



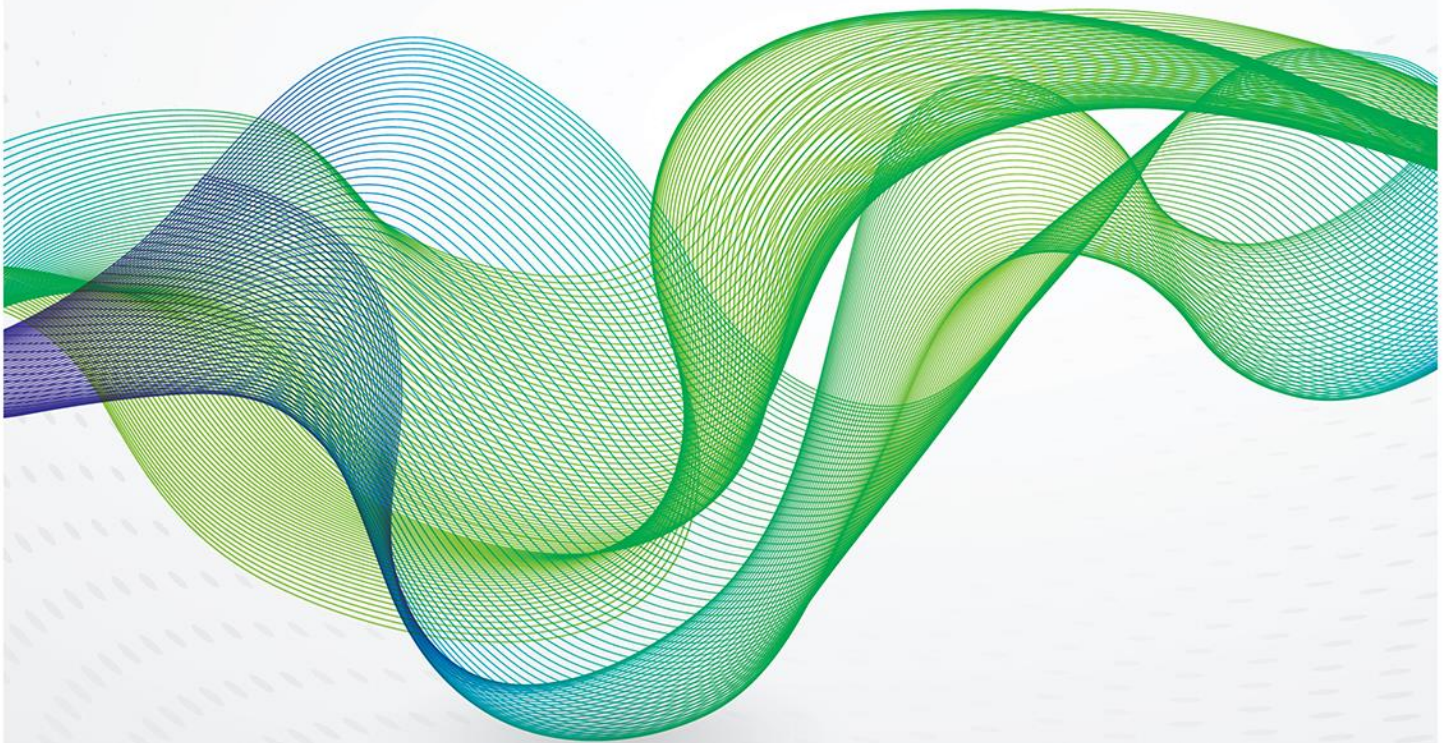
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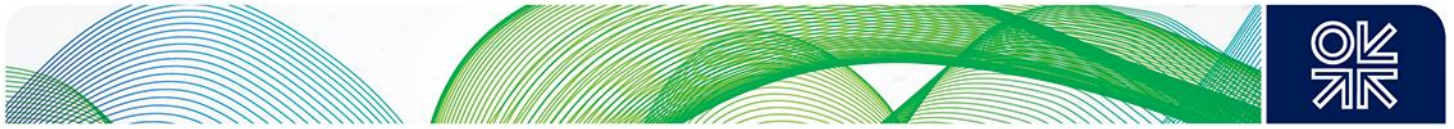
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October 2016

South American Gas Markets and the role of LNG



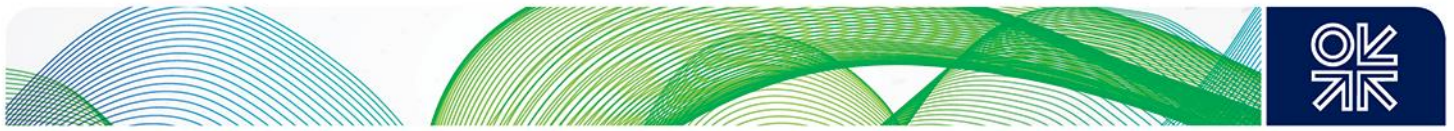


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All the opinions expressed and any remaining errors are my sole responsibility.

Anouk Honoré
Oxford
October 2016



Preface

Although representing in aggregate only a moderate regional demand (145 bcm in 2015 versus 472 bcm in OECD Europe), South America represents a fascinating matrix of natural gas trends both in terms of geological potential and gas resource diversity, supply and demand fundamentals, geo-political tensions impacting intra-regional gas trade and, of late, interactions with the rest of the 'gas world' through LNG imports and (in the case of Peru) LNG exports.

In this paper Anouk Honoré provides a detailed account of the development of each of the major gas producers and consumers in the region and develops scenarios for each out to 2030. Deriving the narrative which explains the development, and ultimately to date the failure of, a successful integrated regional system of gas trade flows is a challenging task which the author succeeds in. This is a complex tale of essentially the breakdown in trust between neighbours as a consequence of unresolved historic grievances, economic crises and the changing pendulum of national resource policy and politics. This is not helped by the distances and terrain involved in constructing the pipeline infrastructure which might transform this 'on paper self-sufficient' gas region into a model of successful co-operation.

Success in developing the region's resources has not been aided by many cases of (generally low) state regulated gas prices and in some instances nationalisations and expropriations. The allure of prospectivity for International Oil Companies (IOCs) remains tough, in Brazil's offshore pre-salt oil and gas and in Argentina's extensive resources of unconventional oil and gas. However, in the current market outlook of a well-supplied LNG market keeping spot LNG prices low, the temptation for South America's countries to rely to a greater extent on LNG rather than on new indigenous production must be high unless development cost levels can be significantly reduced.

Understanding the dynamics of important regional and national gas markets, is a core research theme of the OIES Gas Programme and I am delighted to add this paper to our publications.

Howard Rogers
Oxford
October 2016



Abstract

South America has long been isolated from other natural gas markets, focusing instead on achieving self sufficiency and regional integration. As a consequence, it has never been at the centre of discussions in the natural gas industry until the region decided to turn to Liquefied Natural Gas (LNG) in 2008 following shortages of natural gas production, tensions over price renegotiations and shortfalls of contracted deliveries. LNG imports only started in the late 2000s but reached 17.2 billion cubic metres (bcm) in 2015. Despite relatively small volumes at the global scale, representing less than 5% of the world LNG trades,¹ if the pace continues, the region could become an important player reducing the scale of flows to Europe, the swing market for LNG. This was the starting point of this research, which was carried out with the objective to propose an overview of the gas demand fundamentals to 2030 horizons in a comprehensive way with some highlights of individual market trends (the paper focuses on Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Paraguay,² Peru, Uruguay and Venezuela). The scenarios will need to be updated as policies/prices/generation mix evolve in the future, but the main conclusion of this research is that, as of mid 2016, South America is not expected to be a major future LNG market unless there are extreme climatic conditions, which will not happen every year and will not last many years. LNG will remain necessary to supply much needed flexibility, additional volumes, security of supply and to reach new markets far from infrastructure, but there are also major uncertainties on volumes, prices, timeframe, location and even direction of the LNG flows as some importers could turn exporters at times of low demand toward the end of the timeframe.

¹ GIIGNL (2016)

² Paraguay does not consume nor produce natural gas, but because of its geographical location and previous interests as a potential future market for gas, it was interesting to consider the energy developments in this country.



Executive summary

South America has long been isolated from other global natural gas markets, focusing instead on achieving self-sufficiency and regional integration. However the region turned to Liquefied Natural Gas (LNG) to source additional supply in 2008. Although the volumes imported represent less than 5% of world LNG trade, imports have grown rapidly. If the pace continues, the region could become an important player reducing the scale of flows to Europe, the swing market for LNG. This paper focuses on the continental gas market fundamentals and the future role for LNG up to 2030.

Why LNG in South America?

Discussion concerning natural gas trades across the continent date back to the 1950s and 60s, but gas integration only really started in the early 1970s with the Yabog pipeline between Bolivia and Argentina. Until the mid-1990s, this was the only cross-border gas pipeline in the region. Exports did not really take off until abundant gas reserves were found in Argentina in the 1980s. Looking to monetise its own gas supplies, seven pipelines were built between Argentina and Chile between 1996 and 2001. Additionally, exports to Uruguay started in 1998 and to Brazil in 2000. This was intended as the first stage of a more ambitious project and also to compete with Bolivian gas, which started to flow to Brazil via the Gasbol pipeline 1999. In the north, a pipeline between Colombia and Venezuela started operation in 2007. These pipelines should have provided the basis for regional pipeline integration, but ran into a number of problems.

The most important of these was the decline of Argentinian domestic production to less than its domestic demand, a consequence of its 2001 economic crisis. The country broke its export contracts and gave priority to national consumption. This decision had a major impact on the importing countries, especially Chile, which was 100% dependent on pipeline gas from Argentina. Repeated interruptions created major economic problems for industry and electricity generators, which had to resort to more expensive alternative fuels. The impact was less severe in Brazil and Uruguay, but in addition to supply constraints, this episode created major distrust of Argentina as reliable supplier and towards regional integration as a goal. Bolivian gas exports to Brazil have been reliable in terms of volumes but disagreements over prices have increased over the years. In the North, not all went as planned either. Colombia was to export gas to Venezuela until 2011, and then the pipeline flow was to be reversed in 2012. This did not take place due to delays in developing reserves in Venezuela. Despite political tensions, security of gas supply was relatively good. In 2015, Colombia reduced (and then stopped) gas exports to meet its own demand when the Perla field started operation in Venezuela. Reverse flow, which was expected in January 2016, was again delayed and the under-supplied national market was prioritized.

As a result, natural gas integration never really took off despite the political support for the concept of energy integration, and more specifically natural gas. Cross border exchanges were arguably more bilateral initiatives between producers and consumers than a truly regional market as harmonized regulation, pricing and policies were non-existent. At times of shortage, producing countries gave, and will continue to give, priority to their domestic markets. This atmosphere of distrust led importing countries to look for new gas import sources, and they turned to LNG to increase security of supply, add much needed additional volumes and provide increased flexibility.

South America received its first gas from outside the continent in the form of LNG in 2008, and volumes have been rising rapidly from 0.5 billion cubic metres (bcm) (0.4 million tons per annum -



mtpa) in 2008 to 17.2 bcm (13 mtpa) in 2015. In Chile (4.3 bcm (3.2 mtpa) in 2015), imports are rather flat throughout the year; in Argentina (6.1 bcm (4.5 mtpa)), they are concentrated during winter months while in Brazil (6.8 bcm), they are mostly driven by the level of hydropower in power generation. As of January 2016, South America had 33.5 bcma (24.5 mtpa) of LNG import capacity with a utilisation rate of 51% (2015), albeit with important differences among the countries (60% in Argentina, 57% in Chile and only about 43% in Brazil). Two additional regasification terminals were under construction in Uruguay and Colombia with a capacity of 3.7 and 4.1 bcm per year respectively (2.7 mtpa and 3.0 mtpa).

Natural gas demand: trends and uncertainties

In 2015, gas demand reached 145 bcm, a 20% increase over 2010 (+64% since 2000) driven mainly by rapid economic growth, expansion of the grid to areas not previously covered, addition of new gas-fired capacity, substitution of gas for oil in industry and the rise of gas use for the transport sector.

As the region's economy and population grows, energy demand is expected to continue to increase and become more reliant on natural gas, especially in electricity generation, even if drivers for additional gas demand are as diverse as the markets themselves (size, maturity, infrastructure, generation mix, subsidies and energy policies). Despite the fact that weaker economic growth will slow down energy demand growth in all sectors for the rest of the 2010s, gas demand is still expected to increase. Meeting the needs for both additional generation and additional flexibility will be one of the greatest challenges. Most new generation will be in the form of renewables, especially hydropower, but most new hydro will be run of the river or have small reservoirs. As a result, generation will be even more significantly reduced in dry periods, thus needing more back-up capacity, especially gas plants (but not only). In the non-power sectors, there is also some potential for more gas penetration in industry and for additional use of CNG in road transport (but if oil prices remain low, expectations may be over-optimistic). There is virtually no need for space heating in the region, which explains the low expectations in the residential and commercial sector despite plans to develop gas distribution infrastructure. All in all, this author expects gas demand to increase to 151 bcm in 2020 and 191 bcm in 2030. Brazil is one of the major question marks, especially the normalisation of the hydro situation. During wet years, it may be that gas for power will be limited at 8-10 bcm while potentially shooting up to 40-45 bcm during dry years in 2030.

Natural gas supply: meeting the challenge

Supply shortage and/or delay in increasing indigenous production will constrain these demand scenarios. In addition, flexible supply will be increasingly needed in order to match the seasonal, and often volatile dispatch of gas-fired power plants, whether from indigenous production (if possible) or from imports, especially LNG (as there is no gas storage in the region).

South American countries will have to increase upstream investment and develop new resources in order to boost production. Geopolitical uncertainties, along with economic, geographic, social, and regulatory issues have impacted the pace and the level of natural gas production in the past. While regional diversity needs to be taken into account, the major challenges to increase indigenous production will be geography, the changing regulatory environment and low oil prices. Cutbacks in exploration investment may especially impact high cost unconventional plays (for instance in Argentina but not only), offshore pre-salt projects in Brazil, and all offshore prospects in general. This author expects production to rise to 148 bcm in 2020 and 177 bcm in 2030.



Conclusions on the future role of LNG in South America at the 2030 horizon

'The future is uncertain'. While this arguably can be said for any scenarios in any part of the world, it seems even more appropriate in this very diverse region. Brazil, Argentina and Chile will continue to import LNG and will be joined by Uruguay and Colombia. Peru is likely to remain the only exporter. There will be no region-wide pipeline integration, but there is a possibility of sub-regional integration around LNG import terminals, as suggested by projects in Uruguay, Colombia or even LNG arriving in Chile and being sold to Argentina. This author expects that the region will import about 7 bcma (5.1 mtpa) of LNG in 2020 under 'normal' weather conditions with Bolivian export commitments fulfilled and contracts prolonged. If the Bolivia-Brazil agreement is not prolonged, then LNG imports could soar to 18 bcma (13.2 mtpa) in 2020 under 'normal' weather conditions. By 2030, scenarios show a potential of 19.5 bcma (14.3 mtpa) of LNG under 'normal' weather conditions and if Bolivia's renew both its pipeline export contracts at levels allowing Argentina and Brazil to balance their demand. LNG imports could rise to 30.5 bcma (22.4 mtpa) in the case of no Bolivian exports, still under 'normal' weather conditions. Cold winters in Argentina and dry weather across the region could have a significant impacts on LNG imports. In Brazil alone, it could add up to 35 bcma (25.7 mtpa) of LNG imports (on top of already needed imports) on a dry year by 2030. As a conclusion, South America is not expected to be a major future LNG market unless there are extreme climatic conditions, which will not happen every year and will not last many years. LNG will remain necessary to supply much needed flexibility, additional volumes, security of supply and to reach new markets far from infrastructure, but there are also major uncertainties on volumes, prices, timeframe, location and even direction of the LNG flows as some importers could turn exporters at times of low demand toward the end of the timeframe.



Glossary

'1000Toe	Thousand tons of oil equivalent
bbl	barrels
Bcm	billion cubic metres
Bcma	billion cubic metres per annum
CCGT	Combined Cycle Gas Turbine
Cm	cubic metres
CNG	Compressed natural gas
FSRU	Floating Storage Regasification Unit
GDP	Gross Domestic Product
GHG	Greenhouse gas
GW	gigawatt
HFO	high sulphur fuel oil
IMF	International Monetary Fund
km ²	square kilometres
LNG	Liquefied Natural Gas
Mcm	Million cubic metres
Mcma	Million cubic metres per annum
MMBtu	Million British Thermal Units
Mtoe	Million tons of oil equivalent
Mtpa	Million tons per annum
MW	megawatt
NGV	Natural gas vehicles
OECD	Organisation for Economic Co-operation and Development
R&C	Residential and commercial
Tcm	Trillion cubic metres
TPES	Total primary energy supply
TWh	Terawatt hours
\$	US dollars



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Introduction

Context and purpose of the paper

South America has long been isolated from other natural gas markets, focusing instead on achieving self-sufficiency and regional integration. As a consequence, it has never been at the centre of discussions in the natural gas industry until the region decided to turn to Liquefied Natural Gas (LNG) in 2008 following shortages of natural gas production, tensions over price renegotiations and shortfalls of contracted deliveries. LNG imports only started in the late 2000s but reached 17.2 billion cubic metres (bcm) in 2015. Despite relatively small volumes at the global scale, representing less than 5% of the world LNG trades,³ if the pace continues, the region could become an important player reducing the scale of flows to Europe, the swing market for LNG. The special characteristics of the markets and their relatively new presence on the world scene make it difficult to understand the potential evolution of this region even if it has started to attract attention as a market with growing gas demand but also for investment opportunities, especially in the upstream sector. By 2016, three countries (Argentina, Brazil and Chile) were importing LNG and others were considering the option. In parallel, some countries harbour future ambitions to join Peru as LNG exporters when (or if) their national production permits. These conflicting agendas add to the confusion on the future role of LNG, and even the direction of LNG trades.

This region is noted for ambitious plans, certainly plenty of opportunities and proposed projects, but in reality, uncertainties on both demand and supply are paramount. Natural gas integration never really took off despite the continued political support for the concept of energy integration, and more specifically natural gas. Cross-border exchanges were arguably more bilateral initiatives between producers and consumers than a truly regional market as harmonized regulation, pricing and policies were non-existent. At times of shortage, producing countries gave, and will continue to give, priority to their domestic markets. This led importing countries to look for new gas import sources, and they turned to LNG to increase security of supply through diversification, add much needed additional volumes and provide increased flexibility.

This short regional summary masks the disparity between countries. The South American continent is composed of widely diverse markets with differences in land area, population, economies, policies, hydrocarbons and renewables resources, infrastructure and of course energy mix. Brazil, by far the largest country, represents about half of the regional energy demand and power generation alone, and anything happening in this country will have important repercussions on the regional trends, but it is not representative of what happens (and will happen) in the other markets. The drivers and constraints for future energy trends and natural gas balances are as diverse as the countries themselves.

The main question of this paper is will LNG imports to South America continue to grow, at what pace and in what timeframe? This was the starting point of this research, which was carried out with the objective to propose an overview of the gas demand fundamentals to 2020 and 2030 horizons (via a bottom up approach rather than the contrary) in a comprehensive way with some highlights of

³ GIIGNL (2016)



individual market trends in Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Paraguay,⁴ Peru, Uruguay and Venezuela.

Energy and gas markets are evolving rapidly, and the writing of this paper was substantially completed by mid-2016 with information and statistical data available at the time. The trends and scenarios will need to be updated as policies/prices/generation mix evolve in the future, but the main conclusion of this research is that South America is not expected to be a major future LNG market unless there are extreme climatic conditions, which will not happen every year and will not last many years. LNG will remain necessary to supply much needed flexibility, additional volumes, security of supply and to reach new markets far from infrastructure, but there are also major uncertainties on volumes, prices, timeframe, location and even direction of the LNG flows as some importers could turn exporters at times of low demand toward the end of the timeframe.

Structure of the paper

Following this introduction, the first chapter sets the scene by providing an overview of the natural gas industry in South America up to 2016. It explains the circumstances that drove three markets to turn to LNG imports, and several more to consider the option. The second chapter focuses on natural gas demand, present and future. It explores the potential for additional gas consumption and highlights the main factors that are likely to influence the trends in each market. Logically, the third chapter turns to the supply options. It starts with the challenges to increase indigenous production and finally turns to import/export options, with a special focus on the role of LNG in the mix. The final chapter draws together some conclusions. The main text provides regional views and some key national examples. Additional details on each natural gas market are given in the Appendix.

Notes on statistical data

1. When comparing data on the energy (and natural gas) markets in the region, we used two sources of data: the International Energy Agency's and BP's statistics. Some time lag exists between data available and the publication date of such data (about two years). National statistics sometimes offer more up to date data, but the lack of homogeneity in the statistics definitions across countries makes it impossible to use this data to compare one country to another. National statistics have been used in this paper when highlights or updates on a national market were necessary and did not necessitate a comparison with other markets.
2. The usual unit used in South America for natural gas volumes is million cubic metres per day (mcm/d). These volumes have sometimes been converted into billion cubic metres per annum (bcm/a) in this text.

⁴ Paraguay does not consume nor produce natural gas, but because of its geographical location and previous interests as a potential future market for gas, it was interesting to consider the energy developments in this country.



I. Overview of the natural gas industry: why LNG in South America?

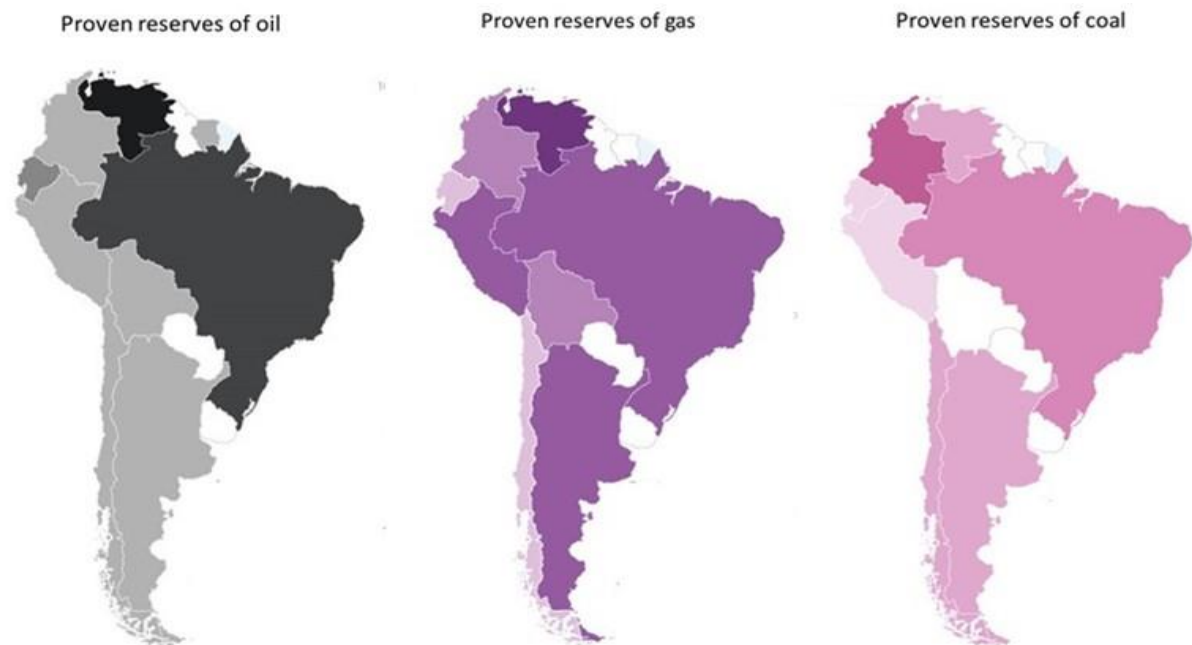
South America has long been isolated from other global natural gas markets, focusing instead on achieving self-sufficiency and regional integration. However the region has turned to LNG to source additional supply volumes since 2008. This first section provides an overview of historical developments of the natural gas industry in the region up to 2016. It sets the scene for the analysis of future gas demand and supply trends that will be looked at in the following sections.

