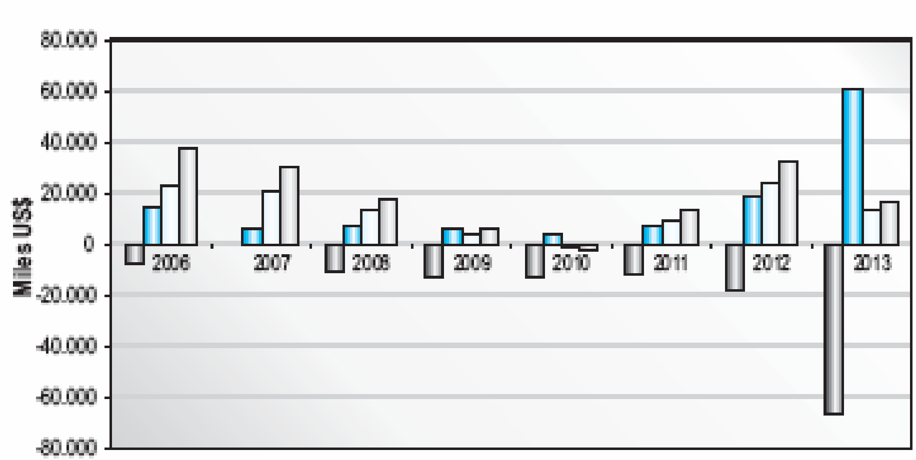


Chart 6-9 shows the net benefit for each of the agents, which is obtained as the sum of benefits found when undertaking the energetic analysis, the benefits arising from the impact on the transmission component and the benefits arising from the reduction in the payment of capacity charges, restrictions and losses. In the case of the Country Net benefit it is worth mentioning that it does not include the cost of the alternatives since it represents a transfer from consumer to transmitter and the country balance is zero.

Chart 6-9. Net Benefit peak flows



As it can be seen in the above results, the country has a positive net benefit, producer has a positive net benefit, consumer has a negative net benefit and there is an increase in the congestion pricing.

The ratio between the congestion pricing and consumer negative net effect is 1.24 for the alternative put forward.

Table 6-3 shows the variation in percentage terms of the impact on the fees imposed on the final user, for the first five years, as regards the project to expand Colombia-Ecuador interconnection from actual capacity to 500 MW, under peak flow conditions. This valuation does not take into consideration the effect of restriction cost reduction arising from congestion pricing

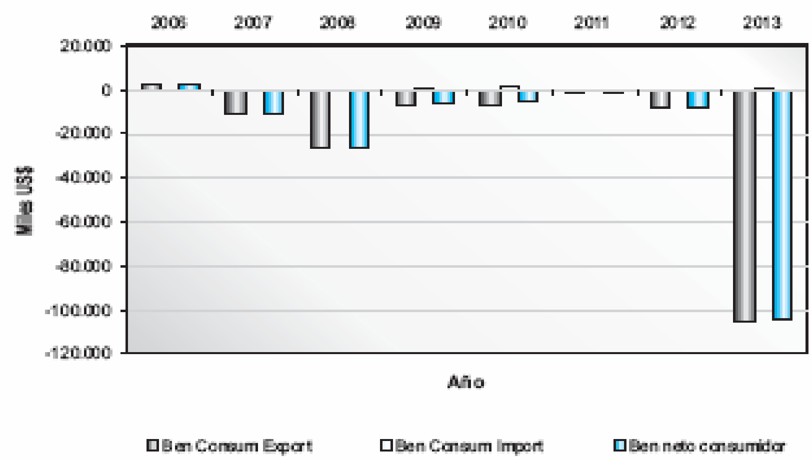
Table 6-3. Impact on final user fees – peak flows

Variation **Percent**	2007	2008	2009	2010	2011
la Tarifa	0,1%	0,2%	0,2%	0,2%	0,2%

6.4.1.2 Average Flow

Chart 6-10 and Chart 6-11 show the impact that expanding the interconnection capacity has on Colombian consumers and producers, respectively.

Chart 6-10. Consumer benefit average flows



Gráfica 6-11. Beneficio Productores caudal medio

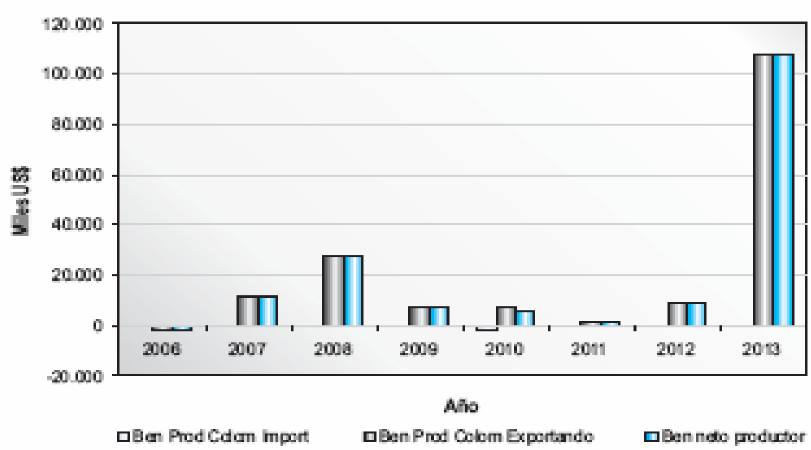


Chart 6-12 shows the impact that expanding the interconnection capacity has on the congestion pricing and Chart 6-13 shows country benefit.

Chart 6-12. Congestion pricing average flows

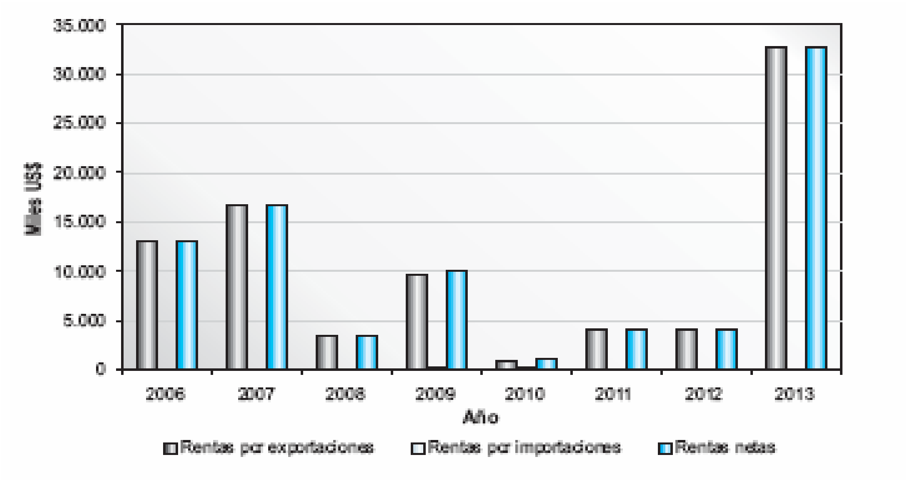


Chart 6-13. Country benefit average flows

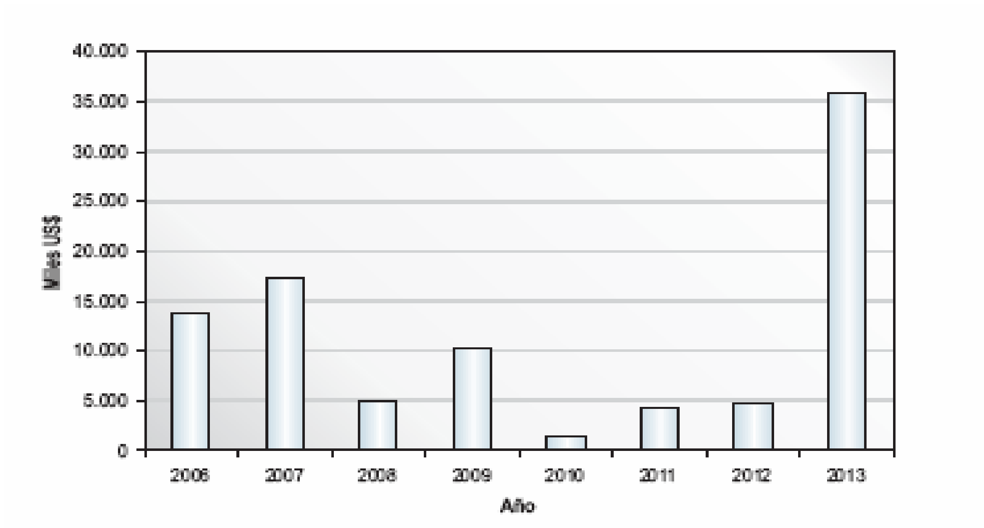


Chart 6-14 Shows the impact that the Transmission component has on Colombian users.

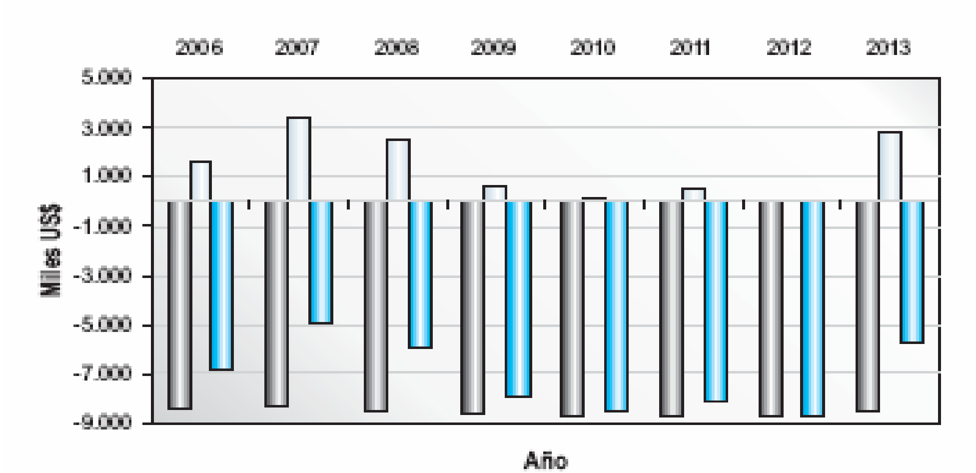


Chart 6-15 shows the impact that reducing the payment of capacity charges, restrictions and losses has on Colombian consumers and the benefit arising from collecting fund contribution. Chart 6-16 shows the net benefit for each of the agents.

