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May 2007

Integration Strategy for the Southern Cone Gas Networks

ESMAP

Energy Sector Management Assistance Program

Public Disclosure Authorized

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Technical Paper 113/07

Energy Sector Management Assistance Program (ESMAP)

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Contents

Tables

Figures

Units of Measure

kms	Kilometers
mm^3/day	Million Cubic Meters Per Day

Acronyms and Abbreviations

CDM	Clean Development Mechanism
CERs	Certified Emission Reductions
EBITDA	Earning Before Interest, Taxes, Depreciation and Amortization
EIA	Environmental Impact Assessment
ENARSA	Energía Argentina S.A.
EPC	Engineering, Procurement and Construction
GDP	Gross Domestic Product
GEGs	Greenhouse Effect Gases
GNEA	Gasoducto del Noreste Argentino (Northeastern Argentina Gas Pipeline)
HRD	High Regional Demand
IDB	Inter-American Development Bank
LNG	Liquefied Natural Gas
LRD	Low Regional Demand
MMBTU	Million British Thermal Units
PCA	Price of Alternative Fuels
RD	Reservas Dinámicas (Dynamized Reserves)
TAG	Technical Advisory Group
VAT	Value Added Tax
WACC	Weighted Average Capital Cost

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Executive Summary

Introduction

Experts from the governments of Argentina, Bolivia, Brazil, Chile, Paraguay, Peru and Uruguay, who participated in this strategic study for the Southern Cone Gas Pipeline Networks, combined their efforts to identify a shared energy alternative which would help boost the development of natural gas in the subregion, and, thus, its sustainable economic development.

On July 6, 2005, the Ministers of Economy and Finance and/or the Energy Secretaries for Argentina, Brazil, Chile, Paraguay, Peru and Uruguay submitted a joint note requesting the assistance of the Inter-American Development Bank (IDB) and the World Bank to be able to carry out work on the design of an institutional framework to determine the feasibility of investment projects and private sector participation in a major "South American Gas Pipeline Project" through regional technical cooperation. To this end, IDB proceeded to support the preparation of a framework protocol document of basic principles for the governments,[1] and the World Bank decided to provide the resources and the management for this study of the technical, economic, environmental and financial aspects in relation to the integration projects. When the time came to begin work, the original countries filing the request were joined by Bolivia. All the governments, at the request of the World Bank, named domestic experts who approved the terms of reference, participated in the selection and hiring of the consultancy group and reviewed the work and drafts summarized in this report.

The team from consultancy firms PricewaterhouseCoopers and Montamat & Asociados was selected to perform this work, the overall purpose of which is to determine the technical, economic, environmental and financial viability of the priority projects which will enable the creation of an integrated system for the supply of gas in the Southern Cone of South America.

[1] *This task corresponds to a different consultancy work and it was awarded to the Argentine consultancy group Rodolfo J. Freyre y Asoc.*

In accordance with the terms of reference, this study was developed in two phases: a first phase which evaluates the economic advantages of the integration of the gas networks in the subregion on the basis of data provided mainly by the governments, determining the priority projects to initiate it; and a second phase containing more detailed technical, economic, environmental and financial prefeasibility studies for these projects.

During the course of the work, it became necessary to hold three workshops in Rio de Janeiro (March 3 and 4, 2006), in Buenos Aires (May 30 and 31, 2006) and in Santa Cruz de la Sierra (August 28 and 29, 2006), at which drafts of the reports submitted by the consulting team were commented on and received contributions from the country experts. The minutes of these workshops are a good reflection of the changing circumstances both within the global energy environment, where the high prices of crude have forced countries to redefine their energy supply strategies, as well as in the regional political framework. Although this changing environment influenced the determination of the hypotheses and the study's alternative scenarios, at no time did it require any alteration to the methodology developed and defined for the technical work, nor the objectivity of the conclusions.

The studies clearly demonstrate that integration of gas networks has a very positive impact as a mechanism for supplying natural gas, a clean and abundant fuel in the subregion. In an environment in which the reliable supply of energy will largely determine the sustainability of economies, the analysis shows that integration, considered to be actions which help produce existing reserves and develop new ones, build gas pipelines which are integrated into a common network, and, by adding synergies, supply the market under rules which ensure free access, would have positive results that would translate into lower costs of supply for importing countries and better export prices for producing countries. The study concludes that implementing an integration plan will result in an increase in the competitiveness of regional economies.

In order to be financed and sustained by the private sector, regional integration requires a series of rules to be agreed and applied by all countries for the operation of the common gas pipeline infrastructure, and can, therefore, only be viewed as a medium- to long-term objective. The study shows that there is, nevertheless, an urgent demand for short-term gas pipeline projects to be carried out to facilitate bilateral trade between countries which have an energy shortfall and need to import gas, and countries with very significant reserves which need the economic resources derived from its export. This complementation between neighboring countries is the basis on which the infrastructure should be constructed and the principles according to which true integration will be achieved.

We would like to stress the eminently technical nature of the work forming this study, as the aim has at all times been to provide governments with an additional quantified tool for analysis of the advisability of regional integration. Therefore, the results arrived at, in no case, compromise the political decisions which the various governments could take for the development of their gas industries, both in relation to their respective markets and in terms of regional trade and integration.

Context

The international context of rising fuel prices raises both the opportunity and the need to ensure that the economies of all countries can count on reliable, abundant supplies of natural gas to prevent energy from becoming a bottleneck hindering the growth for which the entire subregion aspires.

Energy integration should, nevertheless, be seen as a long-term strategy with significant intermediate milestones and targets. The first projects for integration on the basis of binational gas pipelines have not been exempt from obstacles, and certain perceptible backward steps have occurred in the reality of the subregion. Some of the countries involved have, since 2001, suffered macroeconomic crises with a strong impact on the energy industry which led to restructuring of regulations and distortions in the prices of local energy baskets compared to regional and international standards. As a consequence, in the face of restrictions in energy supplies, preference again began to be assigned to self-supply of the domestic market. These policies have adversely affected energy exchange relations between some countries, giving rise to fears for the vulnerability of any supply which might be committed to under a joint energy option.

Since 2004, Argentina has had to reassign to consumption in its domestic market gas reserves initially under contract for export, affecting Chile in particular, and Uruguay and Brazil to a lesser extent. Although the Argentine and Chilean governments have handled the situation without resorting to litigation, Chile has resolved to seek alternatives to natural gas supplies from Argentina. Failure to resolve the conflict over an outlet to the sea for Bolivia, and changes in the political leadership in that country, have, in turn, for the moment deprived Chile of its natural supplier with the largest reserves in the subregion. Chile decided to call for a tender to build a regasification plant in Quintero to be able to obtain supplies of liquefied natural gas (LNG) from other markets, and is prepared to evaluate the purchase of natural gas from Peru at the same time as it builds a second LNG plant in the north of the country.

During these years, Bolivia has been debating the way revenue has been shared between the government and the companies. A new hydrocarbons law, initially strongly resisted by the companies, raised hydrocarbon royalties from 18 to 50 percent. The new government came to power on the promise that it would nationalize hydrocarbons, and on May 1, 2006, it issued Decree 28.701 to that effect. This measure had a particular impact on energy relations between Bolivia and Brazil. Petrobras, a company with a still significant participation by the Brazilian government, is the leading investor in Bolivia, with a major participation in upstream, refineries and pipelines in operation, as well as being the largest gas importer. Petrobras is seeking compensation for the loss of ownership of its assets. At the same time, the governments of Brazil and Argentina are involved in negotiations on an increase in the price of gas supplies from Bolivia. Brazil has a long-term contract which it is reluctant to renegotiate. Argentina has a short-term contract for which it has agreed an increase in the price of gas imports for one year, while it discusses the purchase of additional supplies to undertake the construction of a new trunk gas pipeline.

Undoubtedly, Argentina and Brazil need to purchase more gas from Bolivia, and Bolivia needs economic resources to help it meet its development targets; currently, however, doubts have arisen over the development and certification of that country's reserves, and the advisability of the prices negotiated by Argentina for the creation of a regional gas market. As a result, Brazil is analyzing alternatives to the supply of natural gas from Bolivia, and Petrobras has launched a plan to promote the development of gas fields in the interior, and in offshore areas of Brazil, simultaneously announcing its decision to build two LNG plants, one in Rio de Janeiro and another in the north-east. In addition, the company which operates the Santa Cruz-Porto Alegre gas pipeline, TGB, controlled by Petrobras, requested the Brazilian National Oil Agency, ANP, to cancel the call to tender to expand the capacity of the gas pipeline by 15 million cubic meters per day (mm^3/day).

It should also be noted that out of the ministers of the seven countries in the subregion who were in their respective governments at the end of 2005, when this work was conceived, only two remain; most countries have experienced changes in government, and, in some cases, their political leanings have altered.

Despite all these circumstances which demonstrate the high volatility of the regional and international political situation, the experts who have worked on this report have not considered the undertaking of a joint strategy for gas development to be of any less importance, or any less of a priority for the future of the subregion's economy. As this report demonstrates, on the contrary, the difficulties which the governments are facing urge the need for policy definitions, and strengthen the conclusions reached in favor of regional gas integration.

Why Integrate?

Argentina, Bolivia, Brazil, Chile, Paraguay, Peru and Uruguay participate in this Strategic Study on the Southern Cone Gas Pipeline Networks, having recognized that: i) for importing countries, it is important for the development of their economies to have energy sources which support their economic growth; and that ii) producing countries need to make use of their natural resources to help finance their development. Here, every country faces a different situation:

- Argentina has a mature gas industry, with gas playing a strong role as one of its primary energy sources. It has developed gas exports in the subregion, and it has again been importing gas;
- Bolivia, with the second largest reserves in Latin America, has as its strategic objective to develop the gas industry domestically, and is in a position to become a gas distribution center for the subregion;
- In recent years, Brazil has promoted an increased participation in gas among its primary sources as a means of diversifying its electricity generation capacity and spreading its industrial use. At present, it is facing decisions on how to ensure gas supplies for the medium- and long-term;
- Chile developed its natural gas industry on the basis of rising imports from Argentina, and now needs to diversify its sources of supply;
- Paraguay, a major exporter of hydroelectricity, is seeking to use gas to diversify its primary sources to reduce dependence on the importation of oil products;
- Peru, on the basis of the Camisea fields, has embarked on a rapid development of the gas industry in the domestic market, and has risen as a potential regional exporter; and
- Uruguay needs natural gas, which it would be able to buy in the subregion, to diversify its primary energy sources and reduce dependence on oil and its by-products.

The combination of these realities means that integration offers advantages and disadvantages, which in terms of corporate analysis would be described as strengths and weaknesses.

Advantages

- Increases the reliability of integrated systems, and, therefore, improves the overall reliability of supply for the group of countries;
- Promotes institutional reinsurance tending to strengthen stability in the rules of the game for the group of countries;

- Increases the utilization of common energy resources, and makes gas/electricity integration possible;
- Increases the scale of energy markets and the attractiveness for investment in the sector;
- Strengthens economic and commercial integration among the countries in the subregion;
- Promotes the forming of regional players (public and private) in the energy markets of the group of countries; and
- Promotes natural gas inter basin competition as a regional natural gas wholesale market gains strength.

Disadvantages

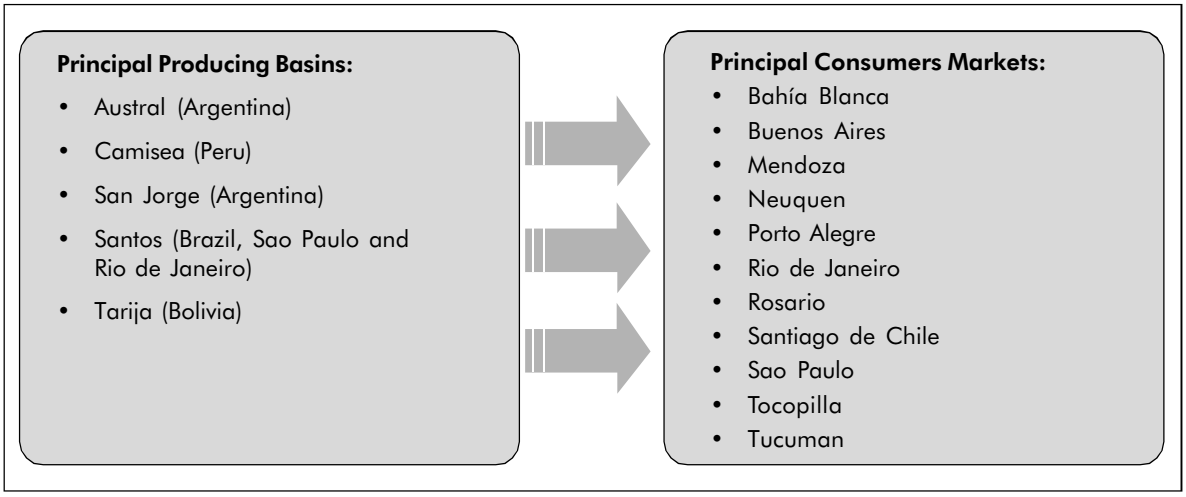
- Limits the margins for discretional action by national regulatory policies and conditions independent domestic development options;
- Restricts domestic options for energy self-supply;
- Weakens the dominant positions of some domestic companies in their domestic markets; and
- Weakens national positions with a greater negotiating strength in the case of bilateral relations which are not integrated.[2]

On the basis of these advantages and disadvantages, the justification for the strategic option to reinforce the gas pipeline system in the south and progress toward gas integration becomes clear: in the group of countries there is a growing demand for natural gas, and in some of them there are proven and probable reserves for development which, in addition to satisfying the domestic market, can support production aimed at exports to the regional and/or international markets.

If an analysis is made of the group of countries, it becomes clearly evident that the main centers of demand are located in Brazil (Sao Paulo) and in Argentina (Buenos Aires), while the main centers for exports to the regional market are located in Bolivia and Peru. In the subregion there is already an infrastructure of interconnected networks (Argentina-Chile; Argentina-Uruguay; Bolivia-Argentina; Bolivia-Brazil). What is required, therefore, is to connect centers for the shipment of natural gas to centers of consumption, expanding the existing system of gas pipelines and building new carrying segments, based on the alternatives which have attracted the interest of private investors, so as to make overall gas integration viable.

[2] *Nevertheless, it should be noted that regional integration increases the dependence on imported energy, with supply interruption risks.*

Figure 1: Principal Supply and Demand Centers



In reaching the results of this final report, a critical path was traveled, beginning with the gathering and unifying of the information delivered by the representatives of the various countries. The main limitations on information were the forecasts for natural gas demand in each country and the different criteria for classifying reserves.

In the case of projected demand, on the basis of observations at the first workshop, each country submitted its own estimates based on high and low demand scenarios according to hypotheses developed by each country, in line with an overall hypothesis for 3 percent growth in the region. At the second workshop, bearing in mind the hypotheses to define the alternative fuel basket for the main centers of consumption, as well as the basket of substitutes for the nonintegration alternative, it was agreed to use natural gas demand, broken down by type of consumption, so as to weigh the relative importance of the various substitutes and their impact on the definition of prices.[3]

Table 1 shows mean demand projections prepared by the countries (average between high and low demand scenarios as defined by them), including in their definition the conclusions which each government arrived at in relation to its secure energy options and potential supply by natural gas. Although the economic growth rate which countries used is the same, annual mean growth rates for gas demand range between 2 and 12 percent.

[3] *It should be noted that the consultants have not checked the reason for or the adaptation to the assumptions stated in the terms of reference of the projections made by the respective national experts.*

Table 1: Actual Demand in 2005 and Expected Mean for 2025

	Demand (MMm³/day)		
Country	*2005*	*2025*	*Annual Growth Rate*
Argentina	95.4	202.3	3.8%
Bolivia	3.6	19.2	8.2%
Brazil	48.0	177.1	6.7%
Chile	17.8	26.3	2.0%
Paraguay	–	2.7	–
Peru	2.5	22.2	11.5%
Uruguay	0.4	3.6	11.6%
Total	167.7	453.4	5.1%

On the matter of use of reserves at the first workshop, progress was made on defining a stock of available reserves which took into account proven reserves and 50 percent of probable reserves, taking a flexible approach to the classification criteria established by each country, determining the stock capable of meeting resulting demand through 2015. At the second workshop, an exercise was requested to boost reserves on the basis of information provided by the various countries, taking into account the period covered by the projection (2005-25).

Using the estimates of proven, probable and possible natural gas reserves as communicated by the country experts, based on figures arising from reserve certifications or official statistics for prior years (2004 or 2005), Table 2 reflects the ratio of available reserves to demand, considering years of reserve on the basis of consumption in 2005 and on the basis of mean consumption expected for the 2006-25 period. This analysis assumes that there are no discoveries of new reserves during this period, and shows that there are sufficient combined reserves to undertake the integration projects.[4]

Furthermore, if a moderate increase in reserves is assumed, on the basis of new investments which benefit from an expanded regional market (scenario based on increased reserves[5]), with the gas trading flows resulting from integration of the various basins are well able to

[4] *The aim of the analysis is to check the availability of reserves to supply the projected demand. However, as it was noticed by Philippe J. Durand, it is logical to expect to discover new reserves in the region during the period under analysis.*
[5] *Source: Juan Rosbaco.*

satisfy both demand scenarios. Table 3 shows two injection scenarios corresponding to a greater or lesser participation by the exporting countries – Bolivia and Peru – in the supply of gas to the integrated system.[6]

Table 2: Ratio of Available Reserves to Consumption

	Period	*Unit*	*Argentina*	*Bolivia*	*Brazil*	*Chile*	*Paraguay*	*Peru*	*Uruguay*	*Total*
Consumption	2005	MMm^3/ day	95.4	3.6	48.0	17.8		2.5	0.4	167.7
Proven reserves	2004/5	MMm^3	612,500	757,480	326,120	24,000		325,360		2,045,460
Proven reserves/ production for current domestic market	2005	Years	14	524	17	3		324		29
Mean expected annual consumption	(2006-25)	MMm^3 /day	150.3	12.9	126.0	24.3	1.7	13.6	2.3	331.1
Probable+ possible reserves	2004/5	MMm^3	289,010	623,820	172,040	23,000		471,620		1,579,490
Proven reserves+ 50% of probable+ possible/ production for the expected annual consumption		Years	11	206	8	4		102		22

Table 3: Total Projected and Potential Injection of Reserves by Country

	MMm^3				
Period 2006-2025	*Argentina*	*Bolivia*	*Brazil*	*Peru*	*Total*
Possible injection on basis of increased reserves	907,645	1,220,366	844,103	387,504	3,359,618
Total injection for the high regional demand period – maximum injection by Bolivia	831,190	1,031,839	618,705	204,672	2,686,406
Total injection for the high regional demand period – maximum injection by Peru	831,157	979,955	602,922	283,996	2,698,030
Total injection for the low regional demand period – maximum injection by Bolivia	813,854	1,037,322	469,065	116,577	2,436,818
Total injection for the low regional demand period – maximum injection by Peru	813,941	936,597	499,261	187,876	2,437,675

[6] *The scenarios considered are detailed in the section on Economic Viability of this Executive Summary.*

An additional analysis discussed at the workshops, outside the scope of this report, was the possibility of complementing the gas pipeline network in the subregion with the building of a pipeline which could supply gas from Venezuela to major centers of consumption in the Southern Cone. Country experts considered this gas pipeline as complementary, capable of contributing a long-term solution as a potential addition to the reserves of the subregion, based on the connection of the Venezuelan gas fields to the basins in the south of Bolivia, and then onto the integrated Southern Cone system being evaluated.

With supply and demand of natural gas as basic information input, and the existing system of networks, in addition to an indicative listing of potential projects, the strategic objective of the first phase was to determine the overall merits of integration and identify priority projects for new gas pipelines to be built and incorporated to the network of existing gas pipelines to establish the backbone of a Southern Cone regional system. The proposed pipeline projects to be built to complete the regional system network include the following:

- The Humay-Tocopilla pipeline;
- The Cuenca Noreste, Paragua-Rosario or Campo Durán-Santo Tomé pipelines, with a branch to Asunción del Paraguay. This gas pipeline is known as the Northeastern Argentina Gas Pipeline *(Gasoducto del Noreste Argentino – GNEA)*;
- The Uruguayana-Porto Alegre pipeline; and
- The Paysandú-Colonia, Colonia and Montevideo-Porto Alegre pipeline to connect to the existing Colonia-Montevideo segment of the gas pipeline linking Buenos Aires to Montevideo.

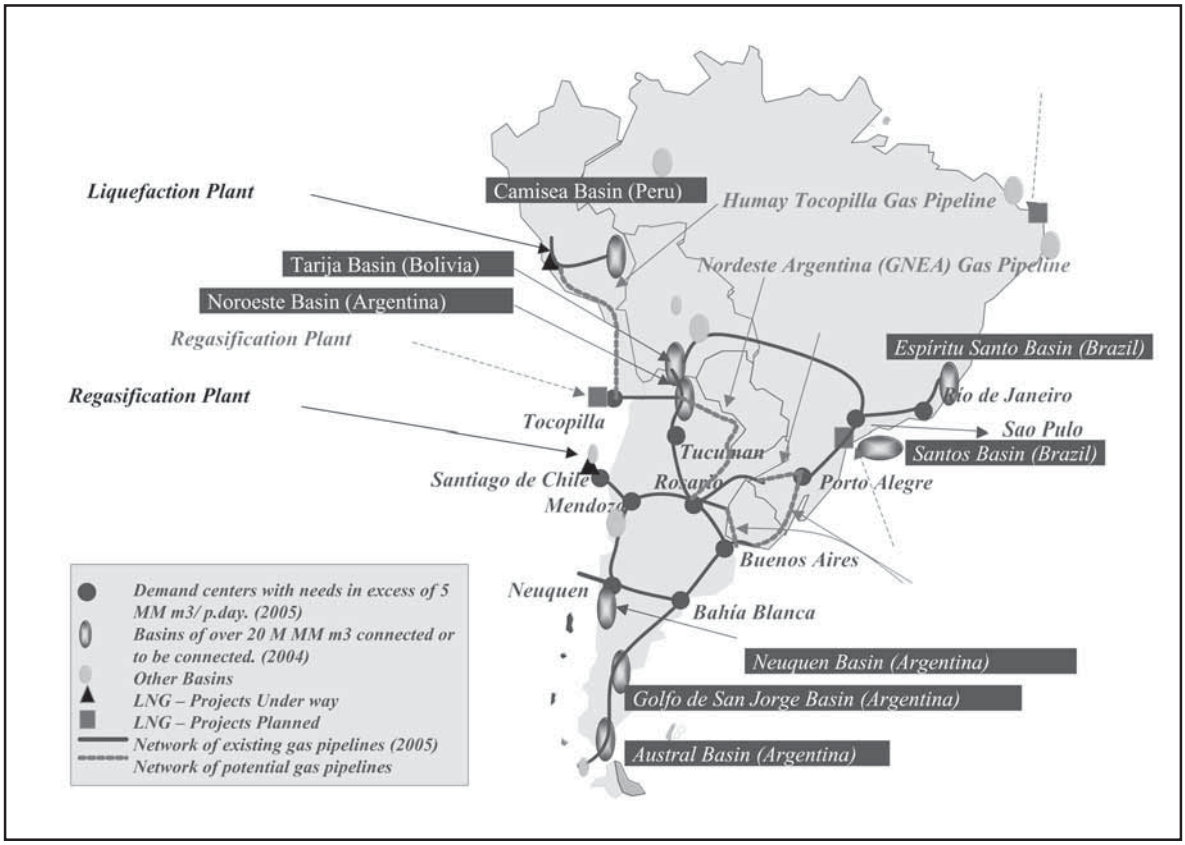
Economic Viability

Model and supply and demand scenarios

The methodology applied is based on the use of a model for the optimizing of physical and economic flows which, based on certain assumptions, enabled calculation of supply of demand for the group of countries involved, at the lowest cost.

The relevant physical information for the model includes injection levels for the various basins in the regional system, volumes carried along the various segments of the system – simulating the existence of significant new segments, with assigning of priorities to new projects, and increases in carrying capacity – and the volume of alternative fuels needed

Figure 2: Gas System in the Subregion



Source: Prepared by PwC on basis of information provided by countries.

for regional demand peak-shaving where the residential sector plays a large role, such as in the case of Argentina.

Model monetary data includes the well head gas price at each basin (obtained as net-back on the basis of the prices of substitute fuels at major consumption centers), carrying rates and tariff surcharges (in those segments where there is capacity expansion and existing tariffs do not recover costs); and the costs of alternative fuels used to replace gas during peak demand.

The model can be broken down into four addends, each of which contain a multiplication of a volumetric expression by a price.

Total minimum cost	=	Injections in different basins	X	Price of gas in each basin (net-back)	+	Transported volumes in each pipeline of the system	X	Transport tariff in each pipeline	+	Expansion of transport capacity	X	Tarrif surcharge on some segments	+	Usage of alternative fuels in peaks	X	Cost of atternative fuels

The math of the model is not based on lineal optimization because there is a nonlineal relationship between mean and peak demand. The model resolves supply from the various dispatch centers, minimizing costs, subject to the following restrictions:

- At each node, the volume which enters is equal to the sum of demand at the node plus that leaving the node;
- In each segment, the volume transported is lower or equal to the expanded transport capacity; and
- The production/injection capacity is limited by the available reserves.

The operation of the model is based on the following assumptions:

- The first assumption relates to the price of oil and its influence on the prices of energy substitutes and impact on both demand and supply forecasts. Given the volatility that exists in crude oil prices and the differing forecasts regarding their future development, country experts assumed responsibility for projecting their demand in high and low scenarios on the basis of average growth of 3 percent for the subregion as a whole, and accepting, as a hypothesis, an average price for oil of between US$50 and 60 per barrel in constant terms until 2015.