1.1. Natural gas: a fairly recent history

1.1.1. A resource rich continent

South America is a region favourably endowed with energy resources, both in terms of fossil fuels (oil, gas, coal) and renewables (hydropower, wind, solar, biomass, and geothermal). The region holds about 19% of world oil reserves, 4% of natural gas reserves and almost 1.6% of coal reserves. While the hydrocarbon reserves are relatively widespread across the continent as seen in Figure 1, they are nonetheless highly concentrated, with one country holding the bulk of the potential for each of the fuels: about 91% of the oil reserves and 77% of the natural gas reserves are located in Venezuela; and 49% of the coal reserves are in Colombia and 48% in Brazil [Figure 2].⁵

Figure 1: Proven reserves of oil, gas and coal in South America, by country, 2012



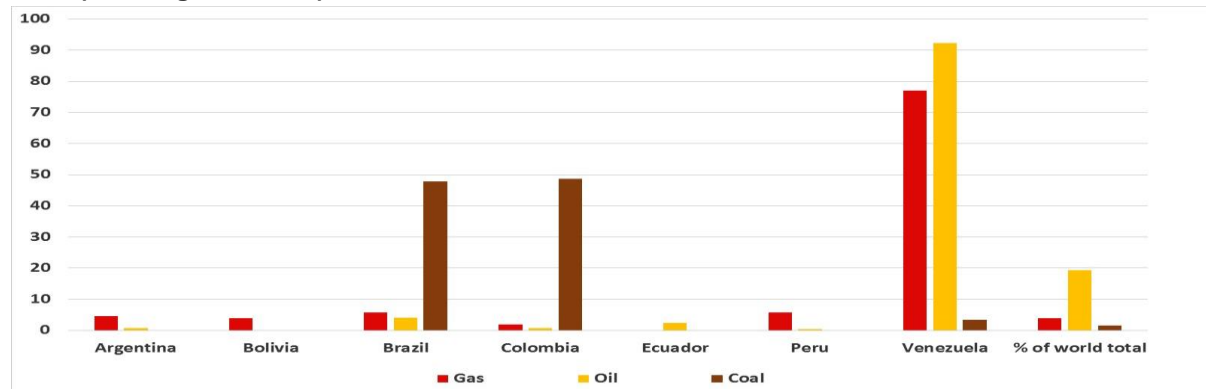
Note: darker colours indicate higher concentration: black for oil, purple for gas and pink for coal.

Source: OLADE (2013)

⁵ Data for 2015. Source: BP (2016). Note: Oil and gas reserves will most probably be revised upward once the pre-salt basins in Brazil have been explored and fully quantified.



Figure 2: Proven reserves of fossil fuels in South America: share by countries at the end of 2014 (% of regional total)



Source: BP (2016)

Natural gas proven reserves have more than tripled since 1980 as shown in Figure 3 as a result of the market liberalisation that transformed the political and energy landscape in some countries in the 1990s and opened up the upstream sector to private capital. This new legal framework led to additional investment in exploration and production of fossil fuels, including natural gas.⁶ However, this impressive growth at the regional level hides wide disparities in geography and in time. While Venezuelan associated gas reserves kept on rising steadily as a result of oil exploration, gas reserves in Argentina were cut in half between 2000 and 2010 following the decline in upstream investments after the country's economic crisis in 2001 and gas crisis in 2004.⁷ At the time, most reserve additions came from Bolivia with a seven-fold increase in proven gas reserves in just thirteen years (1998-2011). The steep decline in Bolivian proven reserves between 2008 and 2009 was due to a review of the previous methodology, but exploration efforts have slowed as an aftermath of the 2006 nationalisation⁸ leading to an actual decline in discoveries of natural gas in the country. In the early 2010s, the main gas discoveries occurred in Peru with the confirmation of block 56 reserves and successful discovery of deep offshore fields in Brazil, in a country where more than 80% of the proven reserves are located off the coast.

Proven regional natural gas reserves reached 7.2 Tcm (Trillion cubic metres) at the end of 2015.⁹ Venezuela has by far the largest gas reserves and accounts for 77% of the regional total as previously mentioned. It is followed by Brazil and Peru with a 6% share each, then by Argentina and Bolivia with 4% each while the remaining countries (Colombia, Chile, Ecuador) had shares less than 2% of the total. Most of the gas reserves are associated gas, with the notable exceptions of Peru and Bolivia.

According to the 2013 EIA report on shale oil and gas resources, the region has a large potential for unconventional gas, especially for shale.¹⁰ Argentina holds the second largest world resources of

⁶ For more information, see IEA (2003), which focuses on the natural gas markets in the 1990s – early 2000s.

⁷ For more details, see Honoré A. (2004)

⁸ In 2006, Bolivian President Evo Morales ordered the government takeover of Bolivia's most important natural resource: natural gas. The role of foreign investors including Total, Repsol, Petrobras and BG Group was diminished to favour that of junior partners of YPFB, the state energy company. See Appendix 'Bolivia' for more details.

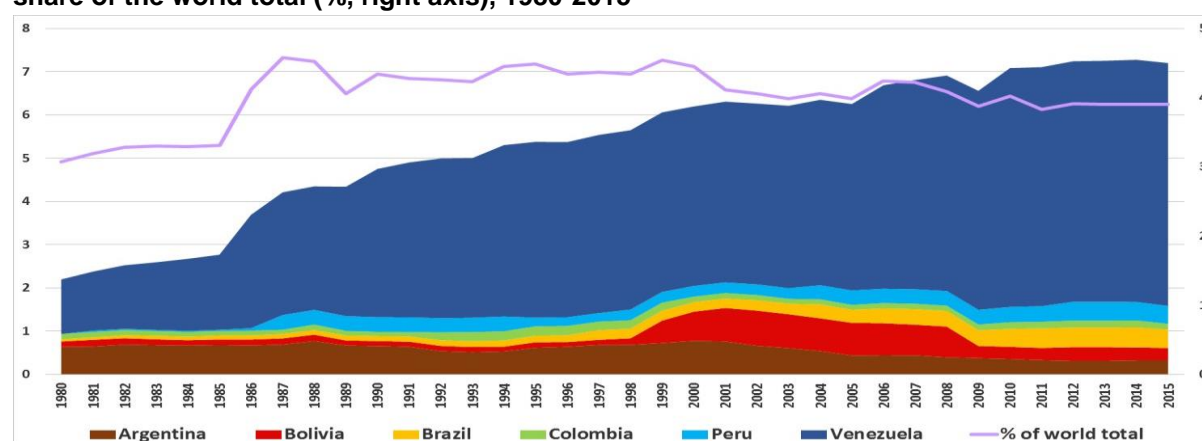
⁹ BP (2016). Total proven reserves in Argentina, Bolivia, Brazil, Colombia, Peru and Venezuela (no detail available on countries with smaller reserves).

¹⁰ EIA (2013). Conventional oil and natural gas is trapped in reservoirs underground, unconventional oil and natural gas are trapped inside rocks that have to be fracked to release the oil and the natural gas by injecting high volumes of water, sand and chemicals into cracks to facilitate the oil and natural gas extraction.



potentially recoverable gas from its shale deposits (22.7 Tcm, about four times the level of conventional gas in Venezuela). Brazil ranks in tenth position with 6.9 Tcm of technically recoverable shale gas volumes. Shale deposits exceed the pre-salt gas reserves, so the country has the potential to become a major player in gas in addition to oil once the pre-salt fields' production eventually gets underway. Venezuela comes in third place for South America with 4.7 Tcm, followed by Paraguay with 2.1 Tcm, Colombia with 1.6 Tcm, Chile with 1.4 Tcm and Bolivia with 1 Tcm.

Figure 3: Evolution of proven reserves of natural gas in South America (Tcm, left axis) and share of the world total (% , right axis), 1980-2015



Source: BP (2016)

In addition to fossil fuels, South America is also rich in renewable energies thanks to the sheer size of the continent and its geographic diversity, which is composed of extensive hydro basins, desert regions and volcanic mountains in the Andes. These characteristics offer an extensive and diverse potential of renewable energy resources. All the countries considered in this paper have a high potential for hydropower, wind and even solar and significant potential for geothermal and biomass as seen in Table 1.¹¹ This considerable potential has only recently begun to be exploited to generate electricity with the important exception of large hydropower. The region accounts for about 17% of the world's hydropower generation.¹²

Table 1: Renewable energy potential in South America, by country and by fuel (2014)

	Hydro	Wind	Solar	Geothermal	Biomass and waste
Argentina	High	High	High	High	High
Bolivia	High	High	High	High	Medium
Brazil	High	High	High	Medium	High
Chile	High	High	High	High	High
Colombia	High	High	High	High	Low
Ecuador	High	Unknown	High	High	Unknown
Paraguay	High	High	High	Unknown	Medium
Peru	High	High	High	High	Medium
Uruguay	High	High	High	Unknown	Medium
Venezuela	High	High	High	Low	High

Source: IDB (2014)

¹¹ See GENI (2009) for more information

¹² Data for 2013. Source: IEA (2015a), Table 1.2, pp.III.8-11

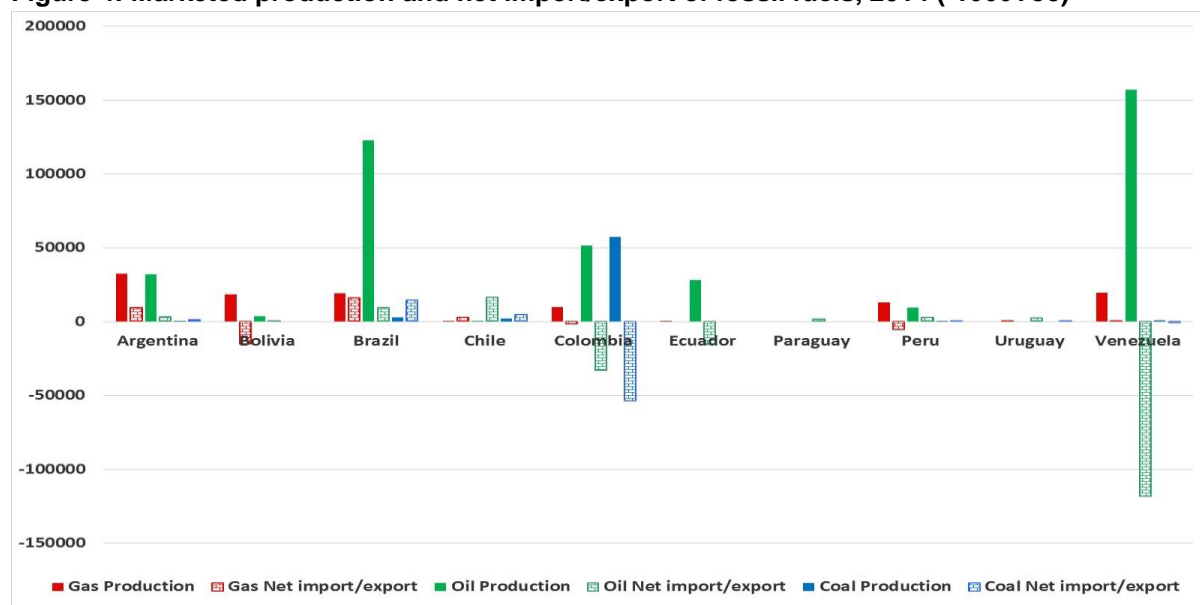


1.1.2. Exploration and production

The development of oil resources began in the early 1900s¹³ and large hydro energy in the power generation sector in the 1970s. Natural gas did not spark much attention before the 1990s and most countries only started to develop their markets in the 2000s¹⁴ except in Argentina, where the gas industry started to develop in the 1960s; and to a lesser extent in Venezuela where (associated) natural gas was a by-product of oil production. The long distances and the difficult geography between gas reserves and main population and industrial centres contributed to discourage gas projects in a region relatively well-endowed with other energy sources which offer higher economic benefits such as oil, or easier means of transport and storage such as coal.

The exploitation and production of the resources offers a diversified picture. The continent is a net oil and coal exporter but has been a net gas importer since 2008. There are wide disparities across countries as shown in Figure 4. Venezuela, an OPEC member, is the largest producer and exporter of oil. Brazil, Colombia, Argentina, Ecuador and Peru are also oil producers but Brazil and Peru both need to complement their production with some imports. Coal is mostly produced in Colombia, which exports 95% of its output. Brazil and Chile are the two main importers of coal, albeit in relatively small quantities. The production of natural gas reached 138 bcm in 2015. It was highly concentrated (>99%) in six countries: Argentina 29%, Venezuela 18%, Brazil 18%, Bolivia 16%, Peru 10% and Colombia 9%. Only two of these producers were net exporters: Bolivia (80% of its production) and Peru (34%). Colombia exported small quantities to Venezuela in the first half before the contract end in June. In contrast, Chile imported 76% of its needs, Brazil 45%, Argentina 21% and Venezuela 1.6%.¹⁵

Figure 4: Marketed production and net import/export of fossil fuels, 2014 ('1000Toe)



Sources: IEA (2016b)

¹³ For more information on the development of the oil industry, see Philip G. (2007). For a literature review on the topic, see Bucheli M. (2010)

¹⁴ See IEA (2003) for more information

¹⁵ Calculated from IEA (2016a)



South America has a well-developed hydropower capacity but other than large hydro, energy policies have rather focused on the exploitation of oil, gas, and also coal in Colombia. There have been very few incentives to promote renewables other than large hydro projects¹⁶ until the late 2000s with the notable exception of biomass, which is used to produce fuels such as ethanol from sugar cane and biomass for electricity generation. But renewable energies such as wind, solar, biofuels and geothermal are becoming increasingly important in governments' agendas and their role has started to rise in the energy mixes. For instance, in Brazil, wind energy has grown quickly to 8.7 gigawatts (GW) at the end of 2015,¹⁷ with no direct subsidies.¹⁸ Environmental awareness, abundance and falling costs of renewables, and maturing technologies offer new opportunities for the region as a whole and more importantly, at the national level where non-conventional renewables (i.e. all but large hydro) could help national markets, especially the smaller ones, to meet their rising energy demand. Renewable energies also provide access to electricity through decentralized micro-grids in remote locations that are not (and perhaps may never be) covered by national grids.

Focusing on natural gas production, the regional total grew rapidly as seen in Figure 5. Marketed production reached 138 bcm in 2015 (four times more than in 1980 and 50% more than in 2000), but important disparities across countries exist. Most of the gas reserves are located in the north of the continent, but more than 60% of the marketed production derives from countries located in the Southern Cone. Argentina is the largest producer with 39.9 bcm in 2015, but while it accounted for most of the increase in the 1990s thanks to liberalisation and privatisation measures, the volumes have been in decline since the 2004 gas crisis.¹⁹ Venezuela is the second producer with 24.8 bcm. Its output has rather stagnated since the early 1990s in its oil-associated fields. Brazil is a close third with 24.3 bcm due to rapidly rising production in its pre-salt plays. Bolivia comes in fourth at 22 bcm, flat from 2014 after showing strong growth since the early 2010s. Peru is fifth with 13.2 bcm, followed by Colombia with 12.7 bcm, a country struggling to maintain production levels. The others were negligible at the regional level.²⁰

It is important to note that marketed production only represents a limited share of total gross natural gas production (about 60% in 2012). As seen in Table 2, about 25% of the gas produced was reinjected into reservoirs, 6% was flared or released into the atmosphere and other 'losses'²¹ accounted for a further 10%, although differences by country were important.²² For instance, while Venezuela had by far the largest gross production with 75 bcm in 2012, its marketed production was only second behind Argentina as a result of significant volumes of gas being reinjected in order to maintain pressure in mature oil reservoirs and boost declining oil production. In contrast, Bolivia, which holds large non-associated gas reserves and benefits from major interconnections with neighbouring (and importing) countries, had the largest ratio of marketed production versus gross production at almost 96% which is explained by the fact that the country does not have the capacity to treat the gas, and exports wet gas.²³ About a third of the gas produced in Ecuador was flared as a result of the remote location of the producing oil fields and the limited potential adjacent market for gas. Gas flaring is on a declining trend and gas reinjection is used for secondary oil recovery and also

¹⁶ Non-large hydro renewables include small hydro

¹⁷ GWEC (2016), p.2

¹⁸ Financial Times, 2 December 2014, Companies see sunny outlook for renewables

¹⁹ See Honoré A. (2004) for more information on the Argentine market during and post the 2004 crisis

²⁰ IEA (2016a), p.II.4, table 1

²¹ Losses can mean various uses here. For instance, the use of gas in a platform to generate power is an important part where production is offshore, for instance about 15% in Brazil. Losses by shrinkage are different: the heavier liquids are removed from the wet gas in a gas processing plant and the remaining dry gas has a lesser volume. Depending on the exact composition of natural gas, shrinkage can amount to 5-6%.

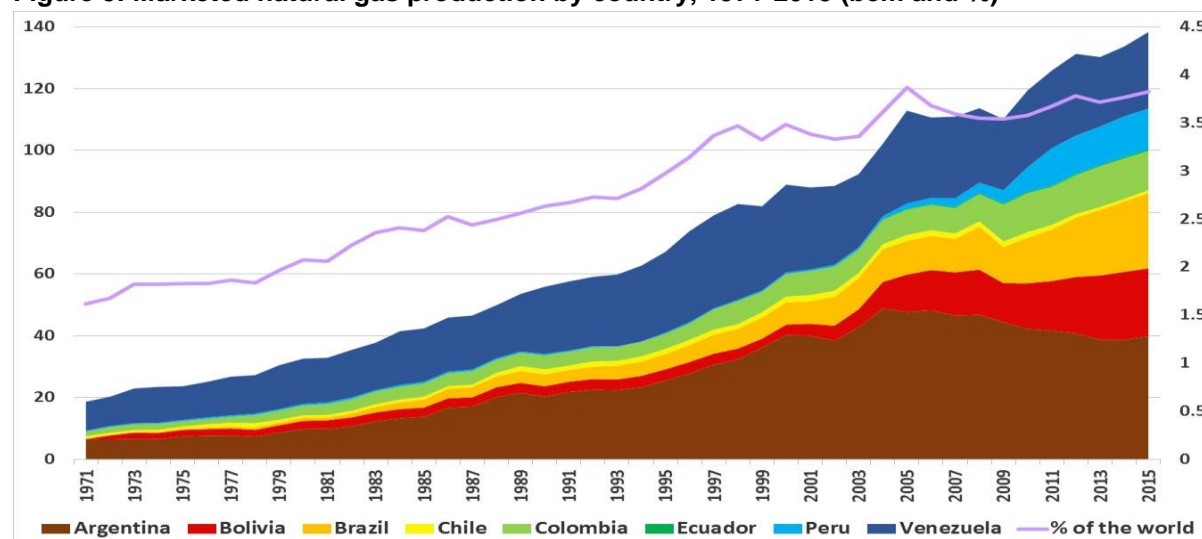
²² Data for gross gas production, reinjection, flared/vented gas and "other losses" are from Cedigaz (2013)

²³ And therefore no shrinkage happens



sometimes because there is no market for the gas. Reinjection has a lesser impact than flaring on greenhouse gas (GHG) emissions.²⁴

Figure 5: Marketed natural gas production by country, 1971-2015 (bcm and %)



Note: Left axis: level of production in bcm; right axis: % of the world

Source: IEA (annual), Natural gas information, several reports, table 1

Table 2: Marketed production, gas reinjected and flared and volume shrinkage, 2012 (bcm)

	Gross production	Gas reinjected	Gas flared	Other losses	Marketed production	Marketed vs gross (%)
Argentina	44.1	0.66	0.94	4.86	37.64	85.35
Bolivia	18.66	0	0.23	0.52	17.91	95.98
Brazil	25.83	3.54	1.44	3.87	16.98	65.74
Chile	1.21	0	0.02	0.01	1.18	97.52
Colombia	31.44	16.8	0.77	1.94	11.93	37.95
Ecuador	1.54	0	0.51	0.51	0.52	33.77
Peru	18.12	4.55	0.23	1.49	11.85	65.40
Venezuela	75.68	29.66	10.2	9.38	26.44	34.94

Source: Cedigaz (2013), p.44

1.2. Regional integration and the start of LNG imports

Considering the differences between markets with energy surplus and in need to monetise their resources and those with an energy deficit and in need of imports, energy integration at the regional level appears to be the most logical and economical way to solve these problems, but this solution has never been a straightforward one, especially in the case of natural gas.

²⁴ The share of gas flared in South America decreased from 32% in 1970 to about 6.5% in 2012, Sources: IEA (2003), p.30, Cedigaz (2013), p.44



1.2.1. Rise and fall of sub-regional gas trades

Discussion concerning natural gas trades across the continent dates back to the 1950s/1960s at least, especially for the Southern Cone, due to asymmetries between countries, which created opportunities to link producers and consumers.²⁵ However, natural gas integration really began in 1972 when gas started to flow through the Yabog (Yacimientos-Bolivian Gulf) pipeline between Bolivia and Argentina. Until the mid-1990s, this was the only cross-border gas pipeline in the region. This first link was largely successful even if exports at the time did not really take off and were limited to the original volumes agreed in the 20-year contract²⁶ because abundant gas reserves were found and developed shortly after in Argentina.

As a result of these gas discoveries, Argentina looked for ways of monetising its own gas supplies and markets to export its surplus. Between 1996 and 2001, seven pipelines were built between Argentina and Chile: three in the south to meet the increased gas demand resulting from the expansion of the Methanex (methanol) plant, two in the centre to serve large cities (including the country's capital Santiago) and two in the north which supply the copper mining industry. In addition to Chile, Argentina started to export gas to Uruguay in 1998, and in 2000 it started to export gas to Brazil to supply an AES 600 mega watt (MW) thermoelectric power plant built at Uruguiana on the Brazil-Argentina border. This was intended as the first stage of a more ambitious project to supply Argentine gas to southern Brazil, and compete with Bolivian gas which started to flow to Brazil at around the same time via the Gasbol pipeline which was finalized between 1999 and 2000²⁷ and was designed to carry 11 bcma.²⁸

In 2007, first signs of integration in the northern part of the continent occurred with the inauguration of a pipeline between the Guajira field in north eastern Colombia and Maracaibo in western Venezuela with gas initially meant for reinjection in order to help Venezuela boost its oil production.

All these pipelines have created the basis for a sub-regional gas transportation network, rather than a wider regional integration. These integration initiatives, especially in the Southern Cone, encountered several hitches over the years.²⁹ The most significant ones were due to the decline of gas production in Argentina. Until 2004, Argentina exported gas to neighbouring countries on a regular (uninterrupted) basis, but when its domestic natural gas production fell below its consumption, the country broke its export contracts to Chile and Brazil (and to a lesser extent to Uruguay),³⁰ suspended authorizations for new export permits and gave priority to national consumption. This decision had a major impact, especially on Chile, which was completely dependent on pipeline gas imports from Argentina. Repeated supply interruptions created major economic problems for industry and electricity generators in Chile, which had to resort to more expensive alternative fuels to fulfil their needs. The impact of the cut was less severe on the Brazilian economy because the volumes were smaller and

²⁵ Ortiz F.M. (2014)

²⁶ The first contract between the two countries ran from 1972 to June 1999, during which time Bolivia exported a total of 53 bcm, worth about \$4.5 billion. Source: IEA (2003), p.59

²⁷ The first part was completed in 1999 and starts at Rio Grande in Bolivia and connects with the Brazilian network that supplies the cities of São Paulo, Rio de Janeiro and Belo Horizonte. The second part was completed in March 2000 and links Campinas to Canoas, near Porto Alegre in the state of Rio Grande do Sul. Source: IEA (2003), pp.58-60

²⁸ A second Bolivia to Brazil pipeline started operating in 2002 mostly to the Cuiabá power station (which was also supplied by Argentine gas for a while). Source: IEA (2003), pp.58-60

²⁹ The subsequent paragraphs only give a brief account of the historical developments of natural gas integration, for more detailed information see IEA (2003)

³⁰ Except for small volumes supplied to residential consumers in Chile and Uruguay



directed at a single customer (who nonetheless suffered important economic losses).³¹ Uruguay is a much smaller market and Argentina continued to supply some quantities to residential customers. In addition to creating energy supply constraints, the supply interruptions also generated concerns towards Argentina as a reliable supplier, which had failed to fulfil its obligations to ensure security of supply and cooperation, and towards sub-regional integration in general.

