Looking for clean energy considering LNG assessment to provide energy security in Brazil and GTL from Bolivia natural gas reserves

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This work aims to identify market opportunities for LNG in Brazil as a complement to natural gas supply, characterizing it both on its production and transportation side and analyzing costs and prospects for expanding the supply and use infrastructure so as to ensure that the growing demand of this energy input is met and allow greater flexibility for the natural gas industry and the power sector, with an idea about risk sources and protection mechanisms used to ensure the reliability of power generation, gas market flexibility and the need for LNG supply planning considering the spot and/or long-term market.

Another aspect approached is the economics and the viability of Natural Gas Industrialization in Bolivia, by producing secondary fuels such as GTL-diesel from natural gas (cleaner than the oil byproduct), seeking a clean development from the environmentally correct use of power by this GLT process. Bolivia has resources that could supply these secondary energy resources as from GTL. It is possible to process 30MCMpd of gas obtaining profits from the gas and also from the liquid hydrocarbons that are found in it. The Bolivian GTL would present the following advantages: It would export diesel and/or gasoline and would not have to import it anymore; the GTL-FT exports could reach 35Mbpy, acquiring competitive prices; It would increase productive jobs not only due to GTL itself, but also due to secondary economy linked to the GTL market; The use of GTL-FT diesel would provide a "cleaner" environment especially in the urban areas; Finally, from the macroeconomic perspective, the investment in the plant construction and supporting works would generate a great number of jobs.

Energy resources play a fundamental strategic role in the development of a country and its economic activity. The worldwide tendency of increasing demand for energy, especially in developing countries - such as Brazil and or Bolivia - made energy resources achievement and supply a critical issue for the continuity of socioeconomic growth. To assure the availability of these resources so as to guarantee the future of the economy, of the

environment and of the society as a whole is a constant challenge. In this sense, all the factors involved that determine or make security and availability exist over time must be highly relevant, as well as the planning of energy supply and use.
Natural gas (NG) is a fossil fuel, formed by hydro-carbons that can be found in nature in an isolated way or associated to oil. Formed mainly of methane, its advantage is to have low amounts of contaminants, such as nitrogen, carbon dioxide, sulfur composites and particulates, which make its combustion be considered clean. Moreover, it has high calorific power, allowing its direct use, without the need of refining.
In that sense, a technical and economic analysis of secondary fuels from hydrocarbons is conducted in order to identify the possibility of manufacturing the Bolivian Natural Gas using GTL to produce byproducts. The energy economics analysis of LNG is also made viewing energy security in Brazil. Technically and economically speaking, it is important to identify the industrialization, technology investment amounts and production costs of a GTL and or LNG project. Commercially speaking, the aim is to identify the current and future situations of GTL and LNG in the market and what that represents. From the energy economic point of view, the intention is to determine the financial issues (amounts, interest fees, benefit periods) linked to investments in GTL and/or LNG. Legally and politically speaking, the present legal situation will be compared to the most appropriate regulatory issues related to natural gas conversions, both chemical (GTL) an physical (LNG).

Keywords:
LNG, natural gas, energy, energy planning, power, GTL, Diesel, secondary Fuels, Reserves, Clean Development, Energy Resources, Generation, Gas-Chemical, Gas Byproducts

1. LNG and its Production Chain

A LNG project basically has four stages, also called production chain: natural gas exploration and production (E&P); next come the liquefying process, transportation to the import terminals and, finally, regasification.

1.1 Natural Gas Production

Liquefied natural gas (LNG) is essentially natural gas (NG), cooled at a certain temperature below its vaporization point. Thus, the LNG productive chain starts in the exploration and production of natural gas.
At this initial exploration phase, there is a close relation between the NG and petroleum industries. This occurs because usually, in the same basin, there may be gas together with petroleum, either dissolved or as a gas layer formed in the upper part of the deposit. In this case, it is said that natural gas is “associated” to petroleum. In turn, the so-called “non-associated” gas is the one found in fields where there is very little or no petroleum, allowing only the exploration of gas. This way, the geological research efforts to locate these fields, as well as the drilling, development and exploration technologies may be shared between the two industries.
The exploration process is divided into geological and geophysical research and drilling. In the research phase, an analysis is made on the rocky structures and on the underground of the region where petroleum and/or gas is being sought, which allows selecting the drilling

sites. Drilling is part of proving the existence of compounds (oil and/or gas) and its economic viability for later exploration.
After the discovery of a basin, and the analysis of the economic viability of the field, comes the production process. With similar characteristics and technologies, petroleum and NG prospections are jointly conducted, so as to provide the exploration of the two compounds. During NG production, the primary purification process of the gas also occurs, when liquids (water and others), particulate matter and contaminants (sulfur) are separated, so as to make NG adequate to be conveyed to the processing unit.

1.2 Liquefying

The natural gas liquefying plant is the main stage in the LNG production chain. In it, the temperature of natural gas is reduced to -162º C, which is below the vaporization point of methane. Hence, the methane gas turns liquid and its volume is reduced to 1/600 of the original volume.
The liquefying plant is usually built in coastal areas, in bays, so that it facilitates the production outflow by vessels, thus making it also desirable for the plant to be close to the NG producing fields, as the transportation price via gas pipelines is considerable and, depending on the distance to be covered, it may increase the global costs of the project.
The premises composing the liquefying plant are: a gas processing unit (UPGN) in case the gas has not been previously processed with the separation of components of greater commercial value and the standardization of the product global composition. The gas is then dehydrated and broken down, so that hydrocarbons are separated: processed or dry gas (essentially methane), ethane, GLP (propane and butane) and C5+ components (especially natural gasoline). This way, the natural gas processed is led to the liquefying stage in a set of heat exchangers and LNG storage tanks.
The liquefaction of NG is conducted at several stages of gas cooling until the cooled liquid is obtained in a process similar to that of a conventional refrigerator. A cooling gas extracts heat from the NG by means of heat exchangers in parallel sets, forming liquefying trains until this gas is cooled at a temperature of -162ºC.
Propane is the main cooling gas, leading the NG temperature to -30ºC; the gas will go through other cooling trains in which nitrogen, associated to other hydrocarbons, act as secondary coolers, making NG go below the vaporization temperature.
The technology that uses propane as initial cooling gas is the most commonly used and gained the market along the evolution and diffusion of LNG in the world market, incorporating several technological improvements, mainly concerning cooling compression turbines, which account for a large share of the plants operational cost and their efficiency, allied to increase in power and environmental improvement in the use of cooling gases, besides the development of much more efficient thermal insulating materials, which revest the storage tanks, were essential for the growth in the insertion of LNG as a viable option to natural gas.
The storage of liquefied NG is made in tanks with compression and re-liquefying systems to recover the gases that leak from stocking and resume the gas state; the logistics of liquefying, shipping and transportation forecasts is necessary for minimizing the stored volume, maximizing the LNG production and therefore mitigating losses from re-liquefying and storage.

1.3 Shipping

In order to convey the LNG between the liquefying and regasification plants, specially built vessels for storing gas in its liquid form are used, which count on large reservoirs capable of keeping the gas temperature during transportation. However, losses occur in this process varying from 1% to 3% of the initial volume, according to the distance to be covered, besides the consumption of the gas employed as fuel for the LNG Carrier Ship.
Figure 1 below shows the two types of vessels that convey LNG: the ones that store gas in spherical tanks and those counting on tanks in longitudinal positions; the costs between the two types is similar both in construction and in operation.

Fig. 1. LNG Carrier Ships

In function of its great meaningfulness for the world LNG industry, Japan concentrates a large share of the shipyards that build these types of vessels, and today it has European and Korean shipyards as competitors in this sector. The major producing companies are Daewoo Shipbuilding, Hyundai Heavy Industries, Mitsui Engineering & Shipbuilding, Samsung Heavy Industries, Kawasaki Shipbuilding and Mitsubishi Heavy Industries.
Besides LNG Carrier Ships, LNG can also be conveyed by smaller tanks, by means of trucks or trains generally used to supply peak, temporary or isolated demands when the development cost of a gas pipeline makes the gas supply too expensive.

1.4 Regasification

Regasification plants constitute the importation side in the LNG chain. They are usually located close to the natural gas consumer centers and harbor LNG Carrier Ships in especially built terminals. The plants are formed by LNG storage tanks and heat exchangers where LNG is again transformed into gas for distribution.

1.5 State of the Art of LNG in the World

The greatest world natural gas consumers count on a mature market and fully established infrastructure with maintenance characteristics in the development of both its infrastructure and demand making it necessary to transport natural gas from other producing countries up to the consumer countries. Hence, the LNG technology emerges an alternative to cover great distances.
These facts make an increment in LNG production by competitors be expected, owing to an increase in natural gas prices and to the reduction in LNG costs managed with improvements in the liquefying, storage and transportation technology, making business

with natural gas fields far away from the consumer centers economically interesting, which makes the construction of gas pipelines too expensive.

LNG consumers may use it as a logistic alternative to natural gas in countries that do not count on reserves or physical links with producing regions via gas pipelines, as is the case of Japan, the greatest LNG consumer in the world. Thus, it can be used as a guarantee of power supply in demand peaks, known as *'peak-shaving'* as is the case of the Unites States.

1.6 Major LNG Producers in the World

The EIA (*Energy Information Administration*) divided the LNG exportation industry into three geographical sectors: Pacific basin, Atlantic basin and Middle East basin[1].

1.6.1 Pacific Basin

The producing countries of this Basin are Indonesia, Malaysia, Australia, Brunei, Unites States and Russia, and Indonesia is the world leader in LNG production and export. Table 1 details each country export and its sales markets.

This Basin accounts for approximately 49% of the LNG world production.

Producer	Exports 2002 (TCF)	Exports 2003 (TCF)	Exports 2007 (TCF)	Major Consumers
Indonesia	1.1	1.4	1.4	Japan, Taiwan and South Korea
Malaysia	0.741	0.741	1.1	Japan, Taiwan and South Korea
Australia	0.367	0.572	0.747	Japan
Brunei	0.351	0.351	0.351	Japan, South Korea
Unites States	0.068	0.068	0.068	Japan
Russia			0.234	Unites States
TOTAL	**2.6**	**3.1**	**3.9**	

Table 1. Pacific Basin: LNG Production and Sales Markets

1.6.2 Atlantic basin

The main producing countries in this basin are Algeria, Nigeria, Trinidad and Tobago, Libya, Egypt and Norway, Algeria being the most important country in the LNG production. In Table 2, details of LNG exports in this basin can be observed.

The exporters in this basin produce about 29% of the LNG world production.

[1] The division of the LNG industry was made by EIA by means of *The Global Liquefied Natural Gas Market*, site: http://www.eia.doe.gov/oiaf/analisispaper/global/

Producer	Exports 2002 (TCF)	Exports 2003 (TCF)	Exports 2007 (TCF)	Major Consumers
Algeria	0.935	1.1	1.1	France, Belgium, Spain, Turkey and the Unites States
Nigeria	0.394	0.463	0.863	Turkey, Italy, France, Portugal, Spain and Unites States
Trinidad & Tobago	0.189	0.482	0.735	Unites States, Puerto Rico, Spain, and Dominican Republic.
Libia	0.021	0.021	0.021	-
Egypt			0.594	Italy and the Unites States
Norway			0.200	Spain, France, and the Unites States.
TOTAL	**1.5**	**2.1**	**3.5**	

Table 2. Atlantic basin: LNG Production and Sales Markets

1.6.3 Middle East

The producing countries in this basin are Qatar, Oman and the United Arab Emirates, and Qatar is the most important, as shown in Table 3.
The Middle East exporters produce about 23% of the LNG production.
Today, with the largest gas reserves ever found, Iran has great potential to export gas to markets in Europe, Asia, and India, both by gas pipelines and LNG.

Producer	Exports 2002 (TCF)	Exports 2003 (TCF)	Exports 2007 (TCF)	Major Consumers
Qatar	0.626	0.726	1.184	Japan, South Korea, Unites States and Europe
Oman	0.356	0.356	0.517	South Korea, Japan
Arab Emirates	0.178	0.278	0.278	Japan
TOTAL	**1.2**	**1.4**	**2.0**	

Table 3. Middle East: Production and LNG Sales Markets

1.7 Major LNG Consumers in the world

The LNG world market can be divided into two large zones; the Pacific and the Atlantic Basins.
Japan, South Korea and Taiwan are the main consuming countries in the Pacific Basin, which means about 68% of global imports; LNG is used to supply about 90% of the natural gas needs in these countries, making this type of fuel of vital importance for energy supply and security.

Fig. 2. Europe: Regasification Terminals for LNG Imports
Source: Energy Information Administration (EIA), The Global Liquefied Natural Gas Market

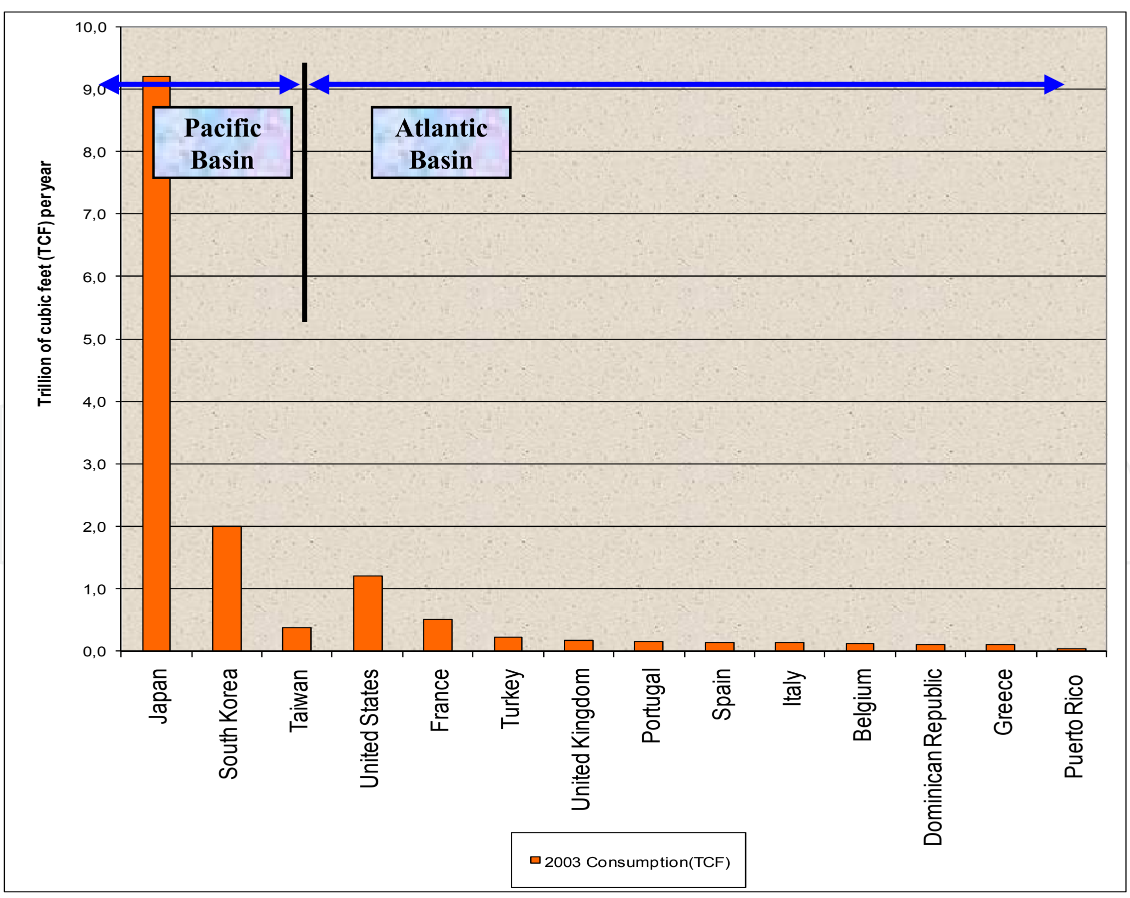

Fig. 3. World: LNG Consumers per Basin

Japan is the largest world consumer, importing around 48% of the world production, counts on 23 LNG regasification terminals, which represent 12% of the power and 95% of the natural gas used by the country. South Korea is the second largest world importers with 3 regasification terminals.
In the Atlantic basin, seven European countries share 28% of the world imports, including the European Union. In this set, the number rises to 32% of the global imports with 11 regasification terminals (Figure 2).