  On the basis of the crude oil price, an estimate was made of the price of fuel oil (US$6.50 MMBTU) and coal (US$3.5 MMBTU). The price of substitute fuel at consumption centers of US$6.05 MMBTU was established based on a substitution basket which weighed consumption of fuel oil (85 percent) and coal (15 percent) according to a breakdown of demand by the user sector provided by the various countries. In Table 4, the prices of natural gas at the basins used to minimize the natural gas price and transportation costs are shown.

Table 4 : Net-back by Basin

Basin	*Prices of Alternative Fuels* *US$/MMBTU*	*Transport Tariff* *Price Set By*	*US$/MMBTU* –	*Tariff Surcharge* *US$/MMBTU*	*Price of Gas in Each Basin* *US$/MMBTU* –
Austral	6.05	Buenos Aires	1.06	0.47	4.52
San Jorge	6.05	Buenos Aires	0.61	0.31	5.13
Neuquina	6.05	Buenos Aires	0.63	0.11	5.31
Northwest	6.05	Buenos Aires	0.81	0	5.24
Tarija	6.05	Sao Paulo	1.70	0.17	4.18
Santos	6.05	Sao Paulo	0.36	0	5.69
Camisea	6.05	Buenos Aires	3.81	0	2.24

(1) The price of the Northwest and Camisea consider tariffs of new pipelines, on the basis of the tariffs estimated during Phase 2 of this work.

The price of this weighted fuel substitute basket, with a discount for transportation, enables calculation of a well head value for gas in Bolivia, the main supply center for the system.[7] This price provides a reference for regional transactions within the integrated system. Purchasers at other centers of demand which are not price formers, like Sao Paulo and Buenos Aires, must evaluate their purchase option on the basis of the opportunity cost of consuming another fuel in this location compared with the reference price at the main production center (Bolivia) plus the cost of transport to that destination. If the price of natural gas is not calculated using this net-back mechanism based on the principal consumption centers, and it is intended to make the calculation using a cost-plus mechanism based on a well head value at the main injection center, it is possible to arrive at the main centers of consumption with prices which discourage substitution and, thus, the development of the demand for natural gas in the subregion;

- When the scenario considered was that of "nonintegration," calculation of higher costs for the regional economy was based on a supply basket diversified between fuel oil, coal and LNG. In the case of the "nonintegration" alternative, the basket is calculated not to fix the cost of the substitute at the main consumer center and develop gas in the various integrated scenarios, but to calculate the "nonintegration" costs. In this case, countries can only count on the regional gas flows existing in 2005, not being able to replace fuel-oil or coal by gas from the networks of the subregion, having to resort to LNG. Under this "nonintegration" alternative, a price of US$8 MMBTU was assumed, based on the import contracts for the Quintero's Plant in Chile.[8] As a result, the price of substitute fuel using the "nonintegration" basket was estimated at US$6.7 MMBTU;

[7] *Nevertheless, it should be pointed out that the system used in Bolivia is the cost-plus.*
[8] *This price does not reflect current prices for LNG, or the different plant locations in the subregion. If current prices and freight costs were to be considered, the cost of alternative fuel could differ significantly.*

- Gas pipeline carrying segments and their corresponding tariffs, based on current data, with adjustments proposed for the Argentine case. This assumption was submitted to the consideration of the country experts, and was accepted with only a few minor adjustments; and
- Using real average physical data for 2005 and data for prices and tariffs, the model was run for a calibration scenario; later, scenarios using different natural gas supply and demand hypotheses were formulated:
  - On the demand side, High and Low demand scenarios were considered. For purposes of the model, High Regional Demand (HRD) was made up of the sum of the highest demands informed by the participating countries;[9] and
  - On the side of supply, or injection of natural gas, work was carried out on various hypotheses, all related to the relative importance of Bolivia as a supplier of Reservas Dinámicas (Dynamized Reserves) (RD), and the supporting role of Peru. In the case of the Argentine and Brazilian basins, injection limits were adopted based on the situation of the reserves and the maturity of the basins. These limits were adjusted according to the results of the reserve dynamics report prepared after the second workshop.

Supply and demand balances needed to take into account existing forecasts for the import of LNG by Chile (subtracted from domestic demand to be met in the regional market), as well as for the export of LNG by Peru (added to domestic and RD for the purpose of calculating production and its relationship to reserves).

Table 5 shows the scenarios that arose from the combination of the hypotheses on supply and demand for natural gas in the group of countries.

Table 5: Demand Scenarios[10]

	Maximum Injection by Bolivia	*Maximum Injection by Peru*	*Nonintegration*
High Regional Demand	HRD-MaxIB (RD)	HRD-MaxIP (RD)	NI/HRD
Low Regional Demand	LRD-MaxIB (RD)	LRD-MaxIP (RD)	NI/LRD

[9] In the case of Bolivia, the consultancy team projected demand using historical data provided, and in the case of Paraguay – where the market has not been developed – the consultancy team projected demand based on the development of comparable markets using specific information provided by the country.

[10] During the course of the work, 10 different scenarios were developed; this table includes the scenarios presented at the last workshop which were agreed as the definitive scenarios.

Results

For these scenarios the model was run taking 2009 as a starting point for operation of the system and setting a reference horizon of the years 2015 and 2025. Given the volumetric and financial flows and the restrictions which have been explained, the model provides the injection of gas in each basin, the necessary capacity increases in the existing segments of the network, and the flows to be transported by the new gas pipelines, in a network which operates in a way to minimize the total cost of gas supply in the subregion. It also provides sale and transport volumes, and the need for investment in capacity expansion and new pipelines.

The development of missing reserves will be concentrated on the newer basins, such as Tarija, Camisea, and Santos. This means that it will be unlikely that Argentina will continue to be a supplier of gas to Uruguay, Brazil and Chile. Integration will have to enable Bolivia and Peru replace Argentina as sources of supply for Chile and Uruguay.

In the "nonintegration" alternative for the group of countries, additional costs of satisfying projected demand for gas using other fuels, including LNG, total US$6.0 billion in 2015 and US$11.2 billion in 2025. These figures only relate to the sales value of the fuel basket used in the face of lack of availability of regional gas supplies via pipeline and do not take into account the adjustment to the investment values of the nonintegration alternative compared with the integration alternatives.

It should be noted that the impact of integration is progressive, and that any delay in implementation implies failure to realize the direct benefits it gives rise to; in addition, the opportunity cost of the delay also includes other impacts which have not been analyzed in this report. Furthermore, in relation to the dynamics described, growth in demand is a highly likely event, and its satisfaction – should integration be delayed – will require alternatives which at first sight appear to be more expensive, such as LNG plants in Sao Paulo, Bahia Blanca or Northern Chile, which once installed would reduce the market for integration by means of gas pipelines, and could go so far as to render it unviable.

To select the new projects to be evaluated in greater detail for the various integration scenarios, each of the gas pipeline segments to be built was ranked by size.[11] Consideration was also given to the number of appearances in the scenarios developed by the new pipelines

[11] *In this regard, given that the analysis focuses on the priority of new pipelines, the expansion of the pipeline Bolivia-Brazil is not considered in the list.*

to be evaluated. From this ranking, a priority need was determined for evaluation of the following projects:

- The Humay-Tocopilla pipeline;
- The Northeast basin, Paraguay-Rosario or Campo Durán-Santo Tomé pipelines, with a branch to Asunción del Paraguay. This gas pipeline is known as the Northeastern Argentina Gas Pipeline (GNEA); and
- The Uruguayana-Porto Alegre pipeline.

The Humay-Tocopilla gas pipeline will make it possible to integrate gas from Peru to the subregion, supplying the north of Chile and later the north of Argentina, to compensate for the gas which Argentina would export by means of a "swap" from the Austral, Neuquina and San Jorge basins. The GNEA, identified as Campo Durán-Santo Tomé, with a branch to Asunción del Paraguay, is the main pillar of this integration, as it will supply gas to the principal centers of consumption in Argentina, and will allow export of some of the gas from Bolivia to the south of Brazil, Paraguay and Uruguay. To carry gas to Brazil, this gas pipeline will be complemented by the existing line between Rosario and Uruguayana and the new pipeline linking Uruguayana and Porto Alegre.

New Pipelines – Capacity Required

As indicated, scenarios were developed based on the maximum injection potential of Bolivia and Peru, on the basis of high and Low Regional Demand (LRD). Table 6 summarizes the injection data, and highlights the average values which were taken as a basis for the technical design of each of the projects.

Table 6: Scenario Results

	Pisco-Tocopilla (MMm³/day)	*GNEA (MMm³/day)*		*Uruguayana-P. Alegre (MMm³/day)*			
		2015	2025	2015	2025	2015	2025
High Regional Demand	Max. Injection Bolivia	12.4	21.4	98.5	151.1	9.5	18.8
	Max. Injection Peru	24.9	34.5	98.5	151.1	9.5	18.8
Low Regional Demand	Max. Injection Bolivia	2.9	4.2	86.6	129.9	5.3	17.4
	Max. Injection Peru	15.8	17.4	80.9	129.5	-	17.4
	Average Demand	14.0	19.4	91.1	140.4	6.1	18.1

These results correspond to the size which these gas pipelines would have in an integration context. The positive contribution from integration would have an impact on the economy of the gas pipelines, as follows:

- The GNEA would not only supply gas from Bolivia and Peru to the northeast of Argentina and Buenos Aires, but would also situate Argentina as a supplier of gas to Chile and Uruguay through "swap" contracts, and would carry gas to the south of Brazil and Paraguay. Out of the planned capacity by 2025 of 140.4 MMm^3/day, 18.1 MMm^3/day would be being delivered to Porto Alegre, 2.7 MMm^3/day to Paraguay, and by means of "swaps," 3.6 MMm^3/day to Uruguay and between 5 and 10 MMm^3/day to Chile. This implies that close to 25 percent of the GNEA will seek to satisfy demand from neighboring countries, minimizing the cost of supply at each node;
- As a consequence of nonintegration, volume on the Humay-Tocopilla gas pipeline would be cut by half because it would not be able to be integrated as a supplier for other countries in the subregion; and
- If the GNEA were not to be built, Uruguayana-Porto Alegre would receive gas supplies from the south of Argentina (should there be any surplus) or through expansion of the pipelines linking the north of Argentina to Rosario, at a higher cost of transportation and on an uncompetitive basis compared with other sources of supply for Porto Alegre via Sao Paulo.

Technical – Environmental and Tariff Viability

The technical design task determines the construction features of the pipelines. The lines taken for GNEA and Uruguayana-Porto Alegre pipelines, which have already been approved by the governments of Argentina and Brazil, have been adopted. In the case of the gas pipeline linking Humay and Tocopilla, a line was adopted which follows the route of the Pan American Highway. The use of these lines makes it possible to assume that the detailed environmental aspects will be of minor significance when the final feasibility studies are performed. For the construction of these pipelines, average demand was equated to the carrying-capacity required in a given year, and the lengths and investments, shown in Table 7, were defined.

Table 7: Investment and Length of Priority Projects

Gas Pipeline	*Length (kms)*	*Total Investments (MMUS$) 2007-25*
Humay-Tocopilla	1,356	1,287.6
Uruguayana-Porto Alegre	565	478.6
GNEA	1,500	5,052.9

The initial investment in new gas pipelines has been estimated at US$4.2 billion, and total investment with all compression expansion during the period of the projection totals US$6.8 billion. This sum is, however, just part of the estimated investment for the network of gas-carrying pipelines in the Southern Cone. In addition, the exiting system must be expanded. The average amount of total investments required in the four scenarios selected to establish the original technical design totals approximately US$21.4 billion for the whole period of the projection, which implies that approximately US$14.5 billion must be invested on expanding existing networks. To this investment should be added the necessary "upstream" investment to develop reserves and supply the system of regional gas pipelines.

Economic and financial evaluation should be made on the basis of carrying tariffs which, added to the well head price of gas, enable gas to be carried to markets at competitive prices compared with substitute fuels. This report does not aim to define well head gas prices or final prices to consumers, as such prices should arise from subsequent negotiations. The well head price established in this report is used as a mechanism for allocation between basins, selecting the basin which meets demand at the lowest price. It has been assumed that conditions exist for upstream investments and carrying tariffs, added to cost of production compared with the market price of substitute energy sources, will leave sufficient margins to be shared between producers and consumers. Specifically, for the financial tariff evaluation a tariff projection was drawn up for the entire period, determining the transportation price on the basis of the distance traveled by the gas. It should be mentioned that the engineers on the consulting team designed the pipelines considering that they would be converted into infrastructure of an integrated network, so that it would, therefore, be advisable for them to be straight (rather than telescopic). Therefore, additional investment will be in compressors and gas retention "loops."

To calculate the required rate of return or the regulated rate to estimate tariffs, rates were constructed for the cost of own capital and borrowing on the basis of an efficiency model in the capital market based on the Capital Assets Pricing Model (CAPM),[12] and differential rates were applied according to the location of the pipeline being evaluated (Table 8).

[12] *The model uses the CAPM theory to estimate the minimum rate of return expected by an investor to invest in each project.*

Table 8: Principal Details of Pipelines Analyzed

Gas Pipeline	*Regulated Rate of Return*	*Operating Costs (US$ millions)*	*Rate at Destination (US$ MMBTU)*
Humay-Tocopilla	10.85	455.5	1,009
Uruguayna-Porto Alegre	10.92	92.1	0,578
GNEA	13.04	760.4	0,606

The high flow established for the GNEA means that if it is used, there would be a substantial reduction in carrying rates between the north of Argentina and Buenos Aires. In turn, this reduction would imply an improvement in the competitiveness of Camisea.

It is important to note that we have assumed that the carrying capacity for the Humay-Tocopilla pipeline will be fully utilized almost from the start, and that to satisfy this demand, Camisea has developed wells and sufficient reserves. This assumption considers that the gas sent to Tocopilla during the first years will, in any case, be sent to Argentina as a consequence of the reversal of the flows of the Noreste Basin – north of Chile pipeline. As a result, the gas thus sent to Argentina would be "swapped" for gas from the basins in the center and south of Argentina delivered via the gas pipelines which link Mendoza and Neuquén to Santiago de Chile and Concepción. Lastly, it was considered that when operations begin in 2009, the Uruguayana-Porto Alegre and GNEA pipelines will have "take or pay" type contracts for close to 80 percent of their carrying capacity by 2015.

The conclusion of this evaluation is that the priority gas pipelines are viable. That is to say, they can be built and operated efficiently within the current gas pipeline system. Nevertheless, the levels of investment for construction and the term of maturity of these projects require a detailed analysis of the capacity of the project to obtain financing in the amount and terms required. This analysis should impact on the certification of the reserves at the basins and the investments to achieve production levels being called for, as well as on the price levels for gas to the end consumer, so as to validate the demand projections.

Financial Viability

In addition, a "Project Finance" model has been structured which assumes that in a term of not more than 10 years as from the initial disbursement of the loan for construction, the enterprise should possess a normalized debt equivalent to that which a gas pipeline would have in the long term. Sustainable debt is that which arises from applying only one-third of operating results net of amortization and depreciation Earning Before Interest, Taxes,

Depreciation and Amortization (EBITDA) generated each year to the payment of interest for a period of 10 years. This implies that the company would be able to comply with its financial commitments without difficulty, except for abrupt changes in market conditions.

The cost of the debt assumed to evaluate the prefeasibility of the projects arises from bonds issued by blue-chip companies on the Buenos Aires, Lima, Santiago de Chile and Sao Paulo markets, and reflects the rate paid by these large corporations in dollars for terms of no longer than 10 years. Nevertheless, it is necessary to mention that this cost of debt does not consider the obtaining of additional guarantees, such as these projects will no doubt be able to obtain through risk-hedging market mechanisms, contracts with offtakers (EPC contractor, gas producers, etc.,), insolvency risk coverage and regulatory risks.

Financial evaluation has been carried out taking into account existing tax regimes. It should be mentioned that the existence of certain tax facilities, such as income tax exemptions and rapid refund of value-added and similar taxes, lowers rates by approximately 20 percent. This reduction will assist integration by lowering carrying costs and increasing well head prices.

As part of the financial model, the indicators shown in Table 9 were estimated.

Table 9: Economic and Financial Feasibility

	Shareholder IRR%	*"Pay-Back" Years*	*Maximum Borrowing (MM US$)*	*Shareholder Contribution (MM US$)*	*Sustainable Debt by 2015 (MM US$)*	*Cost of Borrowing %*
Humay-Tocopilla	12.30%	11.0	765.3	510.0	493.7	8.7%
Uruguayana-Porto Alegre	12.91%	11.0	327.5	180.0	189.5	8.8%
GNEA	14.99%	11.0	2,843.9	1,150.0	1,485.7	10.9%

This second analysis establishes not only the viability of the projects in economic terms but also that of the financing required for their construction. Nevertheless, it is advisable to indicate that the results described are based on assumptions and hypotheses and are, thus, subject to uncertainty. If other assumptions and working hypothesis were adopted, different results could be obtained, and viability could be affected.

Conclusion

Integration involves both advantages and disadvantages. Advantages tend to be economic, such as guaranteed supply, reduction of energy costs, attraction of investments, and increase in the competitiveness of the economies in the subregion. The latter is reflected in the opportunity cost of nonintegration which totals a minimal annual amount (based on an average of the scenarios analyzed) of US$6.0 billion in 2015 and US$11.2 billion in 2025. Disadvantages are concentrated on aspects related to freedom for the development of public policies by each country, also seeking to improve the economic environment.

The investment required in transportation capacity totals US$21.5 billion. This amount implies an investment of US$1 billion per year and, thus, establishes the need to reduce investor uncertainty so as to reduce the cost of capital. This study was performed considering that there are investors willing to assume such a risk in the subregion; nevertheless, companies consulted indicate that certain aspects must be improved to enable investment on the scale required, such as:

- The need for reserves to be audited by international experts, enabling investors to focus their attention on the risks of the operation of the business rather than the risk of lack of product;
- The need for clear rules of the game and stable legal frameworks to help reduce the perception of risk; and
- The availability of financial backing at competitive rates and tax assistance by means of exemptions.

Consideration of these advantages and disadvantages is the duty of each government as part of its sovereign decision-making on public policies and integration. The time factor is of considerable importance. This study estimates that the projects will be in operation in 2009, which supposes, on the one hand, that the political agreements for cooperation will be reached by the various countries and, on the other, that regulatory frameworks will have been suitably modified. Delays will affect the volumes of energy demand which can be committed in projects for different sources of gas and, thus, on the rates of return calculated in the study.

We understand that the financial conditions prevailing in the subregion, together with the existence of different regulatory frameworks and legal environments in each country, as well as changes in negotiation of rules of the game in contracts for supply in the various countries, could require an additional analysis, to include the effect of these factors on the

long-term financing model. This analysis could contemplate a calendar for projects to be carried out on different dates. It will be important for progress to be made on the construction of a common regulatory framework at the same time as the individual projects are completed.

Objective

Argentina, Bolivia, Brazil, Chile, Paraguay, Peru and Uruguay participate in this Strategic Study for the Southern Cone Gas Pipeline Networks in order to identify a shared energy alternative which would help boost the development of natural gas in the subregion.

Ministers from Argentina, Brazil, Chile, Paraguay, Peru and Uruguay submitted a joint note requesting the assistance of the Work Bank in order to hire a consulting group to carry out the tasks which would be supported by the countries as regards information and the follow-up and analysis of documents subject to discussion.

After a selection process carried out in 2005, the companies PricewaterhouseCooper and Montamat & Asociados were selected to carry out these tasks, whose objectives are:

- Phase 1: On the basis of projects defined as priority by the countries involved and the World Bank, establish which projects would best integrate to the existing gas pipeline network; and
- Phase 2: The technical, pretechnical feasibility, economic, environmental and financial assessment of those priority projects selected during the first phase, which will enable the creation of an integrated system for the supply of gas in the subregion.

The report submitted translates the requirements of the reference terms into a proposal elaborated by the consulting group and the agreement subscribed between the consulting group and the World Bank. It is important to highlight that during three workshops held in Rio de Janeiro, Buenos Aires and Santa Cruz de la Sierra, the draft versions of reports subject to review submitted by the consulting group received remarks and contributions of national experts appointed by their countries which enabled the enhancement, correction and update of preliminary documents, as long as they reflect the scope of the task assigned.

We understand it is important to highlight the basically technical nature of this study which implies an additional analysis tool for the countries on the convenience of regional

integration, and, therefore, the results of such study do not compromise the political decisions the different governments may make in relation to the development of the gas industry as well as in terms of regional integration.

Phase 1

Report Objective – Phase 1

The objective of this phase is to select three projects among priority projects submitted as integration alternatives for the Southern Cone energy ring.

The projects subjected to analysis are those which were paid the most attention by the private sector and the countries as detailed below:

- The Humay-Tocopilla pipeline;
- The Northeast basin, Paraguay-Rosario or Campo Durán-Santo Tomé pipelines, with a branch to Asunción del Paraguay. This gas pipeline is known as the GNEA;
- The Uruguayana-Porto Alegre pipeline; and
- The Paysandú-Colonia, Colonia and Montevideo-Porto Alegre pipeline to connect to the existing Colonia-Montevideo segment of the gas pipeline linking Buenos Aires to Montevideo.

Other gas pipeline projects have been discussed since the consultancy group tasks were initiated, at workshops as well as at a country level, looking for different integration and, in some cases, isolationism alternatives. All projects may be taken into consideration in future analysis processes. In addition, future analysis should be more focused on power-gas interaction, thus looking to optimize the results obtained in this study.

Characteristics of the Subregion

The regional natural gas market in South America is a young market which has started to use gas massively during the 90s. Previously, only Argentina had a market with good penetration levels within its energy matrix. The arrival of gas was based on important discoveries of this hydrocarbon in Argentina in the late 80s and early 90s, as well as abundant reserves in Bolivia and Peru in the late 90s, as a result of explorations carried out in the Neuquina and Northeast basins, in the Patagonian and Northeastern regions in Argentina,

respectively and in the Tarija basin, located in the south of Bolivia and the Camisea basin, located in the east of Peru.

Currently, demand is strongly concentrated in Argentina which, in 2005, accounted for 57 percent of regional consumption and will maintain its leadership within the region as the largest regional market within the frame of analysis throughout the 2006-25 period. However, the highest growth rate in demand is concentrated in Brazil, which is expected to threefold (worst case scenario) or to fourfold (best case scenario) its demand in the next 20 years; the highest dynamics shall come from Peru[13] and Bolivia, countries with large young reserves that shall seek to transform their energy matrices as a result of new discoveries within their territories. Table 1.1 shows the daily growth rates and gas consumption volumes expected for the 2006-25 period.

Table 1.1: Real Demand for 2005 and Expected Regional Demand for 2015 and 2025

		High Regional Demand		*Low Regional Demand*		*High Regional Demand*		*Low Regional Demand*	
Scenarios		*MMm³/day*		*(MM m³/day)*		*Annual Growth Rate*			
Country	2005	2015 (E)	2025 (E)	2015 (E)	2025 (E)	2015 (E)	2025 (E)	2015 (E)	2025 (E)
Argentina	95.4	149.5	213.4	141.3	191.1	4.6%	4.1%	4.0%	3.5%
Bolivia	4.0	13.3	19.2	13.3	19.2	12.8%	8.2%	12.8%	8.2%
Brazil	48.0	127.1	207.0	109.5	147.2	10.2%	7.6%	8.6%	5.8%
Chile	17.8	25.4	28.4	23.2	24.2	3.6%	2.4%	2.7%	1.5%
Paraguay	-	1.9	2.7	1.9	2.7				
Peru	2.5	15.4	24.6	11.2	19.7	19.9%	12.1%	16.2%	10.9%
Uruguay	0.4	2.3	3.7	2.2	3.5	19.1%	11.8%	18.6%	11.5%
Regional Demand	168.1	334.9	499.0	302.6	407.6	7.1%	5.6%	6.1%	4.5%

(1) Figures corresponding to Peru include gas consumption by the Humay liquefaction plant; (2) Figures corresponding to Chile are net of the demand to be supplied by the Quinteros LNG plant.
Sources: (1) Argentina: Information furnished by local experts. (2) Bolivia: "Southern Cone Natural Gas Study", Freyre & Asoc. and Purvin & Gertz. 2004 (3) Brazil: Information furnished by local experts. (4) Chile: Information furnished by local experts. (5) Paraguay: Estudios de Mercado de Uso de Gas Natural en el Paraguay (DCT Energía – 2004), PESE and updates VMME 2005. (6) Peru: Information furnished by local experts. (7) Uruguay: Information furnished by local experts.

[13] *According to the latest data estimated by Peru in October 2006, in 2015 the Peruvian domestic market will consume 19.2 MMm³/d and 35.4 MMm³/d in 2025. This projected increase in demand stems from the lower prices for the domestic market resulting from a new pricing formula added to the amendments to the contracts with Pluspetrol. Thus, lower prices result in increased consumption and electric power generation from natural gas. Also, natural gas is expected to be used in important petrochemical projects. Thus, the use of reserves by the domestic market for the next 20 years is expected to increase to 6.6 TCF.*

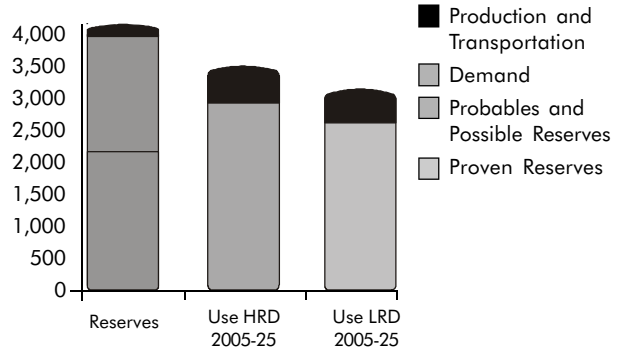
In order to meet the demand of Table 1.1, the subregion has 2.04 billion m^3 in proven reserves and 1.62 billion m^3 in provable and possible reserves; therefore, demand forecasts may be met using the total proven reserves plus 60 percent of provable and possible reserves, in 2025 for the high demand scenario and 40 percent for the low demand scenario pursuant to this study.[14]

Thus, and as shown in Table 1.2, the beginning of integration is possible since the demand and the existing level of gas reserves as of December 2004 show that it would be possible to meet subregional demand until 2020 or 2022 whether there is a high or low demand scenario.