To help meet its gas demand Argentina restarted imports from Bolivia in 2004, and signed a new 20-year contract in 2006. The new contract called for steadily growing shipments of natural gas and an additional pipeline between the two countries (the Gasoducto Integración Juana Azurduy (GIJA) which came on line in 2011). Northern Argentina is not well supplied by the domestic natural gas transmission network and relies on more costly oil products (Bolivian gas is intended to replace costlier diesel, fuel oil and liquid petroleum gas). The Gasoducto del Noreste Argentino (GNEA) is another cross border pipeline under construction which will reach the North East region and receive Bolivian gas from 2017.³²

Bolivian gas exports have been reliable in terms of volumes but disagreements over prices with Brazil have risen over the years.³³ These frictions do not seem to have damaged the long-term relations between the two countries and Bolivia and Brazil have started discussions for a new agreement when the existing take-or-pay contract expires in 2019.³⁴

In the Northern countries, not all went as planned either. In 2007, Colombia signed a gas supply contract with neighbouring Venezuela (the country has some associated gas production but national infrastructure is lacking to transport the gas to the Western part of the country). The deal was that Colombia would export just over 1 bcma to Maracaibo in Western Venezuela until 2011, and then the pipeline flow was to be reversed in 2012 to allow Venezuela to ship its own future excess gas to its neighbour. However, reverse flows were postponed due to delays in developing reserves in Venezuela and, in late 2011, Colombia agreed to continue to supply gas to Venezuela for three additional years.³⁵ In June 2014, the contract was extended for another year.³⁶ Despite some existing political tensions between the two countries,³⁷ the security of gas supply has been relatively good until 2015³⁸ (particularly since May) when Colombia had to reduce gas exports to meet its own power demand. Shortages engendered irregular supply with frequent problems that have even at times curtailed supplies altogether.³⁹ The contract terminated on 30 June 2015 and was not renewed. With the start of production from the Perla field, Venezuela will have enough gas to cover its own demand

³¹ Gomes I. (2014a)

³² See Appendix 'Argentina' for more information

³³ In August 2014, Petrobras agreed to pay Bolivian state-owned petroleum company Yacimientos Petrolíferos Fiscales Bolivianos (YPFB) \$434 million to settle a dispute over gas payments and in April 2014, YPFB agreed to supply an additional 0.8 bcma for the 480-MW power plant at Cuiaba in Mato Grosso until December 2016. Source: Platts International Gas Report, 8 September 2014, Cheaper gas found off Brazil. See also Appendix 'Bolivia' for more information

³⁴ Platts International Gas Report, 8 September, 2014, Cheaper gas found off Brazil

³⁵ Platts International Gas Report, 9 April 2012, Colombia aims at regional status

³⁶ Argus news, 18 February 2015, Gas-short Colombia will need LNG by 2017

³⁷ As shown for instance in 2008 when Venezuelan President Hugo Chavez called for the mobilisation of troops at the Colombian border, or in July 2010 when President Chavez accused Colombia of allowing the US to launch a future attack against his country (and Ecuador and Nicaragua). In turn, Colombia accused President Chavez of aiding and giving refuge to left-wing Colombian guerrilla groups such as the FARC and ELN. Both countries have also major economical differences with Colombia embracing free market economics while Venezuela prefers a more socialist approach of its economy with more state control. Source: Platts International Gas Report, 2 August 2010, Colombia pipes gas to Venezuela

³⁸ A severe drought in Venezuela/Colombia in 2009 saw gas supplies from Colombia temporarily reduced as Bogota prioritized its domestic demand. Source: Platts International Gas Report, 8 November, 2010, Venezuela: anyone but Washington

³⁹ Zamora A., Martinez H. (2014)



and alleviate a looming gas deficit in Colombia if Cardon IV meets production expectations and Venezuela upgrades its transport infrastructure.⁴⁰

Despite the rather limited results of natural gas integration in South America, there have been numerous schemes for additional cross-border pipelines up until the mid-2000s.⁴¹ The most important one was the Gasoducto del Sur (or Great Southern Gas Pipeline). There were trilateral discussions in 2005 between the heads of state of Argentina, Brazil and Venezuela to build a pipeline linking these three countries. The pipeline, with a capacity of 55 bcma, was to cover more than 9,000 km from northern Venezuela through the Brazilian Amazon and down to southern Argentina, with connections to Uruguay and Paraguay on the way, and perhaps even Chile.⁴² Some versions of the project also incorporated Peru and Bolivia.⁴³ Another project was the Gas Ring pipeline, which would have linked Peru to markets in the Southern Cone using existing pipelines and some network expansion. The natural first link was to Chile, but gas pipelines were also planned to Argentina, Uruguay and Southern Brazil and, in some versions, there was also a link to Bolivia. Both pipelines would have transported natural gas over very long distances with the additional challenges of going through natural barriers such as the Andes Mountains, the Amazon rainforests or the Peruvian jungle. In addition to distance and geographic challenges, the sparse population and a total lack of infrastructure (including roads) in some regions would make these very costly and uneconomic projects in addition to potentially damaging ecological impacts. Any new major pipeline projects are unlikely to happen aside from the GNEA pipeline project between the GIJA pipeline in Bolivia and the Northern and Central part of Argentina which is due for completion in 2017 when Bolivian deliveries are set to rise to 27.7 mcm/d (10.1 bcma).⁴⁴

As a result, and despite long distances and geographical obstacles, there is relatively good interconnectivity in the Southern Cone with a dozen cross-border gas pipelines between Bolivia, Argentina, Chile and Uruguay but (only) one cross-border pipeline in the North between Colombia and Venezuela as seen on Map 1. A summary of the existing capacity as of 2016 is provided in Table 3.

Natural gas integration never really took off despite political support for the concept of energy integration. The cross-border exchanges were arguably more bilateral initiatives between a producer and a consumer than truly a regional market structure. Coordinated regulation, pricing and policies were non-existent. Experience of natural gas integration has been complicated, with reductions in volumes or shut-offs, difficult pricing negotiations, uncertain timing for new reserves development in exporting countries and changing political relationships. At times of shortage, producing countries gave and will continue to give priority, somewhat understandably, to their domestic market. As a result, importing countries can expect to face potential supply issues. This atmosphere does not favour new interconnection projects, but it does support alternative solutions such as LNG, (which does not require cross-border cooperation) especially since 2008, when total production fell below gas demand, and external imports were needed to meet the continent's growing demand, even if perfect integration had been in place.

⁴⁰ Platts International Gas Report, 14 July 2014, Perla: Venezuela's big gas hope

⁴¹ See a map of cross border pipeline projects in South America in the mid 2000s in Olade (2014), p.50

⁴² Weintraub S., Hester A. and Prado V.R. (2007), p.428

⁴³ Gomes I. (2014a), p.53

⁴⁴ Platts International Gas Report, 11 August 2014, Default to slow Vaca Muerta



Map 1: Natural gas infrastructure in South America, 2016



Note: The list of "Planned/Proposed" LNG Regasification Terminals represented in this map is not exhaustive
Source: IEA (2016a), p.VI.4 and Author's updates



Table 3: Cross-border natural gas pipelines in South America, 2016

Name	Origin	Destination	Completion	Length	Capacity	Situation 2015
Yabog (Yacimientos Bolivian Gulf)	Bolivia (Santa Cruz de la Sierra)	Argentina (Northern transportation network, Campo Duran)	1972	441 km	6 bcma (increased to 10 bcma in 2015)	Used
Gasoducto Integración Juana Azurduy (GIJA)	Bolivia	Argentina (Salta province)	2011	50 km	7.7 mcm/d (2.7 bcma)	Used
Gasoducto del Noreste Argentina	Bolivia's GIJA pipeline	Argentina (Northern and Central provinces: Salta, Formosa, Chaco, Misiones, Corrientes, Entre Ríos and Santa Fe)	2016	1810 km	27.7 mcm/d (10.1 bcma)	Under construction
Tierra del Fuego (Methanex PAN)	Argentina (South, Austral Basin)	Chile (South, Punta Arena, to serve the methanol plant)	1997	83 km	2 mcm/d (0.73 bcma)	Empty
GasAndes	Argentina (Neuquén basin)	Chile (San Bernardo, near Santiago)	1997	463 km	9 mcm/d (3.28 bcma)	Used winter 2016, reverse flow
GasAtacama (Cuenca Noroeste)	Argentina (Noroeste basin)	Chile (Northern coast, Mejillones)	1999	941 km	8.5 mcm/d (3.1 bcma)	Empty
Pacífico	Argentina (Neuquén basin)	Chile (South, Concepción)	1999	638 km	9.7 mcm/d (3.54 bcma)	Empty
NorAndino	Argentina (Noroeste basin)	Chile (Atacama Desert region, Copper-mining industry)	1999	1066 km	7.1 mcm/d (2.59 bcma)	Used winter 2016, reverse flow
El Cóndor-Posesión (Methanex YPF)	Argentina (South, Austral Basin)	Chile (South, Punta Arena, to serve the methanol plant)	1999	9 km	2 mcm/d (0.73 bcma)	Empty
Patagónico (Methanex SIP)	Argentina (South, Austral Basin)	Chile (South, Punta Arena, to serve the methanol plant)	1999	33 km	2.8 mcm/d (1 bcma)	Empty
Gasoducto del Litoral	Argentina (Entre Ríos, Colon)	Uruguay (Paysandú)	1998	26 km	0.7 mcm/d (0.26 bcma)	NA
Gasoducto Cruz del Sur	Argentina (Buenos Aires)	Uruguay (Montevideo)	2002	193 km	1.8 bcma	NA
TGM (Paraná-Uruguayana)	Argentina (Entre Ríos, Aldea Brasileira)	Brazil (Uruguayana)	2000	450 km	2.8 mcm/d (1 bcma)	Used
Gasbol	Bolivia (Santa Cruz de la Sierra)	Brazil (South, Porto Alegre in Rio Grande do Sul)	1999-2000	3150 km	30 mcm/d (10.9 bcma)	Full
Bolivia-Brazil	Bolivia (Rio San Miguel)	Brazil (Cuiabá in the State of Mato Grosso)	2002	626 km	2.8 mcm/d (1 bcma)	Full
Antonio Ricaurte	Colombia (La Guajira)	Venezuela (West, Maracaibo)	2007	225 km	4.2 mcm/d (1.5 bcma)	Empty

Source: Author's research⁴⁵

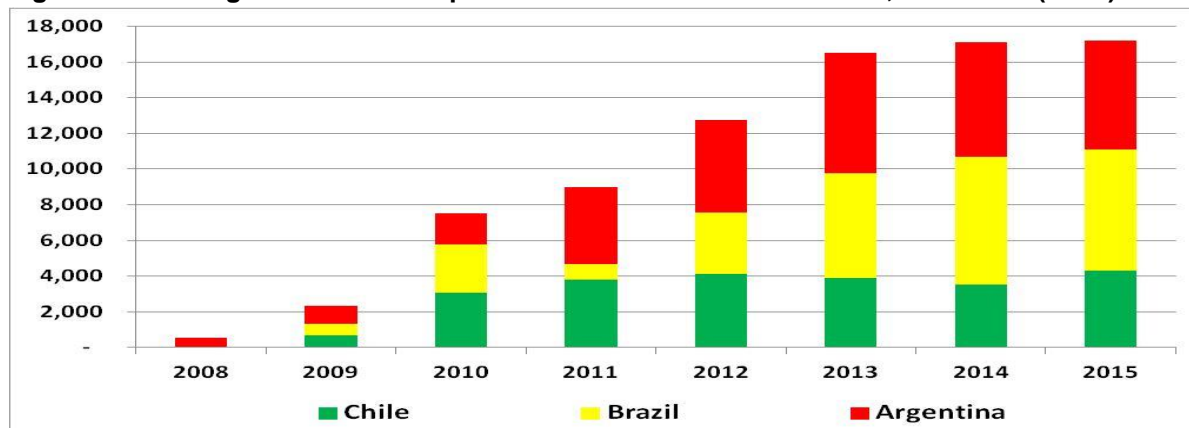
⁴⁵ For additional information on cross border pipelines, see IEA (2003); Gomes I. (2014a)



1.2.2. The need for LNG imports

With the shortfalls of Argentine production, cut exports to Chile and the rapid growth of unpredictable natural gas demand peaks in the Brazilian power sector, these countries had to look for new natural gas import sources. They turned to LNG to increase security of supply, add much needed additional volumes and/or provide better flexibility in the system. The self-contained South American natural gas market first received non regional gas in the form of LNG in 2008, and volumes rose rapidly from 0.5 bcm in 2008 to 17.2 bcm in 2015 as seen below in Figure 6.⁴⁶

Figure 6: Annual growth of LNG imports in South American countries, 2008-2015 (mcm)



Source: Platts LNG data

Chile turned to LNG to improve its security of supply and replace Argentine supplies. The Quintero LNG terminal, close to the country's capital Santiago, came on line in 2009 and the first commercial LNG cargo was delivered the same year.⁴⁷ The terminal, which provides gas for the nearby power plant and the copper smelter, is the first land-based LNG regasification facility to be constructed in South America. The Mejillones LNG terminal (Floating Storage Regasification Unit - FSRU), in the north of the country, came on line in 2010 and is used to supply power generation plants for the region's largest copper and mineral industries.⁴⁸ LNG imports have enabled natural gas to recover part of its market share lost to diesel oil and other fuels especially in power generation. In 2015, LNG imports reached 4.3 bcm. The deliveries are relatively flat throughout the year as seen in Figure 7.

Argentina's reduction of exports and the renewal of imports from Bolivia was insufficient to cover rising gas demand and the country also had to turn to LNG to supplement gas volumes. Since 2008, Argentina has been a net gas importer. The first LNG terminal, the Bahia Blanca terminal (FSRU), 643 km southeast of the capital Buenos Aires, came on line in 2008 and the first LNG cargo was imported the same year. Due to continued gas shortages, the country commissioned a second LNG terminal, the Escobar LNG (FSRU), on the Paraná River 48 km from Buenos Aires. It was inaugurated in 2011. In 2015, LNG imports to Argentina reached 6.1 bcm, slightly lower than 2014 thanks to a warmer winter and slightly higher domestic production. Because of its significant demand seasonality, LNG imports are mostly concentrated in the South American winter months in mid-calendar year to meet peak demand in the residential sector [Figure 7].

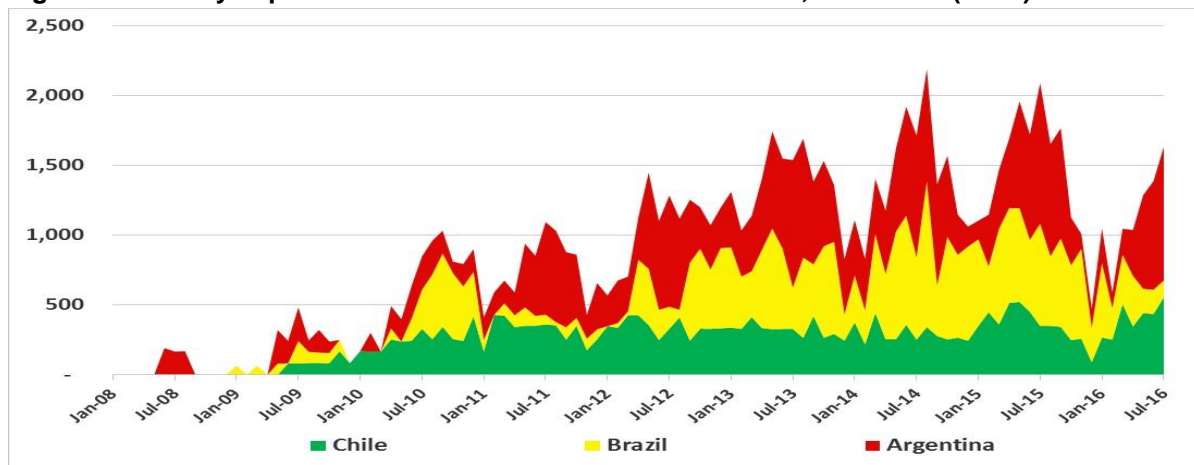
⁴⁶ LNG data in this section comes from Platts LNG data, www.platts.com (unless otherwise stated)

⁴⁷ Reuters, 13 July 2009, BG Group delivers first LNG cargo to Chile

⁴⁸ GIIGNL (2010), p.11



Figure 7: Monthly imports of LNG in South American countries, 2008-2016 (mcm)



Source: Platts LNG data

Faced with rapid growth of peak demand in the power sector, Brazilian state-controlled Petrobras turned to LNG to add flexibility in the system. LNG imports in **Brazil** arrive through three terminals operated by Petrobras. The Pecém LNG terminal, in the Northeast, the first world FSRU, was opened in mid-2008 and the first LNG cargo was delivered the same year. The second LNG terminal, the Guanabara Bay LNG terminal (FSRU) is located at Rio de Janeiro (Southeast) and opened in January 2009. The third LNG terminal, the Bahia regasification terminal, is at the border between the Northeast and the Southeast and started in early 2014. Interestingly, LNG imports have also arrived via Argentina's Bahia Blanca terminal. These LNG imports are regasified and delivered to Brazil through the pipeline that links the Argentine system with the 640 MW Uruguiana thermoelectric plant in the southern state of Rio Grande do Sul close to the border with Argentina.⁴⁹ LNG imports have served to increase the total volume of gas supply but also to add much needed supply flexibility in periods of low hydropower availability when natural gas-fired plants have to be turned up to meet power generation demand (these periods can last for weeks or even months). There is no gas storage in Brazil and associated gas production and pipeline imports from Bolivia are both inherently unsuited to meet short-term flexibility needs.⁵⁰ Short hydro availability placed the country in 2014 and 2015 for the first time as the top LNG importer in South America ahead of Argentina. LNG imports in 2015 were slightly lower than in 2014 at 6.8 bcm due to higher hydropower production and slower economic growth.

Uruguay, another country hit by the reduction of Argentine gas imports, also opted for LNG imports via a floating LNG vessel in the La Plata river off the Uruguayan capital of Montevideo, but the project has been developed at a slower pace. The country is expecting to monetise its surplus from the LNG import terminal and to become a regional hub by selling LNG, pipeline gas or gas-based power during winter months to its neighbours: Argentina (and eventually Brazil). Uruguay expects to start exports to

⁴⁹ LNG imports through Bahia Blanca resumed in 2015. Before that, Uruguiana last operated in May 2014, but was taken off line after Brazil failed to reach an agreement with Argentina over LNG imports via Bahia Blanca. Source: Argus News, 10 February 2015, Brazil resumes LNG imports through Argentina

⁵⁰ There is no gas storage capacity in Brazil, and most gas production is associated with oil. The flexibility in the import contract with Bolivia is also insufficient at times of high demand for natural gas power plants. The take-or pay clause only allows Brazil to reduce monthly demand to 80% of maximum contracted volume (within the limit of 90% of annual contracted volume). Source: OIES/Kapsarc (2016), chapter 6



Argentina sometime in 2017,⁵¹ but the terminal may face new delays, and an opening date later in the 2010s is not unlikely.

In 2015, South America had about 33.5 bcma of LNG import capacity as seen in Table 4. The utilisation rate was only about 51% in 2015, with important differences among the countries (60% in Argentina, 57% in Chile and only about 43% in Brazil).⁵² Two additional regasification terminals were under construction in Uruguay and Colombia with a capacity of 3.7 and 4.1 bcma respectively.

Table 4: LNG import/export facilities in South America, 2015

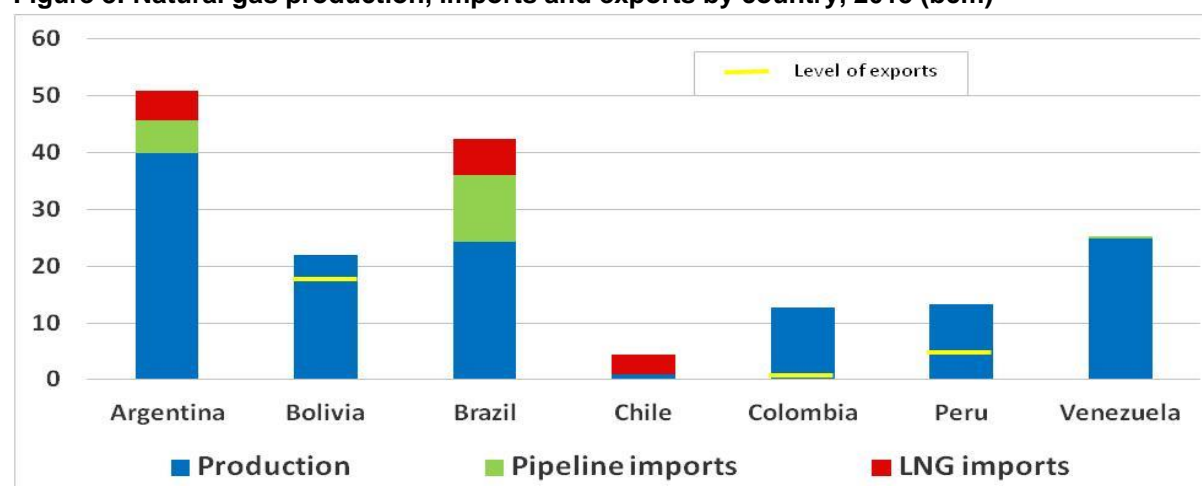
Country	Import / export	Plant	Type	Status	Start-up year	Capacity (bcma)
Argentina	Import	Bahia Blanca GasPort	FSRU	Operational	2008	5.1
Argentina	Import	GNL Escobar	FSRU	Operational	2011	5.1
Brazil	Import	Guanabara Bay	FSRU	Operational	2009	8.1
Brazil	Import	Pecem	FSRU	Operational	2009	2.5
Brazil	Import	Bahia LNG	FSRU	Operational	2013	5.2
Chile	Import	Quintero	Onshore	Operational	2009	5.5
Chile	Import	Mejillones GNL	FSRU*	Operational	2010	2
Peru	Export	Peru LNG	Onshore	Operational	2010	6.1
Colombia	Import	LNG Cartagena	FSRU	Under construction	2017	4.1
Uruguay	Import	GNL del Plata	FSRU	Under construction	2019	3.7

* Terminal with onshore regasification and floating storage

Source: GIIGNL (2016)

The main gas importing countries in 2015 were Argentina, Brazil and Chile, the first two complementing production with pipeline imports and LNG, the third one being almost completely dependent on LNG imports [Figure 8].