Chart 6-15. Benefits for payment reduction in flow means

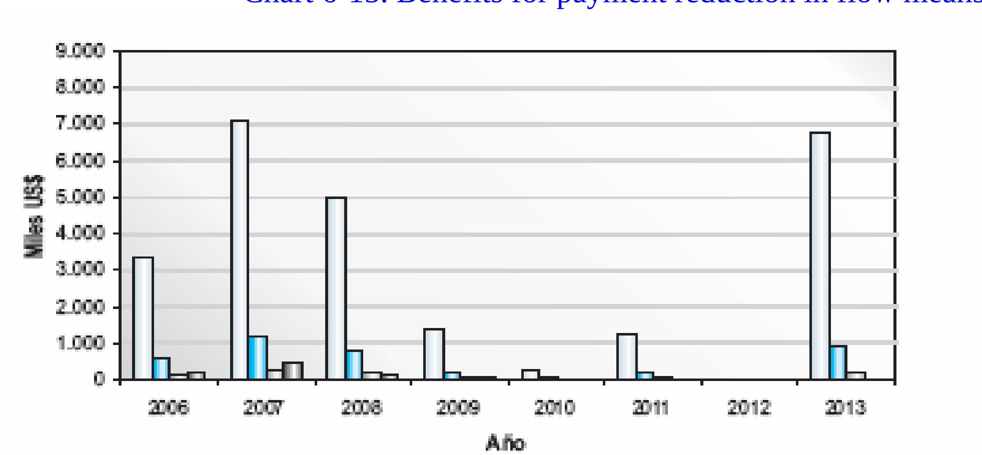
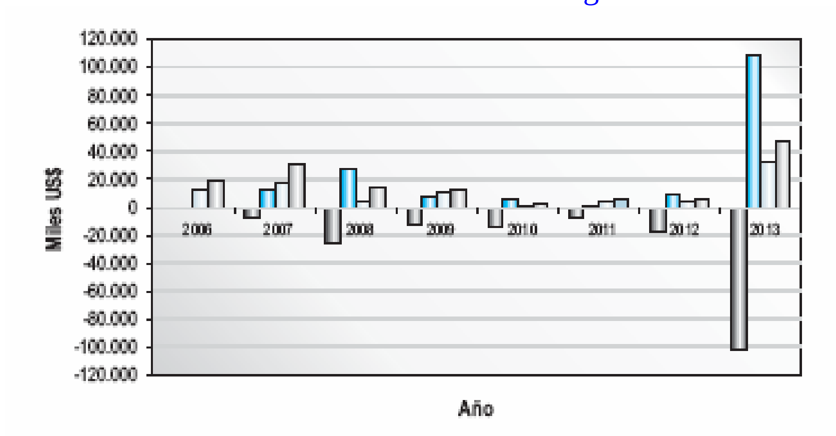


Chart 6 -16. Net Benefit average flows



As it can be seen from the above results, also for average flow conditions the country has a positive net benefit, producer has a positive net benefit, consumer has a negative net benefit and there is an increase in congestion pricing.
The ratio congestion pricing to consumer negative net benefit is 0.53 for the alternative under analysis.

Table 6-4 shows the variation in percentage terms of the impact on final user fees, for the first five years, as regards the project to expand Colombia-Ecuador interconnection from actual capacity to 500 MW, under average flow conditions. This valuation does not take into consideration the effect of restriction cost reduction arising from congestion pricing
Table 6-4. Impact on final user fees average flows

Variation	2007	2008	2009	2010	2011
Percent					
Rate	0,2%	0,5%	0,2%	0,2%	0,1%

6.4.1.3 Lowest Flow

Chart 6-17 shows the impact that expanding the interconnection capacity has on Colombian consumers, under lowest flow conditions.

Chart 6-17. Consumer benefit - lowest flows

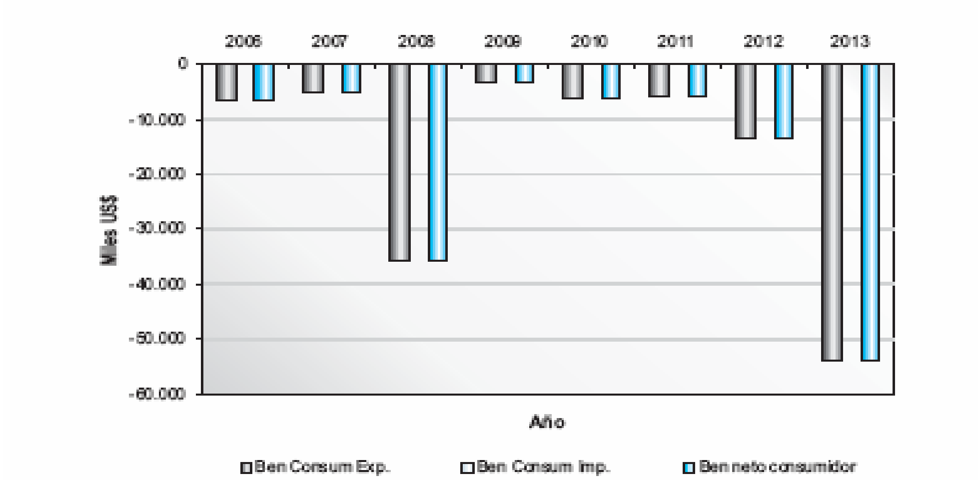


Chart 6-18 Shows the impact that expanding the interconnection capacity has on Colombian producers, under lowest flow conditions

Chart 6-18. Producer benefits - lowest flows

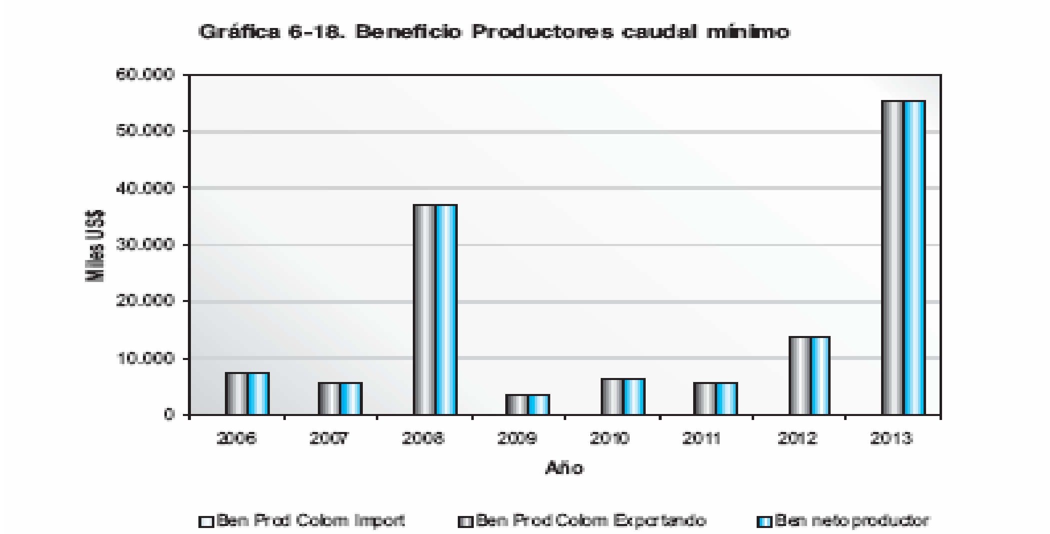


Chart 6-19 shows the impact that expanding the interconnection capacity has on the congestion pricing and Chart 6-20 shows the country benefit, under lowest flow conditions.

Chart 6-19. Congestion pricing - lowest flows

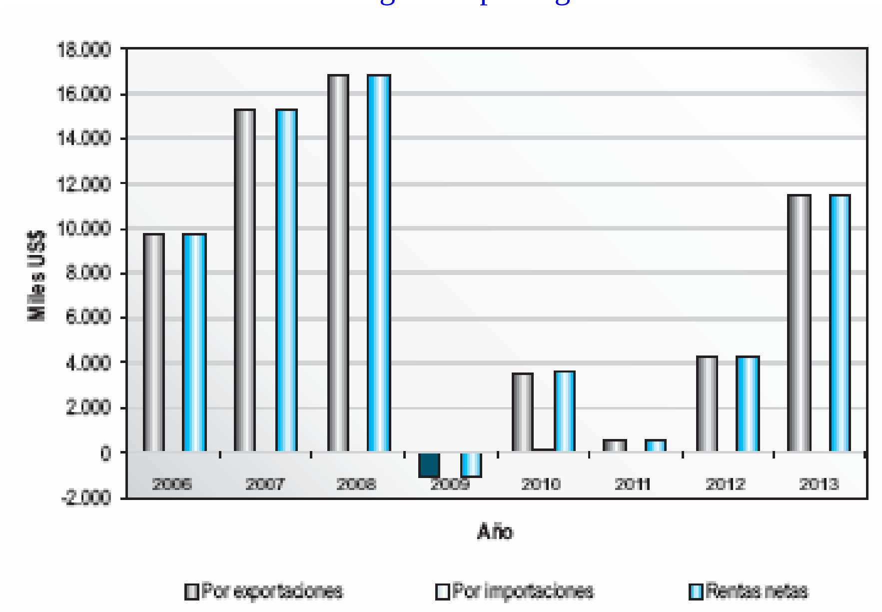


Chart 6-20. Country benefit - lowest flows

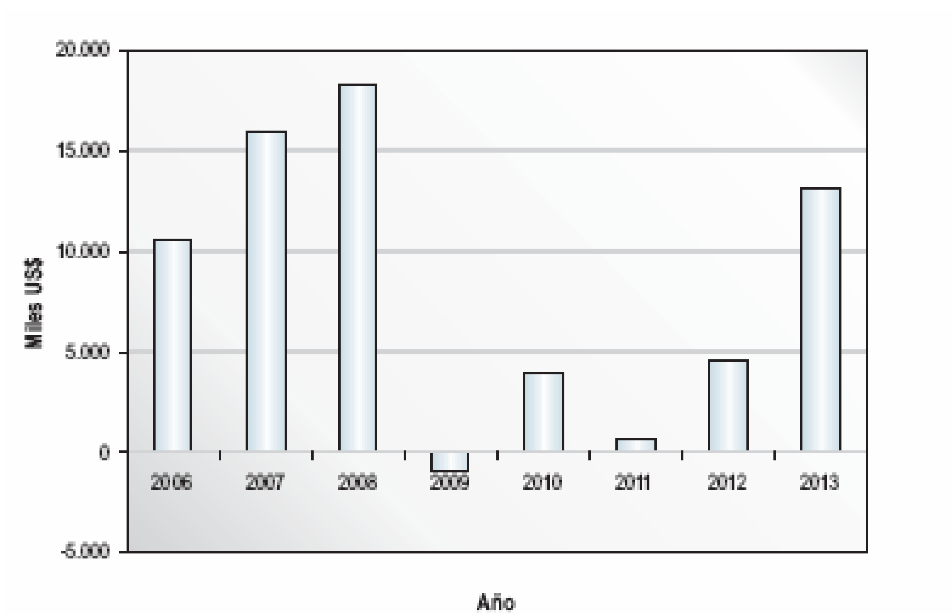


Chart 6-21 shows the impact of the Transmission component on Colombian users, under lowest flow conditions.