Consumers and Suppliers

Integration does not imply the creation of a unique market communicating the main subregional markets and their main basins. In this sense, the highest demand centers are Bahía Blanca, Buenos Aires, Lima, Mendoza, Neuquén, Porto Alegre, Rio de Janeiro, Rosario,

Table 1.2: Proven, Probable and Possible Reserves per Country as of December 2004



Basin	*Proven Reserves*	*Probable and Possible Reserves Billions of m^3*	*Total Reserves*
Argentina	613	289	902
Bolivia	757	624	1,381
Brazil	326	172	498
Chile	24	23	47
Peru	325	518	843
Total	2,045	1,626	3,671

As of the date of preparation of this report, some figures are still under review.
Sources: (1) Argentina: Information furnished by local experts. (2) Bolivia: "Southern Cone Natural Gas Study", Freyre & Asoc y Purvin & Gertz. 2004. (3) Brazil: Information furnished by local experts. (4) Chile: Information furnished by local experts. (5) Paraguay: Estudios de Mercado de Uso de Gas Natural en el Paraguay (DCT Energía – 2004), PESE and updates VMME 2005. (6) Peru: Information furnished by local experts. (7) Uruguay: Information furnished by local experts.

[14] *As to the level of reserves, several comments may be made. As regards Argentina, it must be taken into account that during 2006 the provinces initiated a series of calls for bids for the exploration of areas which are being returned to the National State. Also, public company Energía Argentina S.A. (ENARSA) is subscribing agreements with private companies in order to carry out exploration programs. Finally, it is worth mentioning the passing of a Hydrocarbons Law which grants tax benefits to investments in risky exploration activities. Bolivia, in turn, is making important improvements in the investment in the development of suitable fields for natural gas exportation, having committed to supply Argentina 27.7 MMm/d for a 20-year term. Besides, even though approval by the National Congress has not yet been granted, agreements have been subscribed with gas and oil production companies for the exploitation of reserves. Peru also has new information regarding its level of reserves, which were established as of December 31, 2005 in 8.35 TCF for lot 88 (Camisea) and 2.85 TCF for lot 56 (Pagoreni).*

Santiago de Chile, Sao Paulo, Tocopilla and Tucumán. The productive basins with the highest potential to be integrated are the Austral (Argentina), Camisea (Peru) and Espíritu Santo (Brazil) basins. In the subregion, there are also two Liquefied Natural Gas (LNG) projects under way, a liquefaction project in Humay, Peru and a regasification project in Quinteros, Chile and additional regasification plant-building projects are being created for the north of Chile, the northeast of Brazil subregions as well as the Sao Paulo and Rio de Janeiro subregions, also located in Brazil.

The Southern Cone gas system already has partial integrations originated in gas pipelines exporting gas from Bolivia to Brazil and Argentina and from Argentina to Chile, Uruguay, and Brazil. In 2005, the exchanged volume included exports from Bolivia to Brazil for 24 MMm^3/day and to Argentina for 7 MMm^3/day; and from Argentina to Chile for approximately 16.1 MMm^3/day[15] to Uruguay for 0.4 MMm^3/day and to Brazil for 3.3 MMm^3/day.

Nowadays, the highest producing basin is the Neuquina basin followed by the Tarija basin in Bolivia.

Neuquina is a mature basin already in decline, while the Tarija, Camisea and Santos basins are new basins expected to show great potential. Such a situation was taken into account in the analysis scenarios applied to this study.

The gas pipeline network to be integrated includes 13,031 km in trunk gas pipelines and its expansion implies a 20 percent expansion of the current network in new gas pipelines.

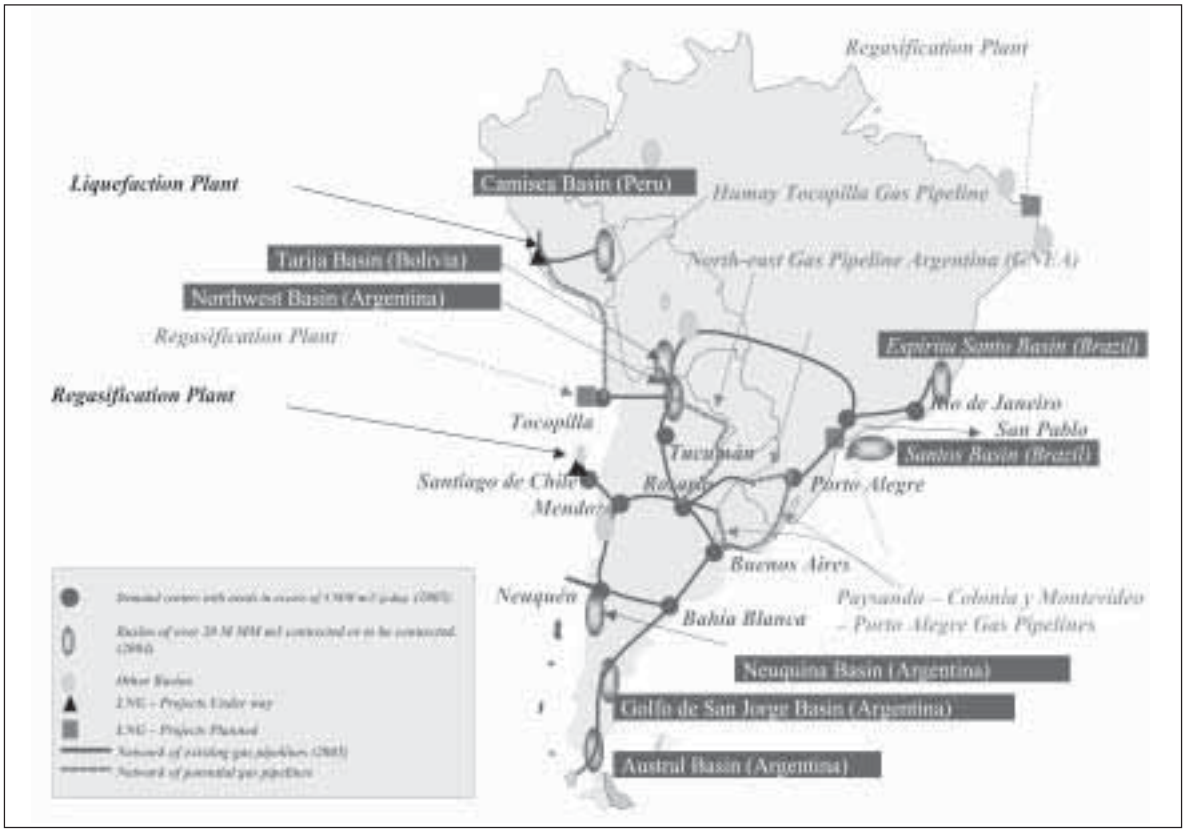
Potential integration mechanisms foresee the construction of three out of four gas pipelines. The Humay gas pipeline, in Tocopilla, which shall connect the Camisea basin with the north of Chile and shall have 1,356 km in length.

The GNEA with a length of 1,500 km shall supply gas to Paraguay, the Argentina Northeastern region and shall enable gas supply to Porto Alegre, through the construction of the gas pipeline from Uruguayana to Porto Alegre.

[15] *Excluding Methanex, exports reached 11.3 MMm^3/day.*

Finally, el Uruguayana-Porto Alegre gas pipeline, is 615 km in length, of which 565 km must be built to reach completion.

Figure 1.1: South Cone Gas System



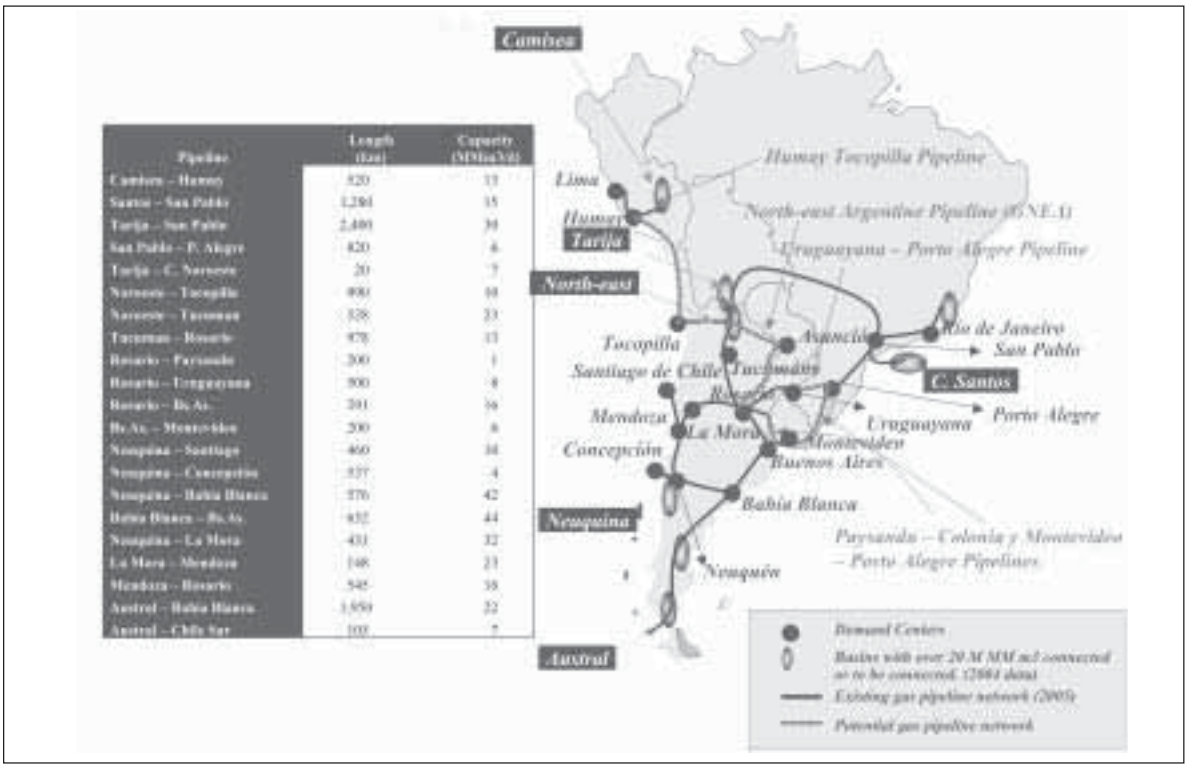
Source: Prepared by PwC on basis of information provided by countries.

Integration implies not only the construction of these gas pipelines, but also their joint construction in order to leverage gas flow to the subregion. In this sense, the GNEA shall transport a 33 percent higher volume if it is built within the integration framework, while tariffs for the three gas pipelines shall be reduced as a consequence of scale economies, derived from a higher gas volume.

Integration

Within this context, Argentina, Brazil, Chile, Paraguay, Peru, Uruguay and Bolivia, the latter as observer, seek to analyze integration strategies which allow the leverage of existing gas reserves in order to meet the increasing subregional demand, within a global context where energy resources provisioning for client countries and the access to better prices for supplier countries is a favorable scenario for the whole subregion.

Figure 1.2: Existing Gas Pipelines



Source: Prepared by PwC on basis of information provided by countries.

It is worth mentioning that the reasons why integration is important for each country are different:

- Argentina has a mature gas industry, with gas playing a strong role as one of its primary energy sources. The country exports gas to the subregion and has resumed gas importations from the subregion. Its strong economic growth within a low reserves renovation framework reveals the need to ensure provisioning from additional energy sources in order to maintain its current growth rates;
- Bolivia, with the second largest reserves in Latin America, has as its strategic objective to develop the gas industry domestically, and is in a position to become a gas distribution center for the subregion. Gas industry may transform the Bolivian economy thus becoming an important source of tax resources;
- In recent years, Brazil has promoted an increased participation by gas among its primary sources as a means of diversifying its electricity generation capacity and spreading its industrial use. Thus, it seeks to mitigate the low-hydraulicity risks in their electric power generation system, as was the case in 2001;
- Chile developed its natural gas industry on the basis of rising imports from Argentina and, therefore, needs to diversify its sources of supply;
- Peru, on the basis of Camisea, has embarked on a rapid development of the gas industry in the domestic market, and has risen up as a potential regional exporter;

- Paraguay, a major exporter of hydroelectricity, is seeking to use gas to diversify its primary sources to reduce dependence on the importation of oil products; and
- Uruguay needs the natural gas that it would be able to buy in the subregion to diversify its primary energy sources and reduce dependence on oil and its by-products.

These observations include and mention the individual strengths and weaknesses each poses for the completion or noncompletion of the Southern Cone Gas Pipeline Network Project. However, there are certain regional aspects which must be taken into account that benefit the vision of an integrated gas industry which are based on remarks compiled within the subregion and on the comparison of experiences in other regional energy integration processes.

Table 1.3: SWOT Analysis

Strengths	*Weaknesses*
Increases the reliability of integrated systems, and, therefore, improves the overall reliability of supply for the group of countries	Conditions autonomous energy provisioning options for the group of countries or individual business alternatives (NLG, South American gas pipeline)
Promotes the need of a regional regulatory convergence	Restricts domestic options for energy self-supply
Promotes institutional reinsurance tending to strengthen stability in rules of the game for the group of countries	Limits the margins for discretional action by national regulatory policies and conditions independent domestic development options
Opportunities	*Threats*
Increases the utilization of common energy resources. Makes gas/ electricity possible	The investment amount and funding needs of the group of countries are more significant than the requirements of an individual option
Increases the scale of energy markets and the attractiveness for investment in the sector	In the short term comparison, in some member countries, price and tariffs restructuring with possible political and social impact prevail
Strengthens economic and commercial integration among the countries in the subregion.	Weakens the dominant positions of some domestic companies in their domestic markets
Promotes the forming of regional players (public and private) in the energy markets of the group of countries	Weakens national positions with a greater negotiating strength in the case of bilateral relations which are not integrated
Promotes natural gas inter-basin competition as a regional natural gas wholesale market gains strength	Compromises national energy sovereignty as a concession to a project which implies, in the long term, shared energy sovereignty
Promotes the interaction with other integrated subregional systems. South Cone integration with the North of the subcontinent	

Integration Economic Convenience Analysis

Work approach: the optimization model

The work approach used to select the gas pipelines which most efficiently serve the existing network, is a simulation model which relates physical quantities transported to the tariffs of the existing and potential gas pipelines network. This model connects the main natural gas demand and production centers in the South Cone as indicated in Figures 1.1 and 1.2.

The simulation assumes the price of gas fluctuates between the different points of sale or "city gate," establishing the gas price in each basin as the "net-back" related to the largest subregional markets – Buenos Aires and Sao Paulo. The prices in each point of sale stem from the well head prices plus transportation costs.

The model used is a static nonlineal planning,[16] which seeks to minimize the cost of gas supply from the productive basins to consumption centers in 2015 and 2025. This model is fulfilled when it satisfies the mean annual demand as well as the peak demand minimizing the total cost of gas according to the following equation.

$$cgT_i = Min \left[\sum_n Q_{ni} \times PG_i + \sum_n Qp_{ni} \times TT_j + \sum_n \left(Qp_{ni} - CT_{n0} \right) \times STT_j + \sum_n CA_{ni} \times PCA_i \right]$$

Where:

$cgTi$ is the minimum cost of gas in each *n node* for each *i* period under evaluation (2015 and 2025);

Q_{ni} is the mean daily gas quantity delivered to the node at the *i* time. Corresponds to mean demand;

PG_i is the well head price of gas at the *i* time, which stems from the model itself;

Qp_{ni} is the mean daily gas quantity delivered to the node at the *i* time. $Qp_{ni} = CT_{ni}$;

TT_j is the gas transportation tariff from each *j* pipeline, from the provisioning basins to consumption centers;

CT_{n0} is the existing transportation capacity for each node as of 2005;

STT_j is the additional tariff to increase the capacity of those gas pipelines which tariffs do not cover their expansion;

CA_{ni} is the alternative fuel volume required in each *n* node at the *i* time; and

PCA_i is the price of alternative fuel at the *i* time.

[16] *It is a lineal planning model with only a nonlineal term; this nonlineal term corresponds to the peak-mean demand ratio.*

The minimized model estimates the wellhead price of gas PG_i , as the *net-back* stemming from alternative fuel PCA_i minus the transportation tariffs and from transportation tariffs, TT_J and STT_J, respectively and selects the injection combination from the subregional basins which meet the demand at the lowest cost for the subregion as a whole.

$$PG_i = PCA_{in} - TT_J - STT_J$$

Where:

PG_i is the well head price of gas at the *i* time, which stems from the model itself;

PCA_{in} is the price of alternative fuel at the main demand centers which was established in the cities of Sao Paulo and Buenos Aires;

TT_i is the gas transportation tariff from each *j* pipeline, from the provisioning basins to consumption centers; and

STT_i is the additional tariff to increase the capacity of those gas pipelines which tariffs do not recover costs.

Restrictions

Simulation faces certain restrictions that limit and reduce the possible results universe:

$Q_{ni} \leq Qp_{ni}$ the amount of gas delivered must be lower or equal the amount of peak gas delivered;

$Q_{ni} = I_i - E_i$ the amount of gas delivered equals the amount of injected gas minus the gas consumption for transportation purposes; and

$R \geq \sum_{i=2005}^{i=2025} I_i$ existing reserves considered as a whole must be higher or equal to the injections during the period under analysis.

Where:

Q_{ni} is the mean daily gas quantity delivered to the node at the *i* time. Corresponds to mean demand;

Qp_{ni} is the peak daily gas quantity delivered to the node at the *i* time;

Ii, is the mean daily gas injection to meet the demand at the *i* time;

Ei is the gas injected additionally to the demand, said gas is used to operate the gas pipeline at the i time; and

R_0 is the stock of proven, probable, and possible reserves as of the start date, 2005.

Finally, when the model is balanced, the volumes of alternative fuel CA_i required in each demand center are obtained by correlating deliveries Qp_{ni} and peak demand Dp_i (taking into account an exponential daily distribution of the demand) according to the following equation:

$$CA = \frac{1}{\gamma_I} \times \left\{ Dp_i - Qp_{ni} \times \left[1 + \left(\frac{Dp_i}{Qp_{ni}} \right) \right] \right\}_i$$

Where:

Y_i is a coefficient related to the demand load factor;

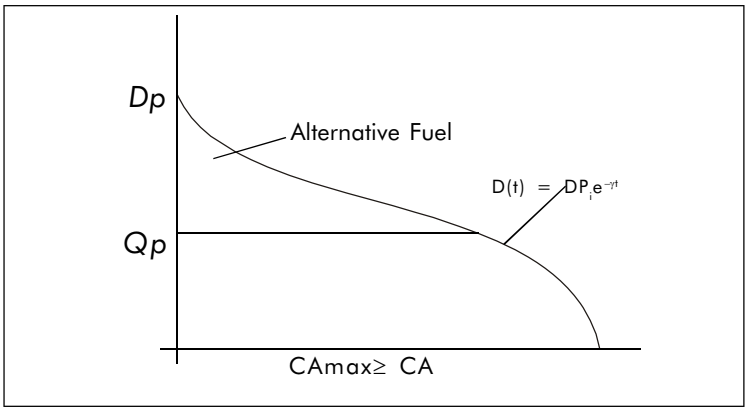
Dpi_i is the peak daily gas quantity demanded in the node at the *i* time. Corresponds to peak demands; and

Qp_{ni} is the mean daily gas quantity delivered to the node at the *i* time.

At each demand center, the alternative fuel utilization capacity (for example, for power generation) is limited by structural characteristics and, therefore, it is also deemed a restriction CA_i d" CA_{MAXi}).

In line with the reference terms, two analysis periods have been defined: 2015 and 2025. In this sense, the results obtained in 2015 (production, reserves, expansions) are used as input in the application of the model for the following period, 2025, and the results of both periods are compared to the gas pipelines capacity as of 2005. This comparison is focused on estimating the necessary expansion for gas pipelines, taking into account that new gas pipelines have null capacity as of 2005.

Figure 1.3: Graphic Representation



Model parameters

The model so defined uses the following parameters or variables predetermined or external.

- The demand forecasts conveniently classified by region for each demand node *(D and Q);*
- The stock of proven, probable, and possible reserves in order to classify natural gas production and injection centers by region *(R);*
- An estimate of the price of alternative fuel (*PCA)* at the points of demand, taking into account the alternative fuels basket such as coal and fuel oil. This basket takes into consideration the kind of demand which shall be met through the gas increase and also the alternative fuels for each kind of demand;
- For each gas pipeline segment *j* between basins and/or demand centers, the current transportation capacities are taken into account as a start point *(CT_0);*
- Transportation tariffs correspond to the current tariffs *(TT_j;)*. For the case of Argentina, it was estimated that the 2015 tariffs shall correspond to efficient tariffs ("full cost recovery tariff") similar to those existing in 2001; and
- They were estimated based on the transportation tariff *(STT_J)* in segments in Argentina, and the Bolivia-Brazil gas pipeline.

Scenarios[17]

Projections on demand take into consideration a natural gas High Regional Demand (HRD) scenario and a Low Regional Demand (LRD) scenario.[18] On the offer side, or natural gas injection, the work was based on different hypotheses, all of them related to the relative importance of Bolivia as the natural gas supplier for the regional market, and the alternative role of Peru to meet the demand of the subregion. In the case of the Argentine basins, injection limits were adopted based on the situation of the reserves and the maturity of the basins. In addition, meetings were held with subregional companies and specialists[19] about the possible replenishment of reserves and such

[17] *During the development of this work, 10 different integration scenarios were elaborated. The scenarios presented herein correspond to those finally agreed upon with country representatives, the World Bank, and the consultants. These four scenarios stem from the report prepared by an independent consultant on the expected reserves dynamics in the different countries, upon request of domestic experts during the second workshop.*

[18] *During the first workshop, it was agreed to avoid setting of a baseline and to work on scenarios which were based on different hypotheses of natural gas offer and demand within the group of countries in the subregion.*

[19] *Consultant Juan Rosbaco was in charge of the analysis of reserves dynamics through the preparation of potential gas replenishment curves based on the data collected from companies and geologists in the South American region and using an estimated gas price equal to US$50 a barrel of oil.*

concepts were set as the limits to the injection allowed in each basin. Supply and demand balances needed to take into account existing forecasts for the import of LNG by Chile (subtracted from domestic demand to be met in the regional market), as well as for the export of LNG by Peru (added to domestic and RD for the purpose of calculating the impact on reserves and the production available for the regional market). The following scenarios were defined in order to implement the model:

- HRD Scenario with Maximum Injection by Bolivia *(HRD-MaxIB)*: Assumes a high economic growth which translates into high demand growth rates from Argentina, Brazil, Chile, Peru and Uruguay and the unlimited natural gas supply by Bolivia;
- LRD Scenario with Maximum Injection by Bolivia (HRD-MaxIB): Assumes a low economic growth which translates into low demand growth rates from Argentina, Brazil, Chile, Peru and Uruguay and the unlimited natural gas supply by Bolivia;
- HRD Scenario with Maximum Injection by Peru (HRD-MaxIP): Regional demand projections are kept, but due to the decline in the offer by Bolivia, injection by Peru into the system is leveraged; and
- LRD Scenario with Maximum Injection by Peru (LRD-MaxIP): Assumes a lower regional demand, but on the offer side, it assumes, like the above scenario, which Peru injects to its full capacity.

Premises, work hypotheses and estimations

General premises and planning scope

The main hypotheses on growth and pricing[20] used in the elaboration of demands, injections, and reserves dynamization are the following:

- Three percent annual accumulated GDP growth;
- Crude oil price: The WTI crude oil barrel prices are high, ranging from 50 to 60 US$/bbl and since 2010 it is maintained within real values;
- Prices impact on production:[21] New discoveries shall be held during a minimum period of five years before being added to production. Prospectivity function derives from the pricing scenario, basin maturity, and new investments;

[20] *Premises agreed upon between participating countries and the World Bank to be included in the reference terms used by the consultant hired to prepare this strategic study.*

[21] *This hypothesis was amended during the first experts meeting accepting that the consideration on the gas offer was based on the definition of reserves available for exportation as proven reserves plus 50 percent of probable reserves capable of sustaining an exportation project for a minimum term of 10 years.*

- The planning scope defined was 20 years;
- This work assumes there are no political restrictions to integration, and only technical aspects need to be solved in the short term, thus making its implementation viable. Thus, the nonintegration cost has been set forth in objective; and
- All figures are expressed in U.S. dollars current in 2005, unless otherwise set forth.

Demand (Parameters Qni – Dpi)

Demand projections correspond to a 3 percent growth of the regional GDP. The preparation, thereof, took into account that gas volume is affected by the weather, specially by the rain seasonality which affects the amount of electric power which may be delivered, as well as political definitions on gas penetration on each country's energy matrix.

HRD: This scenario assumes a higher gas penetration in the energy matrices of Argentina, Brazil, Chile, Peru and Uruguay, as a result of political decisions and/or lower contributions from hydric generation as a result of weather factors.