Figure 8: Natural gas production, imports and exports by country, 2015 (bcm)



Source: IEA (2016a), p.II.4 table 3, pp.II.42-47 tables 24-26

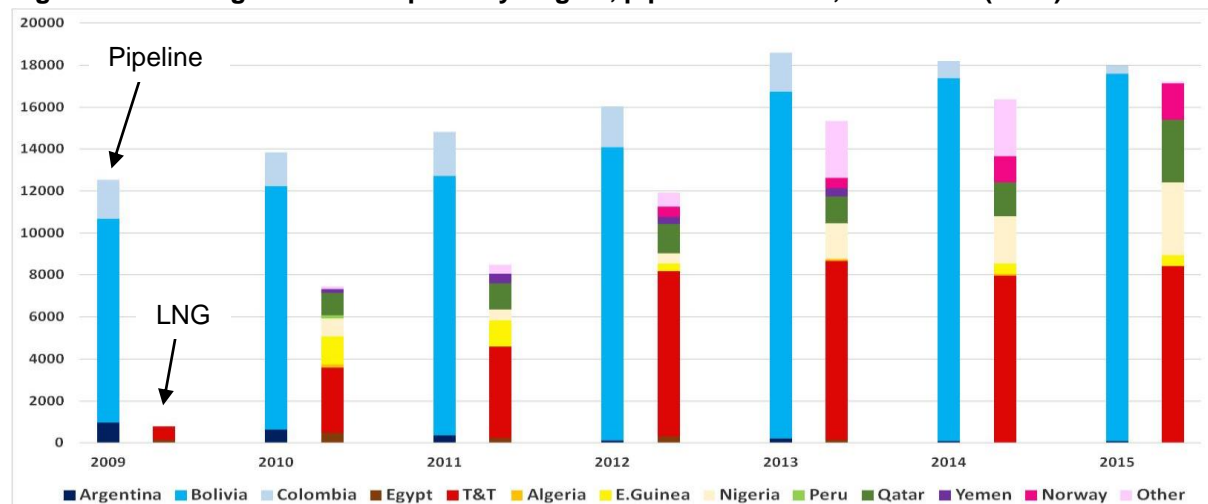
⁵¹ Argus Global LNG, January 2016, Argentina and Uruguay advance gas supply plans, p.6

⁵² Calculated from GIIGNL (2016) and IEA (2016a)



LNG volumes imported to South America have grown rapidly and are getting close to the total of gas traded via cross-border pipeline as seen in Figure 9. Volumes traded via cross-border pipeline originate mainly from Bolivia, as Argentine exports have slowly disappeared and Colombia has been facing rising demand and plateauing production (and is actually waiting to import pipeline gas from Venezuela as of mid-2016). LNG imports have been adding much needed extra volumes but they have also added diversification of sources even if about half of the LNG originates from a neighbouring country - Trinidad & Tobago (T&T).

Figure 9: Natural gas annual imports by origins, pipeline vs. LNG, 2009-2015 (mcm)



Source: IEA, Natural gas information, several reports, Part I: Natural gas market review, tables 19-26 (natural gas pipeline imports by origins) and tables 27 (world LNG imports by origins)

The reasons behind the decision to import LNG vary across countries: insufficient production to match growing demand as in Argentina and soon Colombia; additional volumes to complement production and other imports as in Brazil; and the lack of alternatives and security of supply for Chile and arguably Uruguay. LNG imports are also a source of flexible supply to meet peak demand, but they have proved to be expensive for the importing markets. While Bolivian and Colombian pipeline exports are oil-indexed,⁵³ spot LNG imports into Brazil and Argentina have been based on the highest alternative market price, plus a freight differential, plus a trading margin. Brazil and Argentina have been unwilling to enter into long-term supply agreements albeit for different reasons. In Argentina, financial difficulties have not enabled long-term contracts to be supported by the sole buyer, Energía Argentina Sociedad Anónima (ENARSA). In Brazil, power sector demand uncertainty has made planning LNG requirements difficult if not impossible. After relying primarily on the spot market, Petrobras signed short-term LNG supply contracts in response to rising demand, which has limited further demand for spot LNG cargoes despite low hydropower production in the period 2013 to 2015.⁵⁴ Long-term Chilean LNG import contracts have been based on Henry Hub gas prices (plus a premium) since January 2012.

In addition to import facilities, there is also an export (liquefaction) facility of about 6 bcma located in Peru. The country has a considerable gas surplus and decided to choose the LNG option rather than pipeline exports to neighbouring markets, especially gas importer Chile, as a result of political tensions between the two countries. Chile was constructing an LNG import terminal in parallel, and

⁵³ Argentine pipeline exports seem to have been cost-related. Source: Author's research

⁵⁴ Gomes I. (2014b), p.23

Map 2 below summarises natural gas flows in the region in 2016. By mid-2016, Colombia had ceased to export natural gas to Venezuela (from June 2015) and indigenous gas was redirected to the national market. In Venezuela, the offshore non-associated gas Perla project started producing from July 2015.⁵⁶ Reverse flow from Venezuela to Colombia had been expected in early 2016, but was delayed due to shortages in Venezuela itself and at the time of writing were expected to start in December 2016.⁵⁷ In addition, LNG imports to Chile started to be exported via existing pipelines to Argentina.

The map illustrates the geographical distribution of South American hydrocarbon export infrastructure. Green arrows represent pipeline networks, showing land-based transport routes between countries like Venezuela-Colombia, Brazil-Bolivia, and within Argentina. Red arrows represent LNG export facilities, indicating coastal locations along the Pacific (Peru, Chile) and Atlantic (Brazil, Argentina, Uruguay) shores. The legend in the bottom right corner defines the symbols: a green arrow for 'Pipeline' and a red arrow for 'LNG'.

⁵⁷ Argus Latin America LNG, 4 October 2016, PdV to begin gas exports to Colombia in December, p.11



LNG imports to South American countries represented less than 5% of the total of LNG trades in 2015,⁵⁸ but with fast natural gas demand growth and indigenous production lagging behind, the common expectations are for a continued increase of LNG imports to the continent. How much LNG will be needed for South America is an important factor for the rest of the world, especially for Europe, where most of these volumes might have ended up (Europe being the traditional swing market for LNG). Because the region is already a net importer of natural gas, what the level of additional future gas demand will be is a crucial question. The following section takes a closer look at expectations for gas demand growth at the 2030 horizon.

⁵⁸ GIIGNL (2016), p.14



II. Natural gas demand: expectations and uncertainties

This second section analyses the drivers and constraints for natural gas demand growth in South America. It first takes a closer look at the energy situation in each market and the specific role of gas in their mix. This is an important step due to the important diversity of countries that constitute the region and also because natural gas does not have a captive market and will need to compete with other fuels.⁵⁹ The final considerations focus on the assumptions used to calculate the scenarios up to 2030.

2.1. Heterogeneity of the regional market

2.1.1. Energy markets at a glance

The ten South American countries that we are looking at in this paper are very different from one another in terms of land size, geography, resources, energy mix, population and economy. An overview of this diversity is provided in Table 5. Brazil is by far the largest country and represents about half of the regional energy demand and power generation.

Table 5: Overview of the South American countries' diversity

	Land size*		Population*		GDP (current)*		GDP per capita*		TPES**		Power generation**		Population without electricity ***	National electricity access rate (urban / rural) ***
	Thousand km2	%	Millions	%	US\$ bln	%	USD	%	MToe	%	TWh	%	Millions	%
Argentina	2780	16	43	10	548	15	12744	14	87	15	141	12	1.5	96 (99/66)
Bolivia	1099	6	11	3	33	1	3000	3	8	1	9	1	1.2	88 (96/73)
Brazil	8516	49	208	50	1775	49	8532	10	303	52	591	51	0.8	100 (100/97)
Chile	756	4	18	4	240	7	13344	15	36	6	74	6	n/a	99 (n/a)
Colombia	1142	7	48	12	292	8	6083	7	34	6	70	6	1.2	98 (100/90)
Ecuador	256	1	16	4	101	3	6306	7	14	2	24	2	0.5	97 (99/94)
Paraguay	407	2	7	2	28	1	4182	5	5	1	55	5	0.1	99 (100/98)
Peru	1285	7	31	8	192	5	6115	7	24	4	46	4	2.9	90 (96/70)
Uruguay	176	1	3	1	53	1	15706	18	5	1	13	1	0.0	99 (100/94)
Venezuela	912	5	31	7	371	10	11977	14	68	12	128	11	0.1	100 (100/99)
Total	17329	100	416.4	100	3633	100	87990	100	583	100	1150	100	8.4	-

Note: TPES = Total primary energy supply, excluding electricity and heat trade

* World Bank (2016), data for 2015

** IEA (2016b), data for 2014

*** UNEP (United Nations Environment Programme), data for 2013⁶⁰

⁵⁹ In the residential and commercial sectors, gas competes with electricity, liquefied petroleum gas (LPG) and heating oil. In the industrial sector, gas competes with coal and oil for use in steam boilers. In the production of electricity, gas competes with coal, oil, nuclear, hydro, biomass and other renewable. Source: IEA (2003), p.24

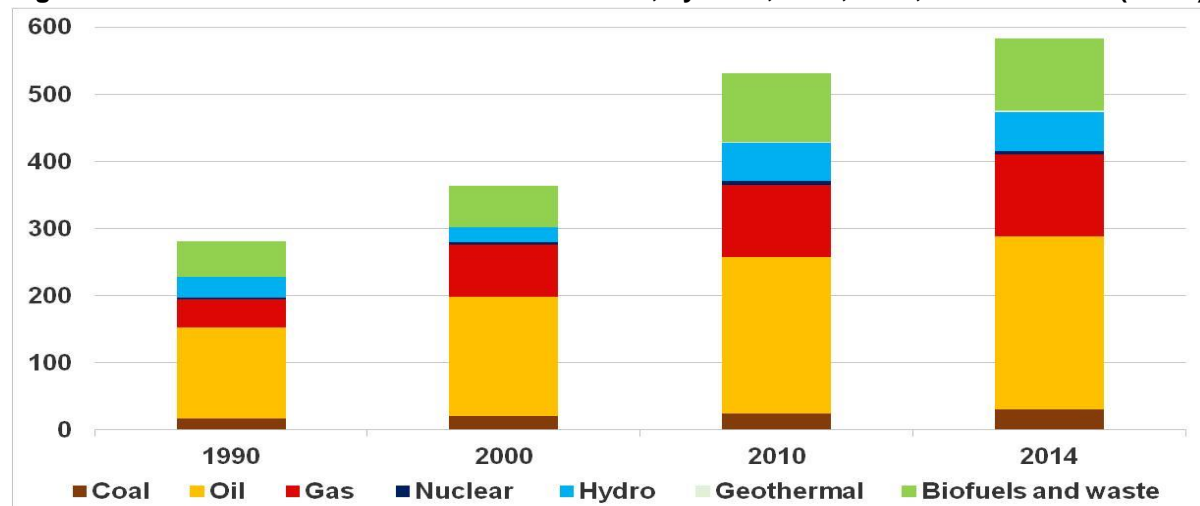
⁶⁰ UNEP (United Nations Environment Programme), database on the website: www.unep.org/media/docs/.../gl_electricity_access_database_final.xls



One common ground between all these different countries is the fast growth of energy demand in the past twenty years or so. After the ‘lost decade’ of the 1980s, economic recovery coincided with sustained growth in energy needs. Total primary energy mix reached 583.3 million tonnes of oil equivalent (Mtoe) in 2014 (excluding electricity trade), up 107% from 281 Mtoe in 1990 and 60% from 364 Mtoe in 2000.⁶¹

Focusing on primary energy supply, the mix has been dominated by oil, which still represents 44% (data for 2014) as seen in Figure 10.⁶² This is not surprising considering that several countries are oil producers, including OPEC members Venezuela and Ecuador. The share of oil has decreased by about 5% since 2000, but the net volume was up by 40% due to total energy demand growth. Shortages in natural gas export volumes in the 2000s led to the increased use of oil products in the power generation and industrial sectors. The second biggest contributor is natural gas, with a share of 21%, which was roughly similar to its percentage share in 2000 but corresponding to a net volume increase of 50%. LNG imports have helped natural gas recover some of its market share, but with rapidly growing demand, oil products are still present in many segments of consumption. Biofuels and waste accounts for almost 19% of the TPES (total primary energy supply) and hydropower for about 10%. Coal, nuclear and geothermal have only limited roles, a common feature in most countries in this region. The only two exceptions were in Colombia and in Chile where coal represented 11% and 19% of the TPES respectively. The former is a major producer and the latter has limited indigenous resources and turned to coal to fill in the gap of its fast growing energy demand.

Figure 10: Evolution of the TPES in South America, by fuels, 1990, 2000, 2010 and 2014 (Mtoe)



Source: IEA, Energy Balances of OECD Countries and Energy Balances of Non-OECD Countries, several reports, tables from individual country pages

The region’s widespread use of renewable sources is notable.⁶³ A share of 29% is significant, especially compared to other regions. However, this picture hides some practical problems. Firstly, biofuels have been claimed to produce as much GHG emissions as the fossil fuels they were designed to replace while at the same time being in direct competition with food crops for land and water usage. Secondly, the reliance on large hydropower causes energy security problems in times of

⁶¹ 2014 was the latest data available at the regional level at the time of writing. Source: IEA (2016b), statistics from individual country tables

⁶² IEA (2016b)

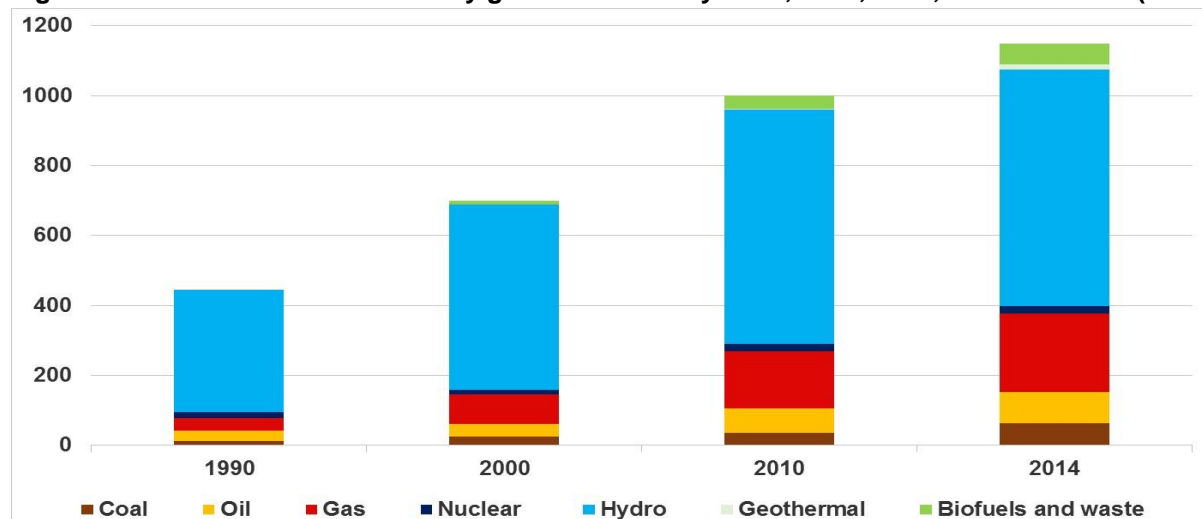
⁶³ Renewable energies include hydro + geothermal + biofuels and waste.



droughts when water levels fall significantly. It can also be a source of environmental and social problems, particularly in sensitive regions like the Amazon rainforest where the construction of the Tucuruí hydro plant in the Brazilian rainforest is an example.⁶⁴

As seen in Figure 11, the electricity generation mix is dominated by hydropower. Most countries that developed large hydropower projects in the 1970s and 1980s had the objective to harness their significant natural resource potential, seek economies of scale and reduce dependency on fossil fuels. Hydropower has been the largest source of electricity since the 1970s, typically supplying around 70% of the regional electricity demand. It still represented almost 60% of the mix in 2014 despite an ongoing drought in several countries.⁶⁵ While the overall generation from hydro has risen (it has doubled since 1990 and increased by 30% since 2000), its relative share in the electricity mix has been declining. Natural gas is the second most important contributor to the generation mix, far behind, with a 20% share, rising from about 12% in 2000 and 8% in 1990 due to the development of the gas industry since the 1990s and the need to add new generation capacity rapidly to meet growing electricity demand and provide back up during low availability of large hydro plants. Power generation from oil products represents about 8% of the mix. Its net generation has risen since 1990, contrary to expectations dictated by a climate change agenda. This is a consequence of rapidly growing power demand but it can also be explained by the -still relatively- limited natural gas infrastructure, which makes it impossible in certain zones to replace these higher generation-cost and more polluting plants with natural gas-fired generation and additional back up at times of low hydro generation. Coal use has remained consistently low and represents just above 5% (2013), even if the total volume of power generated from it has been on the rise. Renewables other than large hydro plants started to develop in the 2000s (6.5% in 2014) with biofuels and waste representing the largest share of this growth. Nuclear is only present in Argentina and Brazil, and is therefore limited in the regional mix (less than 2%).

Figure 11: Evolution of the electricity generation mix by fuels, 1990, 2000, 2010 and 2014 (TWh)



Source: IEA, Energy Balances of OECD Countries and Energy Balances of Non-OECD Countries, several reports, tables from individual country pages

⁶⁴ The construction of the Tucuruí hydro plant led to the flooding of around 2400 km² of rainforest and displaced around 30,000 indigenous people from their traditional territories.

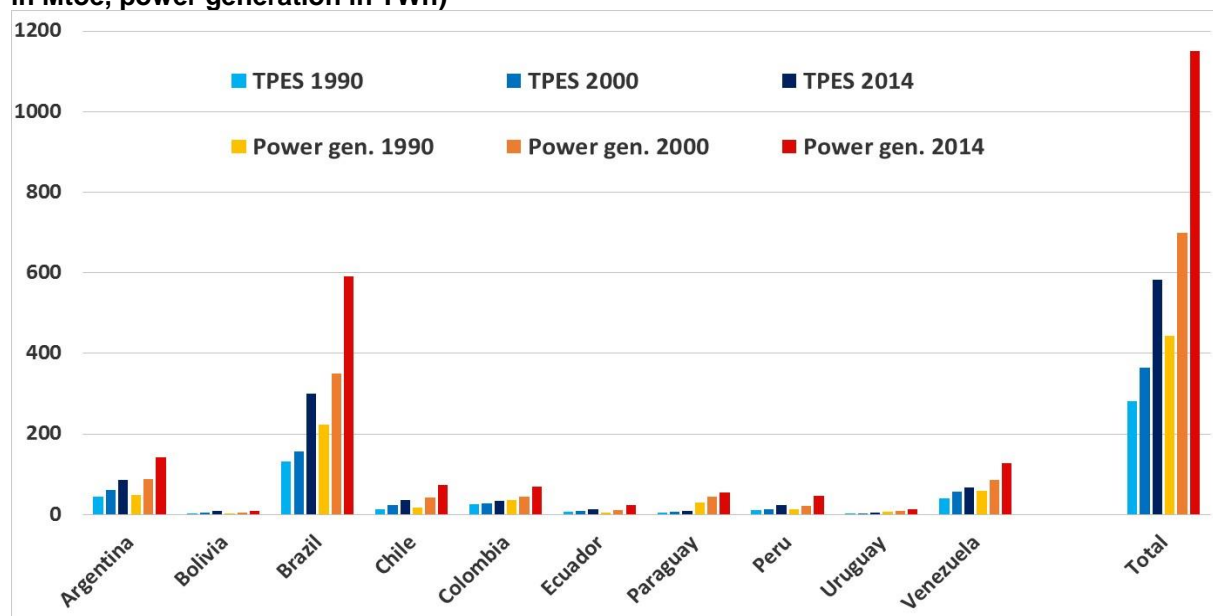
⁶⁵ The world average was 16.4% in 2014. Source: IEA (2016b), p.II.5



In 2014, South America had a total installed generation capacity of 265 GW, of which approximately 54% was large hydropower, 17% was provided by plants using natural gas, 12% oil and diesel, 4% coal⁶⁶ and 6% biomass and waste. Other fuels/technologies (small hydro, wind, solar) each represented less than 3% of the capacity. Nuclear capacity represented less than 1% of the installed capacity.⁶⁷

As seen in Figure 12, Brazil alone accounts for about half of the energy demand of the whole continent. It is also the fastest growing country, well before Argentina and Venezuela, the second and third largest energy markets. What happens in Brazil will therefore have major impacts on the regional total.

Figure 12: Evolution of TPES and power generation by countries, 1990, 2000 and 2014 (TPES in Mtoe, power generation in TWh)



Source: IEA, Energy Balances of OECD Countries and Energy Balances of Non-OECD Countries, several reports, tables from individual country pages

Primary energy fuels mixes vary widely from one country to another as shown in Figure 13, a feature which can easily be explained by the availability (or lack) of indigenous resources. Hydrocarbon exploration and production efforts have been concentrated on the large oil resources. Oil products are the largest source of primary energy (44%) at the regional level and in most countries: Ecuador (83%), Venezuela (57%), Uruguay (45%), Bolivia (44%), Peru (42%), Brazil (42%), Chile (45%), and Colombia (40%).⁶⁸ The only two exceptions are Argentina where gas accounts for more than 49% of the TPES thanks to the early development of the gas industry in the 1960s, and Paraguay which relies on hydropower for 54% of its energy supply. Natural gas is also important in the energy mix of producers and net gas exporters Bolivia and Peru (41% and 34% respectively), but also in Venezuela and Colombia (30% and 25% each), and it represents about 12% of the mix in Brazil and 10% in Chile.

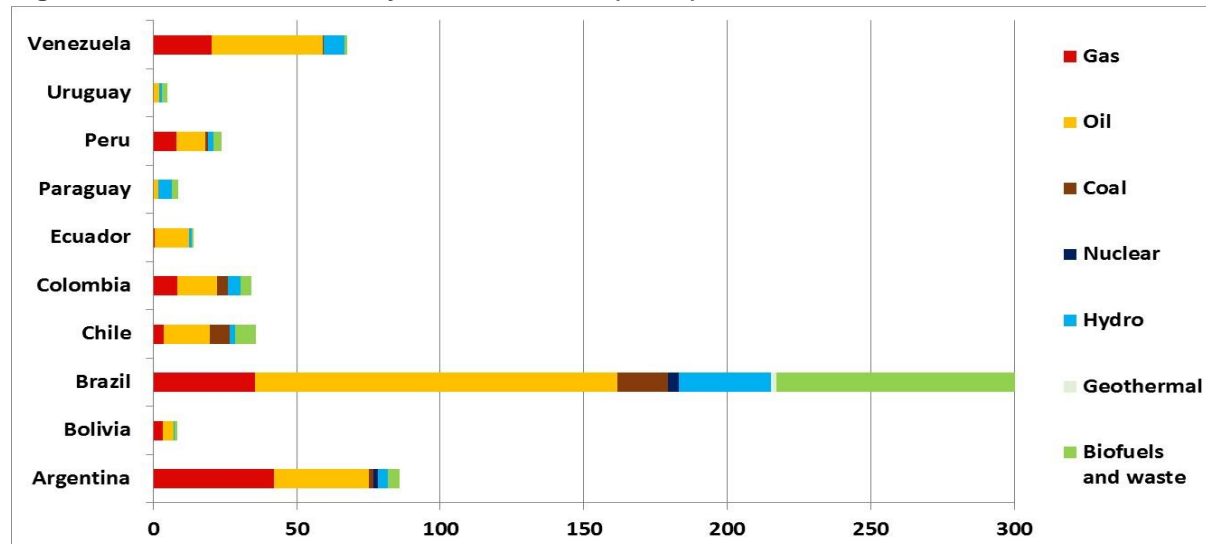
⁶⁶ 1% of the installed capacity is also classified as "other fossil fuels"

⁶⁷ Calculated from Bloomberg New Energy Finance (2015), individual country pages

⁶⁸ IEA (2016b), data for 2014



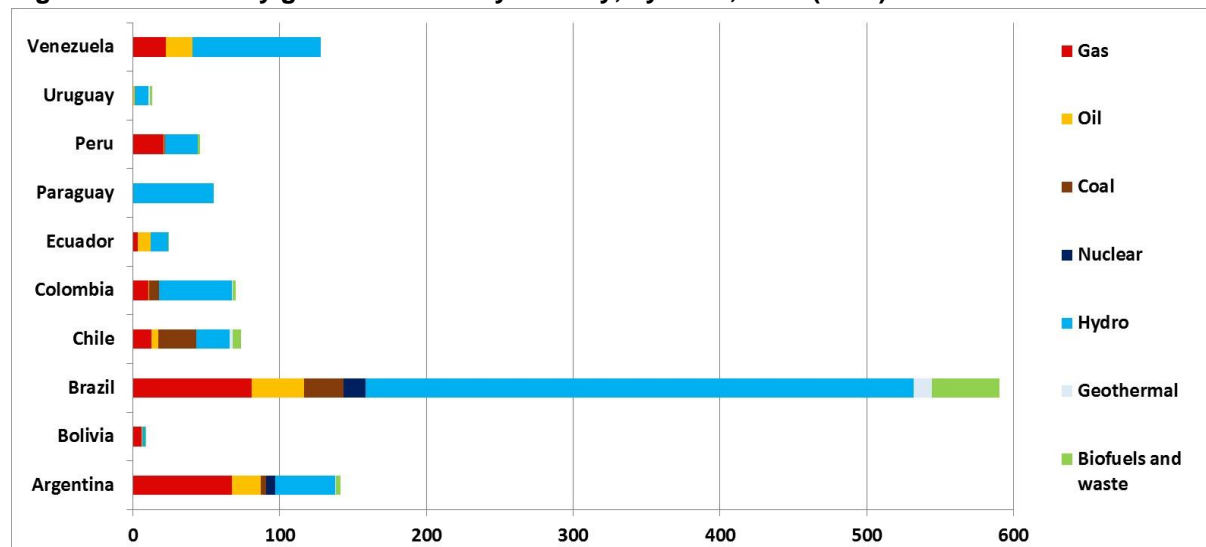
Figure 13: Fuel mix of TPES by countries, 2014 (MToe)



Source: IEA (2016b), statistics from individual country tables

Regarding the **generation mix**, Brazil depends on large hydro to produce about 70% of its electricity, although this share declined to 63% in 2014 due to acute drought.⁶⁹ Hydro is also the main contributor in Paraguay (100%), Uruguay (74%), Colombia (71%), Venezuela (68%), Peru (49%) and Ecuador (47%) as seen in Figure 14. Natural gas is the main contributor only in the (very small) Bolivian market (70%) and in Argentina (48%). It has a large share in Peru (46%) while it wasn't used at all in Paraguay and Uruguay. Chile had the most diversified electricity mix but produced most of its power from coal (35%), and nuclear is only used in Brazil (3% of the mix) and Argentina (4%), as already mentioned.