2. Analysis of the Production Costs in the LNG Chain

2.1 Liquefying

Along the last two decades, the specific cost (cost per unit of LNG produced) of the natural gas liquefying plants has significantly been reduced. This cost reduction was possible mainly owing to the technological improvement of the process and to the scale gains, obtained after the manufacturing of trains with greater capacity, but also in function of a greater competition among the companies acting in the liquefying plants design and construction.

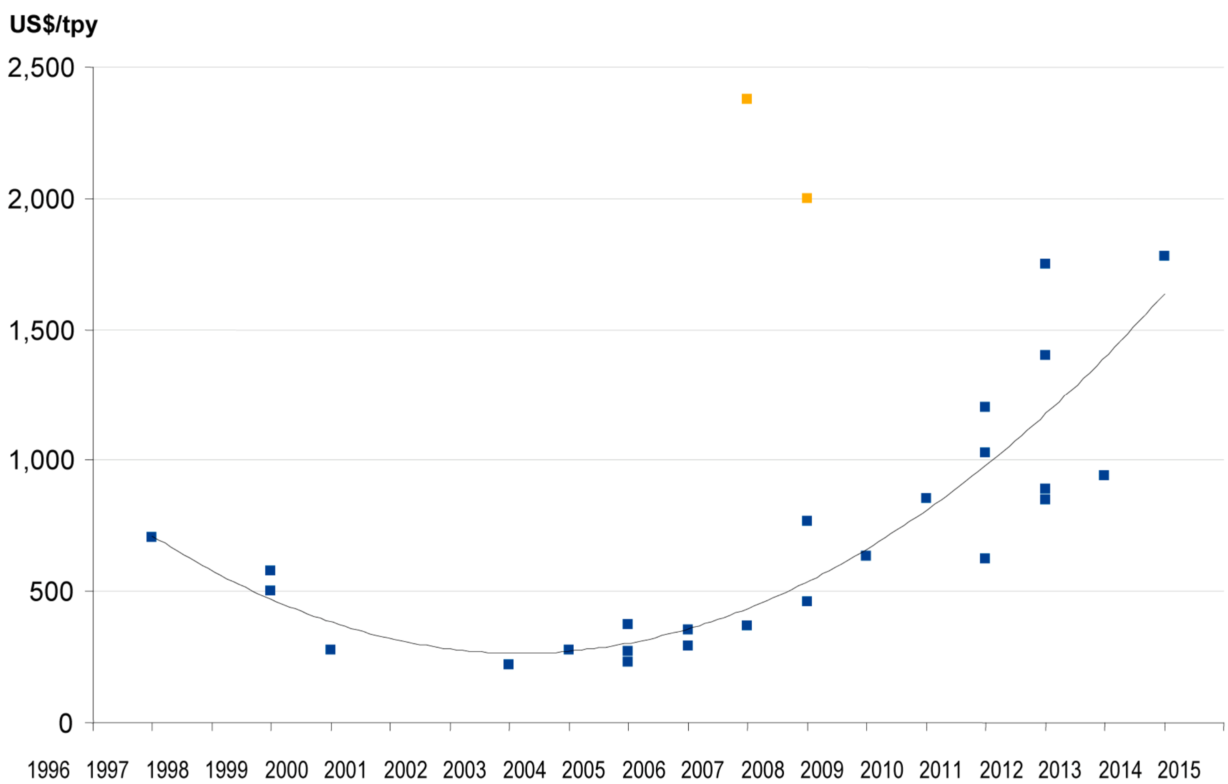

Fig. 4. Specific cost of the liquefying plants

While the first LNG producing plants, built in Algeria in the 1970s, counted on six liquefying trains to reach a capacity of 8 million tons of LNG per year (mtpa), the new projects for expanding the Qatargas and RasGas plants – the major LNG exporters in Qatar and two of the major in the world have about the same production level from a single train.

Since 1964, when the first liquefying plant started operating in Algeria with a single 1.1 mtpa train, the average size of the trains has increased along the years, reaching fourfold greater levels now.

Plant	Location	Started Operation	Capacity (millions of tons per year)	Estimated cost (billions of dollars)	Specific cost
Gladstone	Australia	2014	3.5	6.2	1780
Sunrise LNG	Australia	2013	5.0	4.7	940
Gassi Touil	Algeria	2012	4.0	7.0	1750
Brass LNG	Nigeria	2012	10.0	8.5	850
Soyo	Angola	2012	5.0	7.0	1400
Olokola	Nigeria	2012	11.0	9.8	891
South Pars	Iran	2011	10.0	12.0	1200
Gorgon	Australia	2011	16.0	19.2	1200
Qatargas 4	Qatar	2011	7.8	8.0	1026
Skikda	Algeria	2011	4.5	2.8	622
Pluto	Australia	2010	4.3	9.6	2233
P. Malchorita	Peru	2010	4.5	3.8	854
Qatargas 3	Qatar	2009	7.9	5.0	634
Sakhalin-2	Russia	2008	9.6	19.2	2000
Qatargas 2	Qatar	2008	15.6	12.0	769
NW Shelf T5	Australia	2008	4.4	2.0	460
Snohvit	Norway	2007	4.0	9.5	2375
EGLNG	Equatorial Guinea	2007	3.8	1.4	368
Rasgas 2T345	Qatar	2006	14.1	5.0	355
Darwin	Australia	2006	3.7	1.1	292
Atlantic LNG T4	Trinidad e Tobago	2005	5.2	1.2	231
Egyptian LNG1	Egypt	2005	3.6	1.4	375
Segas	Egypt	2005	4.8	1.3	271
Rasgas 2T3	Qatar	2004	4.7	1.3	277
MLNG Tiga	Malaysia	2004	6.8	1.5	221
Oman LNG	Oman	2003	7.3	2.0	274
NLNG 1-2	Nigeria	2000	6.6	3.8	576
Rasgas	Qatar	1999	6.6	3.3	500
Qatargas 1	Qatar	1997	9.9	7.0	707
MLNG Dua	Malaysia	1995	7.8	1.6	205

Table 4. Existing and planned gas liquefying projects

Despite the reduction in the LNG production costs observed in the last decades, recent contracts for building new liquefying plants have shown an inversion in this trend. Figure 4 shows the evolution in the capital cost per ton per year of some existing liquefying projects and under planning for the next years. The projects are listed in Table 4 further on.

Some factors have to be analyzed in order to understand the rising cost for building LNG plants observed since 2003. Firstly, in the last years, the global demand for energy has grown at record levels, partly due to the strong economic growth in China and in India, but also due to the development of other emerging markets – in which Brazil is included – and this growing demand has generated a world boom in the building sector for energy infrastructure. Moreover, few companies have expertise for LNG designs and, with so many enterprises under planning to start operating in five years, the costs for hiring these companies has significantly risen.

Another aspect is that of the labor costs and the raw material used in LNG designs, such as steel, cement and nickel, the prices of which have substantially and systematically risen in the foreign market along the years.

Some projects are particularly more expensive, most of the time for being located in regions in which there are difficulties to conduct works due to climate conditions, as is the case of the Snohvit projects in Norway and Sakhalin-2 in Russia. Both are located in regions of extreme cold, which implies greater design costs.

2.2 Shipping

After the natural gas liquefying process, large LNG Carrier Ships are filled and convey it to regasification plants, making the shipping by LNG Carrier Ships a crucial element for their flexibility in serving diversified markets all over the world.

The LNG commercial transportation started in 1964, taking LNG from Algeria to the United Kingdom, and since then, the LNG industry has substantially developed, presenting great reliability in terms of security, process technology and operational procedures.

The LNG transportation by LNG Carrier Ships represents from 10% to 30% of the total cost considering the chain from natural gas prospection up to the regasification in the import terminals. The value of the freight represents nearly 70% of the total LNG transportation cost, the rest being related to fuel price, insurance, among others, and the costs for building LNG Carrier Ships exert great influence on the total value for LNG transportation.

Despite the important representativity on the total costs of the LNG chain, shipping becomes more competitive in relation to gas pipelines since the distance run increases. Figure 5 presents a cost comparison between the transportation of natural gas via gas pipeline and the transportation by LNG Carrier Ships, in relation to the distance; it can be verified that the transportation of natural gas via LNG is more advantageous than by sea gas pipeline for distances longer than 700 miles and more advantageous than by land gas pipeline as from 2,200 miles.

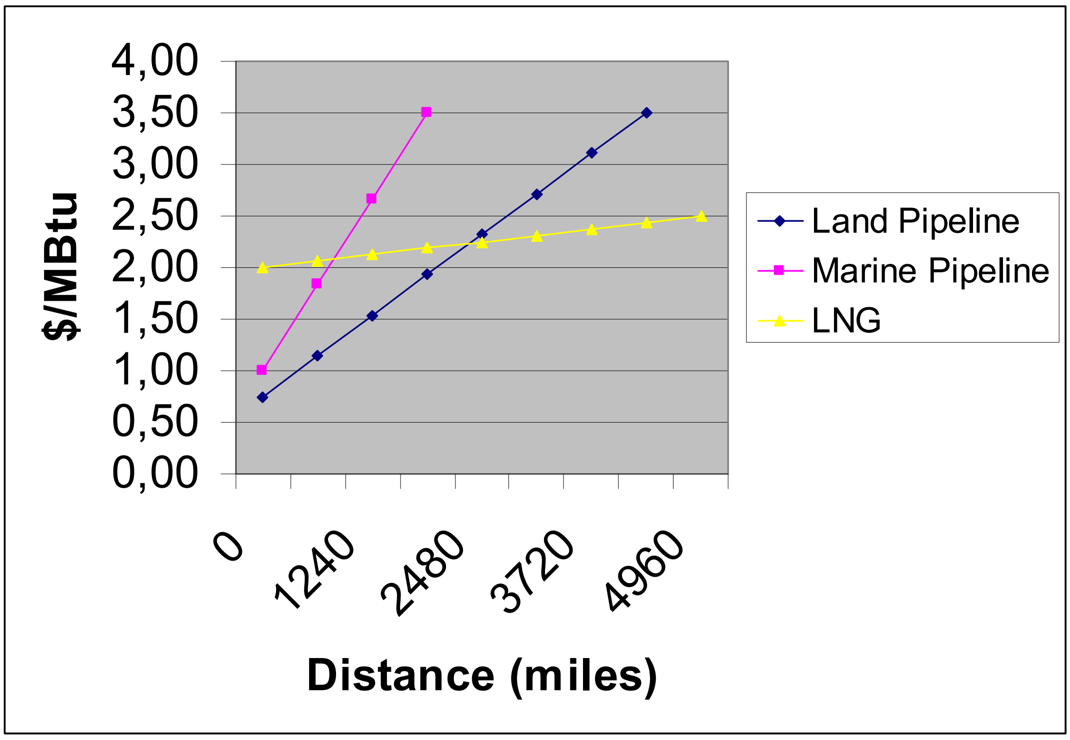

Fig. 5. Comparison between gas pipeline and LNG, in function of distance

In the 1990s, when the LNG industry started to grow more significantly, the number of shipyards with capacity to build LNG Carrier Ships grew and the competition between shipyards led to technological improvements and price reduction, aided by the devaluation of the Japanese and South-Korean currencies, major builders of these LNG Carrier Ships, as related to the American dollar.

However, in more recent years, with so many LNG projects under development, there has been a significant increase in demand for LNG Carrier Ships, leading to an increase in their price.

In the last decade, LNG production grew more than 50% all over the world. During this period, China and India started to import LNG, the United Kingdom resumed LNG imports after 40 years and other LNG markets, such as Spain, South Korea and Taiwan presented an expressive growth.

Due to this growing demand, the fleet of LNG conveying vessels grew from 130 in the early 2002 to about 250 in the late 2007, and by 2011, the number of LNG Carrier Ships may reach 380.

Figure 6 presents the number of LNG Carrier Ships delivered per year since 1993. Figure 7 shows the price evolution per capacity of these LNG Carrier Ships in the delivery year. The graphs show how the demand for LNG Carrier Ships is increasing and the combination of this increase and also the growing cost of raw material and labor led to a strong rise in LNG Carrier Ship prices.