Table 1.4: High Regional Demand: Mean and Peak Daily Demand

High Regional Demand								
Mean Daily Demand								
	Argentina	*Bolivia*	*Brazil*	*Chile*	*Paraguay*	*Peru*	*Uruguay*	*Total*
2005								0
2006	105.2	5.2	81.9	22.9		3.3	0.7	219.2
2007	110.8	5.6	91.2	23.8		4.6	1.2	237.2
2008	116.5	6	98.3	24.8		5.9	1.5	253
2009	120.7	6.5	102.4	23.2	0.9	6.9	1.4	262
2010	125.1	10.8	109	25.3	1.2	11	1.5	283.9
2011	129.6	11.4	112.4	25.2	1.7	11.8	1.7	293.8
2012	134.3	12.1	119.5	25.4	1.7	12.6	1.9	307.5
2013	139.2	12.5	122.2	25.3	1.8	13.5	2	316.5
2014	144.2	12.9	124.7	25.2	1.8	14.5	2.1	325.4
2015	149.5	13.3	127.1	25.4	1.9	15.4	2.3	334.9
2016	154.9	13.7	133.5	25.7	2	16.4	2.5	348.7
2017	160.5	14.2	140.1	25.9	2	17.6	2.7	363
2018	166.3	14.7	147.1	26.1	2.1	18.3	2.8	377.4
2019	172.3	15.2	154.5	26.4	2.2	19.5	2.8	392.9
2020	178.6	15.8	162.2	26.7	2.3	20.4	2.9	408.9
2021	185	16.4	170.3	27	2.3	21.2	3	425.2
2022	191.8	17	178.8	27.3	2.4	21.9	3.3	442.5
2023	198.7	17.7	187.8	27.6	2.5	22.7	3.5	460.5
2024	205.9	18.4	197.2	28	2.6	23.6	3.6	479.3
2025	213.4	19.2	207	28.4	2.7	24.6	3.7	499

High Regional Demand								
Peak Demand								
	Argentina	*Bolivia*	*Brazil*	*Chile*	*Paraguay*	*Peru*	*Uruguay*	*Total*
2005								
2006	146.5	6.7	83.6	29.7		4.3	0.9	271.7
2007	153.2	7.2	93.1	31.2		6	1.4	292.1
2008	160.1	7.8	100.3	31.6		7.6	1.7	309.1
2009	165.6	8.5	104.9	28	1.2	9	1.6	318.8
2010	171.2	14	111.8	30.4	1.6	14.3	1.7	345
2011	177	14.8	115.5	30.2	2.2	15.3	1.9	356.9
2012	183	15.7	122.9	30.4	2.2	16.4	2.1	372.7
2013	189.2	16.3	126	30.4	2.3	17.6	2.2	384
2014	195.6	16.8	129	30.5	2.4	18.8	2.3	395.4
2015	202.2	17.3	132	30.9	2.5	20	2.5	407.4
2016	209	17.9	139	31.2	2.6	21.3	2.8	423.8
2017	216	18.5	146.3	31.4	2.7	22.9	2.9	440.7
2018	223.2	19.1	154.1	31.7	2.8	23.8	3	457.7
2019	230.7	19.8	162.5	32	2.8	25.4	3.1	476.3
2020	238.4	20.5	171.3	32.3	2.9	26.5	3.2	495.1
2021	246.4	21.3	180.8	32.7	3	27.5	3.3	515
2022	254.6	22.1	190.8	33	3.2	28.5	3.5	535.7
2023	263.1	23	200.9	33.4	3.3	29.6	3.7	557
2024	271.9	24	210.3	33.8	3.4	30.7	3.9	578
2025	280.9	25	220.1	34.2	3.5	32	4	599.7

Sources: (1) Argentina: Information furnished by local experts. (2) Bolivia: "Southern Cone Natural Gas Study," Freyre & Asoc y Puvin & Gertz. 2004 (3) Brazil: Information furnished by local experts. (4) Chile: Information furnished by local experts. (5) Paraguay: Estudios de Mercado de Uso de Gas Natural en el Paraguay (DCT Energía – 2004), PESE and updates VMME 2005. (6) Peru: Information furnished by local experts. (7) Uruguay: Information furnished by local experts.

LRD: This scenario assumes a lower gas penetration due to issues contrary to those stated in the HRD scenario.

In each country, demand was distributed among the different provisioning points allocating proportional growth rates for each demand center based on actual consumption.[22]

Table 1.5: Low Regional Demand: Mean and Peak Daily Demand

Low Regional Demand								
Mean Daily Demand								
	Argentina	*Bolivia*	*Brazil*	*Chile*	*Paraguay*	*Peru*	*Uruguay*	*Total*
2005								
2006	104.5	5.2	79.7	19.3		3.3	0.7	212.7
2007	109.4	5.6	86	20.1		4.6	1.2	226.9
2008	114.2	6	90.9	20.3		5.6	1.4	238.4
2009	117.7	6.5	93.5	20.2	0.9	5.7	1.3	245.8
2010	121.4	10.8	99.1	23.1	1.2	9.7	1.4	266.7
2011	125.1	11.4	100.7	23	1.7	9.6	1.6	273.1
2012	129	12.1	106.2	23.2	1.7	10.5	1.8	284.5
2013	133	12.5	107.3	23.1	1.8	11.1	1.8	290.6
2014	137.1	12.9	108.4	23.1	1.8	11.1	2	296.4
2015	141.3	13.3	109.5	23.2	1.9	11.2	2.2	302.6
2016	145.7	13.7	112.8	23.3	2	11.3	2.4	311.2
2017	150.1	14.2	116.2	23.4	2	12.4	2.6	320.9
2018	154.7	14.7	119.7	23.5	2.1	13.3	2.7	330.7
2019	159.5	15.2	123.2	23.6	2.2	14	2.7	340.4
2020	164.4	15.8	126.9	23.7	2.3	14.9	2.8	350.8
2021	169.4	16.4	130.7	23.8	2.3	15.9	2.8	361.3
2022	174.6	17	134.7	23.9	2.4	16.8	3	372.4
2023	179.9	17.7	138.7	24	2.5	17.7	3.2	383.7
2024	185.4	18.4	142.9	24.1	2.6	18.6	3.3	395.3
2025	191.1	19.2	147.2	24.2	2.7	19.7	3.5	407.6

[22] *It is worth mentioning that this assumption tends to increase demand in mature markets and reduce demand in new markets, since the growth rate is usually higher in the latter.*

Peak Demand								
	Argentina	*Bolivia*	*Brazil*	*Chile*	*Paraguay*	*Peru*	*Uruguay*	*Total*
2005								
2006	145.8	6.7	81.4	27.7		3.3	0.9	265.8
2007	151.8	7.2	87.9	29.2		4.6	1.4	282.1
2008	157.8	7.8	92.9	29.6		5.6	1.6	295.3
2009	162.6	8.5	96	26.9	1.2	5.7	1.5	302.4
2010	167.5	14	101.9	29.5	1.6	9.7	1.6	325.8
2011	172.5	14.8	103.8	29.3	2.2	9.6	1.9	334.1
2012	177.7	15.7	109.6	29.5	2.2	10.5	2	347.2
2013	183	16.3	111.1	29.5	2.3	11.1	2.1	355.4
2014	188.5	16.8	112.7	29.6	2.4	11.1	2.2	363.3
2015	194	17.3	114.4	30	2.5	11.2	2.4	371.8
2016	199.8	17.9	118.3	30.2	2.6	11.3	2.7	382.8
2017	205.6	18.5	122.4	30.2	2.7	12.4	2.8	394.6
2018	211.7	19.1	126.7	30.4	2.8	13.3	2.9	406.9
2019	217.9	19.8	131.2	30.5	2.8	14	2.9	419.1
2020	224.2	20.5	136	30.7	2.9	14.9	3.1	432.3
2021	230.7	21.3	141.2	30.8	3	15.9	3	445.9
2022	237.4	22.1	146.7	31	3.2	16.8	3.2	460.4
2023	244.3	23	151.8	31.2	3.3	17.7	3.4	474.7
2024	251.4	24	156	31.3	3.4	18.6	3.6	488.3
2025	258.6	25	160.3	31.5	3.5	19.7	3.7	502.3

Sources: (1) Argentina: Information furnished by local experts. (2) Bolivia: "Southern Cone Natural Gas Study", Freyre & Asoc y Puvin & Gertz. 2004 (3) Brazil: Information furnished by local experts. (4) Chile: Information furnished by local experts. (5) Paraguay: Estudios de Mercado de Uso de Gas Natural en el Paraguay (DCT Energía – 2004), PESE and updates VMME 2005. (6) Peru: Information furnished by local experts. (7) Uruguay: Information furnished by local experts.

Reserves (parameter R)

Reserves data is not uniform in every country.[23] Argentina, Peru and Brazil use definitions provided by the Society of Petroleum Engineers; in Bolivia the DeGoyer & MacNaughton certification prevails[24] and finally Chile[25] uses an "ad hoc" definition in line with the definition applied by the Society of Petroleum Engineers. During the preparation of this report, Argentina, Bolivia and Peru have initiated analysis procedures of their corresponding reserves.

Table 1.6: Reserves per Country and Basin

Country	*Basin*	*Proven Reserves (BCM)*	*Probable Reserves (BCM)*	*Possible Reserves (BCM)*
Argentina (2003)	Northwest	124.51	52.6	
	Cuyana	0.52	0.22	
	Neuquina	311.17	99.28	
	Golfo San Jorge	38.05	23.43	
	Austral	138.25	113.48	
	Total	**612.5**	**289.01**	
Bolivia (2005)	Chuquisaca	13.88	3.4	
	Cochabamba	20.39	13.59	
	Santa Cruz	80.14	66.54	
	Tarija	643.08	540.29	
	Total	**757.48**	**623.82**	
Perú (2004)	Northwest	10.76		
	Selva Central	6.8		

[23] *The lack of uniformity has an impact on the probable and possible definitions.*
[24] *As to the reserves classification, experts experts state that the definition included in the DeGolyer & MacNaughton certification report prevails. Given this classification, the extent to which probable and possible reserves may be reclassified as proven reserves shall depend on future well drillings, test, and behavior. The risk level to be applied to the assessment of probable and possible reserves is influenced by economic and technological factors as well as the time factor. Probable and possible reserves in this report have been adjusted based on this additional risks and, therefore, can be compared to proven reserves.*
[25] *Possible reserves: a very general measurement of geological resources of a field during an initial exploration period, carried out through the comparison of segmental information on basin types and other geological background data. Probable reserves: estimated measurement of a field's geological resources through experimental seismic techniques; therefore, it has a lower accuracy level than the above. Proven reserves: an estimate of extractable resources of a field based on their economic feasibility; therefore, such estimate is sensitive to price variations.*

Country	*Basin*	*Proven Reserves (BCM)*	*Probable Reserves (BCM)*	*Possible Reserves (BCM)*
	Selva Sur	307.81	471.62	
	Total	**325.36**	**471.62**	
Brazil (2004)	Halagaos	5.13	1.73	
	Amazonas	49.45	34.79	
	Bahía	25.27	26.98	
	Ceará	1.07	0.1	
	Espíritu Santo	22.31	16.02	
	Paraná	0.03	2.18	
	Río de Janeiro	119.05	33.75	
	Rio Grande do Norte	21.21	4.74	
	Sergipe	4.12	2.16	
	San Pablo	78.47	49.58	
	Santa Catarina	0.01	0.01	
	Total	**326.12**	**172.04**	
Chile (2005)	Magallanes	24		18
	Valdivia			5
	Total	**24**		**23**

Sources: (1) Argentina: Information furnished by the National Energy Secretariat. (2) Bolivia: The information furnished by the Hydrocarbons Superintendency of the SYRESE states that the data belong to the YPFB source. (3) Brazil: Information furnished by experts of the Mines and Energy of Brazil, their source is ANP/SDP, pursuant to Portaria ANP Nº 9/00 (4) Chile: The information furnished corresponds to public data of the National Petroleum Company (ENAP) (5) Paraguay: The country has no reserves. Information furnished by la National Directorate of Energy and fuels (6) Peru: Information furnished by a local expert (7) Uruguay: The country has no reserves. Information furnished by a local expert.

Natural gas wellhead prices based on Alternative Fuels references (parameters PGi-PCA)

Natural gas well head prices have two important simulation goals: first, to allocate the basin which meets the demand at the lowest prices and, second, to set the minimum price at which a basin would be willing to sell gas.

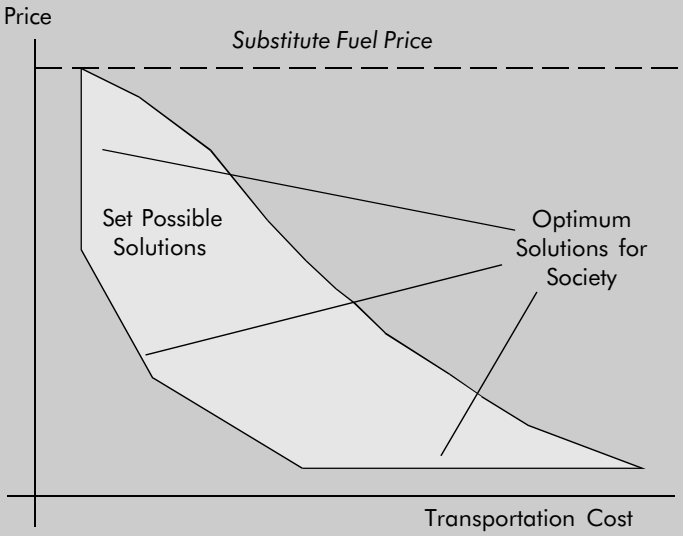
The well head price is set by the main demand centers' net-back. As stated in the model description, the price of alternative fuels *(PCA)* sets the maximum price at which the gas may be delivered at "City-Gate."

Since gas replacement for other power sources within the subregion takes place in demand for thermal generation and industrial consumption, the relevant fuel to be taken into account is fuel oil, but the use of a reference quotation for oil between US$50 and 60 per barrel, generates other replacement options[26] for the thermal industry, such as mineral coal and biodiesel fuel.[27]

The price of gas obtained in this model reflects the implementation of certain premises on market behavior. These premises assume the market fluctuates among demand centers, thus making the price of gas in each basin unique for the whole region. Said price is the ***minimum price*** at which gas owners would market their product given the implemented premises on PCA.

Should a monopoly competition premise be adopted, with the possibility of customer selection the average price each basin would receive would be different to the one used in this study, this new price would derive from the analysis of PCA in each demand center minus the transportation costs from the selling basin to the consumption center. For instance, if PSA in Tocopilla rose to US$6 MMBTU, the price of gas in Camisea for that market would be US$4 MMBTU.

In short, the price would derive from a negotiation between the parties and its result could not exceed the substitute fuel's price in each demand center, minus the transportation cost to the basin, and could not be under the minimum obtained through the implementation of this model



[26] *Remark made by representatives of Argentina and Brazil during the first workshop and which resulted in the adoption of a whole basket of substitute fuels.*

[27] *LNG was also considered an alternative fuel; however, this fuel was deemed a nonintegration alternative and it is an alternative fuel to analyze the price at which gas should be replaced.*

In order to estimate the price of the substitute fuel PCA_i, a basket of substitutes derived from weighing different substitution options in the thermal marketplace was taken into consideration. To do so, natural gas demand classified[28] by consumption segment in the main price referents, Buenos Aires and Sao Paulo was used. Based on this information and assuming that:

- The nonrestricted industrial segment replaces 100 percent of natural gas consumption with fuel from 2006 to 2025;
- The operational thermal generation segment as to 2006, replaces 100 percent of natural gas consumption with fuel oil until the end of the assessed period; and
- The thermal generation segment which shall operate from 2007 to 2025, replaces 100 percent of incremental natural gas consumption with mineral coal.

A price of US$6.05 MMBTU was obtained, which derives from weighing 85 percent of fuel oil prices (US$6.5 per MMBTU) and 15 percent of mineral coal prices (US$3.5 MMBTU).

Table 1.7 shows the PG_i value applied in order to minimize the gas price and transportation.[29]

Table 1.7: Net-back per Basin

Basin	*PCA*		TT_i	STT_i	PG_i
	US$/MMBTU	*Price Set By*	*US$/MMBTU*	*US$/MMBTU*	*US$/MMBTU*
Austral	6.05	Buenos Aires	1.06	0.47	4.52
San Jorge	6.05	Buenos Aires	0.61	0.31	5.13
Neuquina	6.05	Buenos Aires	0.63	0.11	5.37
Northwest	6.05	Buenos Aires	0.81	0	5.24
Tarija	6.05	Sao Paulo	1.70	0.17	4.18
Santos	6.05	Sao Paulo	0.36	0	5.69
Camisea	6.05	Buenos Aires	3.81	0	2.65

(2) The prices of the Northwest and Camisea basins take into account the tariffs of new gas pipelines based on tariffs estimated during Phase 2.

[28] *Information furnished by the countries.*
[29] *It is worth mentioning that the estimation process of the optimum price as of 2015 and 2025 did not take into consideration the effect of currently existing provisioning contracts which prices may differ from gas prices estimated by the model.*

Table 1.8 shows the sensitivity of natural gas well head values, for a substitute fuel basket price which range between US$4 and 10 per MMBTU. *It is important to highlight the fact that these results do not reflect the potential tariff reduction the increased volume may bring about on some existing gas pipelines.*

Table 1.8: Net-back per Basin – Sensitivity to Substitute Fuel Price

Basin	*PG_i US$/MMBTU*						
	4.0	5.0	6.0	7.0	8.0	9.0	10.0
Austral	2.5	3.5	4.5	5.5	6.5	7.5	8.5
San Jorge	3.1	4.1	5.1	6.1	7.1	8.1	9.1
Neuquina	3.4	4.4	5.4	6.4	7.4	8.4	9.4
Northwest	3.2	4.2	5.2	6.2	7.2	8.2	9.2
Tarija	2.1	3.1	4.1	5.1	6.1	7.1	8.1
Santos	3.6	4.6	5.6	6.6	7.6	8.6	9.6
Camisea	0.5	1.5	2.5	3.5	4.5	5.5	6.5

Current and projected transportation capacity; transport tariffs and expansion over tariffs (parameters CTn0 – TT_i – STT_i and model results – Qpni – CTni)

For the estimation of tariffs for new gas pipelines, profile studies were prepared for each gas pipeline. These tariffs were estimated for the whole 2015-25 period, taking into account the investment to be made, a regulatory rate of return, the income tax and capital amortization over 35 years. These data were used to make a preliminary tariff estimation for each pipeline segment. Tariffs obtained during Phase 2 are different from those of Phase 1.

An over tariff was applied to those gas pipelines where tariff does not foresee system expansions. From model implementations stems the fact that over tariffs should be applied in Argentina and the Bolivia-Brazil segment. In the remaining transportation segments, tariffs include expansion costs.

In the case of Argentina, for the calculation of expansion costs, the values published for the TGS and TGN systems for the open season of the 2006 expansion:

- TGS T. del Fuego – GBA 93.9 MMUS$/MMm^3/day
- TGS Neuquén – GBA 56.9 MMUS$/MMm^3/day
- TGN Salta – GBA 82.5 MMUS$/MMm^3/day
- TGN Neuquén – GBA 52.2 MMUS$/MMm^3/day

For the remaining gas pipelines, standards between 0.03 and 0.06 US$/km/MMm^3/day were used.

Table 1.9: Length, Capacity, Tariff and Over Tariff of the Existing Gas Pipeline Networks and Those to be Built

	Length km	*Capacity 2005*	*2015 (Average)*	*2025 (Average)*	*Tariff 2015 and 2025 US$/Mm^3 /day*	*US$/ MMBTU/day*	*Over Tariff US$/ Mm^3/day*	*US$/ MMBTU/day*	*Gas Retention %*
Pipeline									
Camisea-Humay-Lima	520	12.70	29.25	44.73	44.74	1.21	-	-	3.0%
Humay-Tocopilla	1,500	-	11.10	14.78	44.29	1.20	-	-	8.0%
Santos-San Pablo	200	15.00	76.58	127.35	13.29	0.36	-	-	0.2%
Tarija-San Pablo	2,400	30.00	30.00	35.40	62.74	1.70	6.27	0.17	12.0%
San Pablo-Porto Alegre	820	6.00	7.78	8.38	0.04	-	-	-	4.0%
Porto Alegre-San Pablo	820	2.00	6.00	6.00	18.45	0.50	-	-	4.0%
Tarija-C. Noroeste	20	7.00	102.53	156.98	8.49	0.23	-	-	1.0%
Noroeste-Tocopilla	990	9.50	9.50	9.50	36.91	1.00	-	-	1.5%
Tocopilla-C. Noreste	990	10.00	11.60	12.93	36.91	1.00	-	-	1.5%
Noroeste-Tucumán	528	22.50	28.65	35.60	10.60	0.29	7.00	0.19	2.0%
Tucumán-Rosario	978	12.90	12.90	12.90	15.10	0.41	9.97	0.27	2.6%

Length	*Capacity*		*Tariff 2015 and 2025*		*Over Tariff*		*Gas*		
	km	*2005*	*2015 (Average)*	*2025 (Average)*	*US$/Mm³ /day*	*US$/ MMBTU/day*	*US$/ Mm³/day*	*US$/ MMBTU/day*	*Retention %*
Noroeste-Paraguay	600	-	92.10	140.30	11.07	0.30	-	-	2.0%
Paraguay-Rosario	870	-	87.10	132.95	22.14	0.60	-	-	2.8%
Rosario-Paysandu	200	1.00	1.00	1.00	-	-	-	-	2.0%
Rosario-Uruguayana	500	8.00	11.43	21.65	8.40	0.23	-	-	2.8%
Rosario-Bs.As.	291	15.70	63.25	90.35	4.20	0.11	1.47	0.04	0.6%
Paysandu-Colonia	350	-	-	-	15.60	0.42	-	-	1.0%
Montevideo-Porto Alegre	800	-	-	-	25.83	0.70	-	-	3.0%
Uruguayana-Porto Alegre	565	-	6.98	18.10	22.14	0.60	-	-	2.8%
Bs.As.-Montevideo	200	6.00	6.00	6.00	7.75	2.21	-	-	1.5%
Neuquina-Santiago	460	10.00	10.30	10.30	26.94	0.73	-	-	0.6%
Neuquina-Concepción	537	3.90	3.90	3.90	35.06	0.95	-	-	0.6%
Neuquina-Bahía Blanca	576	41.90	41.90	41.90	13.90	0.38	-	-	2.8%
Bahía Blanca-Bs.As.	632	44.40	44.40	44.40	9.30	0.25	4.09	0.11	2.9%
Neuquina-La Mora	431	31.90	31.90	31.90	12.90	0.35	4.52	0.12	2.0%
La Mora-Mendoza	148	23.30	23.30	23.30	-	-	-	-	0.4%
Mendoza-Rosario	545	16.30	16.30	16.30	6.00	0.16	2.10	0.06	1.4%
Austral-San Jorge	954	21.60	24.25	27.30	16.50	0.45	7.26	0.20	3.4%
San Jorge-Bahia Blanca	996	21.80	21.95	23.60	13.30	0.36	5.85	0.16	5.0%
Austral-Chile Sur	105	6.80	9.10	9.20	7.38	0.20	-	-	0.5%

Mean injection per country (Ii variable)

The allowed injection considered each basin's specific characteristics. For old or mature basins, it is assumed that their replenishment capacity is less likely to occur, while the exact opposite happens in the new basins, such as Camisea, Santos, and Tarija.

Table 1.10 shows the mean projected injection (*Ii Pr)* according to the expected demand and potential injection (*Ii Po)* which derives from the information contained in the reserves dynamization report.

Annual injection estimated by the model indicated that Argentina would be injecting gas from probable and possible reserves as from 2020. Bolivia would do so in 2019, Brazil in 2016 and Peru in 2023.

In order to reach this level of injection, Argentina should deliver all its proven reserves plus 40 percent of its probable and possible reserves and Bolivia should develop 20 percent of its proven and possible reserves. Brazil is a special case; to meet its injection level the country should discover new reserves and develop all its proven, probable and possible reserves.[30]

Table 1.10: Projected and Potential Injection per Country

	MMm³/day									
	Argentina		*Bolivia*		*Brazil*		*Peru*		*Total*	
Year	*I Pr*	*I Po*	*I Pr*	*I Po*	*I Pr*	*I Po*	*I Pr*	*I Po*	*I Pr*	*I Po*
2005	109.9		34.5		26		3		172.6	0.0
2006	106.6	122	39.4	40	27.4	54	3.3	5	176.7	220.8
2007	103.6	120	45.0	48	29.6	63	4.1	7	182.2	237.8
2008	101.0	116	51.3	58	32.1	78	5.0	9	189.3	260.8
2009	98.6	110	58.5	69	35.0	82	6.0	12	198.2	272.4
2010	96.5	113	66.8	83	38.4	86	7.3	16	209.1	297.3

[30] *Source: "Plano de Longo Prazo Projeção Da Matriz – 2022. Sumario Executivo." Ministério de Minas e Energia. Secretaria de Energia. Departamento Nacional de Política Energética. Coordenação Geral de Estudos e Planejamento. Dezembro 2002.*

	MMm³/day									
	Argentina		*Bolivia*		*Brazil*		*Peru*		*Total*	
Year	*I Pr*	*I Po*	*I Pr*	*I Po*	*I Pr*	*I Po*	*I Pr*	*I Po*	*I Pr*	*I Po*
2011	94.8	116	76.1	100	42.4	90	9.0	21	222.2	327.1
2012	93.3	120	86.9	119	46.9	95	10.9	28	238.0	362.9
2013	92.0	125	99.1	143	52.2	100	13.3	38	256.7	405.7
2014	91.0	130	113.0	172	58.3	105	16.3	51	278.7	457.3
2015	90.2	135	131.0	206	66.9	110	24.4	68	312.5	519.7
2016	91.5	133	135.9	211	68.7	115	25.5	70	321.7	529.1
2017	93.0	131	140.9	215	70.6	121	26.8	72	331.3	539.3
2018	94.4	130	146.2	219	72.6	127	28.2	75	341.3	550.3
2019	95.8	128	151.6	223	74.7	133	29.6	77	351.7	562.1
2020	97.3	127	157.2	228	76.9	140	31.1	79	362.5	574.6
2021	98.8	127	163.1	232	79.2	147	32.7	82	373.7	587.9
2022	100.4	126	169.1	237	81.6	155	34.4	84	385.4	601.9
2023	101.9	126	175.4	242	84.1	162	36.1	87	397.5	616.7
2024	103.5	126	181.9	247	86.8	170	37.9	89	410.1	632.3
2025	105.1	126	188.7	252	90.8	179	37.9	92	422.4	648.6

Also, injection projections assume a limit to injection capacity of the basins in the Argentine southern region of 40 to 45 MMm³ day, for the Austral and the San Jorge basin. For the remaining Argentine productive basins, a conservative hypothesis has been established, given their mature status. It is convenient to assume a decline in production for the next five years, from 2010 to 2014 stagnation in production and, for the last 10 years, it has been assumed that through new investments, the offer shall grow to reach the current figures.[31] It is important to highlight that within this context if Argentina makes the domestic market its priority, Chile, Uruguay and Brazil – which nowadays receive exports from Argentina – should look for an alternative power source to "swap" or replace gas with Argentina.