Chart 6-21. Impact of Transmission component lowest flows

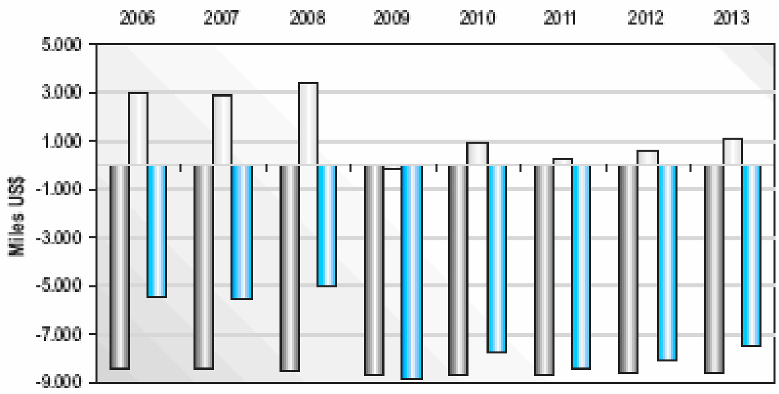


Chart 6-22 shows the impact that reducing the payment of capacity charges, restrictions and losses has on Colombian consumers and the benefit arising from collecting fund contribution in lowest flow conditions. Chart 6-23 shows the net benefit for each of the agents

Chart 6-22. Benefit arising from charge reduction lowest flows

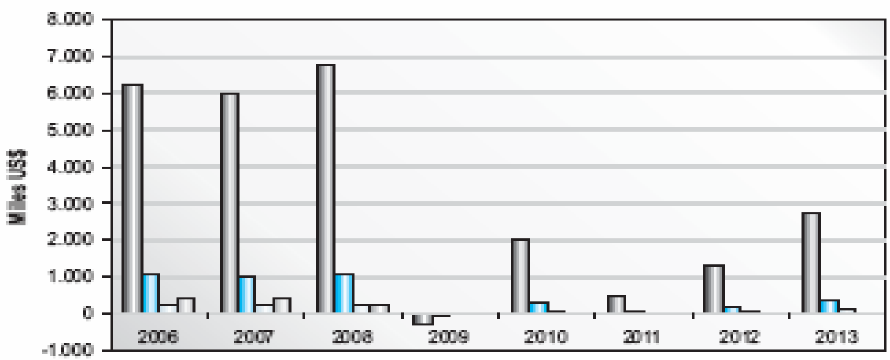
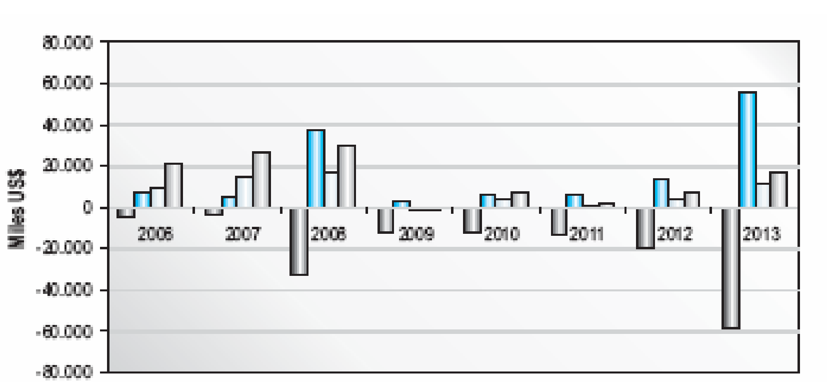


Chart 6-23. Net Benefit lowest flows



Same as under peak and average flow conditions, under lowest flow conditions the country has a positive net benefit, producer has a positive net benefit, consumer has a negative net benefit and there is an increase in congestion pricing.
The ratio congestion pricing to consumer negative net effect is 0.48 for the alternative under analysis.

Table 6-5 shows the variation in percentage terms of the impact on final user fees, for the first five years, as regards the project to expand Colombia-Ecuador interconnection from actual capacity to 500 MW, under lowest flow conditions. This valuation does not take into consideration the effect of restriction cost reduction arising from congestion pricing

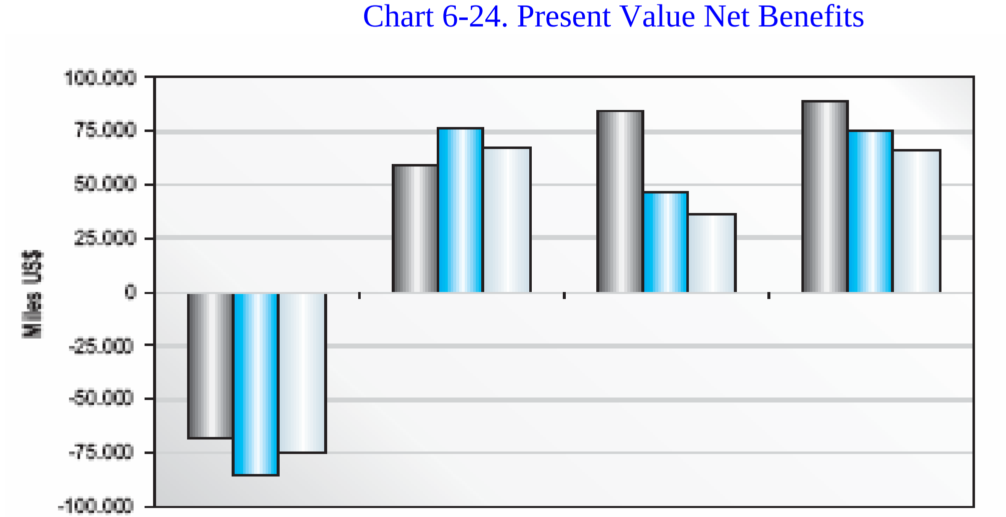
Table 6-5. Impact on final user fees lowest flows

Variación	2007	2008	2009	2010	2011
Percent					
Rate	0,1%	0,7%	0,2%	0,2%	0,2%

6.4.1.4 Results Summary

Chart 6-24 shows the present value of the benefits for each of the agents and for each of the flows applied to the analyses.

Chart 6-24. Present Value Net Benefits



Finally, Table 6-6 shows the summary of compliance with criteria pre-set in the methodology to determine the feasibility of a certain interconnection.

Table 6-6. Criteria to define the feasibility of interconnections

	Benef. País	Benef. Región	RC/BNC_ Betania_ Pomasqui
Caudal			
Máximo	positive	positive	1,24
Caudal			
Mid	positive	positive	0,54
Caudal			
Mínimo	positive	positive	0,48

6.4.1.5 Electrical Analysis

Electrical surveys foresee an expansion of the Colombia-Ecuador interconnection to 500 MW, by way of the Betania-Altamira-Mocoa-Jamondino-Pomasque-Santa Rosa double circuit, and relate to the steady and dynamic status analyses. Steady status analyses relate to load flows and voltage steadiness, whilst dynamic analyses relate to temporary and little signal steadiness.

Cases under study relate to peak load operation conditions, for low-generation scenarios in the South West area and for the years 2206, 2008, 2010 and 2012.

As regards voltage steadiness, the results of sensitivity and modal analyses show that Electric Systems are steady under the different scenarios. The weakest though steady spots are Tumaco, Ipiales and Junin substations at the 115 kV tension level, associated to the Jamondino substation area in Southern Colombia, Curves PV and QV of Tumaco substation show that the latter's operation is steady and that it has an active and reactive power margin.

A three-phase failure in a transmission line with the consequent out of operation status over failure duration of 150 ms is considered to the effects of undertaking the system's temporary steadiness analyses. Results obtained for the highest demand and export of 500 MW from Colombia to Ecuador prove a temporary behavior properly cushioned, which allow concluding that the system is steady for 500 MW transfers from Colombia to Ecuador.

6.4.1.6 Conclusions and Recommendations regarding the expansion of the Colombia – Ecuador interconnection system.

Results obtained show that to achieve a transfer level close to 500 MW it is necessary that Ecuador carries out the interconnection its boundary with Colombia by means of a double circuit line at 230kV and reinforces its Transmission System between Santa Rosa and

Pomasqui.
The Betania – Altamira – Mocoa – Pasto – Limits with Ecuador alternative has further benefits still to be appreciated such as the expansion of coverage in the departments of Huila, Caquetá and Putumayo; the development of energy generation projects in the Caquetá region; the development of the Amazonas frontier zone; and it makes a future interconnection with Lago Agrio oil & gas region in Ecuador viable.
According with the results obtained, the UPME recommends expanding to 500 MW the Colombia-Ecuador interconnection, by a 230 kV double circuit Betania – Altamira – Mocoa – Pasto – frontier line, with operation entry date in December 2006, for which purpose Ecuador should undertake the necessary works: construction of the Frontier- Pomasqui – Santa Rosa double circuit.

6.4.2 Analysis by Area

6.4.2.1 Analysis of Bogotá Area

As regards the short term, the energy and electricity impact of the potential withdrawal of the Paraíso-Guaca generation chain was analyzed, whilst for the long term the studies were performed taking the entry in Bogotá of the 500 MW project into account.

Regarding the potential withdrawal of the Paraíso-Guaca chain, for the energy analysis the system’s marginal cost is calculated bearing expansion strategy LT-3 in mind, from simulations of the ideal delivery with the MPODE model, for a ten-year horizon.

A simulation of the ideal delivery with the number of generating assets (base case) was at first carried out, on which the system’s marginal cost was calculated. Following the same procedure the system’s expected marginal cost was calculated excluding the Guaca and Paraiso generation plants from delivery.

Methodology used to assess such an effect consists of obtaining the monthly difference between the marginal costs of both simulated conditions. Results show that the withdrawal of the Guaca-Paraiso chain entails an average increase of up to 10% of marginal cost.

The System Operation excess cost resulting from the above-mentioned withdrawal (which might amount to 1,385 million 2003 US dollars) is obtained with the difference in Marginal Costs and the monthly demand for energy in Colombia

On the other hand, such a withdrawal has significant impact on the system’s energy reliability which might even result in infringement of the reliability limits, leading to potential energy rationing.

Electrical analyses for 2005 and 2006 do not include the 500 kV Primavera-Bacatá project, since its entry into operation is foreseen by October 1, 2007, and they consider the impact of the potential withdrawal of the Guaca-Paraiso chain from the System. Results under regular operation show that total generation assets are required to operate in order to comply with operation criteria, which entail an increase in operation costs arising from minimum generations in the area.