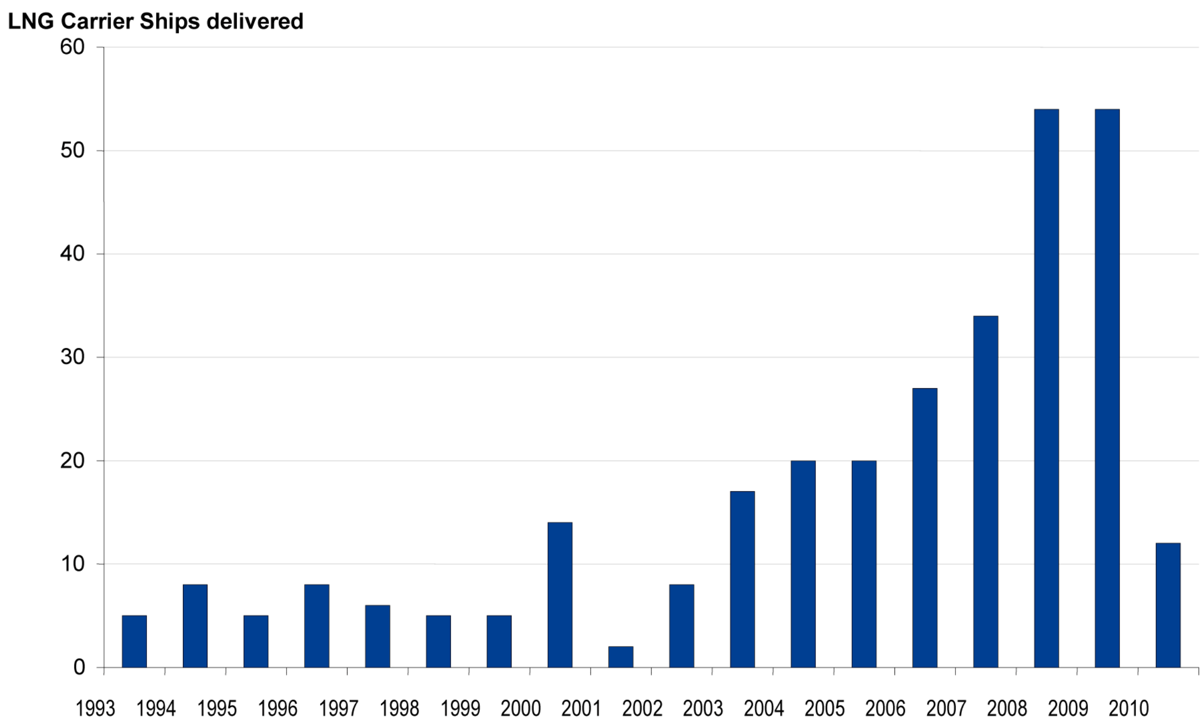

Fig. 6. Number of LNG Carrier Ships delivered

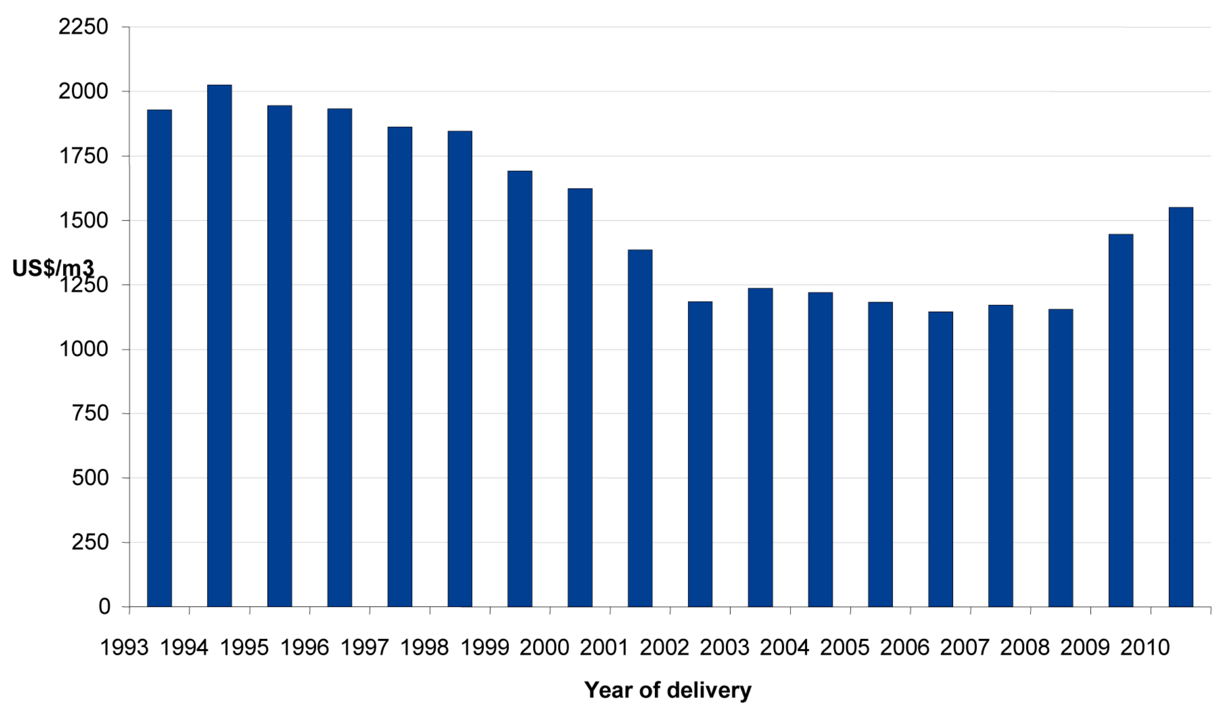

Fig. 7. average price per LNG Carrier Ship capacity

The standard size of the tanks has also changed along the years, in function of the growing demand for greater efficiency and cost reduction in LNG transportation, with scale gains. Whereas in the 1970s and 1980s the average capacity of the LNG Carrier Ships was 125,000 m^3, in the 1990s this average increased to almost 135,000 m^3 and is still growing.
The average capacity of the LNG Carrier Ships delivered in the last years was around 150,000 m^3, and there are at least 40 vessels with a capacity over 200,000 m^3. Figure 8 shows how the average capacity of the LNG Carrier Ships increased since the 1970s.

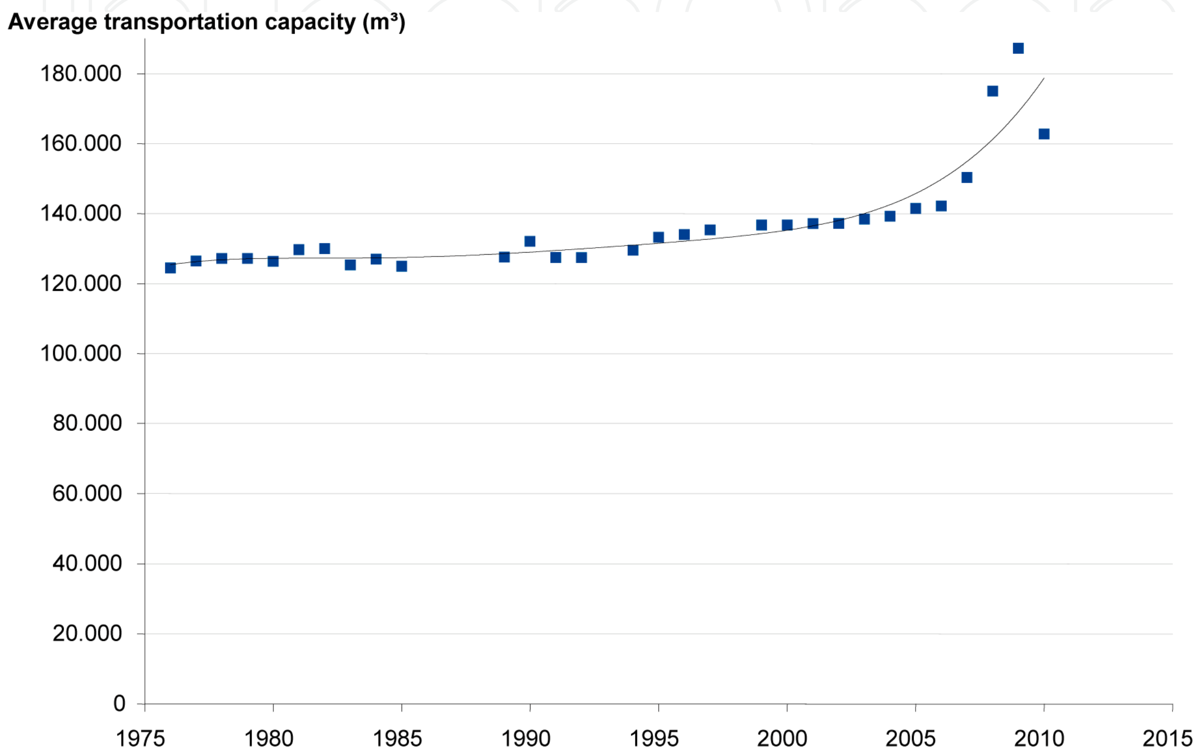

Fig. 8. Evolution in the average capacity of LNG Carrier Ships

Although there is a clear trend for increasing the LNG Carrier Ships capacity, some issues have to be considered to assess whether the LNG Carrier Ships size will keep growing. There is a limiting factor, since only some terminals are able to harbor vessels with capacity higher than 200,000 m^3. Hence, this increase in the number of large vessels may affect the design of new liquefying plants and regasification terminals.
Conversely, these new very large vessels are dedicated to specific projects, exerting their cost advantage with scale gains when sailing in regular routes, carrying regular LNG volumes. In the last years, the markets that have mostly grown are the ones of short and medium-terms, which use standard LNG Carrier Ships from 145,000 m^3 to 160,000 m^3.

2.3 Regasification

Regasification is the final process in the LNG chain, when it is unloaded from the LNG Carrier Ships, reheated and again transformed into gas. By the end of the 1990s, 75% of the LNG regasification capacity was found in Asia, mainly in Japan, where the LNG industry developed early owing to the limited access to gas pipelines and the lack of other local natural resources. However, in the last years, LNG imports have grown especially in Europe and in North America.

Since 2000, most of the LNG new import terminals projects were built in Europe, where the dropping North Sea reserves, the high production costs and liberalization of the power and natural gas markets generated new opportunities for LNG. There are now more than 100 new regasification terminals or expansion projects to start operating in the next years in the world, as a response to the increase in the demand for LNG, and at least 70 of these are in Europe or North America. According to Table 5, only 16% of the new regasification projects will be built in Asia.

	Europe	Asia	America (Atlantic)	America (Pacific)
2000	15%	75%	11%	0%
2000 to 2007	45%	37%	19%	0%
2007 -	30%	16%	47%	8%

Table 5. Regasification capacity in different periods

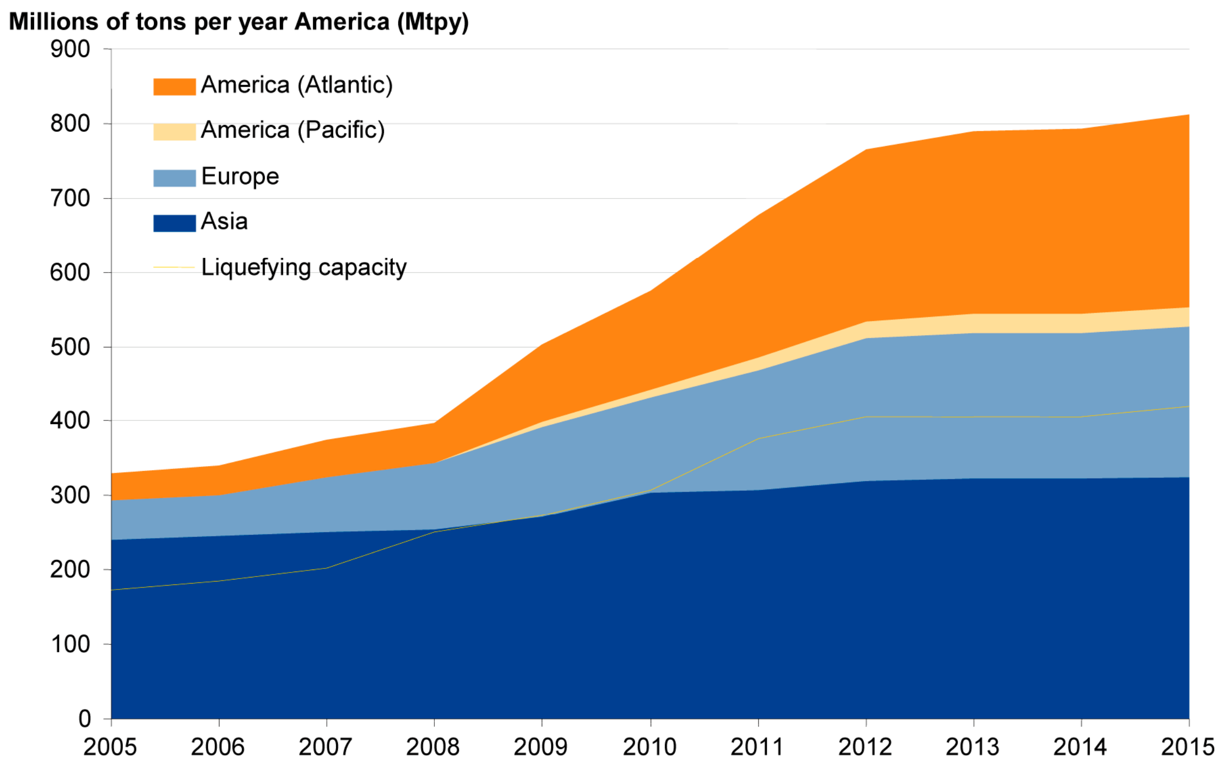

Fig. 9. Expected liquefying and regasification capacity

Figure 9 shows that the new terminals will substantially increase the global regasification capacity that will keep growing until it reaches 800 mtpa in 2015. The graph also shows how the regasification capacity operates with low use rate; it can absorb practically twice the total LNG produced and is growing faster than the liquefying capacity. This disparity reflects a smaller cost as compared to the other segments in its production chain.

The costs for building regasification terminals are very specific for each project, depending on several factors, such as location, cost of the land, type and number of storage tanks, harbor infrastructure, among others. Thus, the costs for building these terminals present great variation and do not follow any trend along the years, as shown in Figure 10.

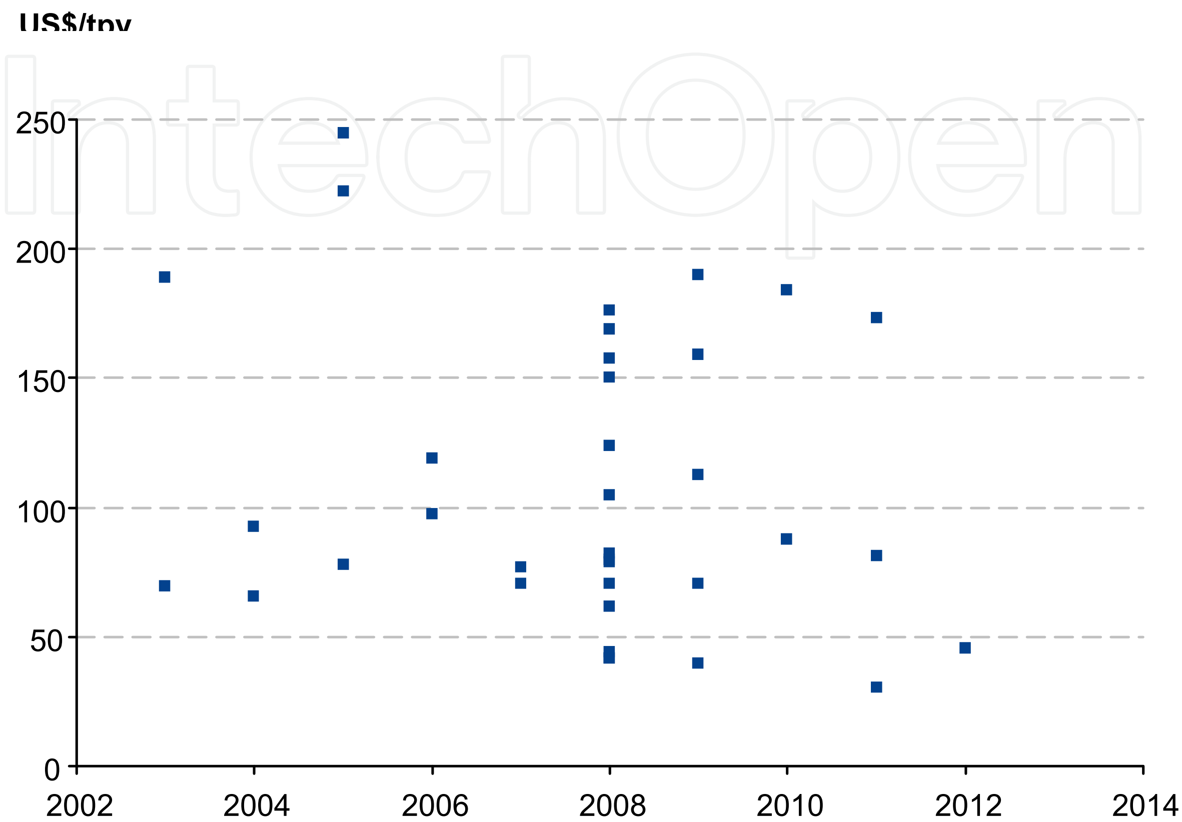

Fig. 10. Specific cost for building regasification terminals

2.4 Investments at each stage of the LNG production chain

Projects in the LNG area require heavy investments and the capital invested at each stage of the production chain may vary significantly. The information found in the media is usually sparse; hence, concrete data and specific details of contracts are difficult to obtain. It is possible, however, to estimate an average of the costs per unit at each stage of the chain in a period.