[31] *The decline period derives from the information furnished by local experts representing Argentina.*

However, in the analysis as a whole, reserves do exist and a lower delivery level by Brazil would be replaced with a higher level of exports from Bolivia to Brazil and from Peru to Argentina, to replace Bolivia as a gas supplier. This situation would mean the expansion of the gas pipelines which join Tarija and Sao Paulo through Brazil and the system which joins Camisea with the Northeast basin.

Table 1.11: Projected and Potential Injection per Country

		MMm³			
Period 2006-25	*Argentina*	*Bolivia*	*Brazil*	*Peru*	*Total*
Possible injection on basis of increased reserves	907,645	1,220,366	844,103	387,504	3,359,618
Total injection for the period HRD MaxIB	831,190	1,031,839	618,705	204,672	2,686,406
Total injection for the period HRD MaxIP	831,157	979,955	602,922	283,996	2,698,030
Total injection for the period LRD MaxIB	813,854	1,037,322	469,065	116,577	2,436,818
Total injection for the period LRD MaxIP	813,941	936,597	499,261	187,876	2,437,675
Total reserves	901,510	1,381,300	498,160	796,980	3,577,950
Proven reserves	612,500	757,480	326,120	325,360	2,021,460
Probable and Possible Reserves	289,010	623,820	172,040	471,620	1,556,490

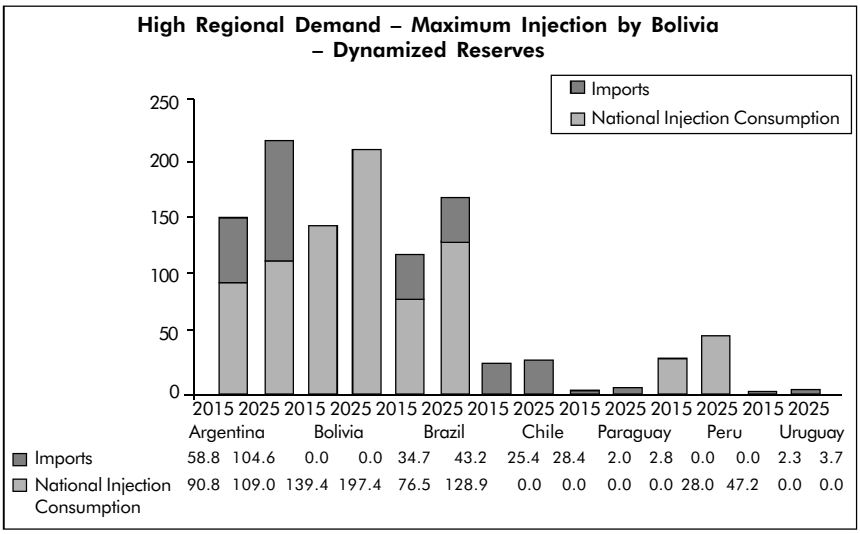
As stated in the Table 1.11, the possible injection based on dynamized reserves[32] shows that the potential injection broadly covers consumption in each scenario.

Analysis Results

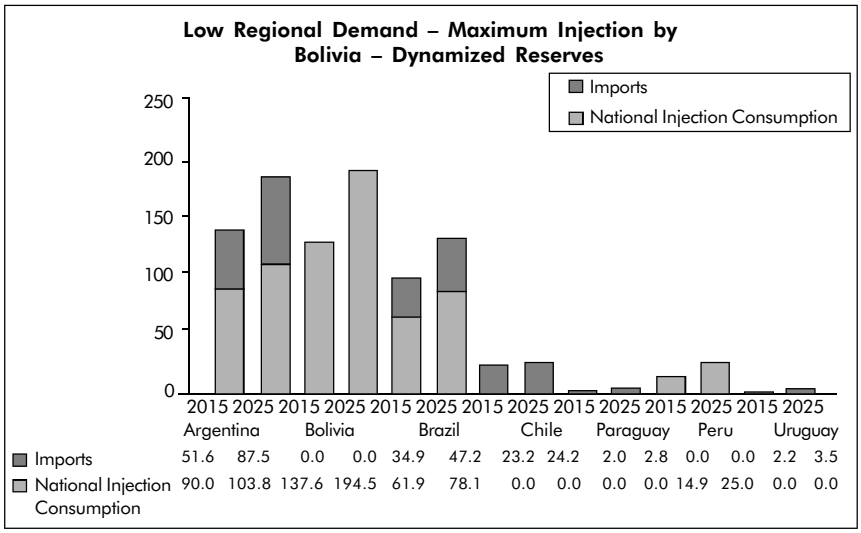
Model results on natural gas provisioning in each country for the different scenarios of the Southern gas pipeline system. National injection and gas commercial exchange.

[32] *Source: Juan Rosbaco.*

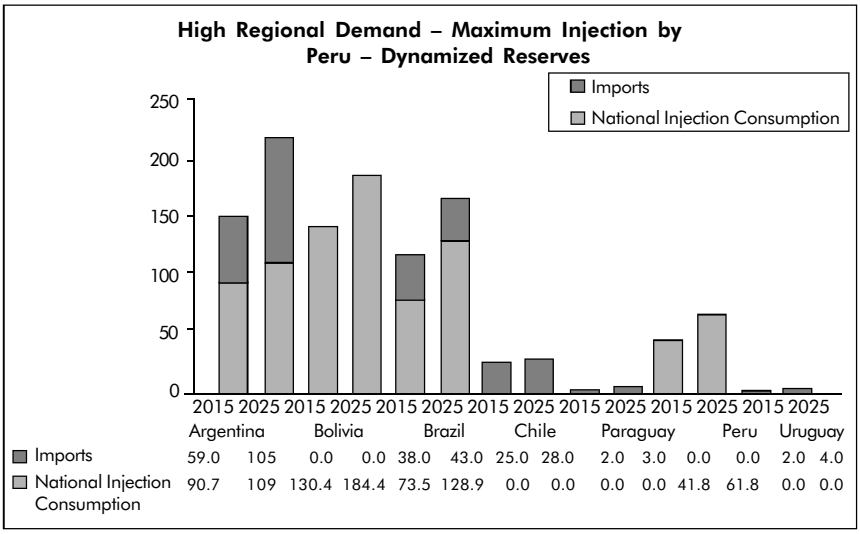
Figure 1.4: Imports Level and National Injection Consumption, per Scenario



	Argentina 2015	Argentina 2025	Bolivia 2015	Bolivia 2025	Brazil 2015	Brazil 2025	Chile 2015	Chile 2025	Paraguay 2015	Paraguay 2025	Peru 2015	Peru 2025	Uruguay 2015	Uruguay 2025
Imports	58.8	104.6	0.0	0.0	34.7	43.2	25.4	28.4	2.0	2.8	0.0	0.0	2.3	3.7
National Injection Consumption	90.8	109.0	139.4	197.4	76.5	128.9	0.0	0.0	0.0	0.0	28.0	47.2	0.0	0.0



	Argentina 2015	Argentina 2025	Bolivia 2015	Bolivia 2025	Brazil 2015	Brazil 2025	Chile 2015	Chile 2025	Paraguay 2015	Paraguay 2025	Peru 2015	Peru 2025	Uruguay 2015	Uruguay 2025
Imports	51.6	87.5	0.0	0.0	34.9	47.2	23.2	24.2	2.0	2.8	0.0	0.0	2.2	3.5
National Injection Consumption	90.0	103.8	137.6	194.5	61.9	78.1	0.0	0.0	0.0	0.0	14.9	25.0	0.0	0.0



	Argentina 2015	Argentina 2025	Bolivia 2015	Bolivia 2025	Brazil 2015	Brazil 2025	Chile 2015	Chile 2025	Paraguay 2015	Paraguay 2025	Peru 2015	Peru 2025	Uruguay 2015	Uruguay 2025
Imports	59.0	105	0.0	0.0	38.0	43.0	25.0	28.0	2.0	3.0	0.0	0.0	2.0	4.0
National Injection Consumption	90.7	109	130.4	184.4	73.5	128.9	0.0	0.0	0.0	0.0	41.8	61.8	0.0	0.0

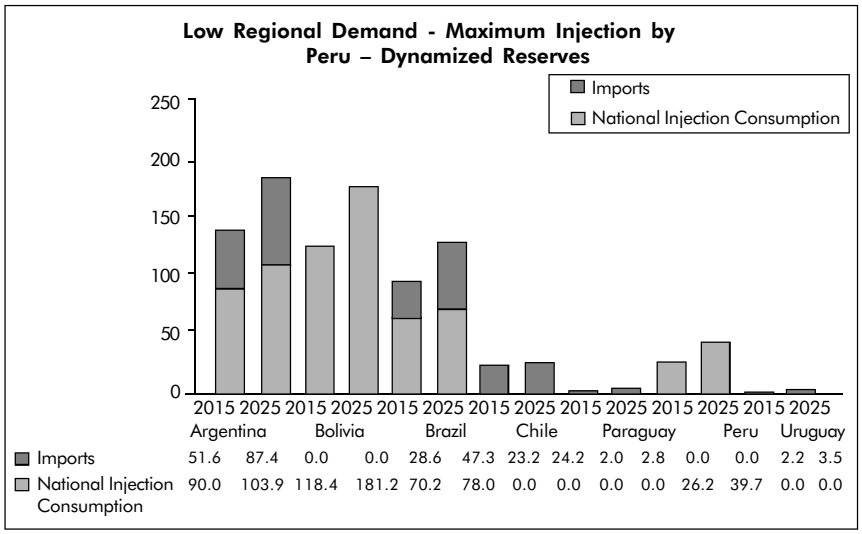
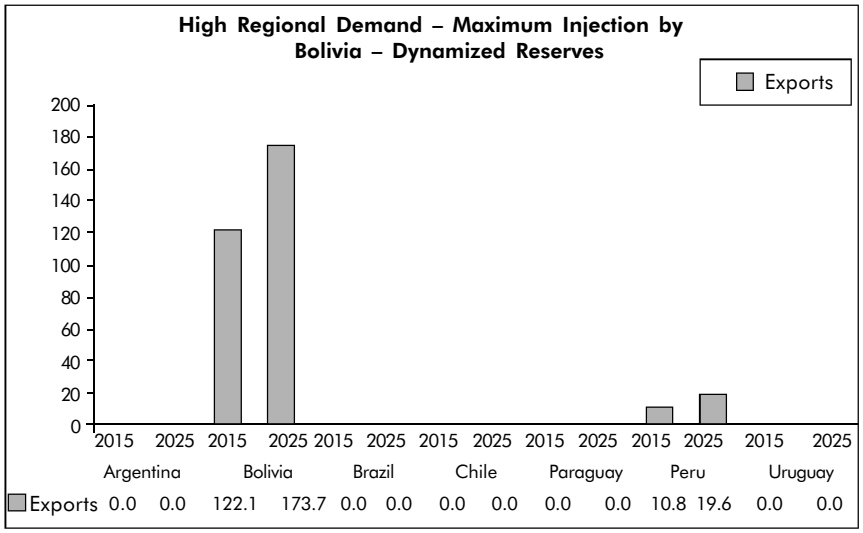
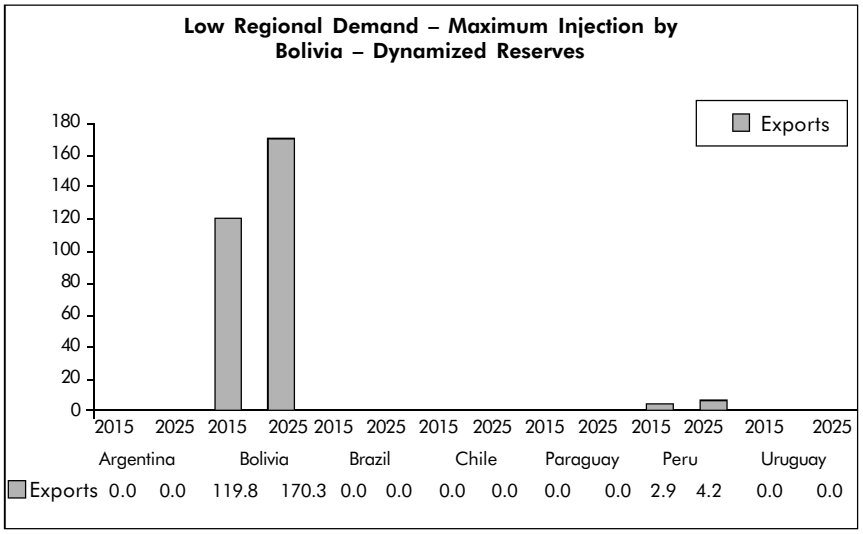
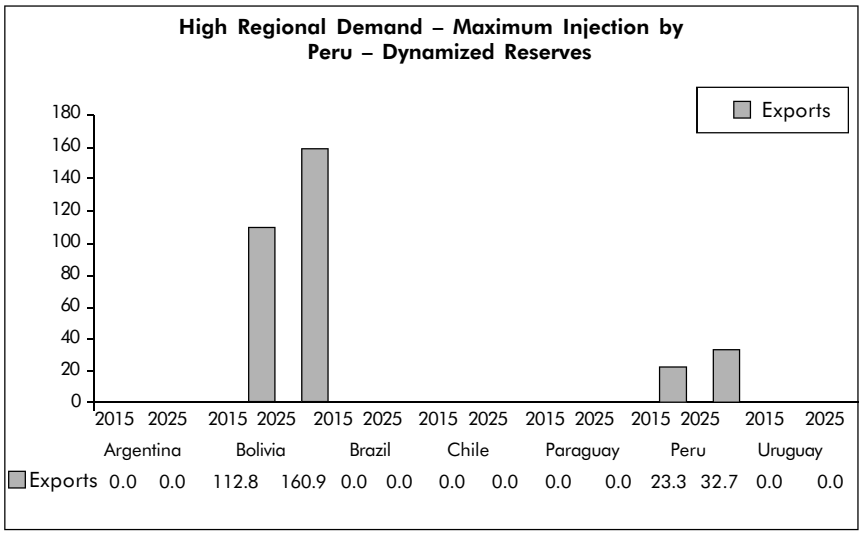
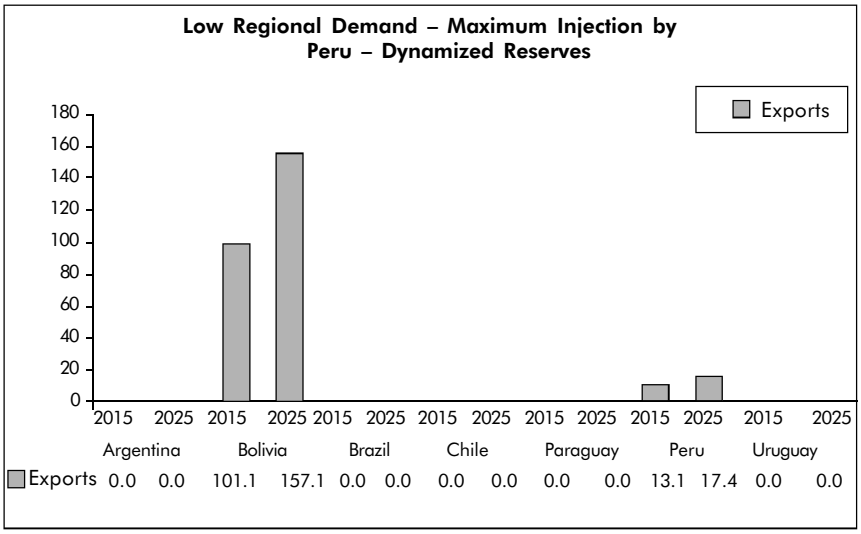


Figure 1.5: Exports Level, per Scenario









Bolivia is, for every scenario and period under analysis (years 2015 and 2025), the most important exporter in the system. Even more so, within the LRD scenario with maximum injection of its basins, where its supplies over 95 percent of the subregional exports market.

In this sense, scenarios which do not include the involvement of Peruvian basins are only viable if restrictions are eliminated in the short term. Regional gas needs shall tend to prioritize feasible projects in the short term and which, once completed, shall impose restrictions to other supply alternatives. This is also true for the construction of LNG plants in some of the main demand centers.

In all scenarios and periods under analysis (years 2015 and 2025), Uruguay, Paraguay, and Chile import all the gas they consume, Bolivia and Peru are self-supplied. In 2015 and 2025, Argentina and Brazil shall be partially supplied. However, Argentina shall become the main gas importer and the gas distribution center from Bolivia and Peru to the South of Brazil, center and south of Chile, Uruguay and Paraguay.

Model results: increase in transportation capacity of gas pipelines and new gas pipelines to be built

Table 1.12 shows a breakdown of capacity increases for each segment of the Southern Cone Gas Pipeline Network for years 2015 and 2025, by existing infrastructure and potential infrastructure or priority projects to be evaluated.

Table 1.12: Increases in Capacity

Transportation Segments	*HRD-MaxIB (RD)*		*HRD-MaxIP (RD)*		*LRD-MaxIB (RD)*		*LRD-MaxIP (RD)*	
	2015	*2025*	*2015*	*2025*	*2015*	*2025*	*2015*	*2025*
Bahía Blanca-Buenos Aires	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Buenos Aires-Montevideo	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Austral-San Jorge	2.6	5.6	2.6	5.6	2.7	5.8	2.7	5.8
Austral-Chile South	2.3	2.4	2.3	2.4	2.3	2.4	2.3	2.4
Camisea-Humay-Lima	20.6	42.4	34.1	56.5	5.0	17.4	18.9	31.7
Neuquina-Bahía Blanca	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Neuquina-Concepción	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Neuquina-La Mora	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Neuquina-Santiago	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Northwest-Paraguay	98.5	151.1	98.5	151.1	86.6	129.9	80.9	129.5
Northwest-Tocopilla	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Northwest-Tucumán	6.7	14.6	6.7	14.6	5.6	11.6	5.6	11.6
San Jorge-Bahía Blanca	0.0	1.4	0.0	1.4	0.3	2.2	0.3	2.2
Santos-Sao Paulo	57.8	136.6	51.8	136.6	56.0	65.5	61.4	77.7
Tarija-C. Northwest	101.7	172.8	89.5	140.7	97.0	143.4	78.3	130.0
Tarija-Sao Paulo	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Humay-Tocopilla	12.4	21.4	24.9	34.5	2.9	4.2	15.8	17.4

Transportation Segments	*HRD-MaxIB (RD)*		*HRD-MaxIP (RD)*		*LRD-MaxIB (RD)*		*LRD-MaxIP (RD)*	
	2015	*2025*	*2015*	*2025*	*2015*	*2025*	*2015*	*2025*
La Mora-Mendoza	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mendoza-Rosario	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Montevideo-Porto Alegre	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
P. Alegre-Sao Paulo	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
Paraguay-Rosario	93.3	143.4	93.3	143.4	81.8	122.8	76.2	122.5
Paysandú-Colonia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rosario-Buenos Aires	50.4	82.7	50.5	82.7	44.6	66.9	44.6	66.6
Rosario-Paysandú	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rosario-Uruguayana	4.8	14.4	4.8	14.4	0.5	12.9	0.0	12.9
Sao Paulo-Porto Alegre[33]	0.0	1.2	0.0	1.2	2.2	0.0	7.1	7.1
Tocopilla-C. Northwest	0.0	0.9	7.4	13.8	0.0	0.0	0.0	3.6
Tucumán-Rosario	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Uruguayana-Porto Alegre	9.5	18.8	9.5	18.8	5.3	17.4	0.0	17.4

Gas pipelines segments, for all scenarios and periods under analysis, which show the higher increase are those transporting gas to the main consumption centers: Buenos Aires and Sao Paulo form the main gas basins in Camisea and Bolivia. Also, it can be observed that the segment mentioned as Humay-Tocopilla is sustainable in moderate injection scenarios by Bolivia, since it meets the unfulfilled demand caused by the lower injection by Bolivia. It is worth mentioning that should Bolivian injection decrease even more, this gas pipeline's capacity and volume would increase.

Estimations on the reserves level based on the injections required for the different scenarios

Table 1.13 shows the available reserves[34]/demand ratio taking into account reserve years in relation to 2005 consumption and in relation to consumption for the 2006-25 period.

[33] *The capacities taken into account at the beginning of each segment and the transported gas-flow rate contemplate the possibility of intermediate demand.*
[34] *100 percent proven reserves + 50 percent probable reserves.*

Table 1.13: Available Reserves/Consumption Ratio

Country	Period	Unit	Argentina	Bolivia	Brazil	Chile	Paraguay	Peru	Uruguay	Total
Consumption	2005	MMm^3/day	95.4	3.6	48.0	17.8		2.5	0.4	167.7
Proven Reserves	2004/5	Billions of m^3	612,500	757,480	326,120	24,000		325,360		2,045,460
Proven Reserves/ Consumption	2005	Years	14	524	17	3		324		29
Mean Expected Consumption	(2006-25)	MMm^3/day	150.3	12.9	126.0	24.3	1.7	13.6	2.3	331.1
Probable + Possible Reserves	2004/5	Billions of m^3	289,010	623,820	172,040	23,000		471,620		1,579,490
Proven Reserves + 50% of Probable+Possible/ Mean Annual Expected Production for the Local Market	(2006-25)	Years	11	206	8	4		102		22

This analysis assumes the development of 50 percent of probable reserves during the next 20 years in order to be compared with mean consumption levels. It also does not imply the discovery of new reserves during the period under analysis. Should other assumptions be made, taking into account a higher or lower development of probable reserves, results may be different.

Integration, in the terms analyzed herein, requires the discovery of reserves in Brazil for 0.4 billion m^3, or the implementation or LNG in the Sao Paulo subregion to fulfill the foreseen injection level. It also requires the construction of any other supply mechanism for the northeast of Brazil, whether gas pipelines from nonintegrated basins or a LNG plant. Argentina and Bolivia should develop all their probable reserves. This analysis does not favor domestic consumption; therefore, should Bolivia want to safeguard a certain amount of its reserves for its domestic market, a higher injection by Peru would be necessary thus, increasing the gas volume transported from Camisea.

Model economic results appraised for the different scenarios

Table 1.14 summarizes the regional movement of appraised natural gas, as well as expected investments in transportation necessary for years 2015 and 2025.

Table 1.14: Model Economic Results Appraised for the Different Scenarios, 2015 and 2025

Amounts Corresponding to 2015 in Homogenous Currency of 2005	*Natural Gas Wellhead Sales 2015 (MMUS$/year)*	*Transportation Sales 2015 (MMUS$/year)*	*Total Sales[35] 2015 (MMUS$/year)*	*Accrued Transportation Investments 2005-15(MMUS$)*
HRD-MaxIB Scenario (RD)	18,300	4,300	22,600	8,500
HRD-MaxIP Scenario (RD)	17,700	4,900	22,600	9,800
LRD-MaxIB Scenario (RD)	16,800	3,700	20,500	6,700
LRD-MaxIP Scenario (RD)	16,600	4,000	20,600	7,500
Average	17,350	4,225	21,575	8,125
HRD-MaxIB Scenario (RD)	26,700	6,200	32,900	14,400
HRD-MaxIP Scenario (RD)	26,200	6,800	33,000	16,000
LRD-MaxIB Scenario (RD)	22,000	5,000	27,000	10,700
LRD-MaxIP Scenario (RD)	21,400	5,500	26,900	12,200
Average	24,075	5,875	29,950	13,325

Gas well head prices derive from the net-back related to the main consumption centers, Buenos Aires and Sao Paulo and prices so obtained are multiplied by the mean annual amount of gas demanded in every demand center. Transportation sales reflect transported volumes on tariffs and over tariffs, and investments derive from estimating the increase in capacity, the gas pipeline length and a cost of US$0.04 per km/MMm^3/day of increase.

The average investment for the 2005-25 period is US$21.4 billion.

Priority Project Selection

In order to establish the three priority projects for Phase 2, the volumetric results obtained from proposed scenarios for years 2015 and 2025 were taken into account. These results are reflected on the delivered gas average and peak volumes for years 2015 and 2025.

Based on the said results, we have made a list of the pipeline's segments requiring the highest increase in capacity, sorted in decreasing order for each scenario, and we have analyzed which segments of potential gas pipelines, among which a selection must be

[35] *In order to make comparison easier, alternative fuels sales and over expansion tariffs were not included.*

made, are required in each scenario. Those priority projects appearing on the higher number of scenarios are those we have deemed a priority to integration.