Chart 6-25 shows the impact that withdrawing Guaca-Paraíso chain in 2006 will have on the electrical reliability, considering non-availabilities arising from technical failure. Even if the Power Rationing Expected Values (PREV) are lower than 1% in all area bars in absence of the Guaca-Paraíso generation, they are higher than PREV ratios in the presence of Guaca-Paraiso, which represents an operating overcharge for 2006 of around 0.75 MUS$.

Chart 6-25. Power Rationing Expected Value by Bar

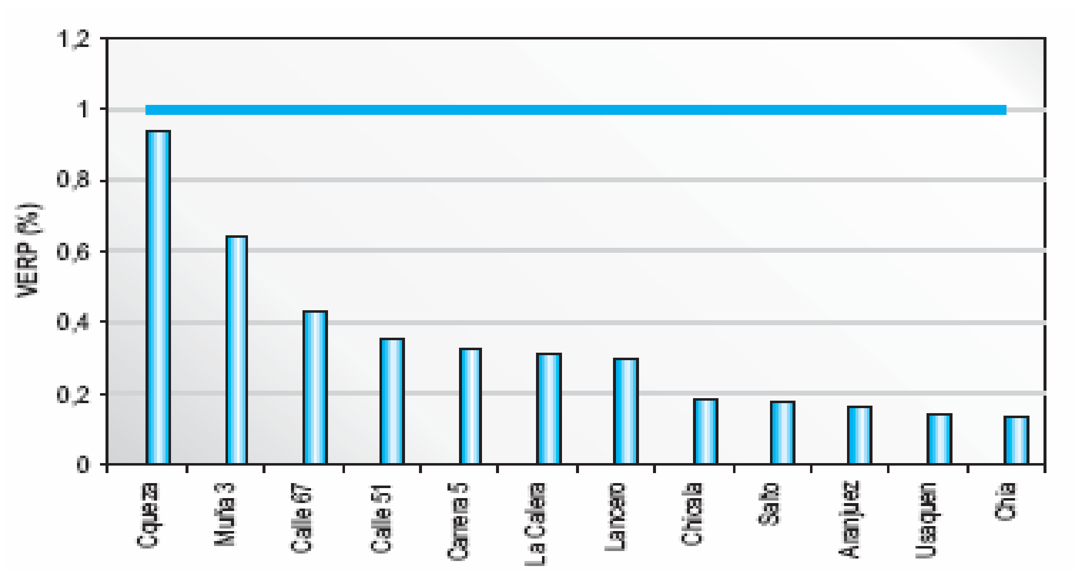
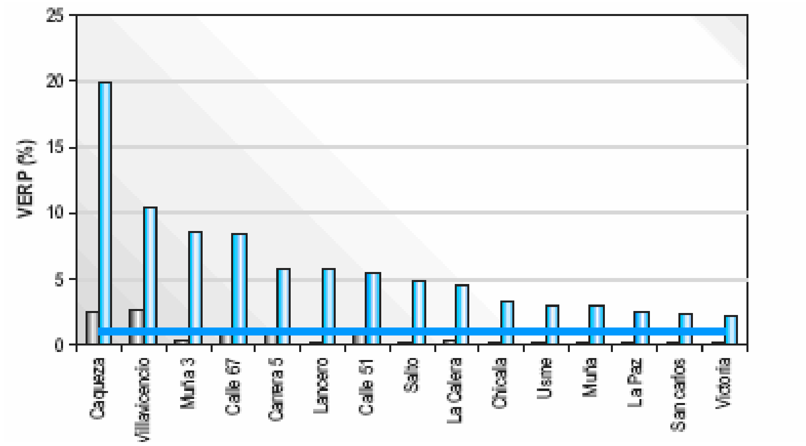


Chart 6-26 shows the impact that withdrawing Guaca-Paraíso chain in 2006 will have on the electrical reliability, considering non-availabilities arising from terrorist attack. Power Rationing Expected Values (PREV) ratios are 20% in Cáqueza and 10% in Villavicencio in absence of the Guaca-Paraíso generation, whilst with such generation PREV ratios for these substations go down to 3% . Such difference in PREV ratios represents an operating overcharge for 2006 of around 41.6 MUS $.

Chart 6-26 . Power Rationing Expected Value by Bar



As regards long term analyses including the entry of the 500kV project in Bogotá, the expansion of capacity in Circo 230/115 kV and in the Suba – Zipaquirá 115 kV line is mentioned as part of the results reached for 2012.

The following version of the Expansion Plan will analyze this area in detail, in the long as well as in the short term.

6.4.2.2 Analysis of Meta Area

As regards this horizon it is found that with the expansion submitted by the NO no overcharge or low tension level problems are expected in the area.

6.4.2.3 Analysis of North Eeastern Area

As mentioned when referring to the above-mentioned expansion plans, for 2006 tensions below 0.9 p.u are foreseen in the area as well as overload in the Bucaramanga and Barranca 230/115 kV transformers, problems aggravated with the growth of demand. Additionally, in 2008 overloads are foreseen in the Palenque 115/34.5 kV transformer and in the 115 kV Realminas-Bucaramanga line.

In order to eliminate such overloads without having to resort to rationing in the area it is recommended to expand the transformation capacity in these substations, since there is no enough energy generation at the 115 kV level to eliminate the overload11.

According with the connection survey submitted by EBSA towards installing a third transformer with 180 MVA capacity in 230/115 kV Paipa substation, for 2005 there is a

360 MVA transformation capacity available. Consequently, it is noticed that transformation overload problems are overcome.

6.4.2.4 Analysis of CQR (Caldas – Quindío – Risaralda) Area

As mentioned when referring to the above-mentioned expansion plans, tensions below 0.9 p.u are foreseen in this area as well as overload in La Hermosa transformer.

Some possible solutions were presented as part of the long term analysis in section 6.3.3, which include increasing the generation in the area at a 115 kV level or expanding the transformation capacity in La Hermosa substation. It has been considered that existing 115 kV Regivit – Cajamarca and 115 kV Papeles Nacionales – Dosquebradas links normally operate closed.

As area demand growths problems aggravate and Esmeralda transformers and Hermosa-Regivit overload. However, these problems may be solved by expanding generation at a 115 kV level.

At the end of the horizon it is not possible to solve the problems by expanding generation at a 115 kV level, reason why it is necessary to expand the transformation capacity in Esmeralda and analyze other alternatives such as the entry of 115 kV Pavas substation, which would connect with 115 kV Dosquebradas and 115 kV Virginia, or the entry of a 230 kV level substation in Armenia. It should be borne in mind that any recommendation adopted by the Network Operator should represent a lowest cost solution to users.

6.4.2.5 Analysis of EEPPM Area

No problems are foreseen in this area for this horizon.
11 Barranca 4 and 5 plants were moved to Yopal and Barranca 1 and 2 plants are for the use of ECOPETROL.

6.4.2.6 Analysis of EPSA Area

For 2006 and for the peak demand conditions in the area, overload is foreseen in the TNS connection transformers, which is relieved with the alternative presented in the OR's expansion plan corresponding to 230/115 kV San Marcos second transformer.

In OR's expansion plan, Attachment B, additional works are included in the planning horizon, which should be studied jointly with the UPME to define the best alternatives and their entry date into operation.

6.4.2.7 Analysis of Tolima – Huila – Caquetá Area

As indicated in the 2003-2012 Expansion Plan, for 2006 overloads are foreseen in the 230/115 kV Mirolindo transformer. The 115 kV Cajamarca – Regivit link operation which is normally closed, was studied as an alternative which reduces the load ability of Mirolindo transformer but increases that of the 230/115 kV Esmeralda transformers. Therefore, the alternative is the expansion in 230/115 kV Mirolindo transformation capacity.

This review of the Expansion Plan further studies the problem of satisfying the demand in Altamira, Pitalito and Florencia substations, since tension low level problems in this area are foreseen arising from failure to consider expansion projects. The following are the alternatives submitted to solve these problems:

* 115 kV Betania – Altamira Second Line.

* 230 kV Altamira Substation, 230 kV Betania – Altamira line with its relevant line modules and 90 MVA 230/115 kV transformation.

It is noticed that under regular operation conditions in 2006 and without expansion alternatives in this zone it would be necessary to ration 7% of the load in area substations, namely Altamira, Pitalito and Florencia. There is no need for rationing under regular operation if posted alternatives are included.

Year 2012 is critical in the zone if no expansion alternatives are available, making it necessary to ration 40% of the load in area substations under regular operation conditions. For this year it is noticed that the 115kV Betania-Altamira alternative is not sufficient to solve area problems, and that it is necessary to ration 26% of the load in these substations under regular operation conditions. Rationing is not required under regular operation conditions with the 230 kV Betania-Altamira alternative.

Table 6-7 shows a summary of the cost of rationing for 2006 and 2012 both for the basic case and including alternatives.

Table 6-7. Cost of Rationing Huila – Caquetá Area

	Rationing Cost	
	Year 2006	**Year 2012**
Generation Betania	3 ud	3 ud
Rationing Cost no alternatives MUS$	2,4	40
Rationing Cost with alternatives Betania Altamira 115 kV MUS$	0,53	26

Rationing Cost with alternatives Betania Altamira 230 kV MUS$	0,057	0,141

6.4.2.8 Analysis of Cauca – Nariño Area

As stated when referring to the above expansion plans, load ability levels very close to 100% are foreseen in 230/115 kV Jamondino transformer for 2006, even with the area generation at 115kV turned on. Consequently, expansion of the 230/115 kV transformation capacity of Jamondino substation is being considered. These analyses do not include exchanges through the Colombia-Ecuador interconnection system at the 138 kV level; exchanges are included through the Colombia-Ecuador interconnection system at the 230 kV level.

6.4.2.9 Analysis of Bolívar Area

As stated when referring to the 2003-2012 Expansion Plan, the steady status analyses show that the low-tension problems in some of the nodes in the area are relieved with the expansion plan submitted by the NO –Attachment B.   However, for 2006 overload problems are foreseen in the 66kV Cartagena-Chambacú line, which, pursuant to the entry schedule submitted by the OR, will change the level tension from 66 kV to 110 kV in 2008.

For this reason we hereby reiterate the recommendation submitted to OR in the sense of analyzing the possibility of bringing this circuit's conversion forward to 2006.

6.4.2.10 Analysis of Guajira – Cesar – Magdalena Area

Several overloads are foreseen for 2008 in the Fundación and Copey 220/115 kV transformers and in the 230/34.5 kV Valledupar transformer. Consequently, should no other alternatives be considered, the recommendation is to expand the transformation capacity.