Figure 14: Electricity generation mix by country, by fuels, 2014 (TWh)



Source: IEA (2016b), statistics from individual country tables

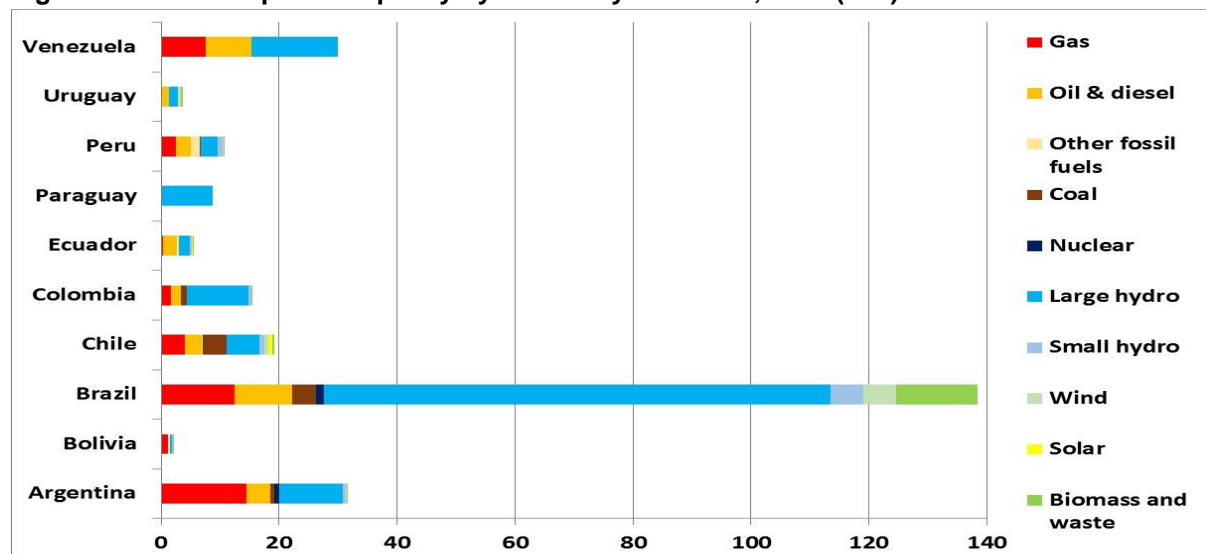
⁶⁹ IEA (2016b), data for 2014



Argentina and Brazil are the two main producers of electricity from natural gas and together generated 66% of the regional total in 2014 (30% for Argentina and 36% for Brazil). While this share is to be expected for Argentina, a mature gas market, such high levels are more surprising for Brazil. This is because the largest power market used flexible power generation such as gas power plants to maintain the grid stability at times of low hydro levels.

Regarding **generating capacity**, the largest hydropower capacity is found in Brazil, but is also well represented in all the countries, as seen in Figure 15. The data on fossil fuels generation capacity is more difficult to interpret due to the category “other fossil fuels” which probably includes multi-fired power plants, some of which can burn natural gas. Of the plants specified as “natural gas”, Argentina has the largest capacity (14.4 GW), close to Brazil (12.5 GW) with Venezuela third with 7.5 GW.⁷⁰ Chile has 4 GW of gas capacity, Peru 2.6 GW, Colombia 1.7 GW, Bolivia 1.1 GW and Ecuador 0.3 GW. Only Paraguay and Uruguay have no gas-fired capacity. Oil and diesel power plants are still well represented despite the high costs of running them and the environmental consequences. If and when the gas infrastructure develops to reach these regions, these power plants could potentially be replaced by gas fired plants.

Figure 15: Installed power capacity by source by countries, 2014 (GW)



Source: Bloomberg New Energy Finance (2015), individual country pages

The use of gas-fired power plants is mainly related to the availability of hydropower capacity, a characteristic that causes large variations in the load factors of the gas plants from one year to another. In 2014, a year characterised by important drought in South America, gas plants ran at an average load factor of 55%-58%. The range comes from the uncertainty regarding the installed capacity qualified as “other fossil fuels” which may or may not use natural gas. Because of this data problem, the range can be significant in some individual countries, as show in Table 6 below.

In Brazil, gas-fired plants ran at a load factor of 74% in 2014, much higher than in normal weather conditions. The country faced the worst drought in eight decades in the period 2012 to (at least) 2016. As hydropower generation declined, the share of electricity generation from gas (and gas used in the

⁷⁰ Bloomberg New Energy Finance (2015), individual country pages, data for 2014



power sector) increased rapidly. Natural gas-fired plants, which are fast ramping and flexible, were called to compensate for low hydropower generation, together with non-hydro renewables.

Table 6: Load factors of natural gas power plants in 2014 (%)

	Max load factor (%)	Minimum load factor (%)
Argentina	53.3	53.3
Bolivia	61.7	46.3
Brazil	74.3	74.3
Chile	35.3	33.7
Colombia	71.7	71.7
Ecuador	n/a	57.1
Paraguay	n/a	n/a
Peru	92.0	58.1
Uruguay	n/a	n/a
Venezuela	34.4	34.4
Total	58.0	55.0

Source: Calculated from Bloomberg New Energy Finance (2015)

The overreliance on hydropower has created economic losses and energy security problems during extended dry periods when water levels fell significantly as seen especially in Argentina, Chile, Brazil and Venezuela. As a consequence, countries have started to look for back-up solutions to prevent blackouts in time of drought. The region is rich in low carbon energy resources, but, because of a mix of delayed development of wind, solar, geothermal and even small hydro, many countries have returned to fossil fuels for generating energy, especially natural gas. The growth of non-hydro renewables will also drive additional needs for gas power plants to be used as back up the intermittency of wind and solar.

2.1.2. The role of natural gas

As for primary energy demand and power generation, South America's gas demand has been on an upward trend as seen in Figure 16. The development of the natural gas industry really gathered pace from the mid-1990s, apart from Argentina.⁷¹ Bolivia started to exploit and produce natural gas around this time, but this gas was mostly exported to its neighbour Argentina rather than directed to its own market. Long distances and difficult geography between natural gas reserves and main population and industrial centres acted as a deterrent to invest in natural gas projects in a region relatively well-endowed with other energy sources. As a result, countries focused on the development of more profitable oil resources and the production (and commercialisation) of natural gas was not considered a priority.

Following the lost decade and the debt crisis of the 1980s, the countries decided to undertake far-reaching economic, regulatory and fiscal reforms to attract private capital in the 1990s.⁷² Logically, each country designed the reforms according to its needs and market characteristics. These changes

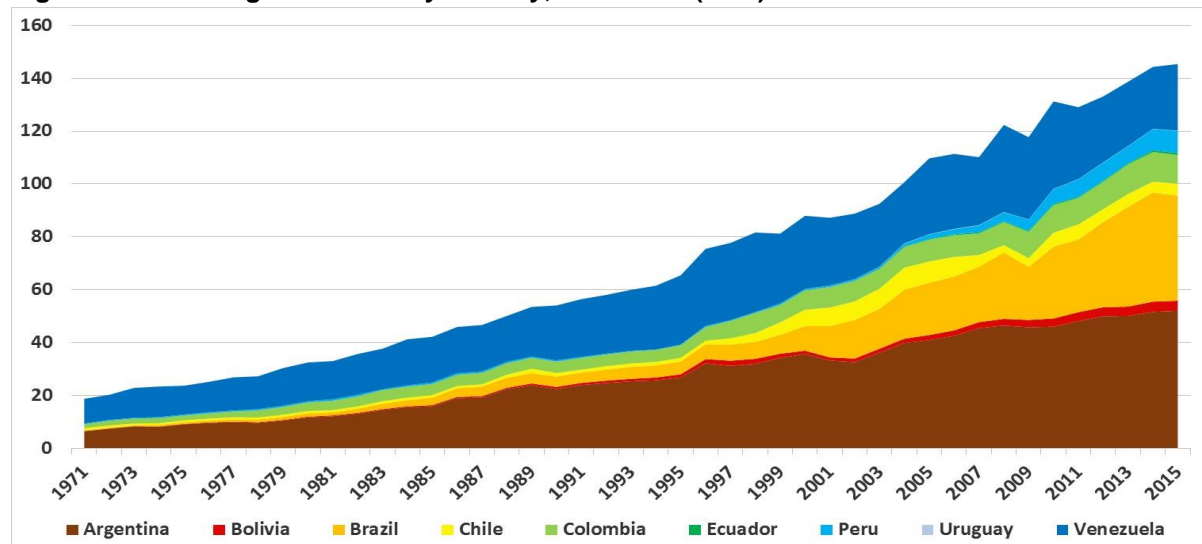
⁷¹ The state gas transmission and distribution company Gas del Estado was formed in 1946, and the first pipeline (the Lavallol – Comodoro Rivadavia Pipeline) was built shortly after, and the North Pipeline, which brings gas from Campo Durán in the north to Buenos Aires, was constructed in the 1960s. Source: Pipeline International, September 2011, The natural gas industry in Argentina: development and perspectives

⁷² For additional information on the problems encountered in the 1980s and the reforms carried out in the 1990s, see IEA (2003), especially pp.66-68 and pp.72-73 for detailed information by country.



produced significant investment which triggered additional exploration and production of hydrocarbon resources, and as importantly, it also facilitated the injection of capital and access to the technology needed to build transportation (including interconnections between production areas and markets), distribution pipelines and gas-fired power plants which provided the means for gas market development in South America. Associated gas produced as a result of successful oil exploration finally found end user markets such as Brazil, Colombia and Venezuela, while other countries experienced a boost in exploration which led to growing reserves and increased production capacity with the construction of an internal network but also cross-border pipelines, like the ones linking Bolivia to Argentina and Brazil, or an LNG export terminal as in Peru.

Figure 16: Natural gas demand by country, 1971-2015 (bcm)



Source: IEA, Natural gas information, several reports, tables from individual country pages

As a result, natural gas demand in South America grew by 5%/year on average in the 1990s, which represented a total growth of 63% or 34 bcm. The additional volumes were concentrated in Argentina (+13 bcm), Venezuela (+7 bcm), Brazil (+5.4 bcm), Chile (+4.8 bcm) and Colombia (+3 bcm) as seen in Table 7. Between 2000 and 2010, the pace slowed, most of which can be accounted for by the financial and economic crisis of 2007-2009. Nonetheless, gas demand growth was still a robust 3.1%/year on average, which represented a total growth of (still) 36% or 34 bcm. This growth was driven by: industrial demand in Brazil and the extension of gas use for power across the region; growth in the mature gas market of Argentina following a freeze of gas prices post the 2004 crisis which boosted gas demand (2.7%/year on average and 15 bcm in total); the development of a gas industry in Peru (22.4%/year on average and 6 bcm in total); continued growth in Colombia (3.5%/year on average and 4 bcm in total); and expansion of the still very small market in gas exporter Bolivia (7.5%/year on average and 2 bcm in total).

In 2015, Argentina was the biggest natural gas market in South America with about 52 bcm (36% of the total) as seen in Table 7. Being one of the oldest gas markets in the world, it has a high level of gas penetration in all end-use sectors and the country enjoys a well-developed infrastructure. Brazil came in second and was rapidly catching up with almost 40 bcm (27%) almost entirely due to growth in its power sector. Venezuela was in third place with 25 bcm (almost 17%). These are fairly large gas markets, which in European terms, would place them in the top six (between the Dutch and the Spanish markets). In fourth place was Colombia, far behind with 11 bcm, followed by Peru with 7.4



bcm, Chile and Bolivia. Uruguay consumed very small quantities while Paraguay does not consume gas.⁷³

Table 7: Natural gas demand by country and average growth rates, 1990-2015 (bcm and %)

	Gas demand (bcm)				Share in 2015 (%)	Average annual growth rate (%)		
	1990	2000	2010	2015		1990-2000	2000-2010	2010-2015
Argentina	22.5	35.7	46.0	52.05	35.8	4.7	2.6	2.5
Bolivia	0.7	1.2	3.1	3.78	2.6	5.2	9.6	4.1
Brazil	3.9	9.3	27.2	39.82	27.4	9.2	11.3	7.9
Chile	1.4	6.2	5.3	4.47	3.1	16.4	-1.6	-3.3
Colombia	4.3	7.3	10.5	10.88	7.5	5.4	3.6	0.8
Ecuador	0.0	0.0	0.4	0.7	0.5	n/a	n/a	11.5
Peru	0.5	0.5	5.7	8.43	5.8	n/a	27.6	8.2
Uruguay	0.0	0.0	0.1	0.09	0.1	n/a	7.9	2.6
Venezuela	20.8	27.7	33.0	25.21	17.3	2.9	1.8	-5.3
Total	54.1	88.0	119.5	145.43	100	5.0	3.1	4.0

Source: IEA, Natural gas information, several reports and IEA, Energy Balances of OECD Countries and Energy Balances of Non-OECD Countries, several reports

Out of a total South American consumption of 144 bcm in 2014, 39% went to the power sector, 23% to industry, 11% to the residential and commercial sector, 6% to transport and 21% to other sectors, which include the energy industry own use.⁷⁴ As seen in Figure 17, the volume of natural gas used in the power sector has doubled between 2000 and 2014 as gas, the cleanest of all fossil-based fuels, has increasingly been used in Combined Cycle Gas Turbines (CCGT). First, the impact of rapidly growing economies but also the expansion of the grid to areas not previously covered meant that power demand grew very rapidly. It was necessary to add new capacity quickly and at moderate costs as most investments were undertaken by private companies rather than by state-owned integrated monopolies.⁷⁵ Not only have CCGTs lower up-front costs, they have also shorter lead times, high conversion efficiency (close to 60%) and flexibility, and lower environmental impacts than coal or oil plants (and arguably, than large hydropower too). The second factor, which explains the rise of natural gas in the power sector was the need to diversify the electricity mix away from large hydro after several episodes of droughts. Interestingly, because the share of renewables is already high, environmental awareness and the climate change agenda are not major drivers for additional natural gas use in power.

The industrial sector, which used to be the largest gas user, has increased its demand for gas by 34% between 2000 and 2014 due to strong economic growth and the substitution of gas for oil, which has several benefits: improving GHG emissions, limiting the costs of imports and enabling the export of displaced oil volumes in producing countries.

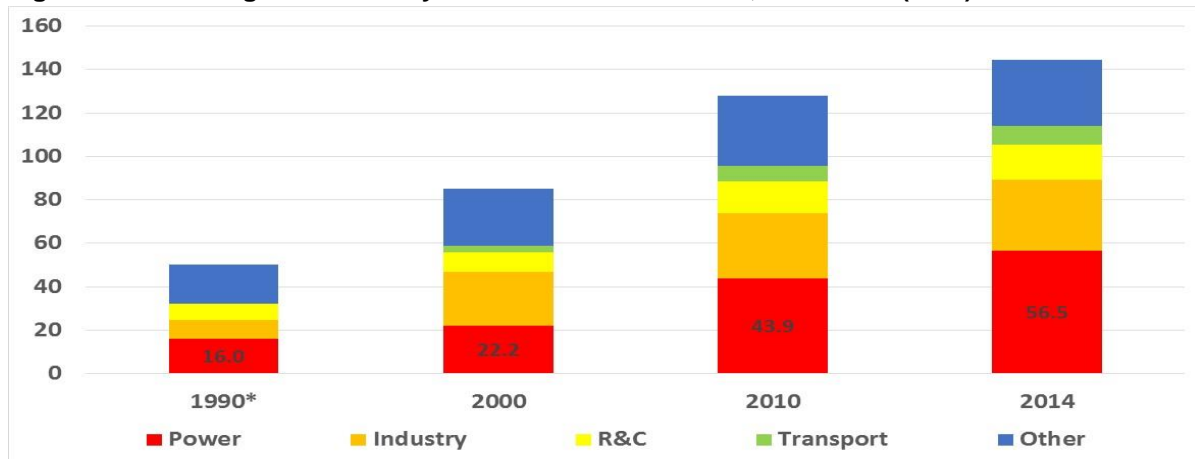
⁷³ IEA (2016a)

⁷⁴ Calculated from IEA (2016b), tables by country. 2014 was the latest data available for natural gas demand by sector from the IEA statistics at the time of writing

⁷⁵ However, private sector participation in power generation varies greatly from one country to another with almost zero participation in countries such as Paraguay and Venezuela



Figure 17: Natural gas demand by sector in South America, 1990-2014 (bcm)



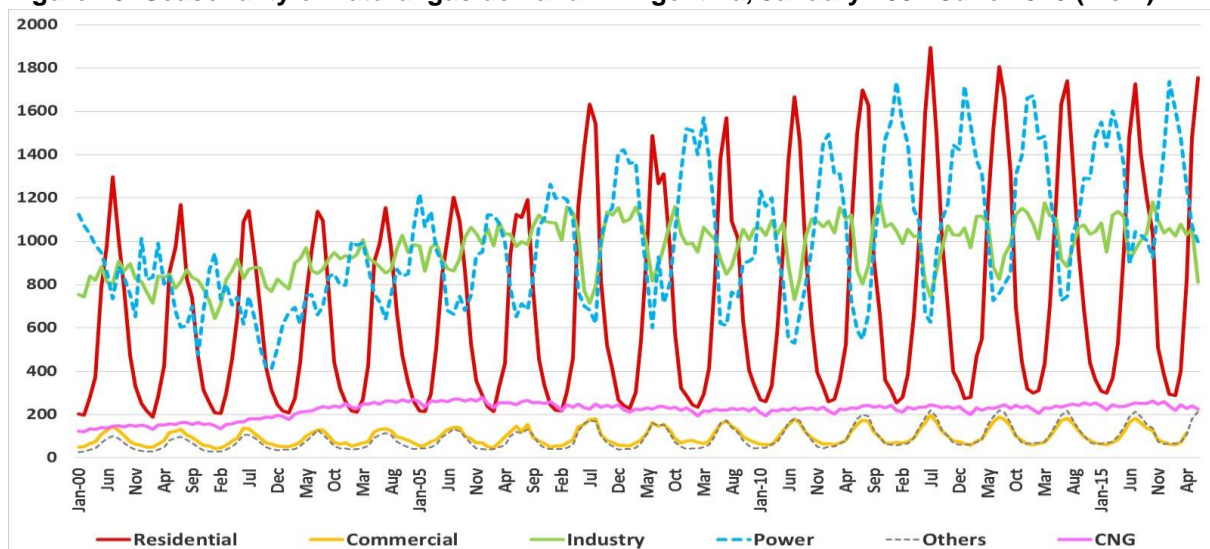
* The data for 1990 was presented using different categories than for 2000, 2010 and 2014 and the comparison should be made with caution.

Note: "Other" includes energy industry own use, non-energy use and losses.

Source: calculated from IEA, Energy Balances of OECD Countries and Energy Balances of Non-OECD Countries, several reports, individual tables by country

Gas demand in the residential and commercial sector remains limited. Mild temperatures limit the need for space heating in most of the continent except in Argentina and Chile and gas for cooling (as a fuel for refrigeration plant) has not yet developed greatly, but is a potential source of future demand. However limited at the regional level, demand for residential and commercial can have important impact at the national level in Argentina. Gas demand is strongly affected by variations in temperature during the year and presents high seasonality patterns. During the Southern hemisphere's coldest months (May to September), the residential consumption which is used mainly for heating purposes, increases by about five to six times compared to the summer months as seen in Figure 18.

Figure 18: Seasonality of natural gas demand in Argentina, January 2001-June 2016 (mcm)



Source: Enargas data, 'datos operativos'⁷⁶

⁷⁶ Enargas data, 'datos operativos', <http://www.enargas.gov.ar/DatosOper/Indice.php>



For instance, in 2015, the average consumption for the residential sector in January was about 309 mcm but it was multiplied by more than five in July at about 1.7 bcm.⁷⁷ Due to the already tight supply-demand balance, and even with additional LNG imports, gas supply to thermal power plants and industry are routinely rationed in order to keep the heating on in the residential market. Thermal power plants are the first to be cut off and are usually forced to switch to diesel, but if this is not enough, then the industry sector needs to be restricted as well. Plants can be shut down sometimes for days in winter (the curtailments vary from region to region, but cuts can reach 30-40% in the industry sector, and can be as high as 75% during the coldest days⁷⁸) or even sometimes during the summer when air conditioning demand rises.