Likewise, potential infrastructure transportation segments are sorted in accordance with transported volumes within the different scenarios during years 2015 and 2025. Flow rates are measured in MMm^3/day and convey an idea of the relative magnitude of gas pipelines to be built.

Model optimization in the different scenarios discards the use of the Paysandú-Colonia and Montevideo-Porto Alegre segments connecting to the Colonia-Montevideo segment and, in some scenarios, it discards the construction of the Uruguayana-Porto Alegre segment.

Results 2015-25

Table 1.15: Transported Volumes per Segment and Scenario, 2015 and 2025

2015							
HRD-MaxIB (RD)		**HRD-MaxIB (RD)**		**LRD-MaxIB (RD)**		**LRD-MaxIB (RD)**	
Northwest-Paraguay	98.5	Northwest-Paraguay	98.5	Northwest-Paraguay	86.6	Northwest-Paraguay	80.9
Paraguay-Rosario	93.3	Paraguay-Rosario	93.3	Paraguay-Rosario	81.8	Paraguay-Rosario	76.2
Humay-Tocopilla	12.4	Humay-Tocopilla	24.9	Uruguayana-P. Alegre	2.9	Humay-Tocopilla	15.8
Uruguayana-P. Alegre	9.5	Uruguayana-P. Alegre	9.5	Humay-Tocopilla	5.3	Uruguayana-P. Alegre	0.0
Paysandú-Colonia	0.0	Paysandú-Colonia	0.0	Paysandú-Colonia	0.0	Paysandú-Colonia	0.0

2025							
HRD-MaxIB (RD)		**HRD-MaxIB (RD)**		**LRD-MaxIB (RD)**		**LRD-MaxIB (RD)**	
Northwest-Paraguay	151.1	Northwest-Paraguay	151.1	Northwest-Paraguay	129.9	Northwest-Paraguay	129.5
Paraguay-Rosario	143.4	Paraguay-Rosario	143.4	Paraguay-Rosario	122.8	Paraguay-Rosario	122.5
Uruguayana-P. Alegre	18.8	Humay-Tocopilla	34.5	Uruguayana-P. Alegre	17.4	Uruguayana-P. Alegre	17.4
Humay-Tocopilla	21.4	Uruguayana-P. Alegre	18.8	Humay-Tocopilla	4.2	Humay-Tocopilla	17.4
Paysandú-Colonia	0.0	Paysandú-Colonia	0.0	Paysandú-Colonia	0.0	Paysandú-Colonia	0.0

It was highlighted that volumes included in the last four scenarios: HRD-MaxIB (RD), HRD-MaxIB (RD), HRD-MaxIB (RD) and HRD-MaxIB (RD), for the 2015 results as well as for 2025, are taken into account in defining injection flow rates as well as the mean technical engineering drawings in order to assess prefeasibility, the objective of Phase 2 of this study.

Projects Ranking per scenario 2015 and 2025

Projects which best integrate the subregion, within the framework of the assumptions and analysis model described herein:

- Campo Duran-Santo Tomé together with the branch to Asunción del Paraguay;
- Uruguayana-Porto Alegre; and
- Humay-Tocopilla.

Should other variables be taken into account, the results may vary. These other variables are subject to review by the countries and the World Bank, which should further their analysis, specially regarding an integration analysis which takes into account the interaction between gas and electric power transportation.

Results in Nonintegration Scenarios

Work approach

For the analysis of the option which does not contemplate the advance in the gas pipeline network integration, it was assumed that gas marketing among countries in 2015 and 2025 will maintain the current 2005 levels, that is, it uses the volumes corresponding to the calibration scenario as of 2005 as data. This assumption implies no expansion of any of the gas pipelines which currently market gas among countries and that none of the priority projects will be built in order to expand the system.

Within this context, we have assumed demand is met through the construction of regasification plants in the main consumption centers: Santiago de Chile, Buenos Aires, San Paulo and Northeast Brazil, and that said plants inject gas at US$6.7 per MMBTU, pursuant to the recommendations of the second workshop where it was requested that the average price to be the opportunity cost of a weighed alternative fuels basket which takes into account the prices of LNG, fuel oil and coal.

Thus, each producing country would limit its gas injection/production to the subregion to the terms of existing agreements, leaving the injection per country equal to:

$$I_{2015} = D_{2015} + Q_{Exp\ per\ gas\ pipeline\ 2005} - Q_{Imp\ per\ gas\ pipeline\ 2005} - I_{2015\ Regasification\ Plant}$$

$$I_{2025} = D_{2025} + Q_{Exp\ per\ gas\ pipeline\ 2005} - Q_{Imp\ per\ gas\ pipeline\ 2005} - I_{2025\ Regasification\ Plant}$$

Finally, the nonintegration cost is estimated as the price effect of meeting the demand through a basket imported at US$6.7 MMBTU, and not through the price estimated by the model for the optimized simulation model in the integrated system. This model was implemented for two different demand alternatives agreed upon during the first workshop, which are described under the next heading.

Scenarios

- Nonintegration alternative – HRD scenario *(NI-HRD)*: It is assumed that there is no international transaction involving natural gas other than those currently existing and that the subregional countries HRD must resort to a basket of alternative products (LNG, fuel oil and mineral coal) to meet the increase of their gas consumption needs; and
- Nonintegration alternative – LRD scenario (NI-HRD): It is assumed that there is no international transaction involving natural gas other than those currently existing and that the subregional countries with LRD must resort to a basket of alternative products (LNG, fuel oil and mineral coal) to meet the increase of their gas consumption needs.

It is important to mention that we have not taken into account the existing lower investments in gas pipelines nor the lower profitability of existing gas pipelines nor the cost of investment in regasification plants to be installed.

From a subregional standpoint, the nonintegration effect implies an additional cost for the purchases of LNG and/or alternative fuels of US$6,448 MM in 2015 and US$12,480 MM in 2025, within the HRD scenarios. In LRD scenarios, the cost amounts to US$5,556 MM in 2015, and US$9,974 MM in 2025. These figures account for the price effect of purchasing a basket for a price of US$6.7 per MMBTU,[36] estimated as the cost price of alternative fuels pursuant to the remarks made during the second workshop.

[36] *Average weighed price of alternative fuels. The price of LNG was taken at US$8/MMBTU (price agreed upon by Chile for LNG), the price of fuel oil was taken at US$6.5/MMBTU and the price of coal at US$3.5 equal to US$/MMBTU. These figures are equal to an oil barrel, which quoted price amounts to US$50.*

If such net regional effects were evaluated for each individual subregional country involved, we notice that certain countries should replace subregional gas with LNG purchases from other markets or replace gas with fuel oil and/or mineral coal in the different points of demand. That would be the case of Argentina, Brazil, Chile, Paraguay and Uruguay, which incremental costs for the provision of a higher-priced fuel are detailed in Table 1.16.

Table 1.16: Monetary Effect of Nonintegration

Alternative	*High Regional Demand*		*Low Regional Demand*	
Year	*2015*	*2025*	*2015*	*2025*
	MMUS$	*MMUS$*	*MMUS$*	*MMUS$*
Argentina	3,299	7,044	2,888	4,965
Brazil	630	2,329	346	2,217
Chile	2,051	2,240	1,865	1,950
Paraguay	270	541	270	541
Uruguay	197	326	187	302
Incremental Cost	6,447	12,480	5,556	9,975

In these results, the low impact of nonintegration for Brazil is surprising, in this sense, the results for Brazil reflects the discovery expectations and development of their own reserves, which reduce the impact of nonintegration. Should assumptions where Brazil requires a higher level of importation be taken into account, the impact of nonintegration would increase.

Phase 2

Report Objective – Phase 2

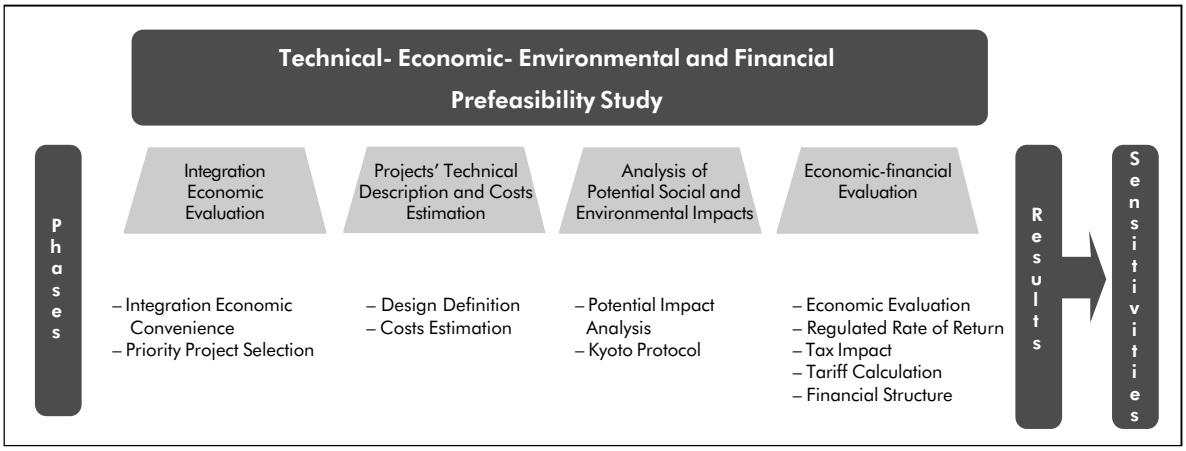
The objective of this report is to carry out a feasibility study detailing the three priority projects selected during Phase 1 of this consultancy:

- Campo Duran-Santo Tomé together with the branch to Asunción del Paraguay;
- Uruguayana-Porto Alegre; and
- Humay-Tocopilla, which, as mentioned before, becomes more relevant within a scenario with moderated injection by Bolivia.

Specifically, the prefeasibility study consists of a technical-economic, environmental and financial assessment of the three priority projects seeking to analyze the tariffs to be applied on transportation, the risks associated to its sustainable startup and operation, including an analysis of the pertinent financing schemes.

Work Approach

Figure 2.1: Work Approach



Economic Assessment

Project evaluation implies the "identification, measurement and appraisals of costs and benefits corresponding to different and multiple project alternatives in order to achieve the objectives proposed." In the case of the Southern Cone Gas Integration Project, Phase 1 implied the economic analysis to show the economic convenience of integration and the best way to implement it through the selection of certain priority projects. In Phase 2 of the project, a brief financial prefeasibility assessment of priority projects was carried out.

Technical Description of the Three Priority Projects and Cost Estimates

As derived from Phase 1, priority projects for integration are:

- The Campo Durán-Santo Tomé pipeline and a branch to Asunción del Paraguay (GNEA);
- The Uruguayana-Porto Alegre pipeline; and
- The Humay-Tocopilla pipeline.

Due to the fact that different scenarios and different model implementations generated a wide range of average and maximum gas injections for the new gas pipelines to be evaluated, based on new data furnished by the report on reserves in the subregion, four new scenarios were implemented. These took into consideration the potential for maximum injection by Bolivia and Peru based on HRD and LRD.

Using the data of these new scenarios, mean injection parameters were defined to set the initial technical design characteristics for every gas pipeline to be evaluated. Therefore, based on the initial technical design and a standardized cost scheme, this analysis may be extended to other injection hypothesis. Table 2.1 summarizes the injection data of the new implementations and highlights the average data used as bases.

Table 2.1: Average Injection Data

Scenarios		*Humay-Tocopilla*		*GNEA*		*Uruguayana-Porto Alegre*	
		2015	*2025*	*2015*	*2025*	*2015*	*2025*
High Demand	Maximum for Bolivia	12.4	21.4	98.5	151.1	9.5	18.8
	Maximum for Peru	24.9	34.5	98.5	151.1	9.5	18.8
Low Demand	Maximum for Bolivia	2.9	4.2	86.6	129.9	5.3	17.4
	Maximum for Peru	15.8	17.4	80.9	129.5	-	17.4
Average Demand		**14.0**	**19.4**	**91.1**	**140.4**	**8.1**	**18.1**

These results correspond to the size of these gas pipelines in an integration context. In this sense, the positive externality of integration has an effect on all gas pipelines:

- The GNEA would not only supply gas from Bolivia and Peru to the northeast of Argentina and Buenos Aires, but would also situate Argentina as a supplier of gas to Chile and Uruguay through "swap" contracts, and would carry gas to the south of Brazil and Paraguay. Of the planned capacity by 2025 of 140.4 MMm^3/day, 18.1 MMm^3/day would be delivered to Porto Alegre, 2.7 MMm^3/day to Paraguay, and by means of "swaps," 3.6 MMm^3/day to Uruguay and between 5 and 10 MMm^3/day to Chile. This implies that about 25 percent of the gas pipeline seeks to meet the demand of neighboring countries minimizing provision costs in every node;
- As a consequence of nonintegration, volume on the Humay-Tocopilla gas pipeline would be cut by half because it would not be able to be integrated as a supplier for other countries in the subregion; and
- If the Uruguayana-Porto Alegre gas pipeline was not to be built, gas supply should come from the Argentine Southern region (should there be any surplus) at a much higher cost of transportation and on an uncompetitive basis compared with other sources of supply for Porto Alegre via Sao Paulo.

Introduction

From the results of the studies carried out, the values of the estimated investment for each gas pipeline under consideration are:

Table 2.2: Estimated Cost of Investment

Study	*Gas Pipeline*	*Estimated Cost (MMUS$)*
I	Humay-Tocopilla	1,287.6
II	Uruguayana-Porto Alegre	478.6
III	GNEA	5,052.9
Total	**New Gas Pipelines**	**6,819.1**

Data

It is understood that the demands of each pipeline shall be met as from 2009, and that for the period 2015-25, they are detailed in Table 2.3, which also shows the lengths of the hypothetical lines foreseen.

Table 2.3: Length and Flow of the Three Priority Projects

Study	*Gas Pipeline*	*Flow (MMm³/day)*			*Length*
		Start date: 2009	*2015*[37]	*2025*[38]	*(km)*
I	Humay-Tocopilla	1.4	14.0	19.4	1,356
II	Uruguayana-Porto Alegre	0.6	6.1	18.1	565
III	GNEA	9.1	91.1	140.4	1,500

Design criteria

The following design criteria were used for the estimation of the total investment.

- It has been assumed that at the start of operations in 2009, the transported flow shall be in all cases 10 percent of the value corresponding to 2015, since at the start of pipelines operations there is a period where consumption is gradually developed. There are

[37] *Pursuant to the optimization model corresponding to Phase1.*
[38] *Pursuant to the optimization model corresponding to Phase1.*

commercial and technological reasons for this (startup of facilities, personnel training, and so on);

- It has been assumed that the required flow shall gradually increase between 2009 and 2025, thus, meeting by 2015-25, the predetermined flow values stated in Table 1.1;
- The increase of transportation capacity of gas pipelines is achieved by means of two procedures: by installing intermediate compressor plants and/or building "loops" (piping connected in parallel to the main pipeline). In general, the solution of installing intermediate compression plants is implemented if it is feasible and there is a suitable length, which enables the increase of transported flow by 40 percent when operating at full load. Compressor plants foreseen in the design and those to be added for capacity expansion are fueled by natural gas. This consumption of gas was considered at the design stage;
- For sizing purposes in route consumptions have not been considered as the maximum demand situation had been taken into account;
- For economic reasons of the project, gas pipelines were developed at the maximum possible pressure supported by construction materials. All materials with the exception of pipings are manufactured pursuant to ANSI specifications (ANSI 600 Series up to 102.04 bar, series 900, and so on);

Table 2.4: Series and Pressure of the Three Priority Projects

Study	*Gas Pipeline*	*ANSI Series*		*Pressure (barM)*
			MAPO	*Hydraulic Design*
I	Humay-Tocopilla	600	102.04	93.08
II	Uruguayana-Porto Alegre	600	102.04	93.08
III	GNEA	900	153.06	139.62

- A compression ratio of 1.5 between suction and discharge pressure of compressor plants is adopted, with the aim of optimizing the ratio between the fuel consumption and the cost of the installed pressure. The installed pressure is determined by taking into account the compression and operating flows ratio; and
- For design reasons and pursuant to international standards (ASME B31.8), piping thickness depends on the type of line and the latter, in turn, on the characteristics of the areas it runs through as well as the type of construction (special crosses, and so on). For major works it is right to assume that 2.5 percent of the line shall require a higher pipe thickness.

Cost estimation criteria

For cost estimation of gas pipelines, it is basically understood that it comprises its three main components: a) materials: b) installation; and c) related costs. These items have different variations depending on the type of works:

- It has been considered that 2.5 percent of the line will be carried out using a higher thickness pipe due to requirements of potential variations in the line type;
- For determination purposes of the cost of each project, values were analyzed breaking down the duct cost and the compressor plants cost;
- Compressor plants cost was estimated on the basis of the installed power in HP, within a range of 1,050/1,450 US$/HP, known market values. A price variation range has been adopted, since compressor plants not only involve machinery but also fixed facilities and civil works such as buildings, access roads, communications systems and so on;
- The cost of the lined and shipped piping has been considered based on its weight at US$1,350 per ton. This value is the result of considering the Latin American market values for the subregion where these projects will be implemented. This value is exclusively related to the cost of steel, its corrosion proof coating and the transportation cost from the lining mill until its unloading at works;
- To define the cost of gas pipelines the following guidelines related to auxiliary installations arising from regulatory and technical issues have been considered:
  - Installation of drive scraper traps in the header, reception traps in the end point and intermediate drive and reception traps every 150 km approximately;
  - Installation of line section valves every 32 km approximately;
  - Installation of measuring stations at header and intermediate ones according to the characteristics of each project;
  - Installation of printed current cathodic protection systems;
  - Installation of fiber optic communications systems.
- The following related costs have been taken into account:
  - Engineering (4 percent);
  - Contingencies (2 percent);
  - Insurances, taxes, customs duties, and so on are included in the costs;
- For determination purposes of the duct installation costs the following components have been considered:
  - Rights of way;
  - Cleaning;
  - Ground opening;
  - Transportation and carriage;
  - Curving;
  - Digging;
  - Foundation;

  - Welding;
  - Lowering and covering;
  - Hydraulic test;
  - Recomposition and erosion control;
  - Construction of accesses to road;
  - Construction camp and works;
  - Cathodic protection installation;
  - Fiber optic installation.
- It has been estimated that most of the laying of the pipelines will be carried out on normal grounds; and
- Depending on the characteristics of the projects it has been taken into account that a part of the project will be developed on more complex grounds.

Related expenses have been defined by specialists taking into account the complexity of each design and the final amount of the works. Foreseen contingencies cover any potential increases in the cost of materials or construction values, in excess of the prices being used in the estimation.

The determination of installation costs of the ducts under analysis has been done by evaluating the values recorded in works of similar characteristics which have been recently carried out in Latin America and those available from the technicians' own databases. This structure is permanently updated with information arising from the professional participation in particularly relevant and specialized projects and, that is, valid for the purposes here.

Design definition

The Humay-Tocopilla pipeline

Three construction stages are foreseen as detailed in Figure 2.2. The design allows for the gradual expansion of the transportation capacity with the addition of two intermediate compressor plants at a first stage, then to a total of five, in order to meet the demand required for the period 2015 and 2025, respectively. Since this is a preliminary project, it has been considered that there are no large variations of topographic altitude in relation with the sea level.

For sizing purposes it has been taken into account that the natural gas to be transported has a typical molar composition and meets all specifications according to international acceptance standards.

Figure 2.2: Design of Humay-Tocopilla Gas Pipeline

Year	*Flow Rate MMm³/d*	*MAPO BarM*	*Series ANSI*	*P. Comp. Intermediates*	*Scheme*
2009	1.4	102.04	600	0	Total L=1,356 km Ø= 30″
2015	14.0	102.04	600	2	R = 1.5 Total L=1,356 km Ø= 30″
2025	19.4	102.04	600	5	R = 1.5 Total L=1,356 km Ø= 30″

Header Compressor Plant Intermediate Compressor Plant Reception Facilities

The Uruguayana-Porto Alegre Gas Pipeline

As in the previous design, three construction stages are foreseen (Figure 2.3).

Figure 2.3: Design of Uruguayana-Porto Alegre Gas Pipeline

Year	*Flow Rate MMm³/d*	*MAPO BarM*	*Series ANSI*	*P. Comp. Intermediates*	*Scheme*
2009	0.6	102.04	600	0	Total L=565 km Ø= 30″
2015	6.1	102.04	600	1	R = 1.5 Total L=565 km Ø= 30″
2025	18.1	102.04	600	3	R = 1.5 Total L=565 km Ø= 30″

Header Compressor Plant Intermediate Compressor Plant Reception Facilities

☐ Loop Ø 48% Long. 120 km approx.

The North-eastern Argentina Gas Pipeline (GNEA)

As in the previous design, three construction stages are foreseen (Figure 2.4). In this case, it is necessary to install loops as indicated in the corresponding drawings for the second stage.

Figure 2.4: Design of GNEA Gas Pipeline

Year	*Flow Rate MMm³/d*	*MAPO BarM*	*Series ANSI*	*P. Comp. Intermediates*	*Scheme*
2009	9.1	153.06	900	0	Total L=1,500 km Ø= 48″
2015	91.1	153.06	900	7	R = 1.5 Total L=1,500 km Ø= 48″
2025	140.4	153.06	900	7	R = 1.5 Total L=1,500 km Ø= 48″

Header Compressor Plant Intermediate Compressor Plant Reception Facilities

☐ Loop Ø 48% Long. 120 km approx.

Cost estimation

Table 2.5 contains estimated construction values according to the criteria mentioned on pages 44-45 for each pipeline covered by the study.

Table 2.5: Cost Estimation Summary

Study	*Gas Pipeline*	*Length (km)*	*Diameter in Inches*	*Flor rate (MMm³/d)*	*MAPO (barM)*	*Estimated Cost (MMUS$)*
I	Humay-Tocopilla	1,356	30	14.7	102.04	1,287.6
II	Uruguayana-Porto Alegre	565	30	18.1	102.04	478.6
III	GNEA	1,500	48	140.3	153.06	5,052.9

Note: This estimation has been done with an approximation of +/- 20 percent.

Analysis of Potential Social and Environmental Impacts

Introduction

During the second workshop, local experts were required to submit the following information once the alternatives for the lines were defined. The reply from local experts regarding the submission of information is included in Table 2.6.

Table 2.6: Information Requested and Sent for the Potential Analysis of Social and Environmental Impacts

Information	*Argentina*	*Chile*	*Bolivia*	*Paraguay*	*Brazil*	*Peru*	*Uruguay*
Regulations	□	□	NA	□	□	-	NA
Theme Maps							
– Sensitive/Protected Areas	-	-	NA	-	-	-	NA
– Indigenous Populations	-	-	NA	-	-	-	NA
– Fauna and Flora	-	-	NA	-	-	-	NA
– Socioeconomic	-	-	NA	-	-	-	NA
– Demographic	-	-	NA	-	-	-	NA
– Economic/Industrial Activities	-	-	NA	-	-	-	NA
Emission Factor per Country	-	-	-	-	-	-	-
Energy Matrix Description	-	-	-	-	-	-	-

The information availability led to the need of modifying the scope of this analysis, resulting in the identification of theoretical activities and impacts though they could not be classified and prioritized. However, the analysis of the legislation submitted by local experts enabled us to identify the minimum contents and requirements established by the relevant authorities for future social and environmental impact studies which may be required by the executive managers of the project.

Peruvian legislation was considered as it is more detailed in terms of social assessment. The Argentine legislation was also taken into account as it contained more detailed specifications. To establish a homogeneous framework for all countries involved in the social and environmental impact study of the same duct line, the consulting group based themselves

in the more detailed legislations. The next step was the search for any available information made public as stated in the list of consulted literature for the social and environmental impact study.

As a result of the analysis of this information, a mapping of the project activities, identification of potential impacts, practices usually implemented to overcome those impacts and the characteristics of a content scheme of baseline detailed studies and assessment of the social and environmental impact were elaborated, as well as any relevant considerations to enable project developers to carry out initial environmental assessments on any line alternatives and environmental impact assessments on definite lines.

The feasibility study about the project within the clean development mechanism under the Kyoto Protocol of climate change was limited to the theoretical analysis of the potential emissions reduction and the resulting generation of Certified Emission Reductions (CERs – greenhouse effect gases emissions reduction certificates) due to the lack of information about the energy pattern and emission factors in those countries which would be using the transported gas.

Preliminary assessment of potential social and environmental impacts

The development of the gas integration project will lead to activities which may potentially generate positive and negative impacts of a social and environmental nature. The intensity and extension of these impacts may vary on the basis of the site conditions of the lines and their implementation methodologies.

To guarantee the social and environmental viability of the projects, it is necessary to carry out a baseline analysis of the potential lines. Taking into account the social and environmental issues of the alternatives under consideration, the line with the least social and environmental cost could be identified.

Once this definite line is determined, a detailed analysis of the social and environmental impacts, Environmental Impact Assessment (EIA), should de carried out with the purpose of obtaining the necessary knowledge for the definition of social and environmental management plans which shall provide mitigation policies and measures for the identified impacts. It should also require knowledge of the activities to be implemented and the methodologies to be used in order to quantify the intensity and extension of the social and environmental impacts of projects, based on the knowledge of the project environment. The study should not only identify and quantify social and environmental impacts but also

requires an analysis of the legislation as a baseline source of the impacts and as the source for the necessary permits and certifications for the development of the projects.

If potential social and environmental impacts and aspects are evaluated and the best available practices for their minimization and mitigation are implemented, projects with certain benefits such as the access to natural gas and the conversion to cleaner fuels could be viable from the social and environmental point of view.