6.4.2.11 Analysis of Chinú Area

As stated when referring to the 2003-2012 Expansion Plan, the 500/110 kV Chinú transformers show load ability values close to 100% in 2006 and such values may be exceeded as from 2008.

Alternatives posted to solve this problem are installing a third transformer in 500/110 kV Chinú or the 220 kV Urrá-Montería line. Results show that the performance of both alternatives is alike. Consequently, it is recommended to carry out the alternative of installing a third transformer in 500/115 kV Chinú, for its cost is 5,1M US$ of 2001, AOM included, whilst the cost of the 220 kV Urrá-Montería alternative is 19.6M US$ of 2201, AOM included. Nevertheless, the NO should submit an economic evaluation of both alternatives including investment costs required at a tension level other than the NTS, so as to make a particular decision.

6.4.3 An analysis of the Colombia – Panama Interconnection System

Even if this version of the Expansion Plan is not intended to give a recommendation as regards this project's feasibility, certain preliminary analyses of the interconnection are provided considering that it is necessary to define the trade model to carry out the transactions between Colombia and Panama.

Connection alternatives submitted by ISA in its request for connection are initially described, followed by a preliminary analysis performed by the UPME regarding the assessment of the economic benefits arising from the interconnection, for which purpose the actual trade model applied with Ecuador, TIES, was used.

6.4.3.1 Alternative 1

This alternative includes a conventional AC double circuit line at 230 kV. Such a line starts from 230 kV Urabá substation in Colombia and goes through the Apartadó, Carepa, Chigorodó, Turbo, Unguía and Acandí municipalities; it then goes by Bayano substation finally reaching 230 kV Panama II substation with approximate length of 434 kms from Urabá.

Given the length of the interconnection, the convenience of having an intermediate substation in Panamanian territory to handle the tension by shunt compensation is to be reviewed, thus resulting in the configuration of 217 km Urabá – S/E Intermediate and 217 km S/E Intermediate – Panamá II double circuit lines. Chart 6-27 shows the basic route for this alternative as from which the needs for compensation and transmission reinforcement in both countries' networks will be reviewed.

Chart 6-27. Alternative I

Source: ISA

6.4.3.2 Alternative 2

This alternative consists of the connection between Cerromatoso and Panama II through a monopole bond in HVDC at 250 kV with a maximum extension of 514 km, which leaves from Cerromatoso substation to Mulatos town in Colombia, goes into the sea and surfaces close to Carreto, and from there it follows the same route as Alternative 1.

Chart 6-28 shows the basic route of this combined alternative, wherein converters would be located in Cerromatoso and Panama II; the underwater portion would be made of cable with an approximate length of 51 kms and land portions would be DC aerial line of approximately 463 kms.

Chart 6-28. Alternative II

Source: ISA

6.4.3.3 Alternative 3

This alternative consists of a monopole HVDC aerial line at 250 kV with a land route from Cerromatoso substation, passing by Urrá substation, and then it goes to Urabá substation and continues along the same alternative 1 route. Total length of this alternative is 571 km and converters would be located in Cerromatoso and Panama II. Chart 6-29 shows this alternative's basic route.

Chart 6-29. Alternative III

Source: ISA

6.4.3.4 Connection Survey Conclusion

According with the connection survey submitted by ISA, the DAA has identified several viable routes which in summary might lead to two main alternatives, one of them a ground alternative and the other a combined alternative with a underwater portion and a ground portion.

The cost of the HVAC alternative would be approximately 173 M US$; the survey submitted by ISA indicates that this alternative is unsteady facing contingencies, including with Ecuador. For this reason it considers that this alternative is not viable from a technical viewpoint.

Alternatives 2 and 3 which foresee HDCV transmission show an appropriate electrical behavior.
Converters provide steadiness to the system and isolate the effect of electrical contingencies from each another. This way the interconnection between Colombia and Panama is technically viable, allowing 300 MW exchanges from Colombia to Panama and 200 MW exchanges from Panama to Colombia.

Approximate cost of alternative 2 is 192M US$, of which 107M US$ are the Colombian portion.

Approximate cost of alternative 3 is 172M US$, of which 87M US$ are the Colombian portion.

6.4.3.5 Preliminary Assessment of Economic Benefits arising from interconnecting Colombia and Panama

To assess these benefits an analysis is carried out similar to that described in section 6.4.1, and only an average flow is taken into consideration.

Chart 6-30 shows the impact that the Colombia-Panama Interconnection has on Colombian consumers.

Chart 6-30. Consumer Benefit

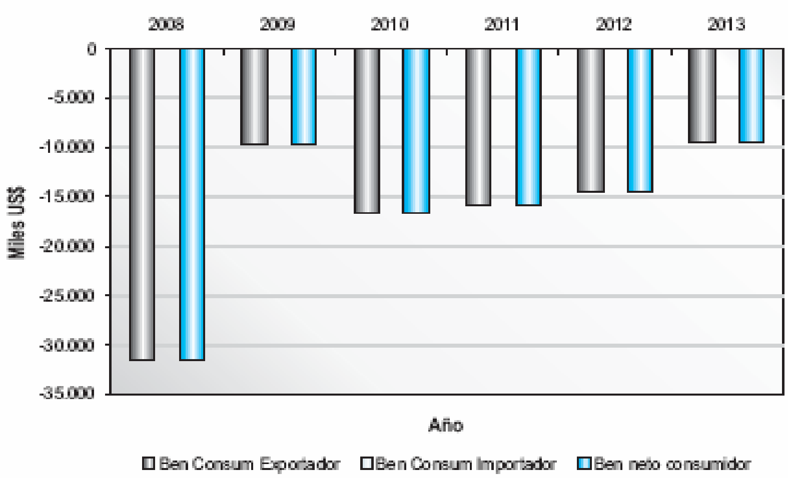


Chart shows the impact that the Colombia-Panama Interconnection has on Colombian producers.

Chart 6-31. Producers Benefit

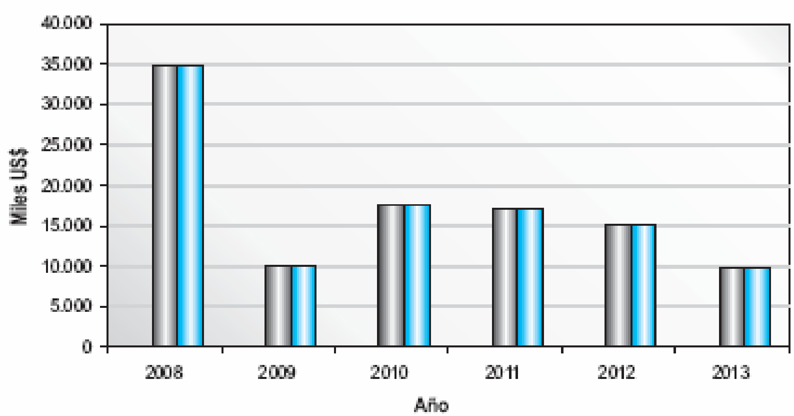


Chart 6-32 shows the rentas de congestion arising from Colombia-Panama interconnection; these values include changes regarding the allotment of peak income established by CREG Resolution 060 of 2004, and Chart 6-33 shows country benefit.

Chart 6-32. Peak Income

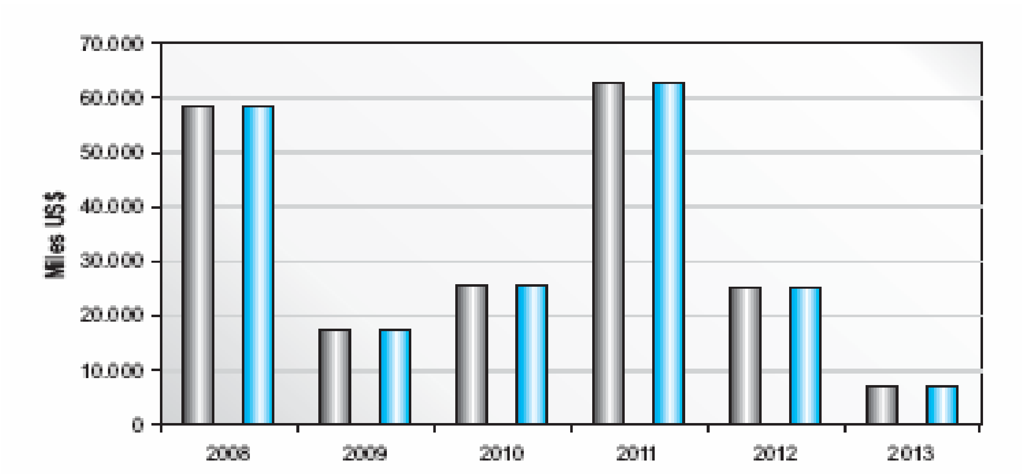


Chart 6-33. Country Benefit

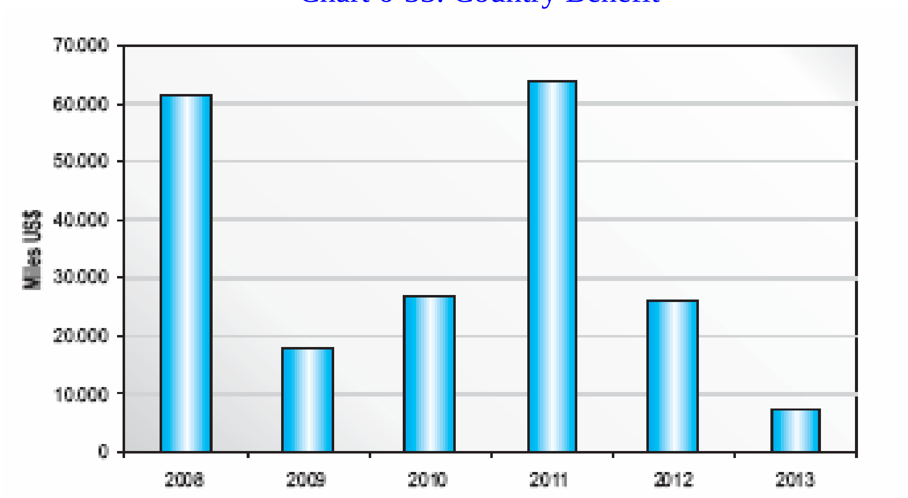


Chart 6-34 and Chart 6-35 show the impact that the transmission component has on Colombian users.