Figure 11 presents how the costs are divided at each stage, from natural gas prospection to LNG regasification for the projects that started operating recently and for those that are to start operating by 2011. From 2002 to 2007, the gas liquefying process showed to be more expensive, accounting for 44% of the total cost. This fact represents an expressive increase in the chain total cost for the next years, seeing the growing costs of the liquefying plants. The graph also shows that in the period analyzed, the average costs of gas exploration did not suffer great alterations and regasification has a smaller impact on the LNG chain total cost.

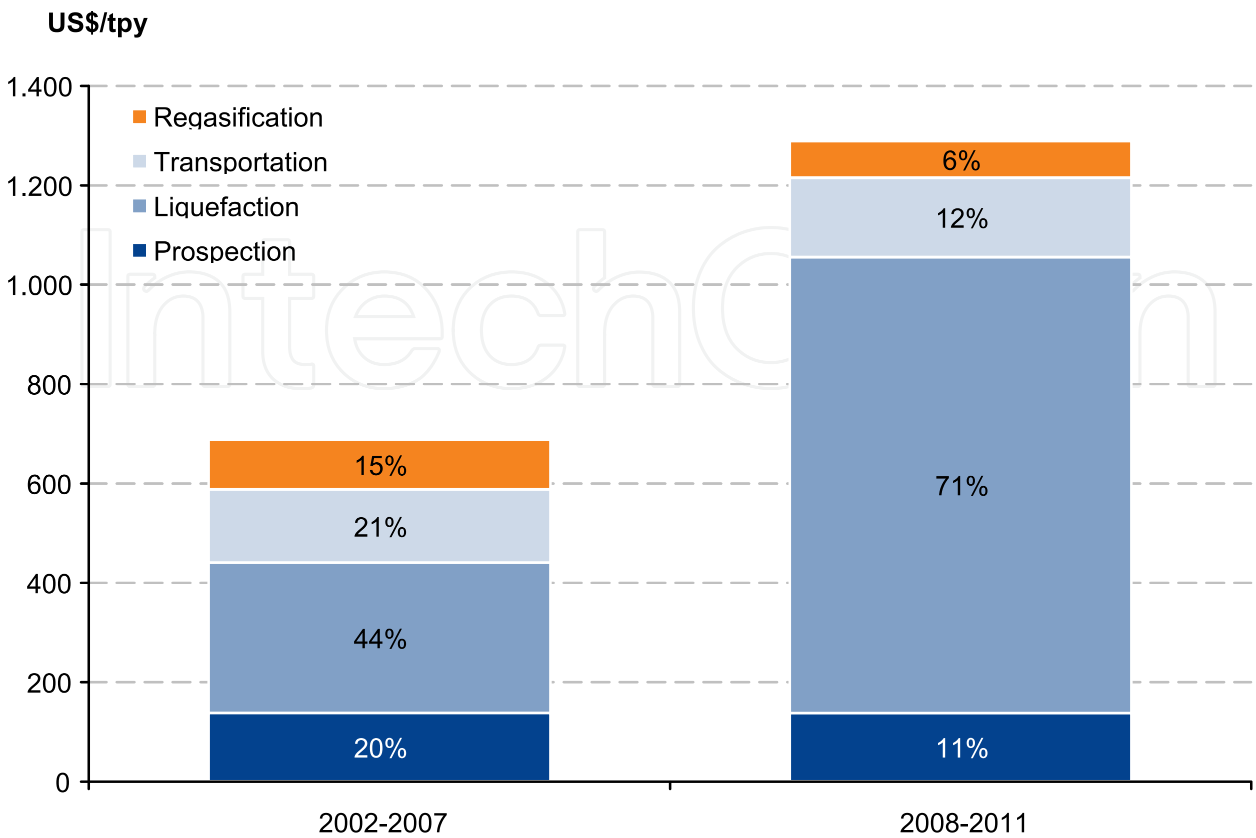

Fig. 11. Average cost per unit of the production chain in different periods

3. Perspectives for LNG in Brazil

3.1 Natural Gas Context

Today the gas volume available is of about 65.5 MMm^3 a day; 30 MMm^3 come from Bolivia, 21.5 MMm^3 from the Southeast and 14 MMm^3 the Northeast. The gas produced in Brazil comes mainly from off-shore platforms (61%), from depths varying between zero and 300m (33%), 1500m (62%) and only a small parcel from depths greater than 1500m (5%). Brazil presents three main and independent production and transportation networks, depicted in Figure 12: one in the North region, one in Northeast region and one in the South cone (S-SE-CO). The South cone network connects Southeast Center-West and South States, and the Northeast network connects the Northeast States from Ceará to Bahia. These two networks will be connected by Gasene, foreseen for the first half of 2010.

The Petrobras main expansion programs to supply natural gas are Plangas, mainly destined to the industrial market in the Southeast and TC - Term of Agreement – a program based mainly on LNG and guided towards thermoelectric consumption.

Fig. 12. Natural Gas Networks in Brazil

The expansion of supply in the short-term occurs mainly with the natural gas from the Espírito Santo Basin and in medium and long-term, the gas used comes from the Santos Basin.

3.2 Recent History

Even though natural gas thermal generation has been stimulated by the government since 2000, by the PPT (Priority Program for Thermoelectric Plants), aiming at the consumption of large volumes for paying the take-or-pay (contracting modality in which, in case the consumption is smaller than the volume contracted, the contracted value is paid; in case it is higher, the measured volume is paid) of the Bolivian gas, the investments foreseen did not materialize. This occurred owing to indefinition in the trading rules and to uncertainties concerning the natural gas price or even the very conception of the Plan.

As a result, Petrobras stimulated the consumption of natural gas in the industrial and transportation sectors. This policy worked very well and, coupled with the rise in petroleum byproduct prices and environmental constraints, resulted in a growth from 10 to 20% per year in gas consumption in Brazil. This growth even affected the operations of natural gas thermoelectric plants which, due to the lack of fuel, started failing to deliver the whole power expected when called to operate.

In April 2005, there was a reduction of 2300 MW on average in the importation coming from Argentina and the Uruguaiana Thermoelectric Plant for unavailability of fuel to meet the demand for power generation. In the late 2006, the National System Operator - ONS conducted availability tests of natural gas thermoelectric plants, which resulted in a cut of 2700 MW on average in the power supply in the South and Southeast regions. Besides, in 2007 Bolivia interrupted the gas supply for the Cuiabá Thermoelectric Plant, resulting in an additional cut of 200 MW on average.

These cuts in availability of power generation by the thermoelectric plants for lack of natural gas caused a structural unbalance in the power supply and demand, leading to a greater dependence on the electric system in relation to the hydrologic regime. As a consequence, Petrobras was forced to sign a Term of Agreement (TC) with ANEEL. The TC was signed to cover the present deficit and is a fixed commitment, subject to penalties. Besides, it contemplates LNG implementation.

3.2.1 Term of Agreement

Insufficient investments to follow the demand for natural gas in the industry and the growing yield of thermoelectric plants composed the present scenario of gas rationing risk. As early as 2005, a gas supply deficit from 20 to 30 MMm^3 per day was verified; the crisis was not anticipated only due to a smaller consumption of gas by the thermoelectric plants (7.1 MMm^3 a day).

In order to have knowledge on the real consumption and generation capacity of the natural gas thermoelectric plants, ANEEL asked the National System Operator (ONS) to conduct availability tests in the 2004 to 2006 thermal generation. In 2004, all the natural gas thermoelectric plants in the Northeast participating in the Thermoelectric Priority Program (PPT) were summoned. The yield registered by ONS observed availability lower than that verified by ANEEL in about 757 MW on average. This deficit led to the signature of the Reserve Recomposition Agreement approved by the ANEEL instruction 1.090/2004.

In December 2006, ANEEL asked ONS to test the natural gas thermoelectric plants. This time the thermoelectric plants of the South-Southeast were called, and effective availability also inferior to that verified by ANEEL was observed, resulting in a cut of reserves of about 2,700 MW on average.

As from these tests results, the Term of Agreement (TC) was signed between Petrobras and ANEEL. In it, Petrobras committed to make natural gas available for thermoelectric plants in the South, Southeast and Northeast, according to a previously established schedule, to be concluded by 2011. Table 6 presents the schedule in which the infrastructure events associated to the evolution in availability of simultaneous generation in the NG thermoelectric plants considered in the TC are listed.

Nº	Subsystem	Events	Mark
1	SE/CW	Increase in the ES production and gas pipeline	1st half 2008
2	SE/CW	LNG in SE (Rio de Janeiro)	1st half 2009
3	SE/CW	GASBEL	2nd half 2009
4	NE	Backup Hiring	2nd half 2007
5	NE	LNG in NE (Pecém)	April 2008
6	NE	Interconnection works (Southern NE and Northern NE)	2nd half 2008
7	NE	GASENE	1st half 2009
8	S	Additional compression in the Paulinia-Araucaria gas pipeline	1st half 2008
9	S-SE/CW	NG from South to Southeast	1st half 2008

Table 6. Schedule of events in the TC

Nevertheless, in 2007 there was gas unavailability for the thermoelectric plants which resulted in an ANEEL penalty of R$ 84 million to Petrobras and in the temporary reduction in the gas supply for the utilities in October 2007. The utilities most affected by the reduction were CEG in the State of Rio de Janeiro and COMGAS in the State of São Paulo; the supply was re-established by a temporary restraining order.
Owing to the risk of natural gas scarcity, in 2006, Petrobras announced the Natural Gas Production Anticipation Plan (Plangas). The plan includes expansion projects in all the natural gas supply stages, from production distribution by gas pipelines.

3.2.2 Plangas

Before approaching the expansion plan schedule, it is worth explaining that the natural gas production has three main stages:

- Exploration and Production (E&P): stage at which the removal of the natural gas from the reservoirs is considered;
- Processing: gas treatment in the so-called UPNG (Natural Gas Processing Units) where liquids and impurities are removed so as to deliver the gas within the composition standards provided by the Brazilian Petroleum Agency (ANP) law;
- Transportation: stage at which the natural gas transportation by pipelines is considered.

Plangas was divided into two stages. At the first stage, natural gas availability in the Southeast had an increment of 24.2 MMm^3 per day. At the second stage, more than 15 MMm^3 per day were made available, totaling an increment of 39.2 MMm^3 per day for the Plangas.
The discovery of new fields (São Mateus, Juruá-Araracanga and Jaraqui) in the North region, will meet the increase in demand and the fall in the Urucu field production. This gas has been available for Manaus from 2009, with the completion of the works in the Coari-Manaus gas pipeline.
In 2008, the arrival of LNG in Pecém in the Northeast accounted for a large part of the addition in gas supply. The gas pipelines network in this region is also in expansion and was recently connected to the Southeast network through the Cacimbas-Catu gas pipeline, a

GASENE branch. The recent increase in gas availability for the Northeast was caused by the beginning of operations in the Manati field, in Bahia.
Still viewing the expansion in the Brazilian natural gas production, Petrobras conducts investments in the Santos Basin. The short-term production expectations in the Santos Basin are 30 MMm^3 per day of natural gas, with excellent perspectives for continuous growth, mainly after the finding of the of the Tupi and Júpiter mega-fields with an estimated reserve of 5 to 8 billion barrels of petroleum equivalent and, more recently, the announcement of the finding of field BM-S-9, known as Carioca, with an estimated reserve of 33 billion barrels of petroleum equivalent.
Besides the distance of these new fields from the Brazilian coast, another great difficulty of these recent findings is the thickness of the water blade and well depth – the sum of the parts results in total depths of over 5,000 meters. This is because the E&P cost considerably increases with the depth of the fields due to the need of using more resistant materials and more adequate to the pre-salt environment, as presented in Figure 13. Hence, the exploration of these wells is only viable and attractive with the increase in the petroleum barrel price.

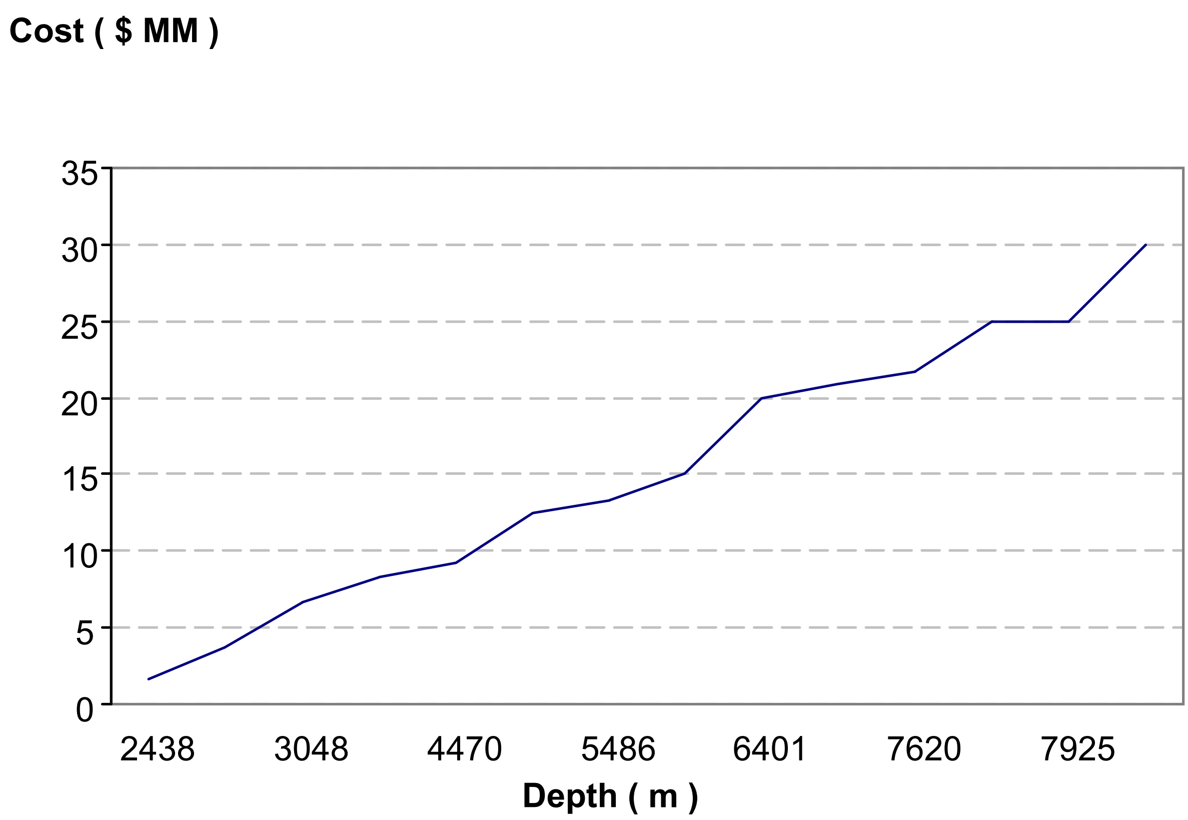

Fig. 13. E&P Cost x Depth (Source: British Petroleum)

4. Market Opportunity for LNG in Brazil

4.1 The need of flexibility for the Brazilian natural gas market and its relation with LNG

Albeit incipient, the Brazilian natural gas industry needs great flexibility. In the 1990s, the conduction of liberalizing reforms changed the economic context in Brazil, causing the industrial organization and the contracts traditionally used in the incipient stage of the natural gas industry not be the best instruments to reduce the investments risks in relation to the infrastructure of this industry. The present context derives from different factors that transformed the basic conditions of the Brazilian natural gas industry, such as: liberalization of the prices of fuels competing with natural gas; exhaustion of the developmentist model of traditional financing by the public sector and foreign credits to state companies; partial privatization of power companies; formation of large international groups capable of competing in the world market, as from the privatization process and the introduction of competition in the power industry and natural gas sector in the developed countries; regional energy integration, also in the natural gas industry; technological evolution, growing technological and business convergence in the power sector and in the natural gas industry.