Based on the availability of the requested information, the activities which are typically included in these projects were identified, the social and environmental impacts which could potentially occur as a consequence of those actions and the generally used mitigation measures used to minimize those impacts were assessed. In addition, the annexed document contains a guide of contents and considerations to be taken into account by the project developer at the time of carrying out the corresponding social and environmental studies.

Analysis of the project activity within the framework of the Kyoto Protocol

The Clean Development Mechanism (CDM) of the Kyoto Protocol gives developed countries the possibility of reducing Greenhouse Effect Gases (GEGs) beyond their borders, by financing different types of projects in developing countries. The governing principle is targeted to the global effect of these reductions regardless of the place where they are generated and the consequent fulfillment of reduction obligations by the developed country. Besides, the implementation of projects in developing countries makes them more profitable and economically attractive.

The development of a project for the transportation of gas implies the possibility of including the project activities within the framework of the CDM. In this case, the additional efforts which developers will make to control gas leaks and leakages during the transportation operation could be considered. Based on these reductions they could request the accreditation of carbon credits. Nowadays, there are approved and pending approval methodologies for this issue.

Regarding the use of natural gas as a source of energy and as an industry asset, different project activities could be developed which may require a case by case analysis in terms of the condition and basis of available energy matrixes and existing industrial sectors in each country. In this particular case, consumer industrial sectors, including the energy sector, would implement the reductions, in case there are alternative and more contaminating sources which may be disregarded. The Protocol states that the reduction must be claimed by those who implement the emission reduction project. Considering that if the transportation

of natural gas would not occur the possibility of fuel conversion would not exist, the transportation project developer could undertake negotiations with these sectors to set up distribution agreements of the generated CERs.

It is worth mentioning that CDM projects require that the reduced emissions be "additional" to those which would have occurred in the absence of the project. This additional premise is one of the main conditions for assessing the potentiality of a certain project to be classified as CDM. In general, it should be demonstrated that there are barriers to the implementation of the project which are overcome when including the project within the CDM. This is achieved as a consequence of the influx of money resulting from the sale of CERs.

Economic-financial Evaluation of the Three Priority Projects

Planning scope

The planning scope is determined taking into account the analysis period as defined in the terms of reference for gas pipelines evaluation and the time necessary to carry out the final detailed studies as well as the specific financial structure for each project.

Based on the above, a planning scope beginning by mid-2007 with the construction of gas pipelines which will be operational from 2009 to meet the demands of the period 2015-25, the last year of the scope, has been considered.

We understand that any delay shall mean that the demands estimated for the delay periods should be met by substitute fuels that will imply a higher cost for the subregion as a whole, in line with the estimations submitted for the nonintegration scenario.

Financial viability model

To analyze the financial viability of the three priority projects, a simple and concise computed mathematical model was designed. The purpose of this model is to obtain the average natural gas transportation tariff for each priority project that may efficiently compensate the required investments to compare it with the current tariffs and verify the impact on prices to producers of the new tariffs.

Tariffs determined through these models show very little variation in prices obtained by gas producers in the subregion, and therefore, the project selection carried out is maintained.

Demand module: This module describes the total current and projected gas demand and transportation capacity for the target area per consumption node. Thus, the demand projections for the next 20 years contributed by local experts shall be used.

Investments module: This module contains the amounts related to the gas pipelines construction and the starting date for the expansion works thereof. As it has been assumed that the demanded flow shall gradually increase between 2009 and 2025, the increase in transportation capacity of gas pipelines shall be met by installing intermediate compression plants and loops, if necessary. Therefore, the estimated investments for gas pipelines construction are grouped in three main categories: 1) piping investment; 2) compression units investment; and 3) expansion "loops" investment.

Administration, operation and maintenance, working capital and taxes module: This module contains an overview of the operational and structure costs. Therefore, it covers all costs and includes those related to administration, marketing, engineering and other functions. This module was developed based on discussions with local experts and analysis of financial statements of the main network pipelines (benchmarking). In addition, working capital issues have been considered, namely accounts receivable, accounts payable and wages, based on comparable information.

The module includes the tax effects of legislation of the countries where gas pipelines shall operate and their impact on tariffs. For that purpose, only taxes applied on the natural gas transportation service and not on its purchase/sale transactions were taken into account, as the activity of the transportation company under analysis is considered as a *pass through* activity in relation with the transported gas.

Regulated or required rate of return module – Capital Assets Pricing Model: This model provides a prediction on the relationship which may be observed between the risk of a financial asset and the expected return. This relationship may be used with two major objectives: first, provide a reference for the estimation of the rate of return required in the evaluation of any investment and, second, allow to obtain a reference rate for companies which are not marketed within financial markets. It is worth mentioning that in countries of the subregion which are interested in integration, the risk-free rate includes the country risk, which is the higher return required by economic agents from an asset to protect themselves from the confiscation risk, changes in the rules of the game and exchange rate risks.

This methodology implies the use of the Weighted Average Capital Cost (WACC), the method used to calculate the weighted capital cost.

$$r = \left[\frac{D}{D+E} * r_d * (1-t) + \frac{E}{D+E} * \left(r_f + \beta \left(r_m - r_f \right) \right) \right]$$

r: Required rate of return
r_d: Company's marginal borrowing rate
r_f: Return of a risk-free asset
r_m: Weighted average of financial assets returns
D: Debt
E: Capital
t: Income tax rate
ß: Measures the relationship between the systematic risk of the financial asset to be appraised and r_m

The use of this model offers the following:

- **Advantages:** i) it is a very flexible model because it enables the rate to be adapted to different asset situations, and thus, it is possible to operate on the investment scope and the risk of the economy where the company is operating; and ii) it is the most accepted methodology by regulators.

- **Disadvantages:** The model is not tested, that is, to say, there is no study which may indicate that it actually predicts the corresponding rate to the invested capital, and the adaptations to the specific economic situations of each market; it requires a complex study which should undertake a series of controversial economic hypothesis.

Tariff calculation module: This module is critically related to the operating and maintenance costs module and the investment module. As mentioned before, the unit operational and maintenance costs were identified on the basis of discussions with local experts and the analysis of financial statements of the main gas transportation companies of the subregion.

Regarding investment unit costs, the determination of unit costs of each works construction item was carried out on the bases of a detailed analysis, particularly taking into account the following: 1) cost of materials and equipment to be used in the different parts and structures of the works; 2) construction cost of gas pipelines and ground facilities; 3) indirect costs; and 4) compression stations costs.

As already mentioned, one of the model objectives is to obtain the natural gas average transportation tariff for each priority project which may facilitate the recovery of all costs

related to the execution of investment and operation projects of each gas pipeline, plus a compensation for a reasonable invested capital. To obtain this tariff, the current costs value should match the current benefits value.

The current costs value is expressed by the following equation:

$$VACostos = \sum \frac{opex_i + capex_i + gastos\ admnistrativos\ y\ comerciales_i + capital\ de\ trabajo_i + impuestos_i}{(1+r)^i}$$

Where: VAcosts = current costs value, i = year and r = discount rate

The current benefits value is expressed by: $VABeneficio = \sum \frac{(t_i * q_i)}{(1+r)^i}$

Where: t_i = tariff value to be determined by the model, q_i = natural gas demand during the year i.

The matching of the current costs and benefits values requires the determination of a tariff from the model which, given the natural gas demand levels, may compensate all costs related to the operation and startup of each pipeline.

Financing structure: Likewise, a financing structure for each project was identified in order to minimize financial costs.

Results: Economic-financial module (stability of the consolidated system): This module contains information from the different modules described above. The product is presented in the form of profit and loss accounts, balance sheets and cash flow statements. In addition to the tables modules, the following additional modules which are considered critical for the verification of results in comparative terms were developed.

Sensitivities: Risk or sensitivities analysis module: The module enables to the analysis of the impact of small variations in the main issues and get to know the sensitivity of each variable to the results. Therefore, this analysis will allow us to center the discussion on the variables with a higher impact on projects.

Demand module

As a consequence of the economic evaluation of the integration carried out in Phase 1, priority gas pipelines necessary to meet the growing demands of the subregion were defined. With this information, the design criteria of pipelines with average demand volumes to be met through the construction of new pipelines, according to the different

scenarios used, were defined in the introduction to the technical evaluation of the project. Table 2.7 defines the demand volume to be met by each new gas pipeline in the different years analyzed.

Table 2.7: Demand Volume to be Met by Each Gas Pipeline

Gas Pipeline	*Flow (MMm³/day)*		
	Start date: 2009	*2015*	*2025*
GNEA	29.8	91.1	140.4
Uruguayana-Porto Alegre	4.9	6.1	18.1
Humay-Tocopilla	5.7	14.0	19.4

Since the gas pipelines were built with an initial capacity which was later extended with the addition of compression plants or loops, and therefore, the capacity increase is achieved gradually and based on the maximum applicable demands, the initial volumes stated in Table 2.7 imply idle capacities at the startup of projects which bear an impact on the required tariffs.

However, given the particular situations of each gas pipeline, the following issues were considered:

- ***GNEA:*** Its capacity has been covered at 80 percent since the start of operations to cover the growing Argentine demand as well as the demand from Paraguay and to facilitate the swap of gas with the north of Chile;
- ***Humay-Tocopilla:*** Its capacity is always covered at 100 percent to meet the demand of the south of Peru, north of Chile and guarantee the swap with Argentina; and
- ***Uruguayana-Porto Alegre:*** Its capacity has been covered since the start of operations at 80 percent to cover the growing demand from Brazil and replace the current capacity required in the start node of the pipeline.

Investment module (Capex)

Investment costs detailed in the technical chapter have been incorporated through time to reach the average demands for years 2015 and 2025 as stated in Tables 2.8, 2.9 and 2.10.

Table 2.8: Stage Investment: Campo Durán-Santo Tomé Gas Pipeline and a Branch to Asunción Del Paraguay (GNEA)

Stage	*Year Investment*	*Length Km*	*Diameter Inches*	*Compression HP*	*Unit Costs US$/"m*	*US$/HP*	*Gas Pipeline MMUS$*	*Compressors MMUS$*	*Capex MMUS$*
Start Date	2009	1,500	48"	28,000	58.66	1,050.0	2,639.5	29.4	2,668.9
1st Stage	2011			520,000		1,050.0		546.0	546.0
2nd Stage	2017	960	48"	132,000	59.01	1,050.0	1,699.4	138.6	1,838.0
Total Investment									**5,052.9**

Table 2.9: Stage Investment: Uruguayana-Porto Alegre Gas Pipeline

Stage	*Year Investment*	*Length Km*	*Diameter Inches*	*Compression HP*	*Unit Costs US$/"m*	*US$/HP*	*Gas Pipeline MMUS$*	*Compressors MMUS$*	*Capex MMUS$*
Start Date	2009	565	30"	9,000	22.04	1,450.0	374.2	13.1	387.2
1st Stage	2015			16,600		1,450.0		24.1	24.1
2nd Stage	2022			46,400		1,450.0		67.3	67.3
Total Investment									**478.6**

Table 2.10: Stage Investment: Humay-Tocopilla Gas Pipeline

Stage	*Year Investment*	*Length Km*	*Diameter Inches*	*Compression HP*	*Unit Costs US$/"m*	*US$/HP*	*Gas Pipeline MMUS$*	*Compressors MMUS$*	*Capex MMUS$*
Start Date	2009	1,356	30"	6,000	26.72	1,450.0	1,087.0	8.7	1,095.7
1st Stage	2012			42,800		1,450.0		62.1	62.1
2nd Stage	2016			89,600		1,450.0		129.9	129.9
Total Investment									**1,287.7**

In all cases it has been considered that the financial life is 35 years.

Administration, operation and maintenance, working capital and taxes module (Opex)

For the purpose of estimating operating costs, standard data evolving gradually with the introduction of new compression plants and/or loops according to investment years specified in the previous item have been considered.

Table 2.11: Operating Costs: Campo Durán-Santo Tomé Gas Pipeline and a Branch to Asunción del Paraguay (GNEA)

Stage	*Year Investment*	*Opex MUS$*
Start Date	2009	29,308
1st Stage	2011	41,528
2nd Stage	2017	50,295

Table 2.12: Operating Costs: Uruguayana-Porto Alegre Gas Pipeline

Stage	*Year Investment*	*Opex MUS$*
Start Date	2009	4,912
1st Stage	2015	5,302
2nd Stage	2022	6,392

Table 2.13: Operating Costs: Humay-Tocopilla Gas Pipeline

Stage	*Year Investment*	*Opex MUS$*
Start Date	2009	25,491
1st Stage	2012	26,090
2nd Stage	2016	27,465

Based on the information obtained from Transportadora de Gas del Norte SA and Transportadora de Gas del Sur SA balance sheets, it is estimated that approximately 30 percent of the Opex corresponds to wages and salaries.

Administration and marketing expenses

According to the information obtained from a companies search in Bloomberg in the "Oil & Gas" and "Pipelines" sectors and based on the information available there, it has been estimated that administration and marketing expenses of those companies represent approximately 20 percent of operating costs (Opex).

Working capital

For projection purposes the following working capital issues have been considered.

Table 2.14: Working Capital Issues

Working Capital	*Days*
Accounts Payable	60
Accounts Receivable (OPEX)	60
Accounts Receivable (CAPEX)	60
Wages and Salaries	30

Taxes

Taxes considered in cash flows are based on the assumption that there is no cascade effect in the different segments of the gas chain. That is to say, only taxes applied on the natural gas transportation service and not on its purchase/sale transactions were taken into account, as the activity of the transportation company under analysis is considered as a *pass through* activity in relation with the transported gas.

For information purposes, the main additional tax costs which should be considered by countries in terms of gas import and export rates regulations which may facilitate integration are presented in Table 2.15.

Table 2.15: Main Additional Tax Costs

Applicable Taxes	*Imports in Argentina (from Bolivia)*	*Imports in Chile (from Argentina)*	*Imports in Chile (from Peru)*	*Imports in Brazil (from Bolivia)*
Import Duties	0%	0%	0%	0%
Other Taxes (b)				
Statistics Rate	0%	NA	NA	NA
VAT	21%	19%	19%	18%
Additional VAT	0%	NA	NA	NA
Income Tax Perception	3% (a)	NA	NA	NA
Turnover Tax (PINS/COFINS)	NA	NA	NA	9.25%
IIBB Perception	1%	NA	NA	NA
Exports Duties	NA	45% (b)	NA	NA

(a) The aliquot is doubled to 6 percent if the importer does not have certain specific documentation.
(b) Through External Notification 28/06 to 7/27/06 US$5 per one million BTU shall be considered as a taxable baseline.

For the purposes of economic-financial projections, all tax impacts of current programs of various countries on each gas pipeline as detailed below have been considered.

Campo Durán-Santo Tomé gas pipeline and a branch to Asunción del Paraguay (GNEA)

We understand that the project will be fully developed in the territory of Argentina and, therefore, shall be under the current tax system of the country according to the schedule shown in Table 2.16.

Table 2.16: Argentine Tax System

Taxes	*Aliquots*
Value Added Tax	21.0%
Financial Transactions Tax (1)	
Payments	0.60%
Collections	0.40%
Turnover Tax	3.0%
Income Tax	35.0%
Tax on Minimum Presumed Income (2)	1.0%
Import Duties	0.0%

- *Financial transactions tax*: Through Act 25,413, the government creates this new tax which is generally applied to the movement of funds in bank accounts. The payable tax is determined by applying 6 percent (6/1,000) on the movements and as from May 2004, 34 percent of income from taxable operations may be computed as a credit against income tax or the minimum presumed income; and
- *Minimum presumed income tax*. The object of this tax is the potential income from certain assets and it is determined by applying 1 percent on the taxable base of a certain period. The applicable legislation allows to deduct the amounts paid from income tax within the next 10 fiscal years.

The Uruguayana-Porto Alegre Pipeline

We understand that the project will be fully developed in the territory of Brazil and, therefore, shall be under the current tax system of that country according to the schedule shown in Table 21.7.

Table 2.17: Brazilian Tax System

Taxes	*Aliquots*
VAT (ICMS) – State (1)	18.0%
Tax on Services (ISS) – Municipal (4)	2%-5%
Financial Transactions Tax	0.38%
Turnover Tax (COFINS and PIS) (3)	9.25%
Revenue Tax (2)	34.0%
Tax on Minimum Presumed Income	NA
Import Duties	0.0%

• General aliquot:	Aliquot range: 7% to 25%		
• Comprising:	Revenue tax	15.00%	
	Additional (for those whose taxable income exceeds R$240,000)	10.00%	
	Social contribution on profits	9.00% (*)	
		34.00%	
	(*) Taxable base different from above.		
• Comprising:	COFINS	7.60%	(*)
	PIS	1.65%	(*)
		9.25%	

(*) Social security contributions determined as a percentage of revenue. The credit calculation system of goods or services imports is similar to the VAT.
• Minimum and maximum foreseen aliquots.

Humay-Tocopilla Gas Pipeline

The current tax system in Peru is shown in Table 2.18.

Table 2.18: Peruvian Tax System

Taxes	*Aliquots*
VAT (1)	19.0%
Temporaty Financial Transactions Tax (3)	0.80%
Turnover Tax	NA
Revenue Tax (2)	30.0%
Temporary Tax on Net Assets (4)	0.60%
Import Duties	0.0%

- Called general sales tax;
- An additional tax of 4.1 percent on distributed profits is applicable;
- A 0.6 percent rate was originally applied for 2006 fiscal period. However, a 0.8 percent rate was extended to December 31, 2006. According to the Act, the tax shall be in force until December 31, 2006; and
- For a taxable base over S 5,000,000 (five million soles) – US$1,515,000 approximately. Original validity until December 31, 2006.

As explained in the Executive Summary, the Humay-Tocopilla gas pipeline will make it possible to integrate gas from Peru to the subregion, supplying the north of Chile and later the north of Argentina, to compensate for the gas which Argentina would export by means of a "swap" from the Austral, Neuquina and San Jorge basins. Therefore, and for projections purposes, it has been considered that all the gas transported by the pipeline is exported first to Chile and then to Argentina, and the impact of VAT would be of little significance.

Required or regulated rate of return module

As already mentioned, the methodology used is based on the WACC which takes into account the cost of different financing sources of a company. The applicable formula is as follows:

$$r = \left[\frac{D}{D+E} * \left(r_{free} + r_{counrty} + r_{debt} \right) * (1-t) + \frac{E}{D+E} * \left(r_{free} + r_{country} + \beta \left(r_{market} - r_{free} \right) \right) \right]$$

r: Required rate of return

$_{debt}$: Corporate bonds risk spread

D: Debt

E: Shareholders' capital

$_{free}$:	Return of a risk-free asset	t:	Income tax rate
$_{country}$	Country risk spread	ß	Measures the relationship between the systematic risk of the financial asset to be appraised and r_m
$_{market}$:	Weighted average of financial assets returns		

The issues used for the calculation of each WACC component are detailed below:

Risk-free rate (Rfree): It is a common and generally accepted practice to take as a risk-free rate the return of U.S. Treasury Bonds according to the investment term (at least 30 years), with a return as of July 26, 2006, amounts to 5.16 percent.

Risk country premium (Rcountry): In emerging countries, unlike developed markets, sovereign debt is not considered free of risk. Therefore, the risk premium of a particular country is usually estimated as the return surplus paid by sovereign bonds of the country over American bonds.

For the purposes of determining the risk premium of different countries, the difference of rates of return (spread) between dollar bonds issued by the corresponding governments and risk-free bonds of the U.S. government of a similar "duration" has been considered. The spread, as of July 26, 2006, is shown in Table 2.19.

Table 2.19: Country Risk Premium

	Argentina	*Brazil*	*Peru*
Country Risk Premium	4.27%	2.14%	2.02%

Market risk premium (Rmarket-Rfree) for stocks: The market risk premium is the difference between the rate of return of the market portfolio and the risk-free interest rate. It is the prize which the investor expects to receive in compensation for the market risk. Taking into account the limitations of our capital market, the arithmetic mean of the difference between the return from the S&P 500 index and the return of U.S. Treasury Bonds for the period 1926-2003 has been considered as an alternative measure.

The market risk prize calculated on the basis of the series published by Ibbotson Associates in its book titled *Stocks, Bonds, Bills and Inflation Valuation Edition 2004 Yearbook* amounts to 7.2 percent per year.

Beta (b) or business risk factor: The beta coefficient measures the volatility of return of a financial asset in particular in relation with the market return and represents its nondiversifiable risk. For the purposes of assessing gas pipelines, the unleveraged beta coefficient considered has been of 0.49, corresponding to the average of listed natural gas transportation companies. For the purposes of WACC calculation, the beta coefficient has been leveraged following the market financial structure and revenue tax rates for each country.

Cost of debt (Rdebt): The cost of the financial debt has been estimated taking into account the average bond "spread" issued by Reuters for utilities companies. For the above spread calculation, an average of spreads for qualified companies from BA1 to BB, was carried out, over seven- and 10-year periods, with a result of 1.63 percent.

Table 2.20: Average Bonds Spread Issued by Reuters for Utilities Companies

Rating	*1 yr*	*2 yr*	*3 yr*	*5 yr*	*7 yr*	*10 yr*	*30 yr*	
Aaa/AAA	8	11	13	20	26	28	37	Investment Grade
Aa1/AA+	9	12	14	21	29	30	47	
Aa2/AA	11	15	16	24	32	38	57	
Aa3/AA-	11	19	21	28	39	50	67	
A1/A+	16	22	24	38	47	67	68	
A2/A	19	25	25	44	51	69	79	
A3/A-	24	32	37	50	64	72	97	
Baa1/BBB+	36	49	56	73	79	87	107	
Baa2/BBB	51	60	70	80	90	112	127	
Baa3/BBB-	56	78	80	90	101	128	132	
Ba1/BB+	240	312	295	227	170	200	159	
Ba2/BB	250	275	300	230	130	145	192	
Ba3/BB-	230	255	275	250	145	190	245	
B1/B+	310	350	455	360	245	300	225	
B2/B	415	440	505	410	245	370	350	
B3/B-	490	520	610	510	380	445	520	
Caa/CCC	580	650	755	710	495	520	620	

To reach the cost of the debt for a gas transportation company in each country, the risk-free rate for a seven-10 year investment and the country risk premium should be added to the Reuters average bond spread. In this way, debt costs were obtained for each country under consideration (Table 2.21).

Table 2.21: Indebtedness Cost for Each Country

Components	*Argentina*	*Brazil*	*Peru*
Risk-free Rate	5.07%	5.07%	5.07%
Country Risk Premium	4.27%	2.14%	2.02%
Average Bonds Spread Reuters	1.63%	1.63%	1.63%
Cost of Borrowing	10.97%	8.84%	8.72%

Capital structure: For the purposes of calculating the discount rate, the average capital structure of companies of the same sector has been used. The structure is as follows: 66 percent net worth and 34 percent financial debt.

In the determination of capital structure, company financing should be calculated using the market values of the financial debt and net worth. For the estimation of the market value of the net worth, it is necessary to know the expected cash flow and apply the calculated discount rate; and to obtain the rate it is necessary to know the market value of the company's debts and stocks which leads to a closed-loop issue for calculation purposes.

Due to that reason, market ratios should be obtained from the capital market itself, in the case of a listed company or through a "benchmarking" with other similar listed companies. As an approach, averages ratios obtained from the comparable listed companies sample are used for the calculation of the beta coefficient.

Implicit inflation: Finally, the expected annual inflation should be deducted to estimate the actual rate of return. To estimate inflation, the value of the rate of return of a 30-year U.S. government bond (risk-free) without an indexation clause with another similar bond with an indexation clause was compared, thus obtaining the implicit inflation estimated by the capital market. The average annual inflation rate expected by the market for the next 30 years arises from the difference of those bonds.

$$\pi = \left[\frac{1 + r_f}{1 + r_{fX}} \right] - 1$$

r_f: Return of a risk-free asset; r_{fX}: Return of an indexed risk-free asset

In this way, the implicit inflation of the market value of risk free assets as of July 26, 2006 is 2.74 percent.

Estimation of the required or regulated rate of return:

Table 2.22: Estimation of the Required or Regulated Rate of Return

Discount Rate	*Argentina*	*Brazil*	*Peru*
Risk-free Rate	5.16%	5.16%	5.16%
Country Risk	4.27%	2.14%	2.02%
Risk-free Rate	***9.43%***	***7.30%***	***7.18%***
Beta	0.65	0.65%	0.66
Market Risk Premium	7.19%	7.19%	7.19%
Capital Cost	14.11%	12.00%	11.95%
Cost of Borrowing	**10.97%**	**8.84%**	**8.72%**
Financial Structure			
Net Worth %	66%	66%	66%
Debt %	34%	34%	34%
Income Tax			
%	35%	34%	30%
Nominal WACC	**13.00%**	**10.90%**	**10.90%**
Implicit Inflation of U.S. Treasury Bonds	2.74%	2.74%	2.74%
Real WACC	**10.00%**	**8.00%**	**7.90%**

Tariff calculation module

As already mentioned, the purpose of the projections model used is to obtain the average natural gas transportation tariff corresponding to each priority project which may allow to generate sufficient revenues to recover all costs associated with the execution of investment and operation projects of each gas pipeline, plus a compensation for a reasonable amount of capital invested.

To obtain this tariff, the current value of costs should match the current value of benefits at the regulated rate of return detailed above. The main issues assumed in relation to said revenue, investments, costs, and expenses are described below.

Transportation service revenue

Considering the transportation volumes explained in the demand module, tariffs for flows to be transported by gas pipelines are obtained as a final objective, once the operating costs, investments and profitability associated to the discount rate detailed at the beginning of this chapter are paid.

Financial structure

For the purpose of projections, the financial issues considered are detailed in Table 2.23.