Chart 6-34. Transmission component impact under alternative 2

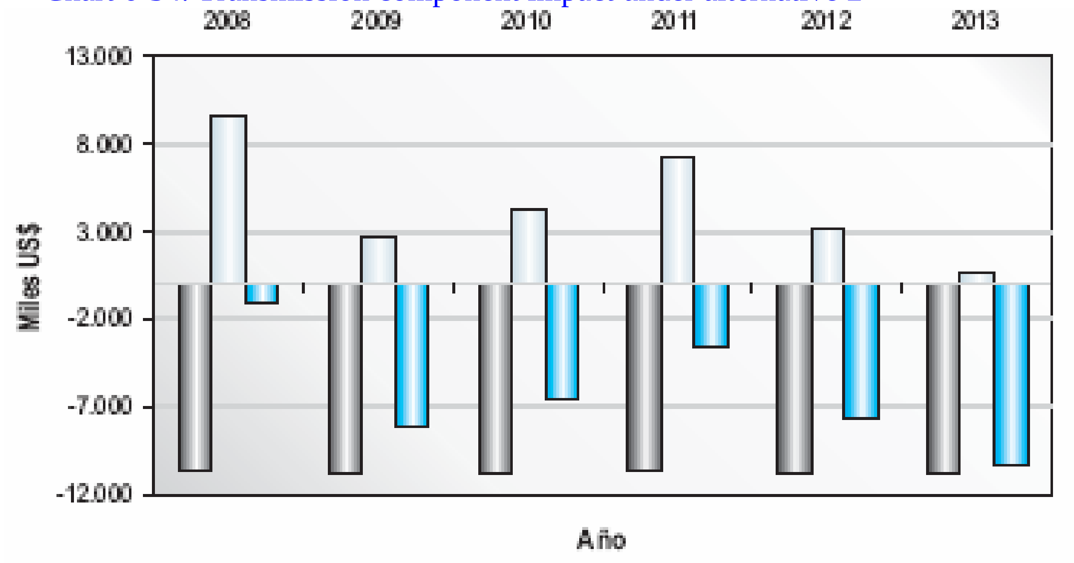
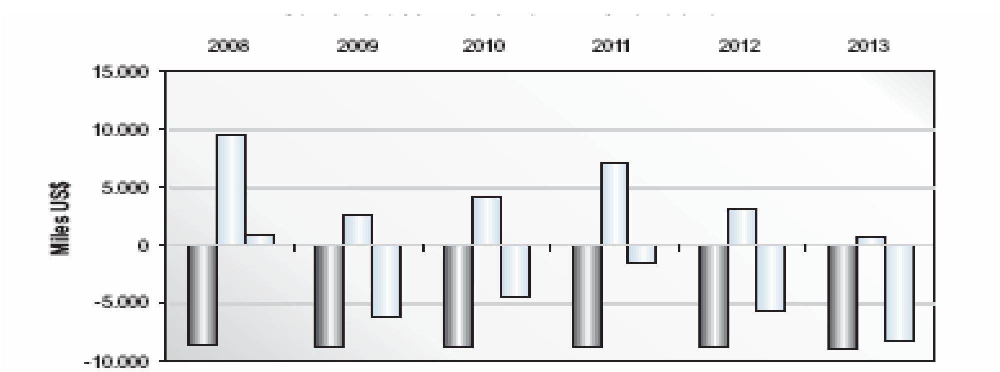


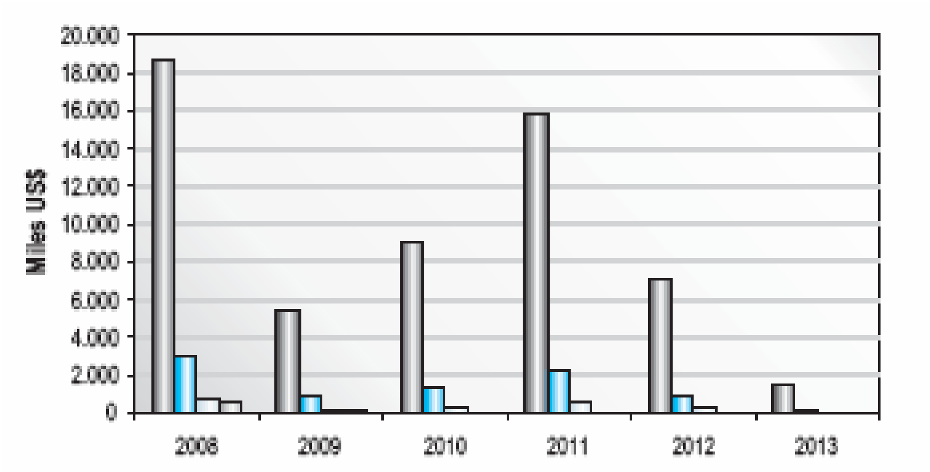
Chart 6 -35. Transmission component impact under alternative 3
Cerromatoso – Panama ground HVDC



Year

Chart 6-36 shows the impact that the reduction in the capacity charges, restrictions and losses has on Colombian consumers and the earnings arising from the contribution of FAZNI and FAER funds.

Chart 6-36 Benefit from load reduction



Charts 6-37 and 6-38 show the net benefit for each of the agents.

Chart 6-37. Net benefit under alternative 2 Cerromatoso – Panama II combined HVDC

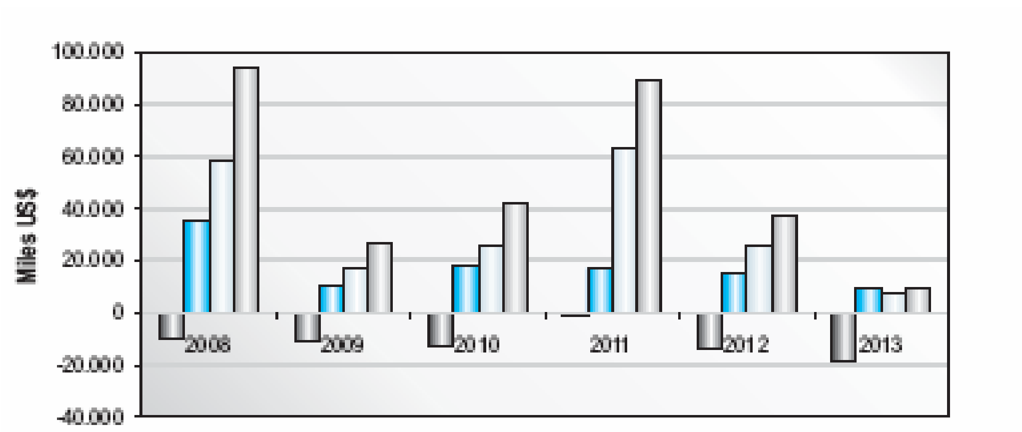
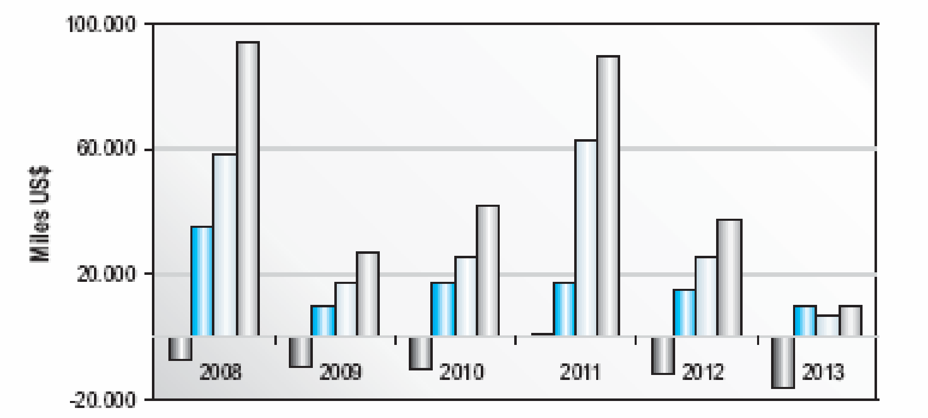


Chart 6-38. Net Benefit under Alternative 3 Cerromatoso – Panama ground HVDC

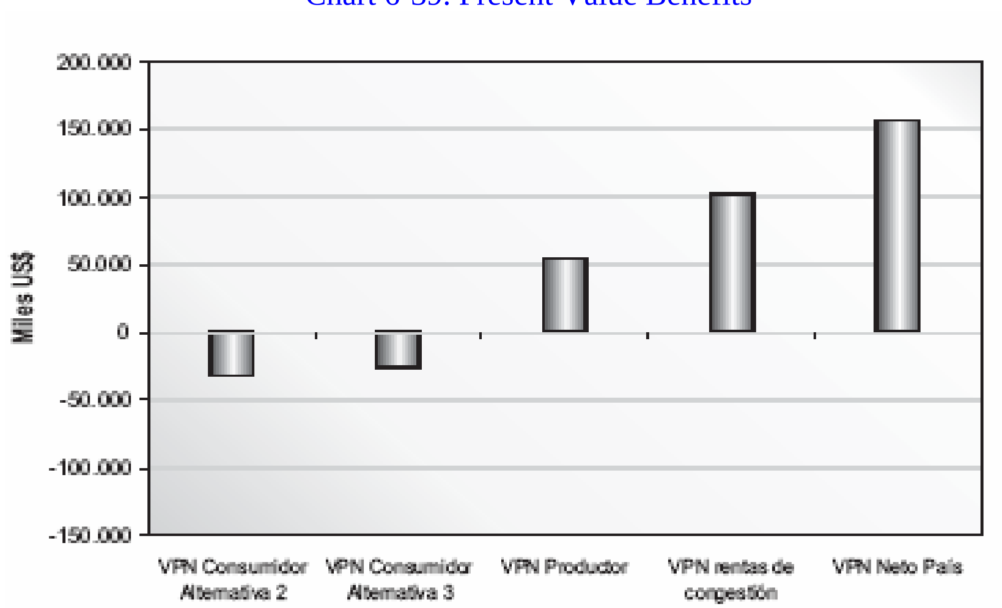


As it can be noticed from the above results, the country shows a positive net country effect, producers have a positive net benefit, consumers have a negative net benefit and there are earnings arising from rentas de congestion.

The ratio rentas de congestión to consumers' negative net effect is 3.31 for alternative 2 Cerromatoso-Panama II combined and 4.06 for alternative 3 Cerromatoso-Panama II ground.

Chart 6-39 shows the present value of benefits for each of the agents.

Chart 6-39. Present Value Benefits



6.4.4 Short circuit level at NTS substations

Attachment D show the short circuit level at NTS substations; as mentioned in the 2003-2012 Generation-Transmission Expansion Plan, the short circuit level at 230 kV San Carlos substation will break this substation's equipment capacity, which is 40 kA.