In the present economic context, the prices of fuels competing with natural gas are given in a liberalized market environment. Therefore, these prices present greater volatility, varying according to the international market, climate conditions and the demand in the Brazilian power sector. As a consequence, the value of natural gas has undergone more changes more often, and a greater flexibility is necessary in the natural gas industry for the gas price to vary, aiming to keep its competitivity with the competing fuels.

An important factor that also contributed to the need of flexibility in the Brazilian natural gas industry is the one related to its power sector. Power generation in Brazil is basically conducted by the hydropower plants, generating about 80% of the Brazilian electric power. The hydropower plants have an installed capacity for generating 77.4 GW, which corresponds to 70.2% of the total power generated. In turn, the thermoelectric plants have an installed capacity of 24.7 GW, 11.8 GW of which from gas thermoelectric plants. This respectively represents 22.4% and 10.7% of the whole supply of domestic capacity for power generation in the country.

Besides the installed capacity, the Brazilian hydropower plants also have large reservoirs, the water storage capacity of which is among the greatest in the world. This great storage capacity allows stocking water, increasing hydropower plants generation capacity and power is generated at very low costs for practically the whole of its market in abundant rain periods. Thanks to the reservoirs system, to the country geographical size and to the interconnection of the Brazilian power system, even if one region in the country is undergoing a period of low rain, another region with abundant rains and full reservoirs may see to the power demand of the of the “dry” region, thus creating a compensation mechanism among the hydropower plants in Brazil and minimizing the risk caused by the lack of rains. As a consequence of this characteristic of the Brazilian power sector, the economic value of natural gas destined to power generation in abundant rain periods is drastically reduced, and may fall to zero.

Despite the important role of the hydropower plants at the base of the Brazilian power generation, the thermoelectric plants have a complementary role, yet fundamental, of guaranteeing a greater security to the national generation system, diversifying the energy source. The yield of these thermoelectric plants depends on variations in the rain regime and on demand peaks. This way, traditional instruments used in the natural gas industry, such as long-term contracts with take-or-pay clauses, would not be adequate to the natural gas thermoelectric plants in Brazil, which need greater flexibility.

The Brazilian natural gas industry does not have flexibility, despite the great need. On the demand side, only as from 2007 did Petrobras provide the possibility of signing interruptible natural gas contracts, yet there is not a secondary market for this input. Predominantly the gas supply contracts used are long-term and have take-or-pay clauses. On the supply side, the existing flexibility is very small, owing to the specificities of the Brazilian natural gas industry, such as: the lack of natural gas storage capacity out of the transportation network; the fact that 75% of the domestic production of this gas is associated, making a variation in gas production aiming at greater flexibility also affect petroleum production; since practically the whole domestic natural gas production derives from off-shore reservoirs there is, therefore, a high development opportunity cost of these gas fields; the on-shore Brazilian natural gas production lies basically in the isolated system of Amazon, and cannot meet the needs of flexibility in the Northeast and Centro-Southeast-South regions and, finally, since Brazil already uses practically the whole total transportation capacity of the Gasbol, there is little surplus capacity to conduct an increase in supply to meet the need of flexibility of the Brazilian natural gas industry.
In this context, opportunities for LNG are identified in in Brazil, in the sense of diversifying the power supply sources while allowing greater supply flexibility for the natural gas industry and for the electric power sector

4.2 The LNG importation project by Petrobras

Since the late 1990s, LNG has been the object of studies for Petrobras, as an alternative to complement the natural gas supply in Brazil. In 2004, Petrobras started studies to import this input flexibly, in order to adapt the supply to the volatile demand of the gas thermoelectric plants. This natural gas import alternative gained momentum after the nationalization of natural gas in Bolivia in May 2006, when a greater uncertainty scenario concerning the future supply of this gas was generated. Therefore, due to the expected growth in domestic demand for natural gas and the risk of the country not being able to meet it with greater flexibility, the Ministry of Mines and Energy (MME), together with the Petrobras projects, in its Resolution nº 4 of November 21, 2006, established the option of using LNG as a way of meeting such needs, as presented below:
"Article 1 - Declaring a priority and an emergence the implementation of Liquefied Natural Gas – LNG Projects, consisting in the importation of natural gas in cryogenic form, storage and regasification, as well as the necessary infrastructure, aiming to:

I - Ensure the availability of natural gas for the domestic market viewing to prioritize the supply to thermoelectric plants;
II - facilitate the adjustment in the natural gas supply to the characteristics of the domestic market through flexible supply;
III - mitigate risks of failure in the natural gas supply due to hazards;
IV - diversify the imported natural gas supply sources; and
V - reduce the implementation deadline of the Natural Gas Supply Projects.

Article 2 – Aiming at the full conduction of the activities provided in Article 1, the implementation of mechanisms for abiding by this Resolution is assured, as well as the articulation of the institutional means to overcome possible problems in the implementation of LNG projects."

As can be seen in Figure 14 below, Petrobras expects the Brazilian natural gas demand to grow nearly 90% between 2007 and 2012 (a greater value than that considered by EPE in the Decennial Plan 2007/2016). To meet this growth in demand, the state company intends to increase its national production to nearly 73 million m³/day, use the maximum capacity of Gasbol and import 31.1 million m³/day of LNG. The main reasons that led Petrobras to opt for the use of LNG as an instrument to complement the Brazilian natural gas supply are its smaller implementation time and smaller fixed cost as related to other options, such as the development of new natural gas fields and the construction of new gas pipelines for importing this gas; the diversification in the natural gas supply; and the possibility of purchasing LNG through short or long-term, fixed or flexible contracts.

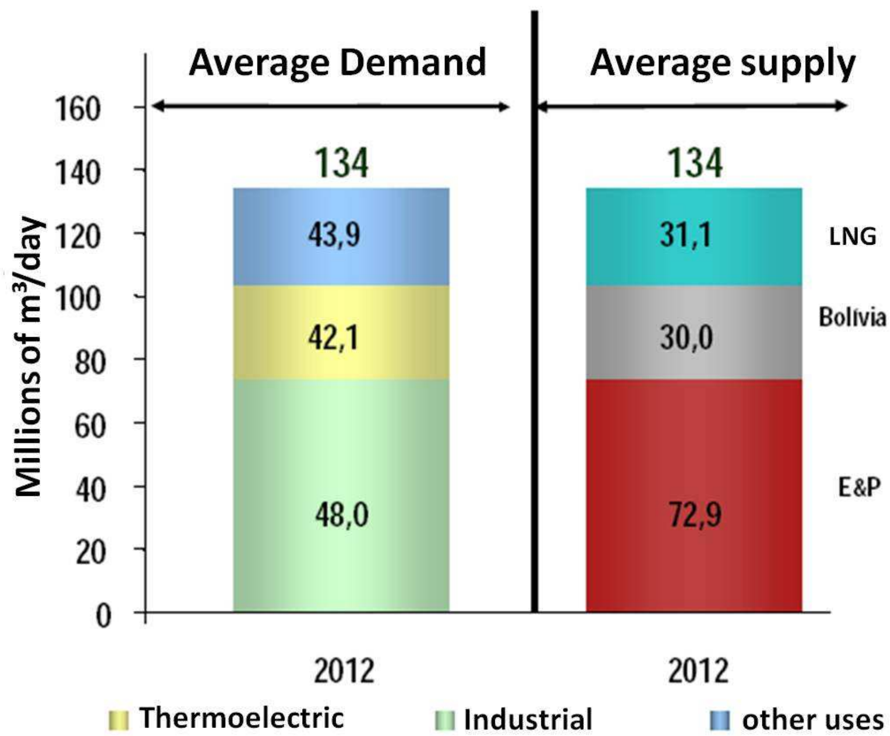

Fig. 14. Expectation of Natural Gas Supply and Demand in Brazil in 2012.

In the late 2007, the Petrobras LNG importation project foresaw investments in infrastructure of about US$ 152 million, for building two flexible LNG regasification terminals, located in the Guanabara Bay (US$ 112 million), in Rio de Janeiro and in Pecém, in Ceará (US$ 40 million). Besides these two terminals, Petrobras also studied four more projects for LNG flexible terminals, located in Suape (PE), São Francisco (SC), Aratu (BA) and São Luis (MA).
The Pecém terminal was inaugurated in August 20, 2008 at a total cost of R$ 380 million, which includes the pier adaptation and the construction of a 22.5 km gas pipeline. The terminal, operated by Transpetro – a Petrobras logistics company – has the capacity to regasify 7 million cubic meters a day, the equivalent to about half of the present consumption of natural gas guided towards the Brazilian thermal market and a 129,000 m³ storage capacity. The Guanabara Bay terminal, in turn, has the capacity to regasify 14 million cubic meters a day and store 138,000 m³. The regasification at the two terminals is

conducted in LNG Carrier Ships, which are used for storage, too. Petrobras contracted the Golar Spirit (Pecém) and Golar Winter (Guanabara Bay) vessels of the Norwegian company Golar LNG at a total cost of US$ 900 million for 10 years, already including operational expenses.

In order to obtain the LNG supply, Petrobras signed a Master Agreement (intent agreement) for importing this commodity with the companies Nigerian LNG, from Nigeria, and Sonatrach, from Algeria. This agreement foresees purchases in the LNG market spot without fixed volume and price based on the natural gas quotation at Henry Hub[2] at the moment of purchase. Petrobras also signed a confidentiality agreement with Oman LNG for negotiating a potential LNG supply, besides negotiating with other vendors. According to Petrobras, the travelling time for LNG to reach Brazil, after the purchase is conducted in the market spot, would be of at most 18 days, depending on the origin. Table 7Table presents the estimated travelling time for LNG to arrive in Brazil.

Destination (simple trip - 19 knots)	Nigeria (Bonny)	Algeria (Skikda)	Algeria (Arzew)	Trinidad & Tobago (Point Fortin)	Qatar (Ras Laffan)
Baia de Guanabara (RJ)	7d 10h	10d 12h	9d 18h	6d 20h	17d 21h
Pecém (CE)	6d 4h	7d 23h	7d 5h	3d 15h	17d 12h

Table 7. travelling time for LNG to reach Brazil

Petrobras means to import LNG so that there is a flexible natural gas supply source, directed to meet mainly the thermoelectric plants demand. It intends to purchase LNG in the market spot and pass it on to the thermoelectric plants according to their needs. The hiring modality of this natural gas with the thermoelectric plants will be of "preferential supply". In this new modality, the consumer (in this case, thermoelectric plants) has the prerogative of interrupting supply, which is interruptible only by the client, being the supplier obliged to provide the supply of gas available when demanded. The gas price in this contract will be composed of two parcels: one concerning the remuneration of investments in infrastructure of the gas transportation (capacity) and the other concerning energy, which will depend on the value of natural gas at Henry Hub. Moreover, the contract will provide the antecedence and the nomination conditions of the gas.

The yield of the thermoelectric plants is determined by the National Power System Operator (ONS), which seeks to optimize the Brazilian power generation, so as to minimize the system operation cost, taking into consideration, among other variables, the level of water storage in the reservoirs of the interlinked system, the occurrence of rains, the fuel costs and the demand for power. Hence, the thermoelectric plants only operate when there is not enough water for the hydropower plants or when it is convenient to reduce hydropower production to save the water in the reservoirs. It is worth noting that the period in which rains are less abundant in Brazil, causing a lower water level in the reservoirs, goes from May to October, which corresponds with the period in which the cold countries of the North hemisphere are experiencing their hottest seasons. Thus, during the dry period in Brazil, the world demand for LNG tends to be reduced, also resulting in a lower price of this

2 Point in the transportation network of the American State of Louisiana, where there is an interconnection of 9 interstate and 4 inner state gas ducts. The prices negotiated at this point are a reference for the spot and future market prices.

commodity at Henry Hub. Therefore, Petrobras will probably conduct most of its LNG purchases in the lower prices period, reducing the cost of generating power with LNG.
It also is worth stressing that, according to Administrative Rule nº 253 of September 2007, of the Ministry of Mines and Energy, the ONS will give instruction notice to the thermoelectric plants that use re-gasified natural gas, two months prior to its effective instruction. This deadline respects the LNG supply logistics, allowing Petrobras to import LNG in market spot, with enough time to meet the demand of the thermoelectric plants.

4.3 Risks associated to market spot

As seen in the previous sections, the natural gas industry in Brazil has little flexibility and Petrobras, for some years, has been studying LNG projects aiming to meet the growing national demand for gas, and also allowing a greater flexibility to see to the fluctuations of this demand, especially concerning thermoelectric generation. As stated before, the "preferential" contract modality will allow Petrobras to offer the thermoelectric plants the flexibility obtained in the LNG market spot.
Nonetheless, although the LNG market spot offers a flexibilized supply of natural gas to Petrobras, it also presents greater price risks, once the spot contracts of the Atlantic basin, in which Brazil lies, are based on the Henry Hub quotation, which is highly volatile, as can be seen in Figure 15 below.