Table 2.23: Financial Structure

Borrowing	*GNEA*	*Uruguayana P. Alegre*	*Humay Tocopilla*
Sustainable Debt Coverage Ratio	3.0 x	3.0 x	3.0 x
Structure D / (D+E) Long-term	34%	34%	34%
Nominal Short-term Interest Rate	8%	7%	7%
Nominal Long-term Interest Rate	11.0%	8.8%	8.7%
Commitment Fee	1.0%	1.0%	1.0%
Nominal Interest for Financial Investments	5.0%	5.0%	5.0%

From the project financing point of view, the following issues have been taken into account:

- It is foreseen that from 2015, gas pipelines shall be under a financial system which will allow them to undertake a certain financial debt level sustainable in the long term and capable of maintaining the coverage ratio defined and the long-term interest rate that was used for the calculation of the discount rate (WACC);
- A short-term initial debt level which may allow the balance of the companies' financial flow to be maintained with the following characteristics:
  - Two years of grace after completion of works and five years term, that is, to say, capital is to be paid as from 2012 and up to 2016;
  - Interests accrued during the years of erection are capitalized as well as 50 percent of interests accrued during the two years of grace. Interests are cancelled with the agreed installments for the period 2012-16; and
  - The company should keep the amount of interests and installments payable during the following year in trust as an additional performance guarantee. This trust only operates for the initial indebtedness and expires when the company is operational, that is, to say, reaches a sustainable debt level.

- The additional financing need which is not covered with these loans is the investment required from partners or shareholders who are interested in the selected projects;
- It has been considered that since the company has a surplus of funds to meet obligations, they will be applicable toward the payment of dividends and financial debt in such a way as to reach during the projection horizon the debt/total financing sources structure as defined in the rate of return calculation (WACC) as that expected in the market; and
- No additional costs such as guarantees, additional risk coverages (hedge positions), syndication fees, and so on have been considered.

Module outputs – Economic-financial module (stability of the consolidated system):

The obtained results are detailed in Table 2.24.

Table 2.24: Results of the Economic-financial Module

	Tariff (US$/MMBTU)	*Shareholders' Contribution (MM US$)*	*Shareholder IRR %*	*"Pay-Back" Years*	*Maximum Borrowing (MM US$)*	*Sustainable Debt by 2015 (MM US$)*	*Cost of Borrowing %*
GNEA	0.606	1,150.0	14.99%	11.0	2,843.9	1,485.7	10.97%
Uruguayana-Porto Alegre	0.578	180.0	12.91%	11.0	327.5	189.5	8.84%
Humay-Tocopilla	1.009	510.0	12.33%	11.0	765.3	493.7	8.72%

Sensitivities (Risk or sensitivities analysis module)

The results obtained arising as a consequence of considering the main projection issues described above are detailed below.

Impacts on tariffs

In the first place, we have analyzed the impact of a certain tariff in the following situations:

- Variation in CAPEX +/- 20 percent, as a consequence of the estimation error indicated in the technical description of projects and associated costs; and
- Variation in the rate of return expected by shareholders in +/- 1 percent.

Table 2.25 summarizes the results obtained.

Table 2.25: Sensitivities: Impacts on Tariffs

Tariff (US$/MMBTU)	*GNEA*	*Uruguayana Porto Alegre*	*Humay-Tocopilla*
Baseline	0.606	0.578	1.009
CAPEX (+) 20%	0.718	0.682	1.170
CAPEX (-) 20%	0.496	0.475	0.848
WACC (+) 1%	0.665	0.649	1.106
WACC (-)1%	0.552	0.515	0.903

Variation % Baseline	*GNEA*	*Uruguayana Porto Alegre*	*Humay-Tocopilla*
CAPEX (+) 20%	18.6%	18.0%	16.0%
CAPEX (-) 20%	-18.1%	-17.9%	-15.9%
WACC (+) 1%	9.8%	12.30%	9.7%
WACC (-) 1%	-8.9%	-11.0%	-10.5%

Financial impacts

In addition, we have analyzed the financial impacts taking the base tariff as fixed under the following situations:

- Tax benefits such as revenue tax exemption and value added tax of the investment;
- A 20 percent savings in the estimated investment;
- Opex variations of +/- 20 percent; and
- Financial cost variation of +/- 2 percent.

Table 2.26: Sensitivities: Financial Impacts. Campo Durán-Santo Tomé Gas Pipeline and a Branch to Asunción Del Paraguay (GNEA)

Sensitivities	*Shareholder Contribution (MM US$)*	*Shareholder IRR %*	*"Pay-Back" Years*	*Maximum Borrowing (MM US$)*	*Sustainable Debt by 2015 (MM US$)*
Baseline	**1,150.0**	**14.99%**	**11.0**	**2,843.9**	**1,485.7**
Tax Effects	950.0	21.06%	8.0	2,193.8	1,445.2
Capex Base (-) 20%	1,000.0	17.61%	9.0	1,883.0	1,543.1
Opex (+) 20%	1,160.0	14.71%	12.0	2,844.9	1,464.4
Opex (-) 20%	1,150.0	15.20%	11.0	2,843.9	1,507.1
Interest (+) 2%	1,300.0	13.28%	12.0	3,175.3	1,327.5
Interest (-) 2%	1,150.0	15.91%	11.0	2,491.3	1,672.0

Variation % Baseline	*Shareholder Contribution (MM US$)*	*Shareholder IRR %*	*"Pay-Back" Years*	*Maximum Borrowing (MM US$)*	*Sustainable Debt by 2015 (MM US$)*
Tax Effects	-17.4%	40.4%	-27.3%	-22.9%	-2.7%
Capex Base (-) 20%	-13.0%	17.5%	-18.2%	-33.8%	3.9%
Opex (+) 20%	0.9%	-1.9%	9.1%	0.0%	-1.4%
Opex (-) 20%	0.0%	1.4%	0.0%	0.0%	1.4%
Interest (+) 2%	13.0%	-11.4%	9.1%	11.7%	-10.6%
Interest (-) 2%	0.0%	6.1%	0.0%	-12.4%	12.5%

Table 2.27: Sensitivities: Financial Impacts. The Uruguayana-Porto Alegre Pipeline

Sensitivities	*Shareholder Contribution (MM US$)*	*Shareholder IRR %*	*"Pay-Back" Years*	*Maximum Borrowing (MM US$)*	*Sustainable Debt by 2015 (MM US$)*
Baseline	180.0	12.91%	11.0	327.5	189.5
Tax Effects	150.0	17.18%	8.0	273.0	180.0
Capex Base (-) 20%	130.0	16.20%	8.0	251.0	189.9
Opex (+) 20%	185.0	12.52%	11.0	327.6	186.0

Variation % Baseline	*Shareholder Contribution (MM US$)*	*Shareholder IRR %*	*"Pay-Back" Years*	*Maximum Borrowing (MM US$)*	*Sustainable Debt by 2015 (MM US$)*
Opex (–) 20%	170.0	13.39%	10.0	305.7	192.9
Interest (+) 2%	230.0	10.95%	12.0	330.6	169.8
Interest (–) 2%	180.0	13.98%	9.0	314.4	212.4

Variation % Baseline	*Shareholder Contribution (MM US$)*	*Shareholder IRR %*	*"Pay-Back" Years*	*Maximum Borrowing (MM US$)*	*Sustainable Debt by 2015 (MM US$)*
Tax Effects	-16.7%	33.1%	-27.3%	-16.7%	-5.0%
Capex Base (–) 20%	-27.8%	25.6%	-27.3%	-23.4%	0.2%
Opex (+) 20%	2.8%	-3.0%	0.0%	0.0%	-1.8%
Opex (–) 20%	-5.6%	3.7%	-9.1%	-6.7%	1.8%
Interest (+) 2%	27.8%	-15.1%	9.1%	0.9%	-10.3%
Interest (–) 2%	0.0%	8.3%	-18.2%	-4.0%	12.1%

Table 2.28: Sensitivities: Financial Impacts. The Humay-Tocopilla Pipeline

Sensitivities	*Shareholder Contribution (MM US$)*	*Shareholder IRR %*	*"Pay-Back" Years*	*Maximum Borrowing (MM US$)*	*Sustainable Debt by 2015 (MM US$)*
Baseline	*500.0*	*15.46%*	*9.0*	*700.1*	*493.7*
Tax Effects	350.0	16.24%	8.0	557.3	501.4
Capex Base (–) 20%	520.0	11.56%	12.0	754.5	475.8
Opex (+) 20%	480.0	13.27%	10.0	710.7	511.6
Opex (–) 20%	570.0	10.96%	12.0	775.8	443.1
Interest (+) 2%	480.0	13.80%	10.0	629.5	552.9
Interest (70) 2%	500.0	15.46%	9.0	700.1	493.7

Variation % Baseline	*Shareholder Contribution (MM US$)*	*Shareholder IRR %*	*"Pay-Back" Years*	*Maximum Borrowing (MM US$)*	*Sustainable Debt by 2015 (MM US$)*
Tax Effects	-2.0%	25.4%	-18.2%	-8.5%	0.0%
Capex Base (–) 20%	-31.4%	31.7%	-27.3%	-27.2%	1.6%
Opex (+) 20%	2.0%	-6.3%	9.1%	-1.4%	-3.6%
Opex (–) 20%	-5.9%	7.5%	-9.1%	-7.1%	3.6%
Interest (+) 2%	11.8%	-11.2%	9.1%	1.4%	-10.3%
Interest (–) 2%	-5.9%	11.9%	-9.1%	-17.7%	12.0%

As it may be observed from Tables 2.26, 2.27 and 2.28, the effects in the three pipelines are similar. Sensitivity analyzed in terms of tax benefits and Capex savings imply a lower investor contribution and, therefore, an important increase in the internal rate of return. This last impact in the Capex reduction is mainly observed in the case of Uruguayana-Porto Alegre and Humay-Tocopilla pipelines as a consequence of their erection engineering which require higher investment percentages at the beginning of these projects in relation with GNEA, where the pipeline scalability through regasification plants and loops takes place at a later stage.

In all cases it may be observed that Opex variations do not bear a significant impact on the results. Besides, a higher interest rate in the long term for a sustainable financial debt would imply a higher contribution by investors and, therefore, a fall in their internal rate of return.

Results

The initial investment in new gas pipelines has been estimated at US$4.2 billion, and total investment with all compression expansion during the period of the projection totals US$6.8 billion. The model assumes that the initial investment will begin between the second half of 2007 and the year 2008. The investment level requires an aggressive indebtedness strategy with a long-term sustainable debt segment of around US$2.1 billion and a unsustainable segment of US$1.2 billion, to be repaid in a term not higher than eight years; as from 2015 all projects shall be operational, distributing dividends and repaying the debt until reaching the standard indebtedness – net worth ratio for the industry.

Rates of return between 12 percent and 15 percent, depending on the pipeline, are compatible with the risks required by a diversified investor interested in this type of project, however, this investment and leverage level demands a low uncertainty environment for

investments. Along these lines, the attraction of investors for these private projects requires the improvement of certain aspects, namely:

- The need for reserves to be audited by international experts, enabling investors to focus their attention on the risks of the operation of the business rather than the risk of lack of product;
- The need for clear rules of the game and stable legal frameworks to help reduce the perception of risk; and
- The availability of financial backing at competitive rates and tax assistance by means of certain exemptions.

These conditions are critical for private shareholders to undertake an 11-year risk exposure of "Pay Back" within a long-term rate of return environment between 8 percent and 10 percent. Failure to meet these requirements would increase the tariffs of these projects, making the integration less attractive and generating alternatives for producer countries to undertake alternative LNG export projects.

Finally, these conditions are also required for the US$14.5 billion necessary for the expansion of the networks that are necessary to supplement the existing pipelines.

List of Technical Reports

Region/Country	Activity/Report Title	Date	Number
	SUB-SAHARAN AFRICA (AFR)		
Africa	Power Trade in Nile Basin Initiative Phase II (CD Only): Part I: Minutes of the High-level Power Experts Meeting; and Part II: Minutes of the First Meeting of the Nile Basin Ministers Responsible for Electricity	04/05	067/05
	Introducing Low-cost Methods in Electricity Distribution Networks	10/06	104/06
Cameroon	Decentralized Rural Electrification Project in Cameroon	01/05	087/05
Chad	Revenue Management Seminar. Oslo, June 25-26, 2003. (CD Only)	06/05	075/05
Côte d'Ivoire	Workshop on Rural Energy and Sustainable Development, January 30-31, 2002. *(Atelier sur l'Energie en régions rurales et le Développement durable 30-31, janvier 2002)*	04/05	068/05
Ethiopia	Phase-Out of Leaded Gasoline in Oil Importing Countries of Sub-Saharan Africa: The Case of Ethiopia - Action Plan	12/03	038/03
	Sub-Saharan Petroleum Products Transportation Corridor: Analysis and Case Studies	03/03	033/03
	Phase-Out of Leaded Gasoline in Sub-Saharan Africa	04/02	028/02
	Energy and Poverty: How can Modern Energy Services Contribute to Poverty Reduction	03/03	032/03
East Africa	Sub-Regional Conference on the Phase-out Leaded Gasoline in East Africa. June 5-7, 2002	11/03	044/03
Ghana	Poverty and Social Impact Analysis of Electricity Tariffs	12/05	088/05
	Women Enterprise Study: Developing a Model for Mainstreaming Gender into Modern Energy Service Delivery	03/06	096/06
	Sector Reform and the Poor: Energy Use and Supply in Ghana	03/06	097/06
Kenya	Field Performance Evaluation of Amorphous Silicon (a-Si) Photovoltaic Systems in Kenya: Methods and Measurement in Support of a Sustainable Commercial Solar Energy Industry	08/00	005/00
	The Kenya Portable Battery Pack Experience: Test Marketing an Alternative for Low-Income Rural Household Electrification	12/01	05/01
Malawi	Rural Energy and Institutional Development	04/05	069/05
Mali	Phase-Out of Leaded Gasoline in Oil Importing Countries of Sub-Saharan Africa: The Case of Mali - Action Plan *(Elimination progressive de l'essence au plomb dans les pays importateurs de pétrole en Afrique subsaharienne Le cas du Mali — Mali Plan d'action)*	12/03	041/03
Mauritania	Phase-Out of Leaded Gasoline in Oil Importing Countries of Sub-Saharan Africa: The Case of Mauritania - Action Plan *(Elimination progressive de l'essence au plomb dans les pays importateurs de pétrole en Afrique subsaharienne Le cas de la Mauritanie – Plan d'action.)*	12/03	040/03

Region/Country	Activity/Report Title	Date	Number
Nigeria	Phase-Out of Leaded Gasoline in Nigeria	11/02	029/02
	Nigerian LP Gas Sector Improvement Study	03/04	056/04
	Taxation and State Participation in Nigeria's Oil and Gas Sector	08/04	057/04
Regional	Second Steering Committee: The Road Ahead. Clean Air Initiative In Sub-Saharan African Cities. Paris, March 13-14, 2003	12/03	045/03
	Lead Elimination from Gasoline in Sub-Saharan Africa. Sub-regional Conference of the West-Africa group. Dakar, Senegal March 26-27, 2002 *(Deuxième comité directeur : La route à suivre - L'initiative sur l'assainissement de l'air. Paris, le 13-14 mars 2003)*	12/03	046/03
	1998-2002 Progress Report. The World Bank Clean Air Initiative in Sub-Saharan African Cities. Working Paper #10 (Clean Air Initiative/ESMAP)	02/02	048/04
	Landfill Gas Capture Opportunity in Sub Saharan Africa	06/05	074/05
	The Evolution of Enterprise Reform in Africa: From State-owned Enterprises to Private Participation in Infrastructure-and Back?	11/05	084/05
Senegal	Regional Conference on the Phase-Out of Leaded Gasoline in Sub-Saharan Africa *(Elimination du plomb dans l'essence en Afrique subsaharienne Conference sous regionales du Groupe Afrique de l'Ouest Dakar, Sénégal. March 26-27, 2002.)*	03/02	022/02
		12/03	046/03
	Alleviating Fuel Adulteration Practices in the Downstream Oil Sector in Senegal	09/05	079/05
	Maximisation des Retombées de l'Electricité en Zones Rurales, Application au Cas du Sénégal	03/07	
South Africa	South Africa Workshop: People's Power Workshop.	12/04	064/04
Swaziland	Solar Electrification Program 2001 2010: Phase 1: 2001 2002 (Solar Energy in the Pilot Area)	12/01	019/01
Tanzania	Mini Hydropower Development Case Studies on the Malagarasi, Muhuwesi, and Kikuletwa Rivers Volumes I, II, and III	04/02	024/02
	Phase-Out of Leaded Gasoline in Oil Importing Countries of Sub-Saharan Africa: The Case of Tanzania - Action Plan	12/03	039/03
Uganda	Report on the Uganda Power Sector Reform and Regulation Strategy Workshop	08/00	004/00
	WEST AFRICA (AFR)		
Regional	Market Development	12/01	017/01
	EAST ASIA AND PACIFIC (EAP)		
Cambodia	Efficiency Improvement for Commercialization of the Power Sector	10/02	031/02
	TA For Capacity Building of the Electricity Authority	09/05	076/05
China	Assessing Markets for Renewable Energy in Rural Areas of Northwestern China	08/00	003/00
	Technology Assessment of Clean Coal Technologies for China Volume I-Electric Power Production	05/01	011/01
	Technology Assessment of Clean Coal Technologies for China Volume II-Environmental and Energy Efficiency Improvements for Non-power Uses of Coal	05/01	011/01
	Technology Assessment of Clean Coal Technologies for China Volume III-Environmental Compliance in the Energy Sector: Methodological Approach and Least-Cost Strategies	12/01	011/01
	Policy Advice on Implementation of Clean Coal Technology	09/06	104/06
	Scoping Study for Voluntary Green Electricity Schemes in Beijing and Shanghai	09/06	105/06
Papua New Guinea	Energy Sector and Rural Electrification Background Note	03/06	102/06
Philippines	Rural Electrification Regulation Framework. (CD Only)	10/05	080/05
Thailand	DSM in Thailand: A Case Study	10/00	008/00
	Development of a Regional Power Market in the Greater Mekong Sub-Region (GMS)	12/01	015/01

Region/Country	Activity/Report Title	Date	Number
Vietnam	Options for Renewable Energy in Vietnam	07/00	001/00
	Renewable Energy Action Plan	03/02	021/02
	Vietnam's Petroleum Sector: Technical Assistance for the Revision of the Existing Legal and Regulatory Framework	03/04	053/04
	Vietnam Policy Dialogue Seminar and New Mining Code	03/06	098/06
	SOUTH ASIA (SAS)		
Bangladesh	Workshop on Bangladesh Power Sector Reform	12/01	018/01
	Integrating Gender in Energy Provision: The Case of Bangladesh	04/04	054/04
	Opportunities for Women in Renewable Energy Technology Use In Bangladesh, Phase I	04/04	055/04
	EUROPE AND CENTRAL ASIA (ECA)		
Azerbaijan	Natural Gas Sector Re-structuring and Regulatory Reform	03/06	099/06
Macedonia	Elements of Energy and Environment Strategy in Macedonia	03/06	100/06
Poland	Poland (URE): Assistance for the Implementation of the New Tariff Regulatory System: Volume I, Economic Report, Volume II, Legal Report	03/06	101/06
Russia	Russia Pipeline Oil Spill Study	03/03	034/03
Uzbekistan	Energy Efficiency in Urban Water Utilities in Central Asia	10/05	082/05
	MIDDLE EASTERN AND NORTH AFRICA REGION (MENA)		
Turkey	Gas Sector Strategy	05/07	114/07
Regional	Roundtable on Opportunities and Challenges in the Water, Sanitation And Power Sectors in the Middle East and North Africa Region. Summary Proceedings, May 26-28, 2003. Beit Mary, Lebanon. (CD)	02/04	049/04
Morocco	Amélioration de d´Efficacité Energie: Environnement de la Zone Industrielle de Sidi Bernoussi, Casablanca	12/05	085/05
	LATIN AMERICA AND THE CARIBBEAN REGION (LCR)		
Brazil	Background Study for a National Rural Electrification Strategy: Aiming for Universal Access	03/05	066/05
	How do Peri-Urban Poor Meet their Energy Needs: A Case Study of Caju Shantytown, Rio de Janeiro	02/06	094/06
	Integration Strategy for the Southern Cone Gas Networks	05/07	113/07
Bolivia	Country Program Phase II: Rural Energy and Energy Efficiency Report on Operational Activities	05/05	072/05
	Bolivia: National Biomass Program. Report on Operational Activities	05/07	115/07
Chile	Desafíos de la Electrificación Rural	10/05	082/05
Colombia	Desarrollo Económico Reciente en Infraestructura: Balanceando las necesidades sociales y productivas de la infraestructura	03/07	325/05
Ecuador	Programa de Entrenamiento a Representantes de Nacionalidades Amazónicas en Temas Hidrocarburíferos	08/02	025/02
	Stimulating the Picohydropower Market for Low-Income Households in Ecuador	12/05	090/05
Guatemala	Evaluation of Improved Stove Programs: Final Report of Project Case Studies	12/04	060/04
Haiti	Strategy to Alleviate the Pressure of Fuel Demand on National Woodfuel Resources (English) *(Stratégie pour l'allègement de la Pression sur les Ressources Ligneuses Nationales par la Demande en Combustibles)*	04/07	112/07

Region/Country	Activity/Report Title	Date	Number
Honduras	Remote Energy Systems and Rural Connectivity: Technical Assistance to the Aldeas Solares Program of Honduras	12/05	092/05
Mexico	Energy Policies and the Mexican Economy	01/04	047/04
	Technical Assistance for Long-Term Program for Renewable Energy Development	02/06	093/06
Nicaragua	Aid-Memoir from the Rural Electrification Workshop (Spanish only)	03/03	030/04
	Sustainable Charcoal Production in the Chinandega Region	04/05	071/05
Perú	Extending the Use of Natural Gas to Inland Perú (Spanish/English)	04/06	103/06
	Solar-diesel Hybrid Options for the Peruvian Amazon Lessons Learned from Padre Cocha	04/07	111/07
Regional	Regional Electricity Markets Interconnections - Phase I Identification of Issues for the Development of Regional Power Markets in South America	12/01	016/01
	Regional Electricity Markets Interconnections - Phase II Proposals to Facilitate Increased Energy Exchanges in South America	04/02	016/01
	Population, Energy and Environment Program (PEA) Comparative Analysis on the Distribution of Oil Rents (English and Spanish)	02/02	020/02
	Estudio Comparativo sobre la Distribución de la Renta Petrolera Estudio de Casos: Bolivia, Colombia, Ecuador y Perú	03/02	023/02
	Latin American and Caribbean Refinery Sector Development Report - Volumes I and II	08/02	026/02
	The Population, Energy and Environmental Program (EAP) (English and Spanish)	08/02	027/02
	Bank Experience in Non-energy Projects with Rural Electrification Components: A Review of Integration Issues in LCR	02/04	052/04
	Supporting Gender and Sustainable Energy Initiatives in Central America	12/04	061/04
	Energy from Landfill Gas for the LCR Region: Best Practice and Social Issues (CD Only)	01/05	065/05
	Study on Investment and Private Sector Participation in Power Distribution in Latin America and the Caribbean Region	12/05	089/05
	Strengthening Energy Security in Uruguay	05/07	116/07
	GLOBAL		
	Impact of Power Sector Reform on the Poor: A Review of Issues and the Literature	07/00	002/00
	Best Practices for Sustainable Development of Micro Hydro Power in Developing Countries	08/00	006/00
	Mini-Grid Design Manual	09/00	007/00
	Photovoltaic Applications in Rural Areas of the Developing World	11/00	009/00
	Subsidies and Sustainable Rural Energy Services: Can we Create Incentives Without Distorting Markets?	12/00	010/00
	Sustainable Woodfuel Supplies from the Dry Tropical Woodlands	06/01	013/01
	Key Factors for Private Sector Investment in Power Distribution	08/01	014/01
	Cross-Border Oil and Gas Pipelines: Problems and Prospects	06/03	035/03
	Monitoring and Evaluation in Rural Electrification Projects: A Demand-Oriented Approach	07/03	037/03
	Household Energy Use in Developing Countries: A Multicountry Study	10/03	042/03
	Knowledge Exchange: Online Consultation and Project Profile from South Asia Practitioners Workshop. Colombo, Sri Lanka,	12/03	043/03

Region/Country	Activity/Report Title	Date	Number
	June 2-4, 2003		
	Energy & Environmental Health: A Literature Review and Recommendations	03/04	050/04
	Petroleum Revenue Management Workshop	03/04	051/04
	Operating Utility DSM Programs in a Restructuring Electricity Sector	12/05	058/04
	Evaluation of ESMAP Regional Power Trade Portfolio (TAG Report)	12/04	059/04
	Gender in Sustainable Energy Regional Workshop Series: Mesoamerican Network on Gender in Sustainable Energy (GENES) Winrock and ESMAP	12/04	062/04
	Women in Mining Voices for a Change Conference (CD Only)	12/04	063/04
	Renewable Energy Potential in Selected Countries: Volume I: North Africa, Central Europe, and the Former Soviet Union, Volume II: Latin America	04/05	070/05
	Renewable Energy Toolkit Needs Assessment	08/05	077/05
	Portable Solar Photovoltaic Lanterns: Performance and Certification Specification and Type Approval	08/05	078/05
	Crude Oil Prices Differentials and Differences in Oil Qualities: A Statistical Analysis	10/05	081/05
	Operating Utility DSM Programs in a Restructuring Electricity Sector	12/05	086/05
	Sector Reform and the Poor: Energy Use and Supply in Four Countries: Botswana, Ghana, Honduras and Senegal	03/06	095/06

THE WORLD BANK

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