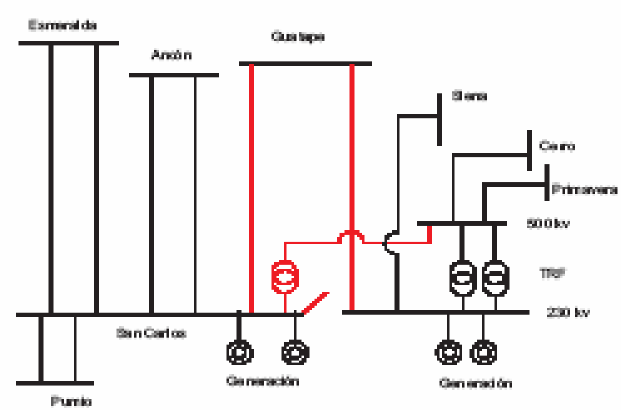
Alternative solutions analyzed by ISA and submitted with the 2003-2012 Expansion Plan were bar sectioning, changing substation equipment, and doing nothing.

In its document "ISA UENCND 03-193, An Analysis of Expansion Alternatives to Eliminate or Reduce 2003-2010 period restrictions", the CND submits three additional alternatives to solve the breaking of short circuit level at San Carlos substation which show better options and have been thoroughly studied, as follows:

6.4.4.1 Alternative 1: Substation sectioning

This alternative consists of placing two fields to make the substation sectioning easier wherever delivery conditions appear which activate the restriction. Placing of these switches and re-distribution of several substation circuits allow distributing the generation from the central station as well as transformation at 500 kV between both substations, as shown in Chart 6-40.

Chart 6-40. Alternative 1



Source: CND

The advantage of this alternative is that it solves the short circuit level breaking problem at a low investment requirement.

Disadvantages are:

* It reduces the substation reliability since the operation impact of a contingency (overload) is higher than that when the substation is integrated and the same contingency arises.

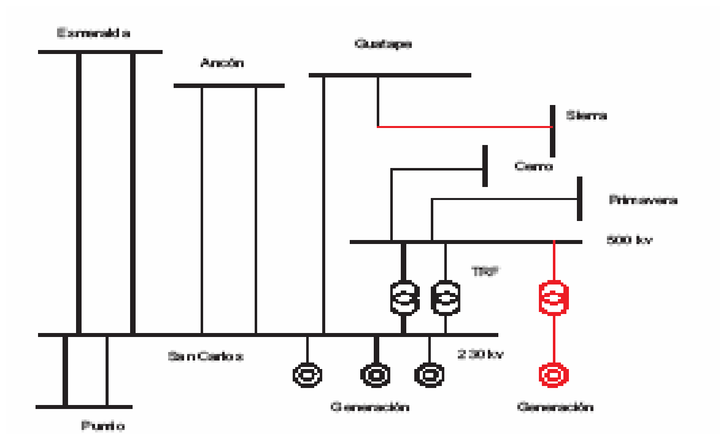
* It creates a transformation unbalance since the transformer on the left section takes a substantially lower load than transformers on the right. This situation is slightly lightened if instead of operating with both circuits (San Carlos-Ancon Sur) two additional circuits Guatapé-San Carlos are built using the so-called diversion.

* A transformation unbalance is produced since San Carlos-Guatapé circuits are located in different sections, with different loads. This may lead to error during operation or electrical analysis.
* It introduces a new variable (short circuit level control) to delivery and operation, unless a decision was made to operate full time with the sectioned substation, which may result in de-optimization of the operation.

6.4.4.2 Alternative 2: Deriving two generation units directly to 500 kV.

This alternative consists of opening the two switches associated with North and South bars thus allowing that electricity generated in San Carlos units 1 and 2 enter directly at 500 kV and reshaping Guatapé-San Carlos 1 and San Carlos-La Sierra circuits into the Guatapé-La Sierra circuit as shown in Chart 6-41:

Chart 6-41. Alternative 2

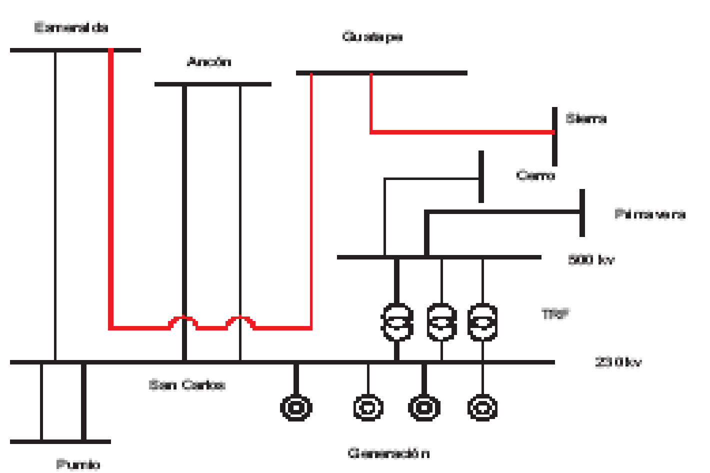


Source: CND
This alternative has the following advantages:
* It solves the short circuit problem.
* It does not create a transformation unbalance.
* Investment is lowest or none given that the infrastructure to set the Guatapé-La Sierra circuit already exists as it has been used in the events of terrorist attach against the infrastructure.
This alternative's disadvantage is that it de-optimizes San Carlos transformation capacity in 140 MW upon 450 MWA transformation bench becoming only required to release the generation of two of San Carlos units with 310 MW maximum capacity.

6.4.4.3 Alternative 3: Modifying actual topology in 230 kV to derive energy injection.

This option consists of re-shaping Guatapé-San Carlos 1 and San Carlos-La Sierra circuits into Guatapé- La Sierra circuit by 2004, and re-shaping Guatapé-SanCarlos 2 and San Carlos-Esmeralda 1 circuits into Guatapé-Esperalda circuit by 2007, as shown in Chart 6-42.

Chart 6-42. Alternative 3



Source: CND

This alternative has the following advantages:
* It solves the short circuit problem.
* Low investment required represented in an additional tower close to San Carlos substation and a short line section.
No disadvantages have been identified so far as regards this alternative.

6.4.4.4 Conclusion

Out of alternatives submitted to solve San Carlos substation short circuit level breaking problem, Alternative 3 may be the most feasible given the low investment required and its non-producing negative side effects.
6.4.5 Connection of Porce III Electricity Generation Project
Several alternatives to connect Porce III project to the National Transmission System were submitted and analyzed as part of the 2003-2012 Expansion Plan, showing that the lowest cost alternative is the construction of a new 500 kV substation to be connected to the actual 500 kV system by interrupting the 500 kV Cerromatoso-San Carlos circuit.

Considering that these works will be a part of the National Transmission System, the completion schedule is foreseen at two and a half years, including the RFP.

During 2004 the Energy and Gas Regulation Commission (CREG by its acronym in Spanish) was requested to clarify that related with the connection contract and the manner in which generation companies are to submit their compliance bonds to warrant expansion works for the NTS, so as to issue the relevant connection opinion and start the RPF process thereto.

6.5 RESULTS OF THE 2004 PLAN

On the grounds of the analyses carried out, it is hereby recommended to perform the following works:

Double circuit Betania – Altamira – Mocoa – Pasto – Ecuador Frontier line at 230 kV and its relevant line modules, 37.5 reactive compensation, Mvar at 230 kV with operation entry date on December 1, 2006, provided Ecuador carries out the required reinforcement of its Transmission System, double circuit Frontier- Pomasqui- Santa Rosa line at 230 kV.

Additionally, the UPME reiterates its invitation to the NOs to jointly undertake analyses that lead to establishing better solutions to the problems encountered by the UPME.

Costo de gestión ambiental en la expansión eléctrica

Cost of Environmental Management in Electric Expansion

. 7. Cost of Environmental Management in Electrical Expansion Plans

This chapter contains the environmental assessment of the projects considered as part of the transmission and generation expansion plans, so as to determine the reference environmental impact guidelines to send signals to the various agents, namely investors, environmental authorities, local authorities, etc.

It is important to clarify that these values have been calculated based on estimations and consequently they are subject to the judgment of anyone who applies them in any manner.

7.1 COST OF TRANSMISSION ENVIRONMENTAL MANAGEMENT

Environmental management estimated costs hereunder refer to NTS expansion project herein recommended, and directly relate to its length and tension level, i.e. a 370 kms Betania-Altamira-Mocoa-Pasto-Ecuador Frontier line at 230 kV

Table 7-1 shows survey environmental management costs, which reach 874.527 dollars of 2003, or approximately 2364 US$/km.

Table 7-1. Survey Environmental Management Costs

Environmental Management Costs for Studies	Cost (US$)
Diag. Environmetal Alternatives	98.896
Environmetal Impact Studies	618.461
Audit management DDA by owner	19.230
Audit management EIA by owner	68.678
Evalution service DAA	34.631
Evalution service del EIA	34.631
Cost w/o study	874.527

Table 7-2 shows construction environmental management costs, amounting to 4.133.769 dollars of 2003, or approximately 11.172 US$/km

Environmental Management Costs in Construction	Cost US$
Erosion control	364.220
Reforestation	2.293.865
Handling ethnic minorities	27.280
Population resettling	277.437
Information & community participation	93.395
Razing vegetable layer	30.950
Patio structures	9.400

Flight deviators	92.752
Signaling and guidebook	7.125
Environmental training	14.651
Residue handling	6.100
Archeological handling	219.768
Assessment follwup	21.038
Environmental Management - contractor	329.653
Environmental Management - owner	95.599
Environmental audit	250.536
Cost in construction	4.133.769

Table 7-3 Shows construction environmental management costs of operation which amount to 217.438 dollars of 2003, or approximately 588 US$/km.

Table 7-3. Operation Environmental Management Costs

Costo Gestión Ambiental in la Operación	Costo US$
Community relations	21.380
Interinstitutional Coordination	33.912
Tree care	153.894
Assessment & followup	8.252
Operational Costs	217.438

Tables 7-4 and 7-5 show the impact of various indicators on construction and operation costs; it can be noticed that the indicator "Fragmentation Influence" has a greater impact on construction, whilst indicator "Potential Territory Reduction" has a null impact thereon.

Table 7-4. Indicator Impact on Construction

Impact on Construction	Amt.
Mod Vegetable Layer	4,54
Influence Fragmmentation	7,78
Pressure veg. resource I	4.04
Suseptability erosion	3.73

Pressure land fauna Resource V	1.73
Cultural complexity	2.50
Age settling	4.18
Modifying settling	4.22
Decrease territory	0.00
Potentially displaced population I	4.60
Susceptibility community affect	5.40
Susceptibility Structural Modificación Estructura Social	4.46

Table 7-5 shows the indicators having the greater impact on the project's operation phase, which in general related to biotic aspects.
Table 7-5 Indicator Impact on Operation

Impact on the operation	Amt.
Pressure veg. resource II	3,80
Pressure land fauna Resource VI	6,47

7.2 COST OF GENERATION ENVIRONMENTAL MANAGEMENT

Environmental management costs during the construction and operation stages of the projects are included herein for the short term alternatives and the long term strategies.