In the transport sector, the use of compressed natural gas (CNG) as a fuel for road transport has expanded rapidly and shows further future growth potential. South America already has more than five million natural gas vehicles (NGVs), about one quarter of the world's NGV stock, with almost half of it in Argentina, boosted by high gasoline prices vs low gas prices [Table 8]. Brazil also has a large fleet of about 1.8 million vehicles.⁷⁹ The conversion of passenger vehicles, trucks and buses to use natural gas is well underway in several countries such as Bolivia, Peru and Colombia due to its economics and environmental benefits.⁸⁰

Table 8: NGV and CNG stations in South America, by countries

	Number of NGVs	Number of CNG stations	Number of CNG stations under construction or planned
Argentina	2487349	1939	n/a
Bolivia	300000	178	n/a
Brazil	1781102	1805	n/a
Chile	8164	15	70
Colombia	500000	800	n/a
Ecuador	40	1	n/a
Peru	183786	237	n/a
Venezuela	90000	166	300
Total	5350441	5141	n/a

Source: NGV Journal⁸¹

As with the TPES and generation mix, unsurprisingly, patterns of gas demand differ greatly from country to country. In 2014, the power sector was the largest consumer in seven countries out of ten, Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador and Peru as seen in Figure 19. Since 2000, the most important growths occurred in Brazil, Peru and Argentina. Brazil started adding gas-fired generation to its system to provide additional capacity and mostly to add back up generation to hydropower after the 2001 drought. As such, the industrial sector which represented the majority of gas sales until 2011 was overtaken by the power sector since 2012 which accounted for 47% of gas demand in 2014.⁸² Peru created a new domestic market after the development of its reserves, especially the Camisea field in the second half of the 2000s and Argentina continued its market

⁷⁷ Enargas data, 'datos operativos', <http://www.enargas.gov.ar/DatosOper/Indice.php>

⁷⁸ Argus news, 18 June 2015, Argentina re-imposes gas rationing amid cold snap

⁷⁹ IEA (2014b), p.63

⁸⁰ For more information on CNG technology and market in South America, see: Southern Pacific Review, 5 April 2012, Natural Gas Vehicles: South America moves ahead of the USA

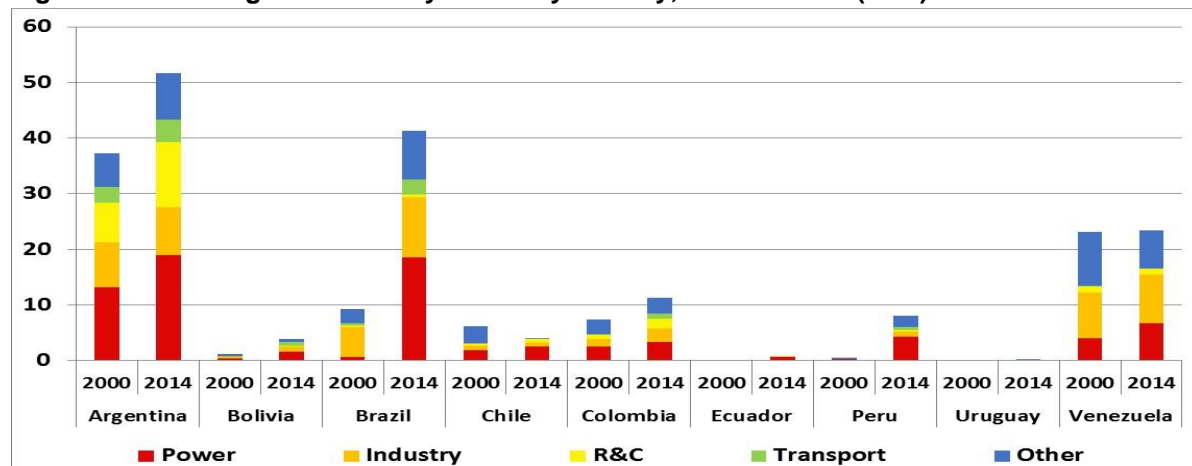
⁸¹ NGV Journal, statistics retrieved in March 2015, <http://www.NGVJournal.com>

⁸² Gomes I. (2014b), p.23. See also Abegas comunicação, 9 February 2015, Com aumento de 16,3% em 2014, consumo de gás natural minimizou crise no setor elétrico



expansion to supply its fast growing demand encouraged by frozen and low gas prices post 2004. The industrial and the transport sectors grew marginally in several markets, but the most notable expansion occurred in Brazil.

Figure 19: Natural gas demand by sector by country, 2000 vs 2014 (bcm)



Source: Calculated from IEA, Energy Balances of OECD Countries and Energy Balances of Non-OECD Countries, several reports, individual tables by country

2.2. Scenarios

2.2.1. Regional drivers and constraints

Demand for natural gas is influenced by many factors, but not necessarily the same ones for each market due to the heterogeneity of the region.⁸³ The following paragraphs focus on the main drivers, namely GDP growth and changes in the power sector. Some views are given on the other sectors: industrial, transport and residential and commercial. The subsequent sub-section takes a closer look at country specifics.

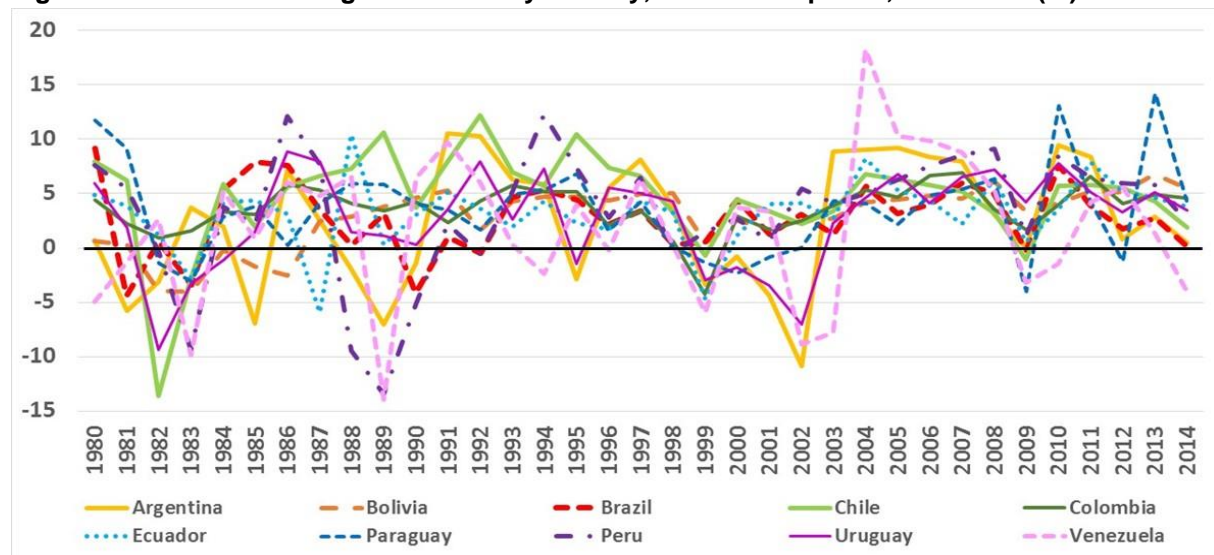
- Economic growth

Structural and economic reforms helped South American countries recover sustained levels of economic growth in the 1990s. The 2001-2002 crises were also quickly forgotten and the 2009 global recession had an even more limited impact on the economic activity of the region as seen in Figure 20. Although the impact of economic growth on energy demand is not straightforward, this triggered fast growing energy and electricity demand to meet the needs of growing economies, new sectors of gas demand and grid expansion.

⁸³ It is worth noting that not only do the regional trends hide disparities across countries, there are also very large differences in economic development, level of energy demand and even access to electricity between urban and rural / remote areas inside national markets. In wide countries such as Brazil and even Argentina, there are also very substantial differences from state to state or province to province. While this is an important characteristic of the South American region, this question is not looked at in this paper, which focuses on the national and regional level.



Figure 20: Historical GDP growth rates by country, in constant prices, 1980-2014 (%)



Note: data retrieved in August 2016. At the time, 2015 was still presented as “estimates”, and as a result, is excluded here but shown in Figure 21

Source: IMF (2016)

As the region’s economy and population grows, energy demand is expected to continue to increase. Its energy matrix is also expected to be increasingly reliant on natural gas, especially in electricity generation. The differences between markets in terms of size, maturity, infrastructure, generation mix, subsidies and energy policies complicate the picture when it comes to understanding the future of natural gas demand across the region.

The economic outlook published in April 2016, by the International Monetary Fund (IMF) presented a rather grim picture for future GDP growth in South America, especially due to the weakening of key commodity prices. This caused the private sector to lower its spending and gave rise to national policy uncertainties in several countries. This will undoubtedly impact the energy sector and the choices made for future –more limited- investments. Venezuela, Ecuador and Brazil are the most hit. Brazil’s economy contracted by 0.60% in April-June 2014, marking the second consecutive quarter of negative GDP growth and therefore entered a “technical recession” in early 2014,⁸⁴ and the situation did not improve in 2015 and in 2016. However, the IMF expects the Brazilian economy to pick up around 2017. Venezuela is projected to be in recession until the end of the decade, a sharp revision from 2014 scenarios⁸⁵ when the IMF expected the country to be out of recession by 2016. By contrast, the IMF expects Venezuelan GDP to contract by 10% in 2016 with an annual inflation of more than 700%.⁸⁶ Lower oil prices have also impacted Ecuador’s economy, which is also a lot worse off in these new scenarios compared to earlier ones and should only expect some improvement by the end of the decade. In contrast, views on Argentina are slightly more optimistic following the election of market-oriented president Mauricio Macri in November 2015.⁸⁷ The other countries should also maintain decent levels of GDP growth up to 2021, albeit lower than before, as seen in Figure 21.

⁸⁴ MercoPress, 28 October 2014, Brazilian economy remains in recession; Central bank survey indicates 0.27% growth this year

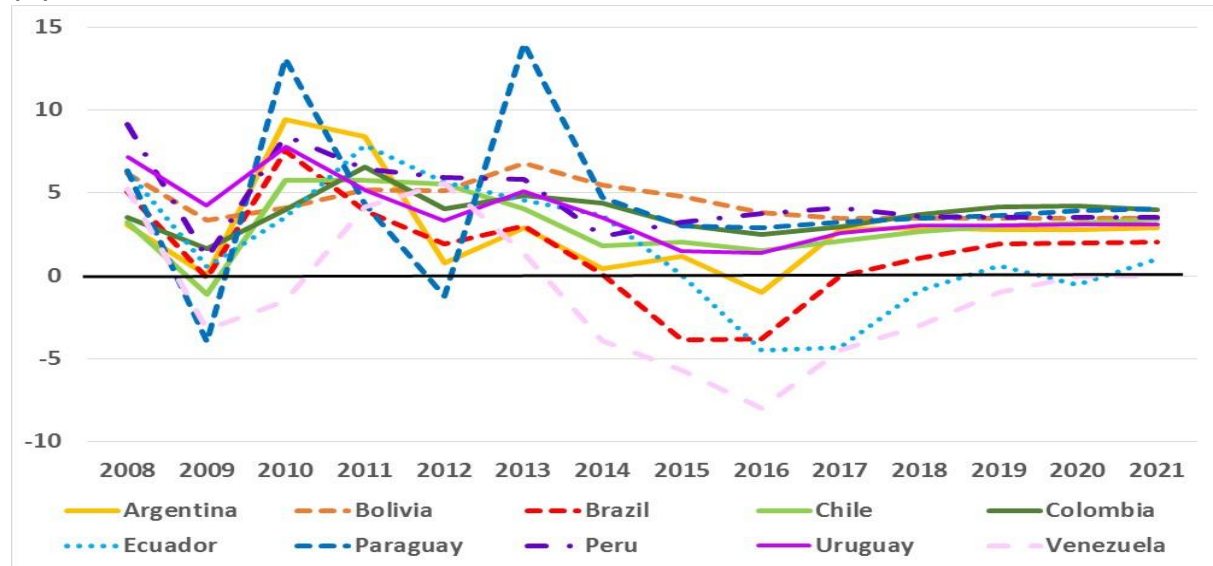
⁸⁵ IMF (2014)

⁸⁶ Argus Latin America Energy, 16 August 2016, Running short of options

⁸⁷ See Appendix ‘Argentina’ for more information



Figure 21: Historical and forecast GDP growth rates by country, in constant prices, 2008-2021 (%)



Note: 2008-2014: historical data; 2015-2021: estimates

Source: IMF (2016)⁸⁸

- Power sector

The regional energy mix is largely dependent on hydro and this will likely continue. With the primary requirement of 'not letting the lights go out', gas consumption is expected to continue to grow at a sustained pace in this decade and the next. Weaker economic growth will influence the energy demand outlook in all sectors; but it seems that meeting the needs for power generation will be one of the greatest challenges, both for additional generation and additional flexibility to be developed.

The IEA considers that electricity demand will increase by about 50% up to 2030 in the Latin American region, creating considerable future opportunities for developers.⁸⁹ Although electrification rates have improved significantly in many countries over the last fifteen years especially in Brazil, Colombia, Peru and Bolivia and are reaching saturation level especially in urban areas,⁹⁰ the still relatively low level of appliances ownership means that the potential for additional power demand growth is indeed important despite efforts to impose energy efficiency measures on electrical equipment and appliances.⁹¹ The income elasticity of energy and power demand will start to decrease as already seen in some countries, but the energy and power growth is expected to continue.

The challenge for national governments will be to find the right balance of sources that best provides energy security, meets growing demand, remains environmentally sustainable but also can be developed at a competitive cost. Although additional gas-fired power stations are likely to provide appropriate and economically sound solutions, it will not be the only option. For instance, the Chilean

⁸⁸ The IMF also publishes the Regional Economic Outlook: Western Hemisphere (the latest version at the time of writing was dated October 2015) which focuses on the Americas, including South American countries, <http://www.imf.org/external/pubs/ft/reo/2015/whd/eng/wreo1015.htm>

⁸⁹ IEA (2015c), p.307 (New Policies Scenarios)

⁹⁰ See Table 5, and World Bank (2016) for historical data

⁹¹ For instance, the Chilean government set an energy savings target of 20% by 2025, in order to save 20 TWh/year, in its new energy plan strategy published in 2014. Source: Ministerio de Energía (Chile) (2014), p.17



government in its 2014 energy plan strategy aims to develop hydropower, thermal projects but also renewable energies. The government aims to lift the barriers for Non-Conventional Renewable Energy (NCRE) and renewables are expected to account for 20% of power generation by 2025. The energy strategy aims to cover 45% of the new installed capacity between 2014 and 2025 with renewable capacity.⁹² Another example is Uruguay. The country is pursuing diversification to reduce the country's dependence on hydroelectricity, which was exposed to power shortages during periods of drought. However, the government's primary interest is in renewables –especially wind power– rather than natural gas. In Argentina, newly elected President Macri (in November 2015) placed renewables at the centre of its efforts and plans to install 10 GW from renewable sources over the next ten years in order to help the country reduce fuel imports and save \$300 million per year.⁹³

While the power sector is the largest contributor to gas demand, gas is not the fuel of choice in South America. Most additional power generation is likely to come in the form of renewables, especially hydropower. There is still a considerable potential for large hydropower expansion. However, despite lower operating costs, large hydropower projects have high capital costs. They are also facing increasing environmental controversy and public opposition. The vulnerability that comes with high dependence is also a constraint to the development of new large hydro infrastructure projects.⁹⁴ Several new hydropower plants are under construction or planned, but it is increasingly difficult to build plants with large reservoirs,⁹⁵ which allow for multi-month storage and continued generation even during periods of drought. For instance, between 2000 and 2012, only 10 of the 42 hydro plants constructed were with reservoirs.⁹⁶ Most new hydro plants are and will continue to be run of the river projects or have small(er) reservoirs. As a result, power generation will be even more impacted by normal and seasonal variations. It will be significantly reduced in dry periods, increasing the need for back-up capacity to balance the system. Natural gas-fired plants are well placed to back up these variations in hydro-generation thanks to their flexibility in addition to lower up-front costs and shorter lead times. Non-conventional renewables (wind, solar, bioenergy, small-scale hydro) will also play an increasing role in the generation mix, adding generation but also possibly additional uncertainty due to intermittency and unpredictability of dispatch. As a result, exactly how much additional gas the region is going to consume is difficult to establish since this depends on variable hydropower output, and in turn, rainfall patterns and renewables availability. This position of natural gas as a backup option means that flexible supply will also be increasingly needed in the region in order to match the seasonal, and often volatile dispatch of gas-fired power plants, whether from indigenous production (if possible) or from imports, especially LNG as there is no gas storage in South America and no interest to develop this flexibility tool.

Gas prices in most South American countries are government-controlled and subsidised, adding additional incentives to use the fuel. Interestingly, prices of natural gas for the power sector in Brazil (except for PPT plants) and in Chile are not subsidized, contrary to most other countries. The subsidies have been designed to improve access to electricity for low-income communities but they are a significant economic burden on many economies. According to the IMF,⁹⁷ natural gas subsidies (post-tax) represented almost \$9 billion in Argentina and \$7 billion in Venezuela in 2015 as seen in Table 9. Lower subsidies will raise energy prices and will likely promote energy savings and efficiency

⁹² Ministerio de Energia (Chile) (2014), p.17

⁹³ Clean energy sources must account for an 8pc share of Argentina's installed generation capacity by the end of 2018, rising to 20pc by 2025. Source: Argus News, 25 May 2016, Argentina kicks off renewable drive

⁹⁴ Hydro power has low operating costs, but a high CAPEX. It has also no waste or CO₂ emissions but it requires significant land for large plants with dams/lakes which leads to public resistance.

⁹⁵ Large reservoirs can store significant quantities of water that can be converted to power during dry periods.

⁹⁶ IEA (2015d), p.51

⁹⁷ IMF (2015). See also IMF (2013), Appendix table



measures, but they are not considered popular measures. As a result, they are unlikely to be removed completely in most countries.

Some efforts have already started in some countries, like in Argentina for instance. The economic recovery post 2004 was strong, but the government has since struggled to reduce the fiscal burden of energy subsidies. With growing deficits, tightened fiscal and monetary policy and rampant inflation, eliminating state energy subsidies or at least lowering them significantly, has been high on the government's agenda (but without much success for a long time).⁹⁸ In 2014, it was reported that consumers in Argentina only paid about 20% of the cost of natural gas, with the balance being subsidized by the government.⁹⁹ In April 2014, the government started to lower natural gas subsidies, which were reduced by 20%, but the power sector, industrial consumers and low-income residents were expected to be exempted from the subsidy cuts, while the middle and upper classes would bear most of the burden.¹⁰⁰ The subsidy cuts were accompanied by measures to encourage efficient energy use. More importantly, on April 1 2016, the new government of Mauricio Macri increased wellhead natural gas prices for residential, commercial and CNG users by up to 1,700%. The gas price for residential customers rose by 180-525% (from 1.75 to 4.21 pesos/cm or about 12-28 cents/cm), for commercial users: 816-1700% (1.75 to 2.29 pesos/cm) and CNG: 333% (to 3.16 pesos/cm).¹⁰¹ Wellhead price for natural gas used for thermal power generation was roughly doubled soon after (retroactive to April 1) with new prices ranging from \$4.48-\$5.53/MMBtu.¹⁰² The reactions have been important, as purchasing power of the consumers was hurt. On August 18, 2016 the Supreme Court repealed gas rate hikes for residential customers until public hearings were held, while increases for commercial and industrial users remained. The government then decided to scale back the rise to \$3.42/MMBtu (on average) in October 2016. This measure is to be followed by roll-out adjustments every six months to reach \$6.78/MMBtu in October 2019.¹⁰³ The initial increase had set the price at \$4.72/MMBtu from April 2016. This setback may be significant for hurdles ahead for the government in implementing its market-based measures and therefore adds some uncertainty for investors. Removing price subsidies for energy (gas, power and retails fuels) will help tackle a fiscal deficit of about 7% of GDP, and if these actions are followed through, they should also temper the growth of natural gas demand in our timeframe. For instance, electricity demand fell by 9.4% in March 2016 (yoy) after a power tariff hike in February.¹⁰⁴ If these actions are followed through, they will temper the growth of natural gas demand in our timeframe, but also stimulate indigenous production.

When considering new generation capacity, options are not limited to hydro and gas. Private investors will also consider renewables that benefit from support schemes. Renewable energies such as wind, solar, geothermal and small-scale hydropower are receiving growing attention and could play a more important role in the future both for base and peak load electricity. There are enormous opportunities for so-called non-conventional renewable energy (i.e. non-large hydro) development in the region as seen in Chapter I. Brazil has been the pioneering market in South America with the use of energy auctions since 2004 for renewable energy technologies with the offer of 20-year contracts ahead of

⁹⁸ For examples, see Reuters, 28 November 2008, UPDATE 1-Argentina says to cut natural gas subsidies; Mercopress, 28 March 2014, Argentina begins natural gas and water subsidies reduction in three stages

⁹⁹ Mercopress, 28 March 2014, Argentina begins natural gas and water subsidies reduction in three stages

¹⁰⁰ Industrial users, low-income consumers receiving social or unemployment benefits, pensioners and inhabitants of the colder southern provinces were exempt from these measures. Source: Mercopress, 28 March 2014, Argentina begins natural gas and water subsidies reduction in three stages; The Economist, 31 March 2014, Government announces subsidy cuts

¹⁰¹ Wholesale power tariffs and retail fuel prices were also increased, while wellhead crude prices were unchanged in order to support the oil industry. Source: Argus Latin America Energy, 5 April 2016, Price hikes test Argentina

¹⁰² Argus News, 13 April 2016, Argentina doubles gas price for power generation

¹⁰³ Argus Latin America Energy, 13 September 2016, Government to reinstate price hikes

¹⁰⁴ Argus Latin America Energy, 26 April 2016, Argentina power demand plummets after tariff hike



delivery for the regulated market.¹⁰⁵ Various policy supports exist as seen in Table 10, which have led to growth in non-large hydro renewable energy capacity in Brazil but also in other countries as seen in Figure 22.