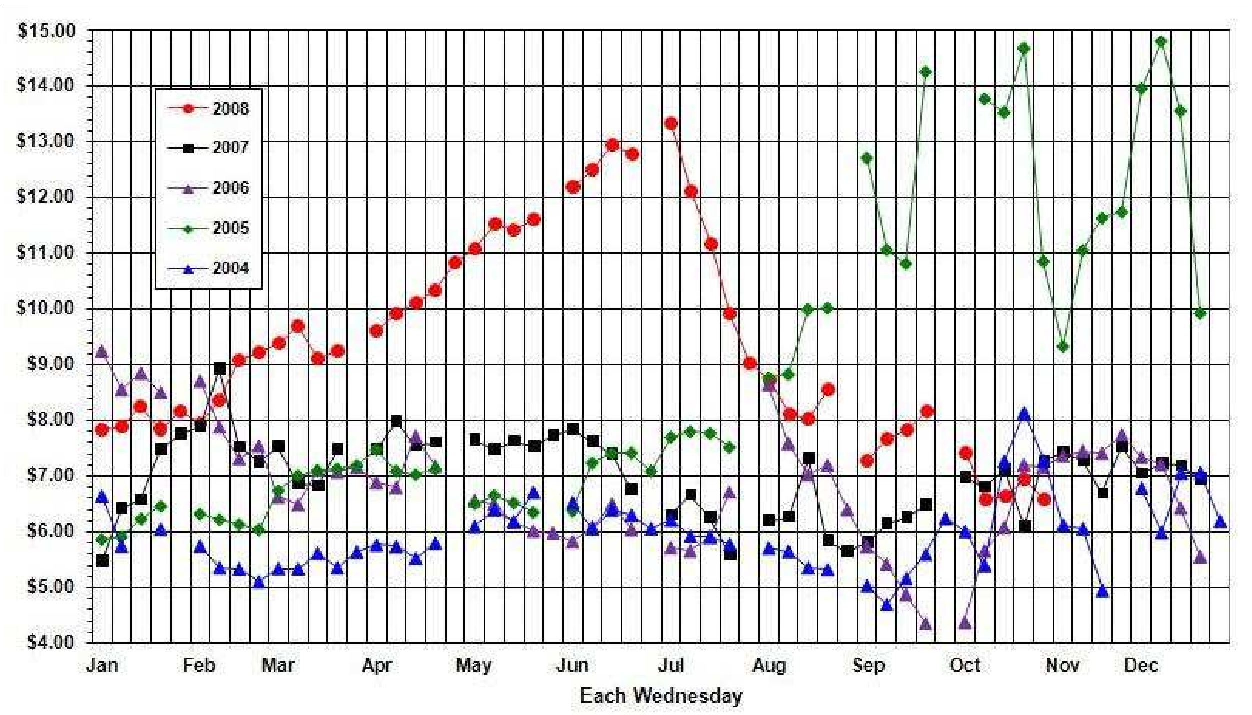

Fig. 15. Spot price of natural gas in Henry Hub in US$/MMBtu

Such a fact generates uncertainty in relation to the future price of LNG paid by Petrobras, making the natural gas Brazilian industry be influenced by events in the American market. Besides, this uncertainty may influence investments in the national gas industry which uses LNG as a basic input, due to the difficulty in foreseeing future prices of this input and, consequently, its use economic viability.

The purchase of LNG only in the market spot also has risks concerning the volume available, generating uncertainties as to its future supply. Albeit growing, the LNG market spot is still incipient, accounting for only 13% of the total. Thus, if there are any contingency in LNG supply, its sellers prioritize meeting the obligations provided in their fixed and long-term contracts, leaving the market spot aside. A way of mitigating this risk would be storing LNG, so as to use it in a high-price period and purchasing when prices were lower. However, Brazil does not count on storage infrastructure out of the transportation network, already reduced.

Today, as a way of reducing the uncertainty generated by the price and volume risks of purchasing LNG in the market spot, the Brazilian natural gas industry counts on the possibility of conducting a combination between the purchase of this commodity by means of spot contracts and of strict long-term contracts. Hence, the guarantee of supplying LNG with a price already determined in a strict long-term contract would reduce the uncertainty generated by the risks of purchasing LNG in the market spot. In turn, the LNG purchases in the market spot would reduce the uncertainty deriving from a strict long-term contract.

5. About GTL Production with Natural Gas from Bolivia

Bolivia intends to industrialize natural gas in different ways; one of them is the conversion to liquid process (especially diesel), also known as Gas To Liquids (GTL) process, which is based on obtaining syngas by the Fischer Tropsch method (F-T). The conversion efficiency is of the order of 60% but it is foreseen to reach up to 70%.

Today presenting a small energy industry based on natural gas and practically no project of massive use of this resource, the implementation of this project and other large-scale ones is a huge challenge for Bolivia allowing, by the implementation of a GTL-FT project, generating added value for the natural gas reserves and allowing access to scale economies.

5.1 Technical Specificities of the Bolivian Natural Gas

The major characteristics of natural gas in Bolivia are non-associated gas and very rich in methane, making the exploitation and use of this resource very attractive. Table 8 details the Bolivian natural gas composition.

Main components	Chemical formula	Percentile in volume (*) [%]
Methane	CH4	89.10
Ethane	C2H6	5.83
Propane	C3H8	1.88
Butanes	C4H10	0.74
Pentates	C5H12	0.23
Hexanes	C6H14	0.11

Table 8. Chemical composition of the Bolivian natural gas

5.2 Natural Gas Petrochemistry

The hydrocarbons that come with methane in Natural Gas, such as ethane, propane and butane (n-butane and iso-butane), could be applied in byproduct production, by means of a traditional petrochemical plant, because this industry uses, among others, the same hydrocarbons above; however, those are obtained in the extraction of crude oil (the condensed propane and butane are generically named LPG, "Liquefied Petroleum Gas"), which is distributed in steel containers for residential consumption. Figure 3 presents a summarized diagram with the processes and some of the products associated to the traditional petrochemical industry of crude oil refinement.

Particularly, the area within the dotted line in Figure 16 is associated to petrochemistry (gas-chemistry), based specially on the transformation of ethane, propane and butane deriving from crude oil refinement, in a process called "steam cracking". This process allows obtaining oils, such as ethylene and propylene, from which it is possible to get, for example, polypropylene and polyethylene, highly used and known plastic materials.

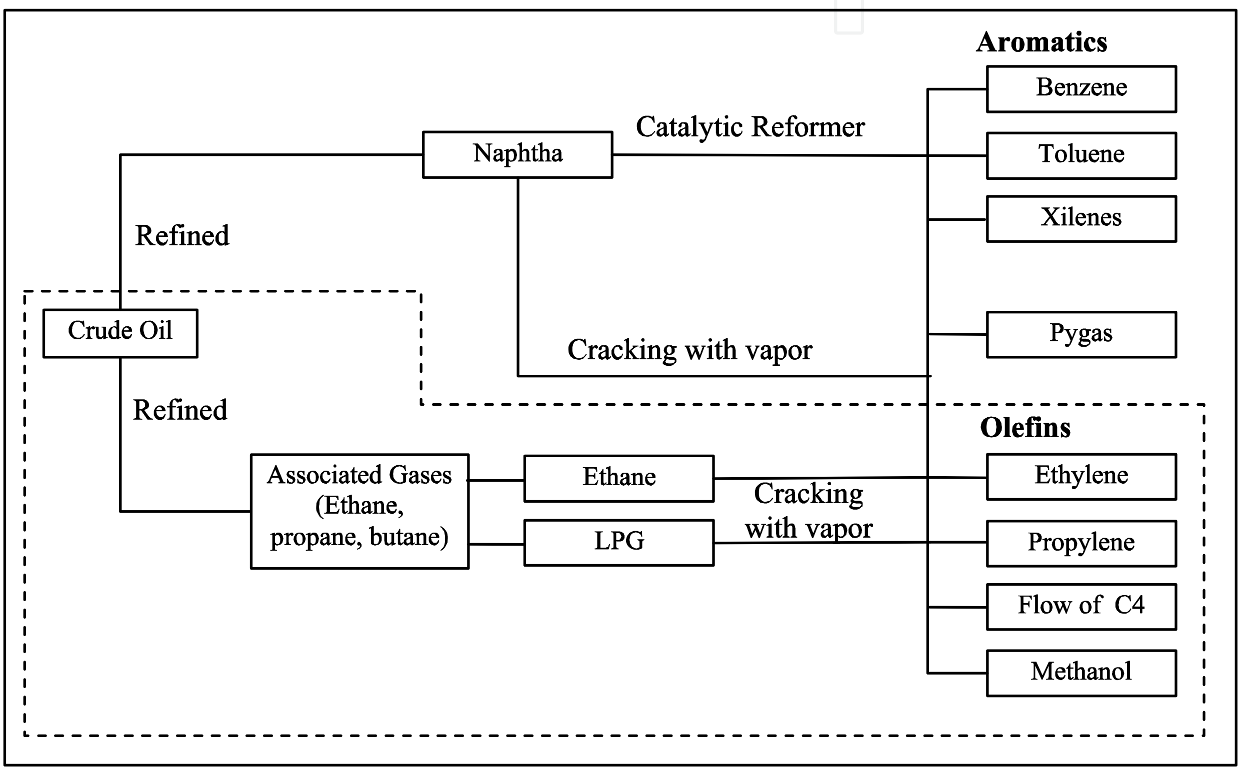

Fig. 16. Traditional Petrochemical Industry

In a similar way, ethane, propane and butane, companions of methane found in the Bolivian NG, can be applied in traditional petrochemical processes, here named gas-chemistry. However, since the companions mentioned are found in low quantities in Bolivian most important cas reserves, it can be concluded that only the massive exportation of methane will allow obtaining sufficient amounts of the "liquids of natural gas" to generate a gas-chemical industry in the country.

In summary, the creation of a gas-chemical industry in Bolivia depends on the LNG project, since this is a methane massive exportation project and, with that, it will be possible to count on great amounts of liquids from NG and then develop a Bolivian gas-chemical industry.

5.3 The CH_4 Industrialization

Methane industrialization, as well as the petrochemical (gas-chemical) industry and energy strategy should be considered fundamental for the Bolivian industrialization. As the Bolivian NG, in the most important gas fields, is mostly constituted of methane, it is important to talk about the methane industrialization, and, on this basis, the other components that come with it (GTL, GTO, GTM, etc.).

The first stage in the industrialization of methane is to obtain the syngas. The synthesis gas is a mixture of carbon monoxide and hydrogen, obtained from chemical reactions of methane with substances easily found in nature, such as carbon dioxide, oxygen and water. As its name shows, the synthesis gas is the basis to synthesize many compounds that are both economically and industrially important. Depending on the desired compounds, the synthesis gas is prepared with different proportions of carbon monoxide and hydrogen, as shown in Table 9.

Reacting Compounds	Chemical Reactions (under adequate conditions of pressure and temperature)	Proportion (mol to mol) of carbon monoxide and hydrogen in syngas
Methane with carbon dioxide	$\mathbf{CH_4 + CO_2 \rightarrow 2CO + 2H_2}$	1:1
Methane with air oxygen	$2CH_4 + O_2 \rightarrow 2CO + 4H_2$	1:2
Methane with water	$\mathbf{CH_4 + H_2O \rightarrow CO + 3H_2}$	1:3
As an example, to obtain a synthesis gas in which the carbon monoxide and hydrogen are in a proportion from 1 to 2, respectively, a partial combustion of the methane with the oxygen of the air is made, reaction additionally generates considerable amounts of thermal energy.		

Table 9. Methane reactions in order to form synthesis gas

5.4 Synthesis Gas as Vector for secondary Fuels

From the reaction of the syngas (synthesis gas) components, using different catalysts, many products can be made (see figure 17); among the most important products, depending on the proportion of carbon monoxide/hydrogen in the syngas, it is possible to have:

- LPG, petrol, diesel, jet fuel and ultra-pure paraffin, all of those with the Fischer-Tropsch process. The Natural Gas transformation into the products above, all of them liquid, is denominated GTL (Gas to Liquids) process.
- Hydrogen, denominated the Fuel of the Future.
- Ammonia, basis of the fertilizing industry, which is the product of the reaction of the nitrogen in the air with the hydrogen from methane.
- Dimethyl ether, a diesel and LPG substitute, which can also be used in the electricity industry.
- Methanol, from which it is possible to synthesize olefins, such as ethylene and propylene, and, from these, the products in Figure 17

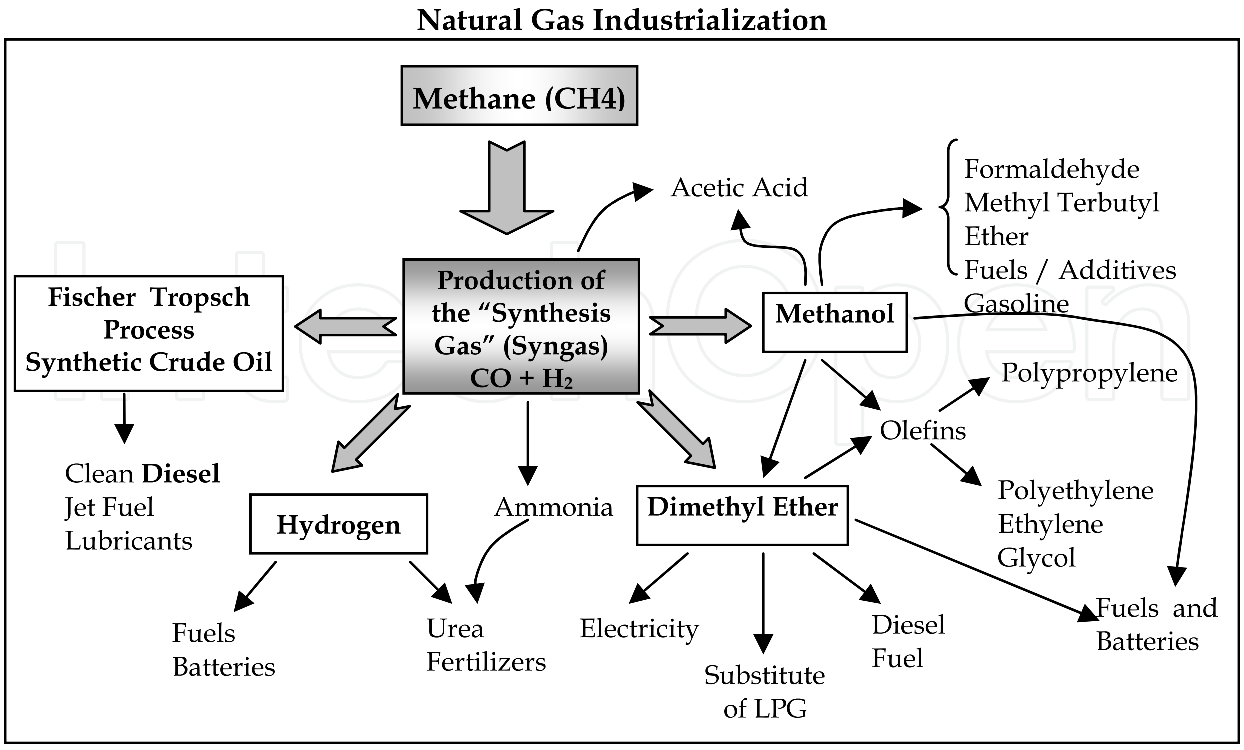

Fig. 17. Products from the syngas

Fundamentally, it is necessary to consider these general aspects:
- The technology;
- The present and future markets;
- The possibility of getting to these markets;
- The amount of investments;
- The advantages;
- And the specifically Bolivian aspects, such as:
- Benefits to the country and areas of production;
- Mediterranean Climate;
- Legal security.