7.2.1 Short Term Alternatives

From the viewpoint of generation Environmental Management potential costs in the short term, 2 alternatives are to be analyzed; the first one gathers alternatives ST-1 and ST-3, given that the projects are the same, and the second alternative gathers ST-2 and a 78 MW hydraulic project with entry in 2008. Ongoing projects considered are La Herradura (19,7 MW), La Vuelta (11.8 MW), Jepirachi (19,5 MW), and Termo Yopal 1,2 y 3.

Table 7-6 shows potential costs in the construction and operation stages for the two alternatives just referred to. Main component of these costs is contractor's environmental management costs, project owner's environmental management and technical audit during construction, which make up to 50% of total cost.

Table 7-6. Potential Costs (US$000's)

	Construcción	Operación
Alternative 1	922	482,5
Alternative 2	2430	585,4

Alternative 2 has higher potential construction and operation costs due to the inclusion of the 78 MW hydraulic project in 2008. Construction environmental management costs have a low impact on the cost structure, since the biotic, physical and social impact is the lowest as well as investments required to develop environmental management plans.

7.2.2 Long Term Strategies

In the long term the LT-1 and LT-2 generation expansion strategies only take into consideration the entry of Porce III (660 MW) hydric project, and the cost of the environmental management is approximately 9.2 million dollars during the construction stage and 0.44 million dollars during the operation stage.

Porce III project's physical costs represent 47% of total cost, considering the sensitivity to erosion of the region where the project is developed and erosion control handling costs, whilst for Amoyá project the highest cost percentage is that of Technical Audit and Management (46%), and the physical costs amount to 23%.

LT-3 strategy includes closure of open cycles at present in operation on the Atlantic Coast in addition to the hydraulic project. Environmental management costs to close existing cycles were not calculated in the plan version hereunder.

7.2.3 Payment of transfers arising from the sale of energy and 1% investment

The payment of transfers in hydroelectric and thermoelectric projects serves as a guide to investors for it completes the structure of the projects' environmental management costs.

The following data are used to calculate such transfers:

* Installed nominal power in MW.
* Hydroelectric usage factor expressing the ratio average energy expected to be produced according to market conditions, to electricity generation installed capacity for the plant under study, as a percentage value.
* Energetic regulation fees pursuant to CREG Resolution 135 of 1997 which needs to be adjusted pursuant to the CPI (Consumer Price Index)
* Dollar official market Exchange rate
* Energy gross sales

Table 7-7 shows the transfer value as regards each of plant's usage factor.

Table 7-7. Transfer Payments

Project	Potencia MW	Factor Utilización %	Transferencias Miles US$
Yopal 1	18	50	47
Yopal 2	28	50	73
Yopal 3	36	50	94
Porce 3	660	75	3286

Table 7-8 shows 1% investment for projects that make the Energy Generation Expansion Plan, calculated on the basis of the project's technical costs[12] and total environmental management costs.

Table 7-8. 1% Investment

Project	Investment 1% US$ Thous.
Jepirachi	281
La Vuelta	160
La Herradura	245
Yopal 1	108
Yopal 2	169
Yopal 3	217
Amoyá	974
Porce 3	5732

7.2.4 CO2 Emissions

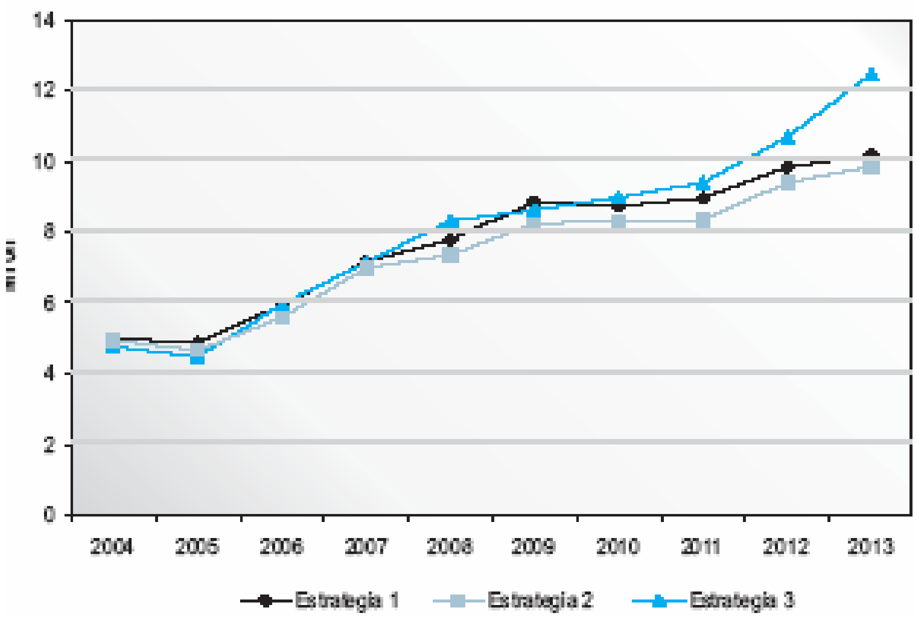
Table 7-9 shows CO2 emissions in Million Tons, for each of the generation strategies; for calculation purposes, the generation and fuel consumption with their own emission factors, obtained with the FECOC[13] (Factores de Emisión para Combustibles Colombianos) program developed by the Academy of Science for the UPME are used. Calculation is made on the grounds of fuel, gas and coal chemical composition, particularly carbon, hydrogen and oxygen content.

Along with fuels, emission factors for each of the plants are calculated including the efficiency of thermal plants and the type of technologies.

12 Technical costs are calculated as regards the value of installed kW by type of project .
13 The document may be found in SIMEC's environmental module: http://www.upme.gov.co/sima/

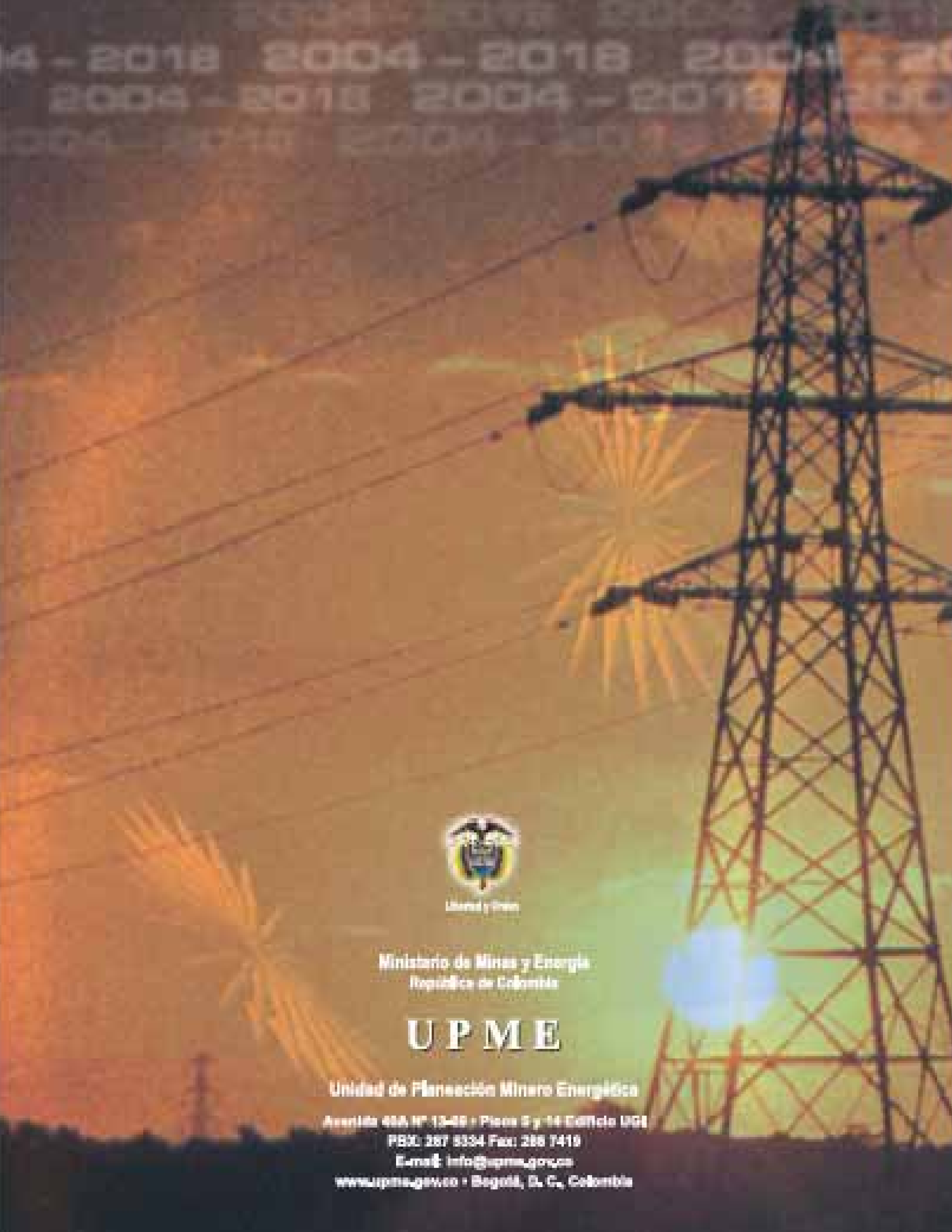
Strategies were constructed with short term and long term energy generations (for instance, ST1-LT1). As shown in Chart 7-1, emissions of strategy 2 in 2008 reflect the incorporation of 78 MW hydraulic project, by a slight reduction of CO2 emissions. Likewise, strategy 3 shows an increase in long term emissions arising from the higher thermal generation required by such strategy, particularly to the end of the period.

Chart 7-1. CO^2 emissions



Generally speaking, Colombian system's emissions are well below those of previous years. Low emissions as submitted in the Plan show the energetic efficiency of thermal generation plants in Colombia, as well as the important hydraulic component of our system, resulting in general system's emission factors below 200 kg of CO2 per MWh. In countries with high coal generation components, this factor gets close to one ton per MWh.

Below are the main expansion projects put forward by Network Operators at a NTS level and IV tension level. However we make it clear that, pursuant to regulations in force, these projects are to be submitted to UPME together with supporting technical and economic analyses, for them to be included in the Expansion Plan in the case of NTS projects, and for tariff review by the CREG in the case of level IV assets.



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República de Colombia

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