Table 9: Fossil fuels and electricity subsidies, 2015

	Post-tax subsidies in \$ billions (nominal)					Post-tax subsidies as a percent of GDP				
	Petroleum	Coal	Natural gas	Electricity	Total	Petroleum	Coal	Natural gas	Electricity	Total
Argentina	0.55	0.65	8.96	7.37	17.53	0.10	0.12	1.66	1.36	3.25
Bolivia	1.77	0.00	0.53	0.23	2.53	4.74	0.00	1.41	0.61	6.77
Brazil	39.40	3.59	3.00	9.45	55.44	1.67	0.15	0.13	0.40	2.35
Chile	7.15	1.67	0.45	0.00	9.27	2.56	0.60	0.16	0.00	3.32
Colombia	8.54	1.28	1.02	1.84	12.67	2.00	0.30	0.24	0.43	2.97
Ecuador	5.58	0.00	0.06	0.39	6.04	5.22	0.00	0.06	0.37	5.65
Paraguay	0.50	0.00	0.00	0.13	0.63	1.43	0.00	0.00	0.37	1.80
Peru	0.87	0.14	0.82	0.00	1.83	0.40	0.06	0.38	0.00	0.84
Uruguay	0.26	0.00	0.01	n/a	0.26	0.44	0.00	0.01	n/a	0.45
Venezuela	31.56	0.09	7.08	6.43	45.17	13.95	0.04	3.13	2.84	19.96

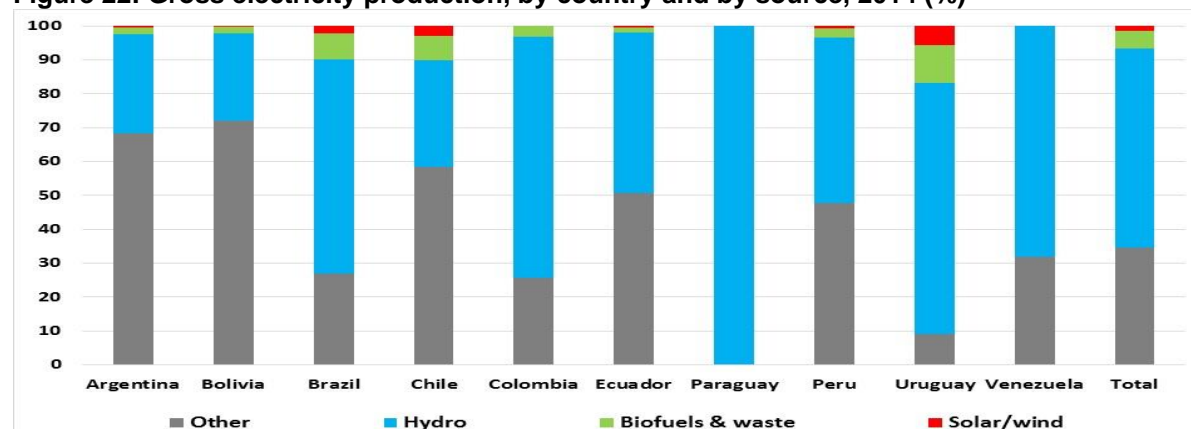
Source: IMF (2015)

Table 10: Clean energy policies by country, 2013

	Argentina	Brazil	Chile	Colombia	Chile	Ecuador	Paraguay	Peru	Uruguay
Energy target	X		X		X			X	X
Feed in tariff	X	X				X			
Auctions	X	X						X	X
Net metering		X	X		X				X
Biofuels blending mandate	X	X		X		X	X	X	X
Debt/equity incentives		X							
Tax incentives	X	X	X	X	X	X		X	X
Utility regulation		X						X	

Source: Bloomberg new Energy Finance (2014), p.54¹⁰⁶

Figure 22: Gross electricity production, by country and by source, 2014 (%)



Source: IEA (2016d), pp.II.9-II.11

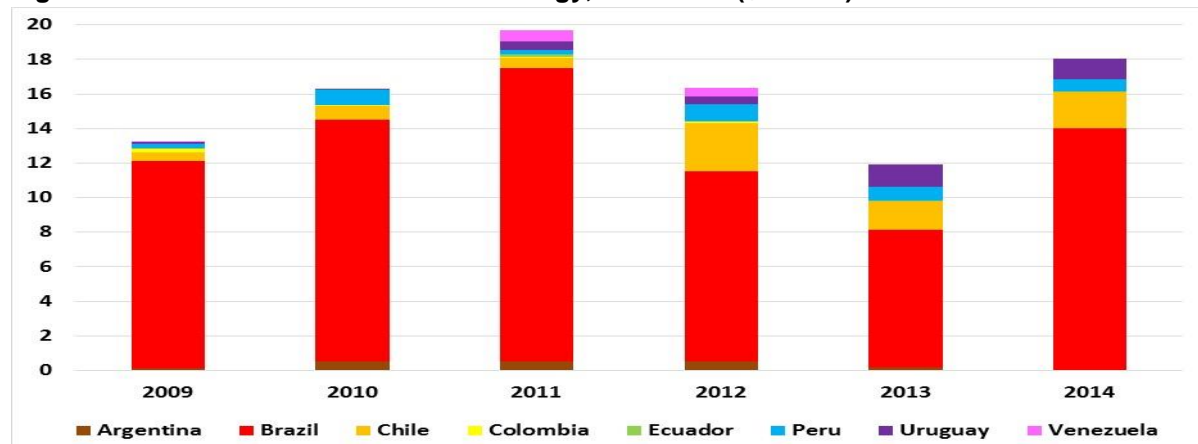
¹⁰⁵ IDB (2014), p.31

¹⁰⁶ An update on policies in force in each country is available at <http://global-climatescope.org/en/policies/#/>



Although wind, biofuels and small hydropower have received the largest share of investment in the past, solar energy has started to draw considerable interest since 2013, especially in Chile and Peru.¹⁰⁷ Total annual investment in clean energy reached \$18 billion in 2014 (almost 80% in Brazil as seen in Figure 23). However, as countries battle through economic recessions or slowdowns in the second half of the 2010s, even the renewable energy sector is likely to feel some impact.

Figure 23: Annual investment in clean energy, 2009-2014 (\$ billion)



There was no data available for Bolivia and Paraguay

Source: Bloomberg new Energy Finance (2015), Country profiles

Decentralised generation from renewables would also enable the supply of populations in remote locations when new grid connections are too costly or not possible in environmentally sensitive areas. Increased access to electricity in these regions will trigger important growth. While electrification rates are high with close-to-universal electricity access in many countries,¹⁰⁸ there is still a portion of the population that lives in very remote areas. In Brazil for instance, there are still 3.4 million people without access. In Bolivia and Peru, where the electrification rates are the lowest with 78% and 86%, there are about 2.3 and 4.3 million people without electricity, respectively.¹⁰⁹ Some oil-fired generation is used to supply remote villages or cities e.g. in the Amazon region where off-grid small or medium diesel generators are common. Even if diversification from oil products would be welcome, these are not likely to be substituted by gas. In most cases, decentralised renewables will be more cost effective to supply small remote communities than natural gas because of the cost of building pipelines to supply faraway communities with small volumes would be enormous. Bolivia and Peru for instance have already started providing rural electrification through PV systems, and demand for small-scale renewable projects will increase.

The diversification of energy sources for energy security reasons will also be supported by the desire to limit local pollution, large hydro reservoirs and large transmission lines. Renewable energy will be promoted for the same reasons and for all these reasons will be a growing competitor to gas in the mix in the future.¹¹⁰

¹⁰⁷ Details by source can be found in Bloomberg new Energy Finance (2015), Country profiles

¹⁰⁸ See Table 5

¹⁰⁹ Bloomberg new Energy Finance (2014)

¹¹⁰ Coal is not a favoured option, and oil products are more expensive and more polluting than natural gas.



- Industrial sector

There is still some additional potential for gas penetration in industry, especially in Brazil in areas not yet reached by pipelines, but gas prices may be an issue (gas is expensive compared with fuel oil and cheap biomass-residues), and in gas-rich Peru and Bolivia (these two countries consume only small quantities of gas in the sector), and eventually in Chile where energy demand is growing and natural gas is favoured by the government. In other countries, the expansion of gas networks and the implementation of environmental legislation may trigger some further fuel switching by industrial consumers, but this is uncertain. The development of cogeneration in industrial (and commercial) sectors could also favour gas, as this technology has yet to reach its potential.

- Transport sector

Use of CNG in road transport is expected to increase in countries that have developed conversion programmes like those in Bolivia, Peru and Colombia.¹¹¹ However, if oil prices remain low, these expectations may be overoptimistic. In Brazil, the fleet of dual-fuel ethanol-gasoline cars is growing while CNG consumption is decreasing. Natural gas use in transport peaked in 2007 at 2.6 bcm and has faced a steady decline since then to less than 1.8 bcm in 2015.¹¹² In Argentina, CNG cars were boosted by gas price subsidies, which are being revised downward as already mentioned.

- Residential and commercial sector

Except for Argentina and Chile, there is virtually no need for space heating in the region, which explains the low expectations for significant additional numbers of residential and commercial gas customers despite plans by several South American countries to develop gas distribution infrastructure. Some new demand for gas-fuelled applications for space cooling and refrigeration may develop by displacing some electricity use especially in the commercial sector. This is not expected to have a major impact on total demand for gas, in the timeframe adopted in this paper.

2.2.2. Country specifics

The largest gas markets are Argentina, Brazil and Venezuela, and they are the ones that will have the most significant impacts at the regional level.

Argentina is a mature gas market. At 52 bcm (2015), it represents 36% of the regional demand.¹¹³ It has a gas intensive economy and the fuel accounts for about half of the primary energy mix (49%). After the 2001-2002 crisis, the government implemented gas (and power) price controls that kept prices artificially low. This stimulated strong demand growth in all sectors. The power sector is the largest consumer (37%), followed by the residential and commercial (23%), industrial (17%), and transport (8%) sectors.¹¹⁴

Additional demand is expected to be moderate and will most likely be conditioned by the development of additional (indigenous) supply. The power sector is expected to grow slowly. There is potential to

¹¹¹ NGV Global News, 17 January 2015, Bolivia Performs Over 27,000 CNG Conversions in 2014

¹¹² MME (annual), Tabelas do BEN - Dados por Fonte - Gás Natural (tab 2.3)

¹¹³ IEA (2016a)

¹¹⁴ IEA (2016b), data for 2014. National statistics can be found in Enargas (annual)



replace large amounts of high cost oil plants,¹¹⁵ but this will be limited by the availability of gas supply. On the other hand, if or when the country successfully develops its shale gas resources, natural gas for power is likely to increase in order to make up for growing demand, although this scenario could also be complicated by the rise of renewable energy and/or nuclear in the mix.

Gas demand in the industrial sector has been flat since the mid-2000s due to a lack of supply. In 2014, a weakening economy combined with high inflation started to reduce consumption in this sector.¹¹⁶ Despite potential for additional gas consumption due to past suppressed demand, additional gas needs will be limited by a weak economic growth and continued financial difficulties will most probably prolong this trend.

Argentina is one of the world's largest consumers of gas in the transport sector due to high gasoline prices vs. low gas prices, which boosted the number of car conversions from oil to natural gas, but the transport sector may also be impacted by government measures and reduced interest in NGVs. The IEA expected 8 bcm more demand between 2012 and 2018 in this sector, but this may also be called into question.¹¹⁷

By 2016, it is expected that the natural gas coverage of the country will be close to saturation, so there will be limited gas demand growth due to a growing customer base.¹¹⁸ Finally, natural gas prices in Argentina have been highly subsidized. The reform wanted by new President Macri and the expected increase of gas prices will dampen demand growth in all sectors.

Brazil will undoubtedly be the key driver for regional growth due to the size of the country, the economy and its population, but it also facing important uncertainties. Gas consumption has increased rapidly in the 2000s in all sectors of consumption to arrive at 39.8 bcm in 2015.¹¹⁹ However, the most rapid one was the power sector following the mass construction of gas-fired stations to back-up hydro generation after the severe drought-induced power crisis in 2001.¹²⁰ In 2014, the power sector became the largest user in Brazil, ahead of the industrial sector, and this was still the case in 2015 as seen in Figure 24. All idled thermal power plants were restarted to address the crisis, boosting natural gas demand (and imports of LNG). However, this predominance of the power sector in the mix is therefore uncertain and unpredictable.

In 2015, gas for power represented 51% of total demand, followed by the industrial sector (26%), energy own use (15%), while the other sectors were much smaller (transport 4%, residential and commercial 1%, others 2%).¹²¹

In the power sector, the normalisation of hydropower generation should lower the need for gas-fired power plants in the generation mix in the rest of the 2010s. The level of future gas demand in the power sector will depend on the pace of construction of new gas-fired power plants and their utilization. Uncertainties around hydropower generation in Brazil are growing. The new projects are highly concentrated, and any delays in one or two of these projects may cause serious problems.¹²² Even if the projects do happen in time, it has become increasingly difficult to build large reservoir hydroelectric plants due to stricter environmental regulations and social opposition.¹²³ New hydro

¹¹⁵ These plants are very old and only functioning when there is not enough gas for the power sector, especially in winter when priority is given to the residential sector.

¹¹⁶ Additional statistical data can be found on Indec website

¹¹⁷ IEA (2014a), p.49

¹¹⁸ IDB (2014), p.56

¹¹⁹ IEA (2016a). Total gas demand amounts to 42.7 bcm in 2015 in national statistics published in MME (annual)

¹²⁰ After the severe drought-induced power crisis in 2001, thermal stations were developed to compensate for hydroelectric plants, which accounted for about 90% of electricity generation back then.

¹²¹ MME (annual)

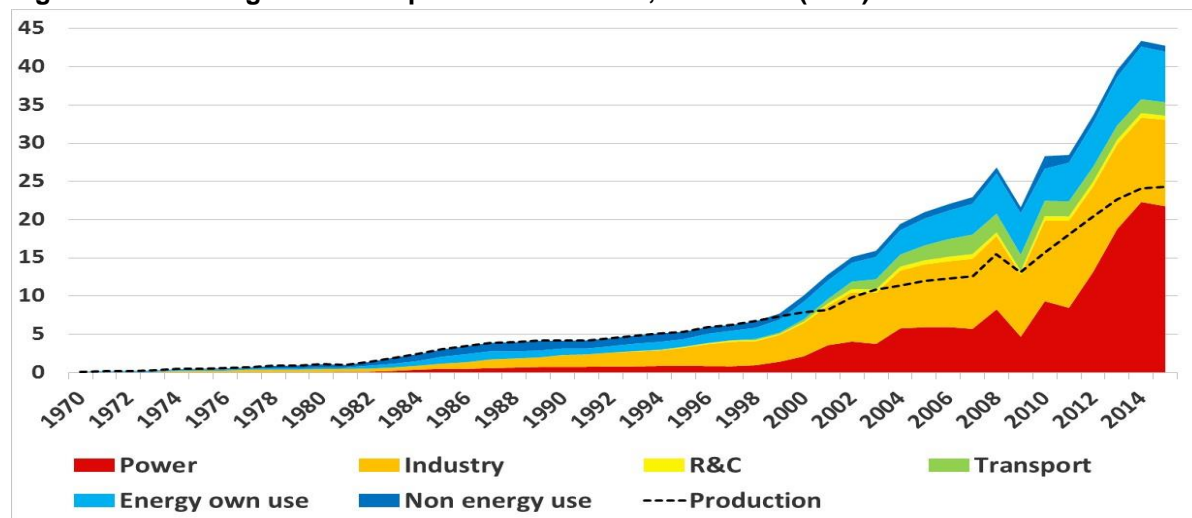
¹²² Three projects represent about 76% (more than 21.6 GW) of all hydro projects planned for 2015-2024 (28.3 GW). Source: MME (2015), p.85

¹²³ Large reservoir projects may put some sensitive areas (like the Amazon forest) at risk of flooding which would also lead to the displacement of communities.



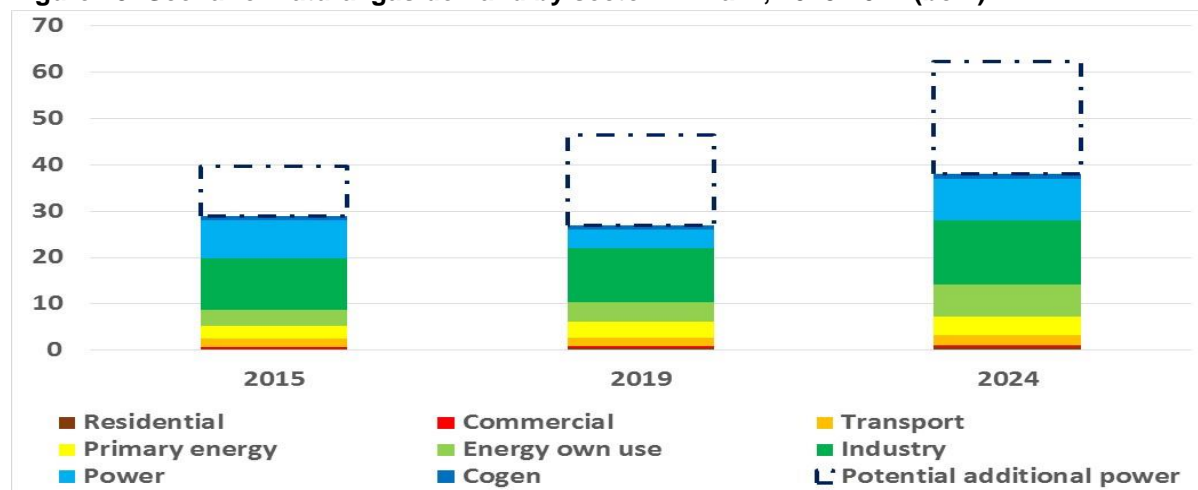
projects will have smaller reservoirs or be run of the river. This has already changed the shape of hydropower generation, with less storage available (25 months of storage in hydro plants in 1970, 10 months in 1990, 5 months in 2013 and it is expected to decline to 3 months in 2023). Instead of using hydropower to balance the system, natural gas-fired generation has become an important source of flexibility and security of supply, and it is expected that this trend will continue as hydro generation becomes more volatile. The growth of renewables is also going to contribute to the use of gas plants as backup power. As a result, gas-fired plant dispatch is expected to gradually increase in Brazil. However, there will be wide differences between wet and dry years. The EPE for instance expects that gas for power will be limited at about 10 bcm in 2024 in the case of a wet year while at the same time, possibly ramp up to 33 bcm in the case of a dry year as seen in Figure 25.¹²⁴ Extending this trend, gas for power demand would oscillate between 9.5 bcma and 43 bcma in 2030.

Figure 24: Natural gas demand per sector in Brazil, 1970-2015 (bcm)



Source: MME data¹²⁵

Figure 25: Scenario: natural gas demand by sector in Brazil, 2015-2024 (bcm)



Source: MME (2015), p.51

¹²⁴ Some power plants have contractual levels of minimum dispatch, so there will be some gas-fired power plants being used even during wet years.

¹²⁵ MME data: <http://www.mme.gov.br/web/guest/publicacoes-e-indicadores>



Some but no major growth expectations exist in the other sectors. The industrial sector grew rapidly in the 2000s due to sustained GDP growth, but demand has stagnated since 2011 owing to gas-price competitiveness and the morose economic situation. Prospects for the industry sector have been revised down due to the country's economic performance in 2014-2015 (and probably 2016). The EPE Decenal Plan published in January 2016 assumes gas demand of 13.9 bcm in 2024 (from 11 bcm in 2014), a sharp drop from the 19.9 bcm expected for 2023 a year earlier.¹²⁶ There are also limited remaining possibilities of substitution of gas for high sulphur fuel oil (HFO) (maybe about 3-4 bcm).¹²⁷ However, lower gas prices thanks to the world LNG supply glut in the second half of the 2010s and eventually a pickup of the economic situation circa 2017/2018 as expected by the IMF¹²⁸ could improve this rather gloomy vision.

Despite a large fleet of CNG vehicles, natural gas use in the transport sector has declined in the 2010s (see Figure 24). CNG vehicles represent only about 2% of the total vehicles due to sugarcane based ethanol competition, which is expected to continue in the future.

Demand in the residential and commercial sector is limited and accounted for less than 2% of gas demand. Brazil has a population of 201 million and approximately 62.8 million households. The number of households served with natural gas is just 2.44 million.¹²⁹ The low penetration can be explained by the mild climate (no need for heating), the lack of urban infrastructure for natural gas, the competition from subsidized LPG for small residential users¹³⁰ and fuel oil, and finally the limited transport network to bring the gas to consumption centres. A large part of inland Brazil is not supplied by natural gas, although this is (very) slowly improving. Mild weather means that there is no need for heat appliances even if air conditioning could create some additional demand during the summer months.

Venezuela consumed 25.2 bcm of gas in 2015.¹³¹ The largest consumer is the industry sector (37% in 2014), followed by the group labelled 'other' sector (29%) which includes energy own use and the natural gas used in the oil industry (refineries and heavy oil upgrade plants). The power sector has been increasing and represented the third largest consumer at close to 29%.¹³²

Natural gas demand has been encouraged by low, subsidized gas prices.¹³³ PdVSA has a monopoly of sales in Venezuela, so all production must be sold to the company at a price which it sets, which is not a market price. PdVSA bears the gap between the cost of gas and the domestic sales price. The government aims to develop the national gas market in all the sectors and extend the supply network to cover the entire country in order to displace some of the diesel and other liquid fuels used in power stations, petrochemical plants and other facilities.¹³⁴ Natural gas is also needed for reservoir injection to increase the production of light and medium crudes in mature oil fields in the western part of the country (the region that received Colombian gas), where wells need gas injection to raise recovery.

¹²⁶ MME (2015a), p.51; MME (2014), p.47

¹²⁷ Gomes I. (2014b), p.24

¹²⁸ IMF (2016)

¹²⁹ Gomes I. (2014a)

¹³⁰ LPG for commercial users is not subsidized

¹³¹ IEA (2016a)

¹³² IEA (2016b)

¹³³ After the Gas Law was introduced in 2001, the gas price agreed with the private gas producers was fixed at \$0.60-0.90/MMBtu for lower cost onshore gas production. In 2014, the wellhead price was \$0.127/MMBtu and for the consumer it is \$0.784/MMBtu. The argument is that the gas is being used in power plants (electricity prices are also subsidized), it frees up diesel and fuel oil for export at international prices, providing revenues to support the subsidies. It is understood that for the country's first offshore gas development, PdVSA has agreed a higher price, with Repsol/ENI being paid \$3.69/MMBtu. Source: Platts International Gas Report, July 14, 2014, Perla: Venezuela's big gas hope

¹³⁴ PDVSA (2008)



As a result, some growth can be expected, but unless the country develops its own reserves, gas demand will be constrained by a lack of available supply and infrastructure.

Natural gas demand reached 11 bcm in **Colombia** in 2015.¹³⁵ The power sector used 30% of the gas in 2014, the industry sector 21%, the residential and commercial 16%, the transport sector 9% and the “other sector” –which includes energy own use- 24%.¹³⁶

There are plans to convert several power plants to burn gas rather than more costly fuel oil and other liquids in conventional power plants in order to generate power during abnormal weather cycles.¹³⁷ Excluding El Niño periods, about 3/4 of power is generated from hydro. During El Niño, when hydro cannot produce so much power, the country needs to rely on additional generation from gas-fired power stations. For a six-month period at the end of 2009 and the beginning of 2010, hydro fell to 50% of power production, with gas’ share of power increasing from 15% to 34%.¹³⁸ At times of low hydro, natural gas demand can increase by up to 2 bcma in the power sector, as seen in 2009-2010 and again in 2013-2014.¹³⁹

The Unidad de Planeación Minero Energética (UPME) considered in 2016 that levels of gas used in the power sector should remain high between 2015 and 2018 (with possible peaks) but will decrease post 2019 with the start of new hydropower plants (for instance, Ituango and Porvenir). From 2024 onwards, gas for power demand rises slowly and gets close to 2015 levels in 2030 (average levels, excluding peaks).¹⁴⁰ The industrial, residential and commercial sector and the transport sector (taxis, buses and cars) are also expected to expand due to additional infrastructure. In total, UPME expects that gas demand will grow at an annual average of 2.2% between 2015 and 2035.¹⁴¹ Declining indigenous supply may constrain additional gas demand growth (or at least until LNG imports are fully developed).

In **Chile**, natural gas demand recovered thanks to LNG imports from 2.7 bcm in 2008 to 4.5 bcm in 2015.¹⁴² Gas is mainly used for power generation (61% in 2014), followed by industry (20%), residential and commercial (16%) and finally far behind, “other sectors” (3%) and transport (0.9%).¹⁴³

The government wants natural gas to play a key role in the energy industry. In its Energy Agenda published in 2014,¹⁴⁴ which focuses on the 2015-2019 period (but also sets longer term targets), the use of LNG will be promoted in power generation as a substitute fuel with new high efficiency gas-fired plants replacing old and polluting oil-fired and coal-fired plants,¹⁴⁵ but also in industrial and residential use. Following the suspension and delay of several major coal-fired and hydroelectric projects, the country aims to replace expensive imports of diesel in the power sector by natural gas, which would provide some baseload production, as well as a backup role for wind and solar projects and finally eventually replacing the extensive use of firewood in many cities in central and southern Chile.¹⁴⁶

The slowdown of the economy may, however, delay gas demand growth despite the government’s expectations. For example, copper mining projects expansion in Northern Chile seems to have been on hold at the time of writing (mid 2016).

¹³⁵ IEA (2016a)

¹³⁶ IEA (2016b)

¹³⁷ Platts International Gas Report, 24 March 2014, Colombia plans regas plant

¹³⁸ IEA (2011)

¹³⁹ IEA, Energy Balances on Non-OECD Countries, several reports

¹⁴⁰ UPME (2016), p.25

¹⁴¹ UPME (2016), p.27

¹⁴² IEA (2016a)

¹⁴³ IEA (2016b)

¹⁴⁴ Ministerio de Energía (Chile) (2014)

¹⁴⁵ Taxes on CO₂ emissions from power plants are also expected in order to limit coal plants.

¹⁴⁶ Platts International Gas Report, 1 December 2014, Gas Natural in Chilean wrangle



Bolivia's national gas market is small (3.8 bcm in 2015¹⁴⁷) but has been rising rapidly. Continued strong gas demand growth is expected, driven by a favourable economic situation and energy policies in favour of gas consumption (i.e. subsidies).