Considering all the general and specific aspects mentioned above, it is necessary to carefully decide about the best industrialization route or routes to be taken.

5.5 GTL Production Factors

A project of Gas to Liquids (GTL) production by the Fischer-Tropsch process – GTL-FT – consists in obtaining syngas from the partial combustion of methane with oxygen in oxygen-poor stoichiometric proportion. The syngas obtained can thus be transformed into liquid fuel of massive use, such as gasoline, diesel and jet fuel from different catalyzers and syngas reaction times.
The basic GTL-FT process starts with the methane separated from its liquid companions (dry). Compounds such as ethane, propane, butanes and pentanes, can be industrialized independently of the GTL-FT project, originating polymers, and synthetic oils.
The F-T process is a multiple- step process, with great power consumption, which separates the natural gas molecules, predominantly methane, joins them again to produce larger

molecules. The first step requires the incoming of oxygen (O_2) separated from air. Oxygen is blown into a reactor to extract the methane hydrogen (CH_4) atoms. The products are synthetic hydrogen (H_2) gases and carbon monoxide (CO), called syngas (Figure 18).
The second step uses a catalyzer to recombine hydrogen and carbon monoxide, leading to liquid hydrocarbons. In the last stage, liquid hydrocarbons are converted and broken down into products that can be immediately used or be mixed to other products. The most widely known product is the extremely pure diesel, also known as ***gas oil***. The diesel obtained from the F-T process, as opposed to that deriving from petroleum distillation, has practically null sulfur oxide and nitrogen oxide content, virtually does not present aromatics, its combustion produces little or no particulate matter emission, and it has a high rate of cetane. Kerosene, ethanol and dimetil ether (DME) can also be produced. Another product of the reaction is naphta, which has high paraffin content. Waxes deriving from the GTL process may be pure enough to be used in the cosmetic industry and that of canned food.

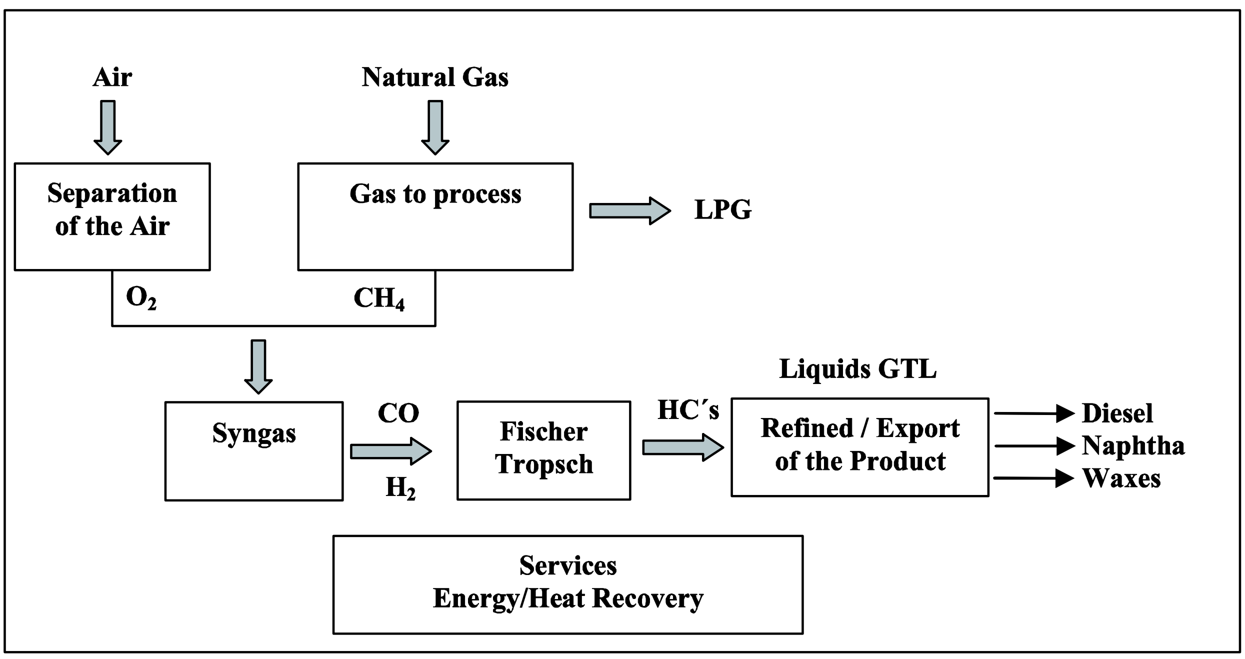

Fig. 18. Conversion of natural gas into liquid fuels
Source: Authors' elaboration, 2006.

For all this, it may be concluded that the GTL-FT technology has to be developed on industrial scale, for the range of products that may be obtained and for the amount of existing gas. In this sense, Bolivia may produce investment costs and commercial production scenarios that allow having a general view of the project and analyze its benefits.

6. Market for products of a GTL-FT Industry

If Bolivia were to process 30 million m^3 of Natural Gas daily (the same amount agreed with Brazil and the same expected to be exported to the USA), approximately 100 thousand bpd of mostly liquid hydrocarbons, gasoline and diesel would be produced. This amount, as Table 10 shows, is minimal if compared to the worldwide demand.

Products	Estimated Demand in 2005* (million bpd)	Estimated Demand in 2010* (million bpd)
Naphtha	5.2	5.7
Gasoline	20.9	22.3
Kerosene	6.6	7.7
Diesel	22.2	25.1
Fuel Oil	9.2	9.1
Others	8.8	9.6

Table 10. Projected Hydrocarbons Demand

In Bolivia, there is an internal market for 14 thousand bpd, from which 5 thousand bpd are imported. Considering the price of US$35.00 per diesel barrel, the money spent on this activity is US$64 million per year. There are two very tempting markets available to Bolivia for selling diesel: Chile and Brazil.

6.1 Pacific Market – CHILE

Chile would be a great buying potential for Bolivia's diesel-GTL since it consumes 250 thousand bpd of oil and their byproducts and 95% of what it consumes come from imports. Due to the high environmental degree of contamination it presents, Chile would become a guaranteed purchaser of GTL diesel. Figure 19 shows the distribution of the oil import in Chile according to origin.

In order to export eco-diesel (diesel-GTL) to Chile, also a South-American Country, and countries on the other side of the Pacific Ocean, the port of Arica (normally used for Bolivian exportations) would be used for exporting to other countries, such as China.

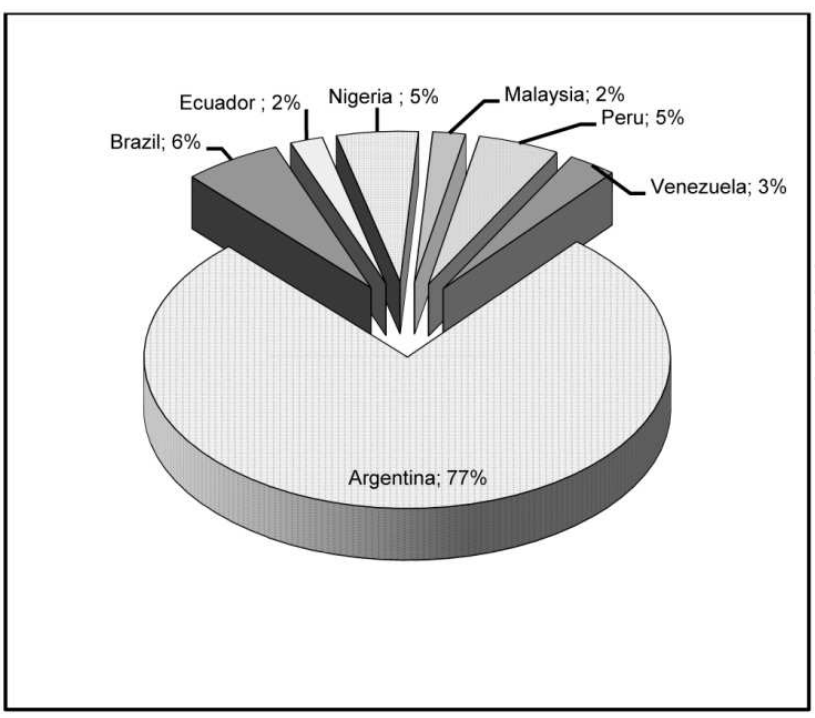

Fig. 19. Oil importation for Chile in 2001

6.2 Atlantic Market – BRAZIL

Brazil is another potential purchaser of Bolivian eco-diesel because its refinement capacity will be insufficient, according to the National Oil Agency (ANP).

The diesel consumed in the States of Rondônia, Mato Grosso do Sul, Mato Grosso and Goiás is mainly obtained from the neighboring State of São Paulo, though it is possible to obtain fuel from Bolivia (diesel-GTL). As seen in Figure 20, the eco-diesel produced in Bolivia would be more economic for the mentioned states, better still if the project is jointly implemented by Brazil and Bolivia.

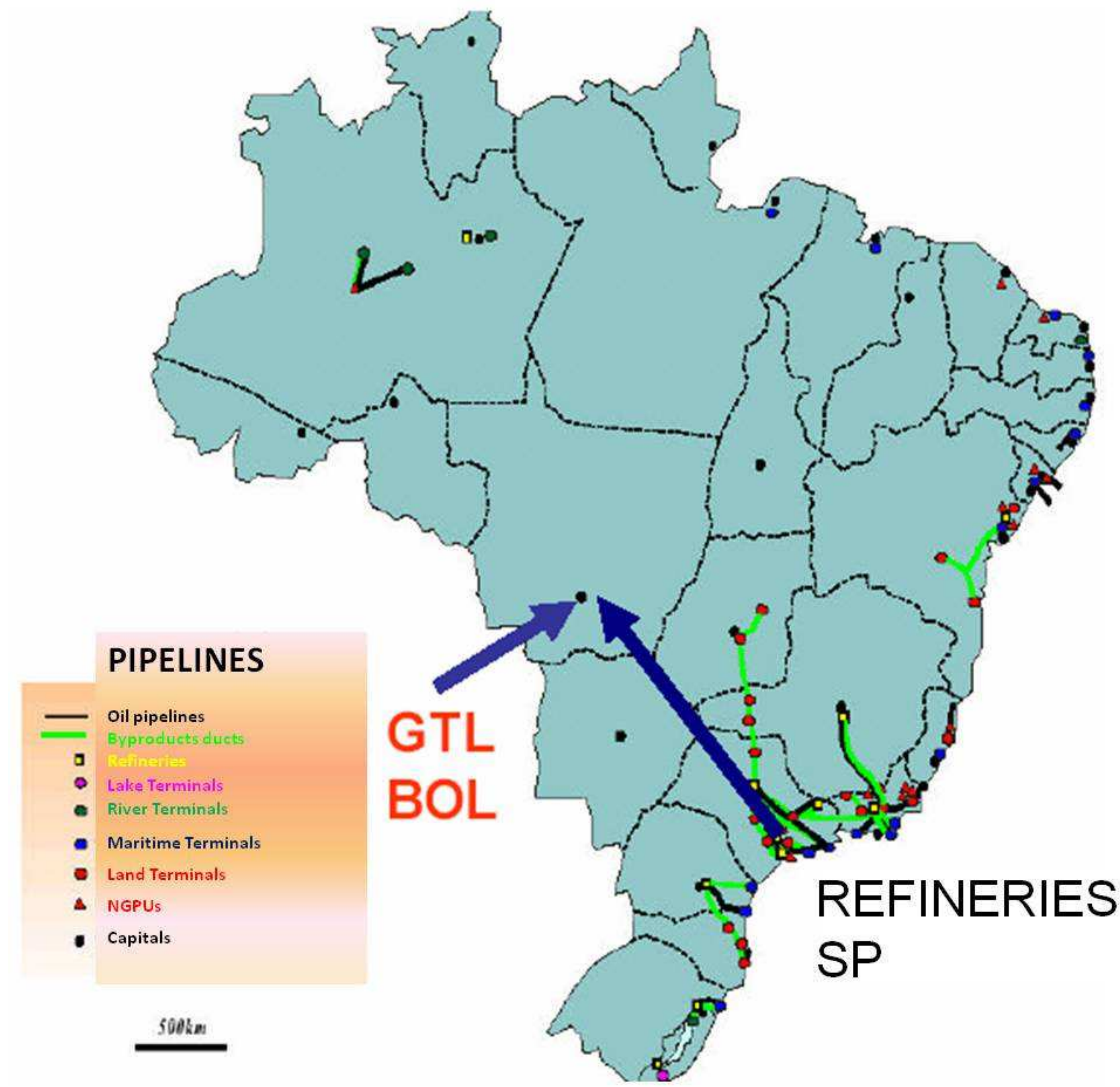

Fig. 20. Eco-diesel from Bolivia to Brazil (Atlantic side)

Brazil needs to invest great amounts in refineries (Figure 21) to avoid importing diesel for diesel engines. The Brazilian state oil enterprise, Petrobras, has gas reserves without market in Bolivia, which makes it possible to manufacture eco-diesel from the gas reserves and export it to Brazil. It is worth mentioning that both countries would gain from that.

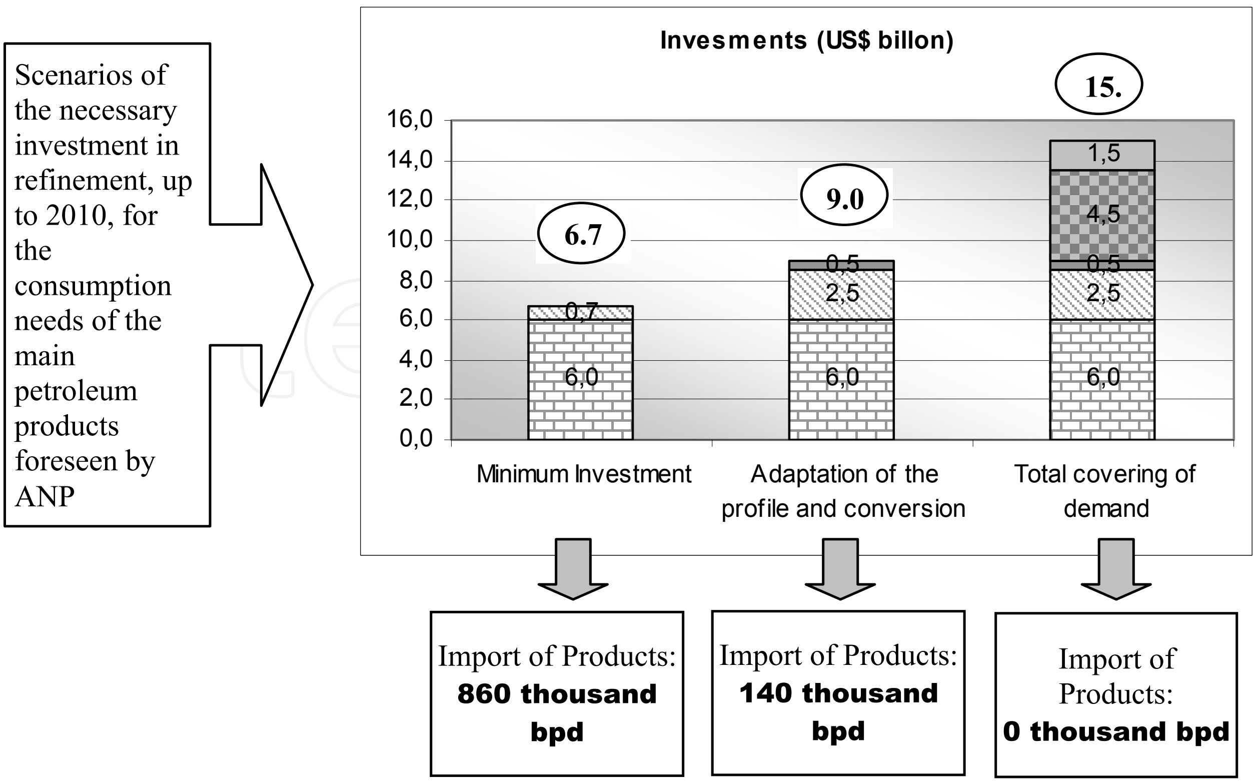

Fig. 21. Oil byproducts 2010 ANP scenarios

6.3 Market for liquid hydrocarbons

The price and the quality of GTL-FT products will determine, as for any other product, their capacity to gain access and to compete in the world hydrocarbon market in favorable conditions. Their nearest competitors are the products of the oil distillation process. In a GTL-FT diesel projected production of 100 thousand bpd, only 0.3% would be covered by the international market (Table 10).

In Figure 22, for example, there is a comparison between the qualities of GTL diesel and the conventional one, also referred to as 'dirty' diesel. Compared to the conventional diesel, GTL-FT diesel contains much reduced amounts of aromatic hydrocarbons and sulfur, and for that reason it emits reduced amounts of detrimental compounds into the atmosphere. For the same reason, GTL-FT diesel fully meets the strictest specifications of developed countries legislation. Figure 9 corresponds to a standard proposal of a rule in the United States on the maximum amounts or limits of aromatic compounds (10%) and sulfur (15 ppm) contained in the diesel.

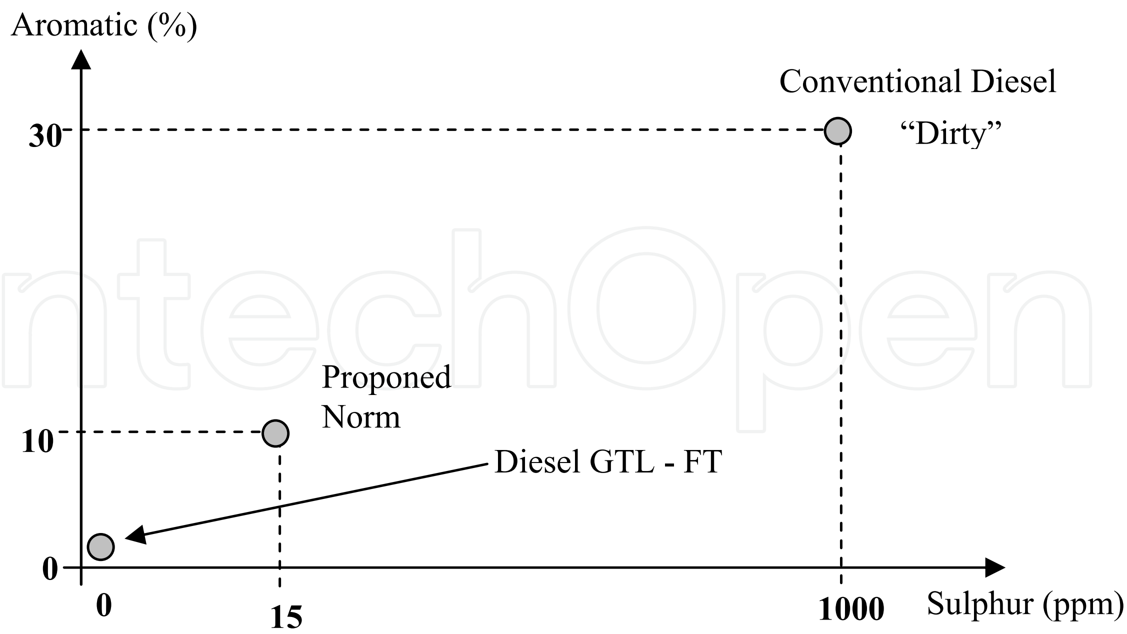

Fig. 22. GTL-FT diesel is a clean fuel

Regarding the price, it is important to stress that the possibilities for this to be competitive are going to depend on the cost structure of the company. In Figure 23, an attempted cost structure is shown, elaborated by the Foster Wheeler company for the production of clean diesel on commercial scale. It can be observed that the GTL-FT diesel production cost is of approximately US$ 19.80 per barrel, far below even the present international price of the diesel, of around US$ 35.00 per barrel, the reason why the profits would be very attractive, considering that the ecological clean diesel has an additional benefit in quality.

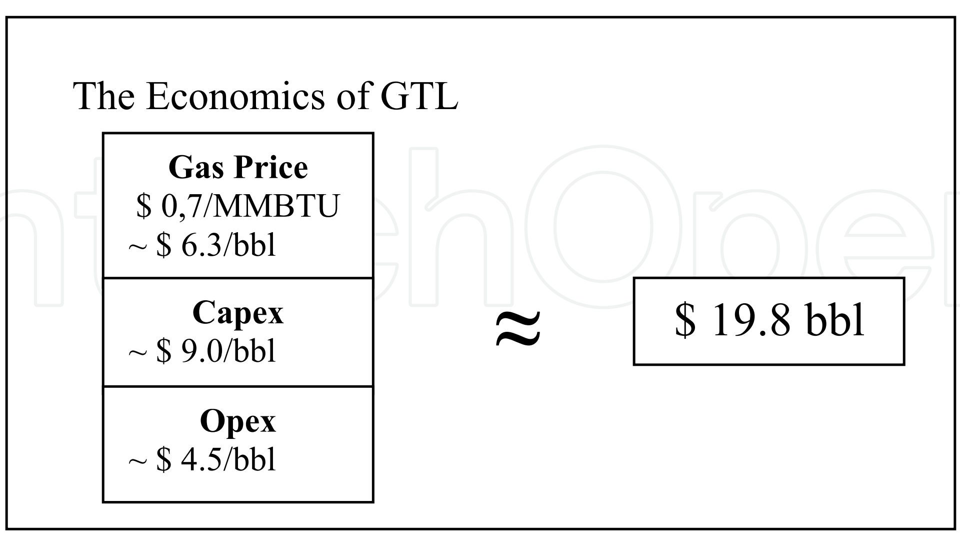

Fig. 23. GTL-FT diesel production cost

If the production cost of a barrel of GTL-FT 'clean' diesel with the present sale price is compared to the diesel originating from oil distillation (around US$ 35.00 by barrel), it is possible to conclude that GTL-FT diesel is a very competitive product in price.
As seen in figure 10, the production cost of the clean diesel is of US$ 18.00 per barrel. As an illustration, this cost was calculated considering that:

- 9 thousand cubic feet of gas are required to produce a barrel of diesel.
- The cost of one thousand cubic feet of dry natural gas is US$ 0.70.
- The capital expenses are about US$ 9.00 per barrel.
- The operation expenses are about of US$ 4.50 per barrel.

Table 11 displays a production cost sensibility analysis for a barrel of GTL-FT diesel, which uses the price of the raw material (of the Natural Gas) to be used in the GTL plant clean diesel production as a control variable. The price was calculated so that the plant could buy the gas, and is expressed in dollars per thousand cubic feet and their equivalent in dollars per barrel of diesel. In addition, the costs of capital and the costs of operation shown in figure 11 have remained unaltered, and are expressed in dollars per barrel.

Gas Price (US$/1000cf)	Gas Price (US$/bbl)	Capital Costs (US$/bbl)	Operation Costs (US$/bbl)	Approximated GTL-diesel Costs (US$/bbl)
0.7	6.3	9.0	4.5	19.8
1.0	9.0	9.0	4.5	22.5
1.4	12.6	9.0	4.5	26.1
1.8	16.2	9.0	4.5	29.7
2.0	18.0	9.0	4.5	31.5
2.2	19.8	9.0	4.5	33.3
2.5	22.5	9.0	4.5	36.0
2.8	25.2	9.0	4.5	38.7
3.0	27.0	9.0	4.5	40.5

Table 11. Gas price and the diesel GTL costs

6.4 Assessment of GTL project

In order to have an idea of how financially attractive GTL-FT projects are, a part of the manuscript "Banks Endorse Qatar GTL Project", is transcribed. This text was published in the Petroleum Economist of March, 2003:
Bankers consider that GTL schemes provide a triple advantage on the traditional projects of oil and gas, which is true in the oil product market as well as for pipelines or LNG.

- The products are commercialized globally in a mature market, so that the sponsor does not have to depend on a specific buyer for long-term agreements.
- The gain margins are much greater than those for the traditional oil refinement that seems to be kept under pressure in the near future.
- The GTL Gas chain is much smaller than in the traditional Gas schemes.

Furthermore, N. White, Director of Energy Economy (of the Arthur D. Little company), says: "the advantage of GTL is that there is not an obligation to construct a new logistic system. It is possible to use the existing distribution system to bring products to the markets".

6.5 Existing Natural Gas to implement a GTL-FT project

The Bolivian Natural Gas fields are appropriate to implement one or more GTL project from the qualitative and quantitative point of view:

From the quantitative point of view, to produce around 100 thousand bpd of GTL byproducts, for 25 years, is necessary to process 30 million m^3 of gas per day, which demands 10 TCF of the economic gas reserves. Bolivia had, among proven and probable reserves, about 50 TCF in the beginning of 2005, fully meeting this requirement.

From the qualitative point of view, the Bolivian reserves are of non-associated gas; this means that it does not have many accompanying liquid hydrocarbons, which allows minimum investments to separate the methane from other hydrocarbons. Bolivia has the greatest non-associated Gas reserves in South America: greater than, for example, the ones in the 226 TCF of total gas reserves in Venezuela (the greatest gas reserves of South America), but only 14 TCF are of non-associated gas.

Another important aspect is that the sulfur contents of Bolivian hydrocarbons are generally low, which avoids investments in desulphurization plants and, furthermore, avoids the poisoning of the catalysts, fundamental aspect in the process.

Figure 24 illustrates the flow of the potential projects and exportation and industrialization products of the Bolivian natural gas.

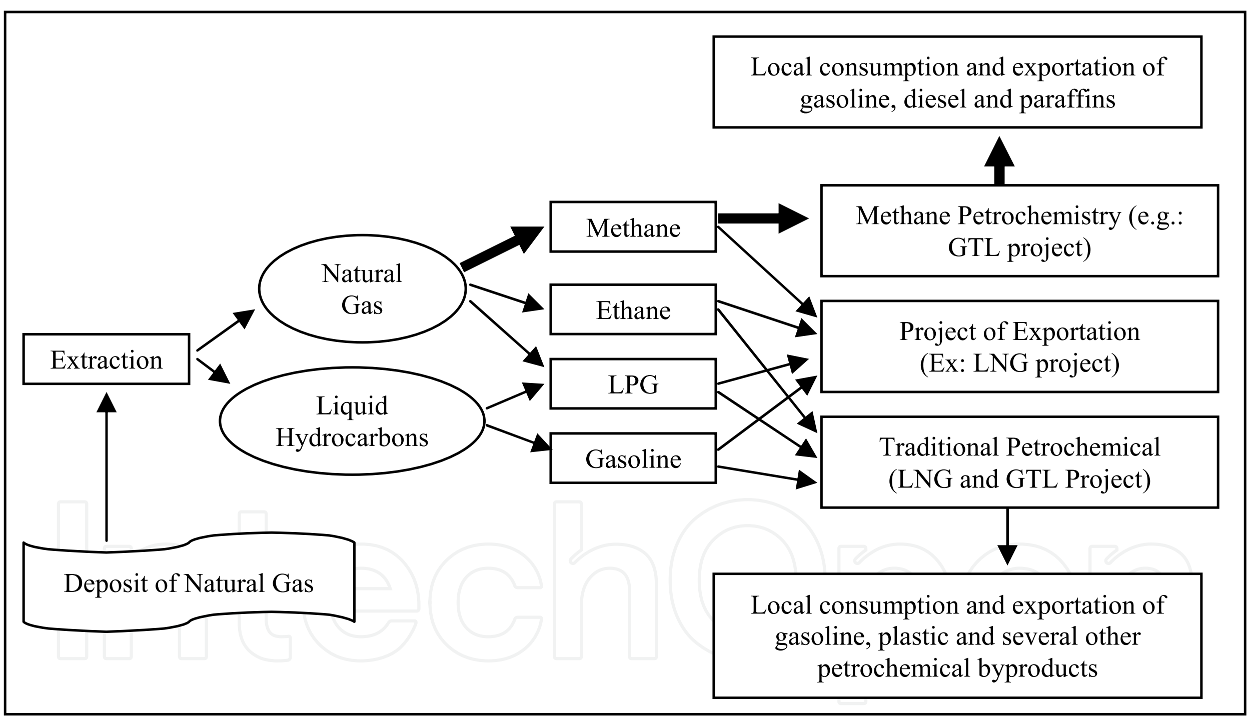

Fig. 24. Potential of the Bolivian natural gas

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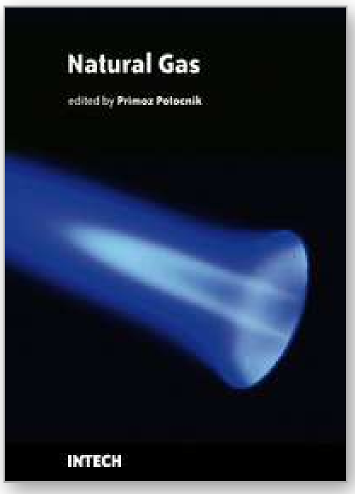

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The contributions in this book present an overview of cutting edge research on natural gas which is a vital component of world's supply of energy. Natural gas is a combustible mixture of hydrocarbon gases, primarily methane but also heavier gaseous hydrocarbons such as ethane, propane and butane. Unlike other fossil fuels, natural gas is clean burning and emits lower levels of potentially harmful by-products into the air. Therefore, it is considered as one of the cleanest, safest, and most useful of all energy sources applied in variety of residential, commercial and industrial fields. The book is organized in 25 chapters that cover various aspects of natural gas research: technology, applications, forecasting, numerical simulations, transport and risk assessment.