In the power sector, focus will be placed on diversifying the generation mix in favour of renewables including hydro. Bolivia has 1,900 MW of installed capacity and has a target of 13,382 MW in 2025, mostly from new hydroelectric plants.¹⁴⁸ Natural gas will be the natural back up to hydropower and will account for some growth in this sector. Additional gas for power demand will come from the country's plans to have electricity cover all of its territory by 2025, which it expects will increase the total demand for power generation.¹⁴⁹ Bolivia would also like to build power generation capacity and export electricity to Brazil and Argentina, which would be more profitable than exporting natural gas. By 2020, the government is planning to increase the gas-fired capacity to around 4,800 MW from the 1,100 MW in 2014.¹⁵⁰ If run baseload, these plants would use a maximum of about 4 to 5 bcma of gas.¹⁵¹

Bolivia also expects to develop exports of processed products rather than the simple export of natural gas as a commodity. It is planning large investments in several petrochemical plants to develop an industrial base founded on gas.¹⁵² The government intends to develop three projects; a petrochemical plant, a polyethylene plant and a fertiliser plant in the coming decade.¹⁵³

Transport is also expected to grow with a target of 500,000 CNG vehicles by 2020.¹⁵⁴ However, as in Colombia, additional gas demand growth will be constrained by supply and none of these projects will happen unless exploration is reactivated and reserves start to grow again. This is an even more pressing issue for Bolivia, which does not have the option to import LNG and has big export commitments to neighbouring Argentina and Brazil.

In **Peru**, natural gas is going to remain at the centre of future energy growth. However, with rising national demand and stagnating upstream activity, there are concerns about future availability of natural gas to supply both the domestic market and LNG exports. The development of the Gasoducto del Sur project will provide additional supply to the system and also favour additional demand growth.

In the other markets, absolute consumption levels will remain small. In **Uruguay**, there are projects for the conversion of several oil-fired power plants to natural gas and the construction of a 530 MW CCGT. LNG terminal delays mean that the plants may have to be initially fueled with diesel.

In **Ecuador**, priority is given to hydropower but there is a basic need for thermal generation as the coast is far away from hydro power resources, and there are plans to import LNG to fuel a CCGT.

Figure 26 below shows the author's assumptions on natural gas demand growth in individual countries. These scenarios are bottom-up estimates by this author based on historical trends, official scenarios from national, regional and international entities when available, and/or personal assumptions. Additional details for each country can be found in the Appendix.

¹⁴⁷ IEA (2016a)

¹⁴⁸ Argus News, 24 July 2015, Bolivia to open protected areas for exploration

¹⁴⁹ Ortiz F.M. (2014)

¹⁵⁰ Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America

¹⁵¹ Author's estimates

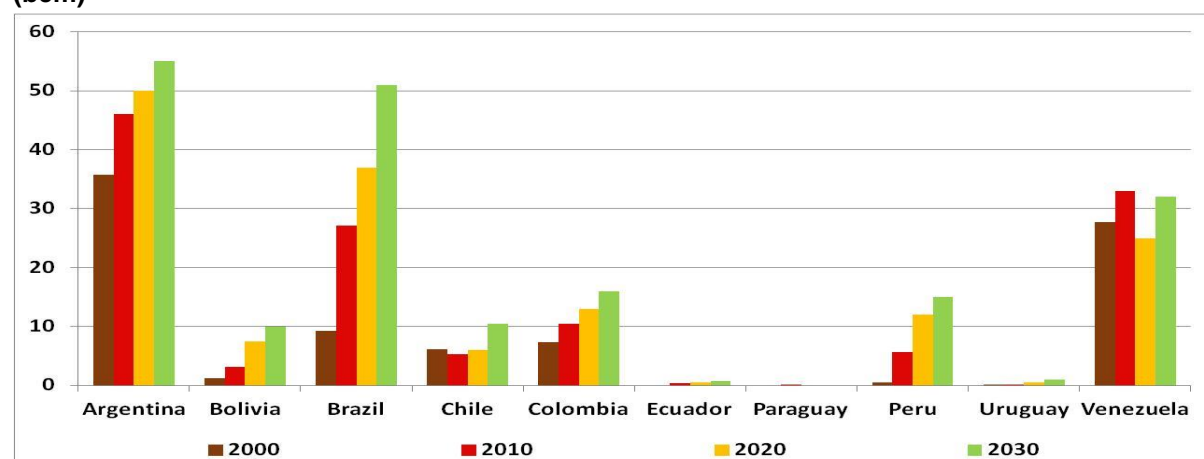
¹⁵² Additional details on the projects can be found in Ortiz F.M. (2014)

¹⁵³ YPFB (2013)

¹⁵⁴ Argus News, 24 July 2015, Bolivia to open protected areas for exploration



Figure 26: Scenario for natural gas demand in individual countries, 2000, 2010, 2020 and 2030 (bcm)



Source: Author's assumptions

In this author's scenarios, Argentina remains the largest gas market in the region by 2030, followed by Brazil and Venezuela. Gas demand continues to grow in all countries, with some limitations in Venezuela mostly as a result of supply constraints and unfavourable economic situation in the 2010s and possibly 2020s. The related growth rates, which were 4.1%/year on average between 2000 and 2010, fall down to 1.4% per year on average between 2010 and 2020 and to finally rebound to 2.4% per year on average between 2020 and 2030 [Table 11].

In this scenario, and despite some hurdles due to economic uncertainties, political situations and/or energy sectors hit by low oil prices,¹⁵⁵ the regional demand grows from 145 bcm in 2015 to 151 bcm by 2020 and 191 bcm by 2030 as seen in Figure 27 below.

Table 11: Annual average natural gas demand growth rates, per country, up to 2030 (%)

	2000-2010	2010-2020	2020-2030
Argentina	2.6	0.8	1.0
Bolivia	9.6	9.1	3.1
Brazil	11.3	3.1	3.3
Chile	-1.6	1.3	5.8
Colombia	3.6	2.2	2.1
Ecuador	n/a	2.1	4.8
Paraguay	n/a	n/a	n/a
Peru	27.6	7.7	2.3
Uruguay	7.9	20.3	7.2
Venezuela	1.8	-2.8	2.5
Total	4.1	1.4	2.4

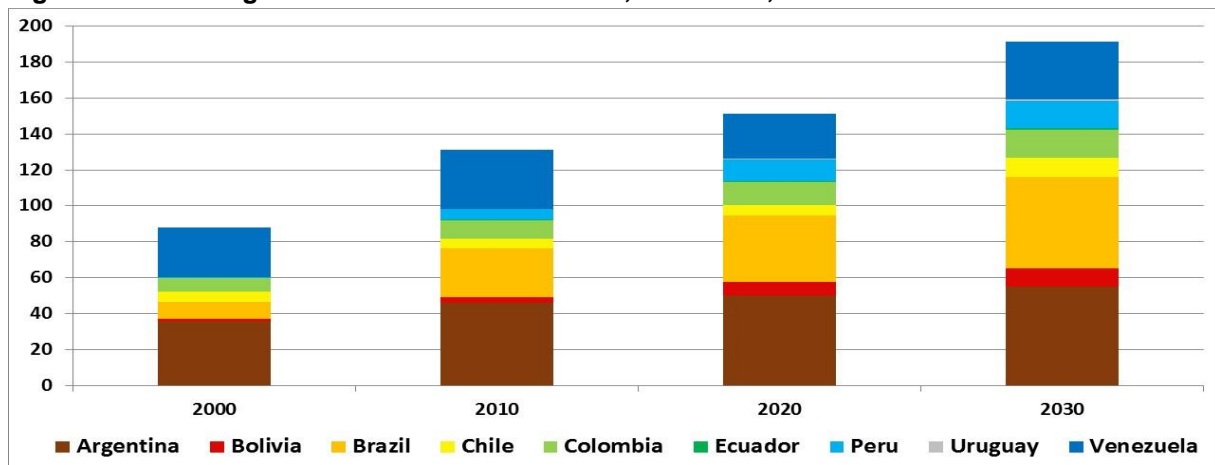
Note: Uruguay displays the strongest growth rates, but from a very low base. Total gas demand in this country will not have an important impact on the regional total, even by 2030.

Sources: 2000-2010: IEA, Energy Balances of Non-OECD Countries, several reports ; 2010-2020 and 2020-2030: author's assumptions

¹⁵⁵ In May 2016, Brent Crude futures traded at \$40.90. Source: Financial Times, 24 March 2016, State investment remains robust and huge shale reserves attract oil majors



Figure 27: Natural gas demand in South America, 2000-2030, bcm



Sources: 2000-2010: IEA, Energy Balances of Non-OECD Countries, several reports ; 2010-2020 and 2020-2030: author's assumptions

This author's scenarios on natural gas demand in the South American countries will appear optimistic to some and pessimistic to others. As already mentioned, there is a wide range of factors that will drive or on the contrary, constrain the evolution of natural gas uses in the region in our timeframe. One of the biggest uncertainties relies on the availability of adequate supply, in terms of volumes, prices, timing and flexibility. Demand scenarios will evolve positively or negatively depending on how the supply challenges are tackled. The following section focuses on the availability of gas, which is a fairly complex issue on its own in the region, at the 2030 horizon.



III. Natural gas supply: meeting the challenge

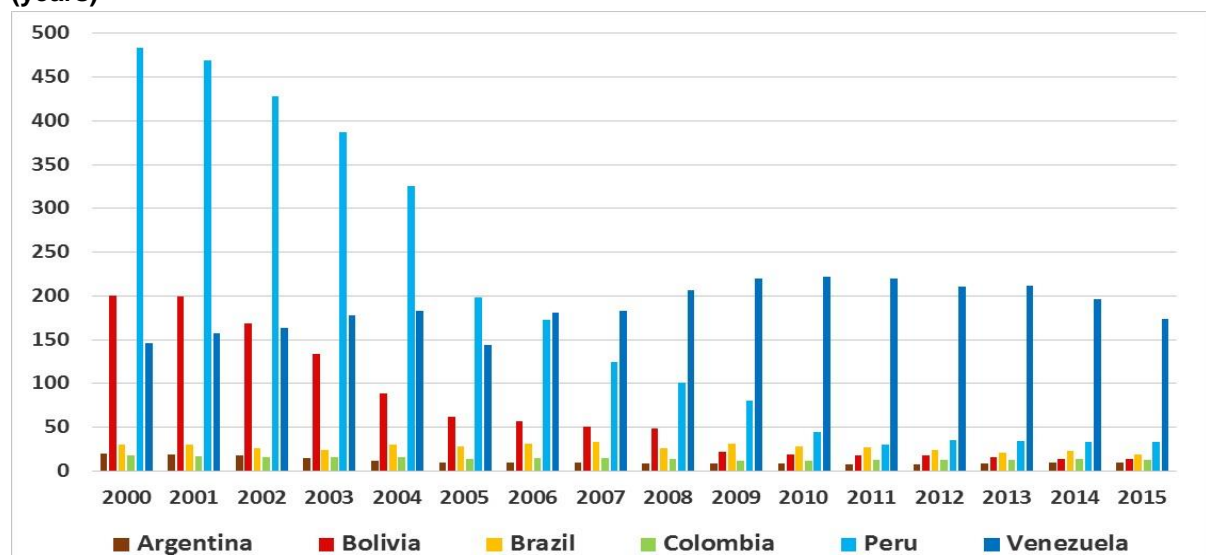
This third chapter focuses on natural gas supply. While the region has sufficient reserves to theoretically fulfil its needs, the level of gas production has not kept pace with gas demand growth. A first section focuses on future indigenous production, with the biggest expectations coming from Argentine unconventional output and Brazilian pre-salt production. The second section highlights the evolution natural gas balances and the consequences for the role of LNG in the region in our 2030 timeframe.

3.1. Resources, exploration and indigenous production

3.1.1. The difficult task ahead

As already mentioned, South American natural gas proven reserves have more than tripled since 1980, and this trend is expected to continue due in particular to the large resources found off the coast in Brazil (presalt basins) and the initial development of unconventional resources in Argentina. However, as a result of limited upstream investment and/or fast growing production, the proven reserves to production (R/P) ratios have fallen sharply since the early 2000s in all countries except Venezuela as seen in Figure 28. Venezuela still had an impressive R/P ratio of 173 years in 2015 (up from about 150 in 2000). The ratio was 33 years in Peru (down from 483 years in 2000), 18 years in Brazil (30 years in 2000), 13 years in Bolivia (a sharp decline from the 200 years in 2000), 12 years in Colombia (17 years in 2000) and 9 years in Argentina (19 years in 2000).¹⁵⁶

Figure 28: Evolution of the natural gas reserves to production ratios by country, 2000-2016 (years)



Source: Calculated from BP (2016)

¹⁵⁶ Calculated from BP (2016)



South American countries will have to increase upstream investment, develop new resources and boost production while dealing with geopolitical uncertainties, along with economic, environmental, social, and regulatory issues that have been impacting the pace and the level of natural gas production in the past. There are various factors that will constrain the increase in indigenous production; the following paragraphs focus on the geography, the regulatory environment and the impact of low oil prices since 2014.

- The geography of South America

Some gas fields are located in remote and/or environmentally sensitive areas or with complicated access, such as the Peruvian jungle and the Brazilian Amazon as well as the southern tip of Argentina and Chile. The potential for marketing the gas locally is relatively small and therefore gas monetization would require expensive transportation making the production of this gas uneconomic.

The region is also potentially rich in unconventional gas resources; however, the true potential will not be known before exploration takes place. As for conventional production, the right incentives for foreign investors to bring the necessary capital, skill, and technology to the region will need to be put in place. The scale of investment required and the uncertainties over resource potential make estimates of the volume and timing of any significant output highly uncertain.¹⁵⁷

- The regulatory environment

The major challenge facing the countries in developing their upstream sector is probably the regulatory environment. In South America, regulation and policies applied to upstream investment have shifted twice over the last two decades (in the 1990s and in the 2000s).¹⁵⁸ All markets are open to outside investment to varying degrees, but not all offer competitive terms and confidence for investors and while rapidly growing energy and particularly gas demand provides an incentive for upstream investment, perceived or real regulatory instability is seen as a deterrent. In the early 2010s, most countries were seeking to adapt their regimes to face the challenges ahead, but the expected results remain uncertain. Oil and gas companies have delayed investments and looked for guarantees and assurances before investing the several billions of dollars necessary to develop the regional gas potential. Policymakers need to find the right balance between making the market attractive and competitive to attract the necessary capital and technology while at the same time bringing in enough rent to develop the national economy and fund social programmes. Contrary to what was seen in the 1990s, governments want to develop the natural resources but, at the same time, keep an effective strategic control of these resources. The election of market-oriented president Mauricio Macri in Argentina in November 2015 turned another page toward more market oriented

¹⁵⁷ IDB (2012)

¹⁵⁸ The political and regulatory changes of the late 1980s and 1990s were characterised by liberalisation and privatization of the state companies, which opened the doors to private and foreign investment in sectors previously reserved to state entities in most countries, including the upstream hydrocarbon sector. Changes happened first in Argentina and Peru at the beginning of the 1990s, then followed in Bolivia (1996) and Brazil (post 1997), the latter serving as a model for Colombia's reform in 2003. These policies succeeded in attracting both capital and technology, but were sometimes faced with difficult public acceptance, such as the capitalisation programme (open oil and gas sector to private investment) in Bolivia. Despite the regional trend toward liberalisation, there were still differences between countries on the role of the market and the role of the state regarding the use and ownership of energy resources and rents. Some countries were more open to private investments (Chile, Colombia and Peru) than others (Venezuela, Ecuador and Bolivia), and some adopted a mix of both (Argentina and Brazil). The trend was radically modified in the 2000s when several countries turned back to state intervention. Oil rents and price controls were the two main drivers of the 'resource nationalism' decisions. Governments implemented new regulation with higher royalties and taxes, and some even turned to the nationalisation of assets, for instance Morales's 2006 nationalisation of the Bolivian hydrocarbon sector and the nationalisation of Yacimientos Petrolíferos Fiscales (YPF) in Argentina in 2012. See IEA (2003) for more information.



policies compared to the 2000s. With the difficulties faced by other socialist leaders (such as in Brazil and Venezuela for instance), this may only be a beginning.¹⁵⁹

- Low oil prices since 2014

Oil exporting countries, where government budgets rely heavily on oil taxes, royalties and sales such as in Venezuela, Ecuador, and – to a lesser extent – Colombia, have been hit by lower oil prices, even if the range of these impacts on their economy and political situation differs from one country to another. The most vulnerable country has been major oil exporter Venezuela where oil revenues represent 40% of the fiscal income and one third of the GDP.¹⁶⁰ The drop in oil prices has contributed to economic recession, high inflation, important public debt (50% of GDP), goods scarcity and political complications. The 2015 budget was based on a \$60/bbl oil price, but it is assumed that to meet the level of expenditures and sustain government-subsidized programmes,¹⁶¹ the oil price needs to be closer to \$120/bbl.¹⁶² Smaller exporters such as Colombia and Ecuador will also face important repercussions. In Colombia, oil exports represent about a quarter of fiscal income and 5% of the total budget. The fiscal and public deficit will most likely be more important than previously expected.¹⁶³ In Ecuador, fiscal stability requires an oil price above \$120/bbl and lower prices will continue to increase an already important fiscal deficit (5% of GDP).¹⁶⁴

Following the decline of oil prices since 2014, upstream players slashed their budgets. For instance, Petrobras revised its budget based on a \$70/bbl. assumption for 2015, while its 2014-2018 business plan issued in 2014 assumed a \$105/bbl. Brent price for 2014.¹⁶⁵ Another example is from YPF, which made downward revisions to its capital expenditure programme for 2015-2019 to \$2.42 billion per year, from \$3.03 billion booked for 2014.¹⁶⁶ Plans to increase exploration activity have been curtailed and there are many uncertainties on the level (and the timing) of investment that will be made.

Lower investment levels across the region will especially impact the development of high cost unconventional plays and offshore pre-salt projects such as those in Argentina and Brazil, and all offshore prospects in general, where development costs are a challenge such as those in Colombia and Venezuela for instance. As a result, future indigenous gas production will be delayed and potentially lower than expected. In addition, existing production is also at risk, as most gas is found in reservoirs with a large percentage of liquid hydrocarbons (associated gas) during oil exploration.¹⁶⁷ Therefore, low oil prices rose uncertainties on gas volumes to be produced in the whole region (at least) this side of 2020.¹⁶⁸

¹⁵⁹ For more information, see Conway T. (2014), pp.6-9 ; Flores-Quiroga A. (2014), p.4 and Financial Times, 25 November 2015, Mauricio Macri will make a difference beyond Argentina

¹⁶⁰ The Economist, 30 December 2014, Falling oil prices: winners and losers in Latin America

¹⁶¹ The average rate of subsidization for fossil fuels (ratio of the subsidy to the international reference price) was highest in Venezuela at 93% in 2013, representing about 10% of the national GDP. Source: IEA (2014c), p.321

¹⁶² Venezuelananalysis.com, 22 October 2014, Venezuelan Government Unveils 2015 Budget, Anticipates Drop in Oil Prices

¹⁶³ Reuters, 3 December 2014, Colombia to face fiscal deficit, current account pressures in 2015 -analysts

¹⁶⁴ The Economist, 30 December 2014, Falling oil prices: winners and losers in Latin America

¹⁶⁵ Petrobras (2015), slide 52

¹⁶⁶ Platts, 6 January 2015, Latin America Oil Outlook 2015

¹⁶⁷ With the notable exception of significant discoveries of non-associated gas in Bolivia and Peru

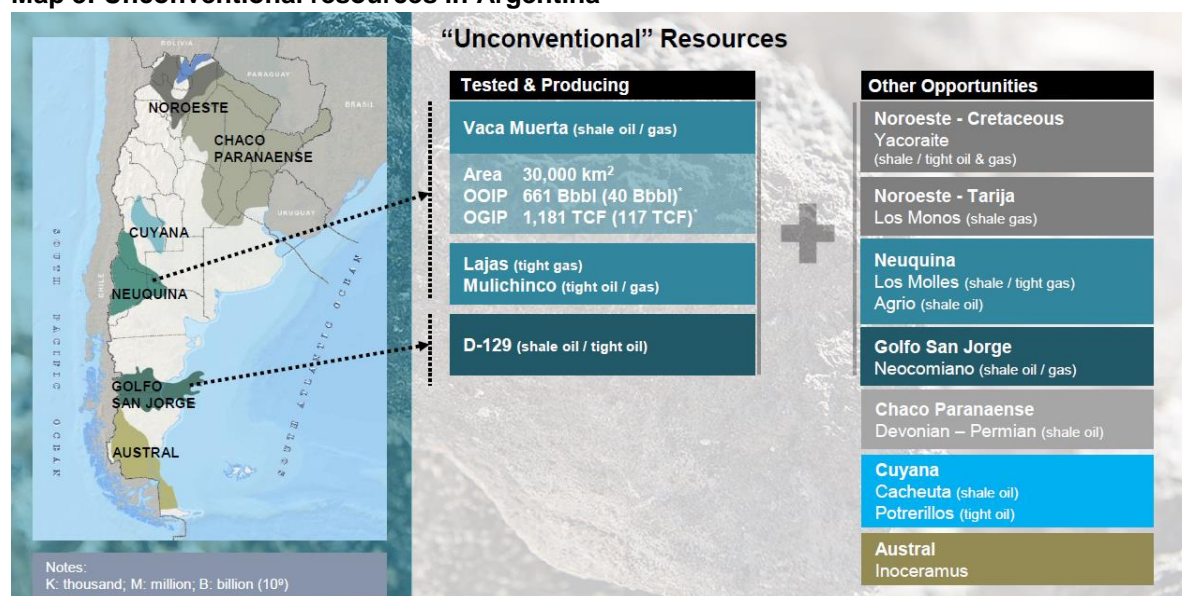
¹⁶⁸ Oil production offers better financial returns than gas production, which means that the exploitation of these reserves has been and will continue to be linked to oil production.



3.1.2. Estimates for potential additional gas production

In **Argentina**, expansion of the gas market was not matched with equal effort in expanding reserves and production. The main objective of the country is to overturn the decade-long decline of its (oil and) gas indigenous production. A mature producer in terms of its conventional gas, the country has attracted new interests thanks to its unconventional resources (shale and tight¹⁶⁹), especially in the Vaca Muerta shale play located in the middle-western Neuquén province; more than 1,000 kilometres from Buenos Aires (see Map 3 below).

Map 3: Unconventional resources in Argentina



Source: YPF (2014), slide 5

The great potential of these unconventional resources is due to the geological characteristics and their geographical location.¹⁷⁰ The Neuquén Basin covers 137,000 km² (more than the size of England), of which the Vaca Muerta shale play covers about 30,000 km² (about the size of Belgium). The size is an important factor, but the geology also seems very promising with 1,000-foot-thick shale formation, which allows higher drilling outputs with a smaller number of wells.^{171 & 172} In addition, Neuquén Basin has been a major producer of hydrocarbons for over 100 years and it is the country's most prolific region for conventional natural gas output (about half of the national production). As a consequence of being a mature petroleum-producing region, the Vaca Muerta shale play is located in

¹⁶⁹ There are both shale and tight reserves in Argentina. The shale plays are more oil-prone, while the tight plays are predominantly gas. Argentina ranks in second position for its shale gas resources according to the 2013 EIA report (and fourth for its shale oil resources). Source: EIA (2013), pp.V.6-29

Liquids potential of Argentine shale gas will be a key factor for investors, but early estimates suggest that only 20% of the most important basin Vaca Muerta has liquids. However, in the context of the gas shortage, this will not be a major issue (contrary to what happens in the US for instance). Source: Mares D. (2014)

¹⁷⁰ Vaca Muerta multiplied Argentina's oil reserves by a factor of 10 and its gas reserves by a factor of 40. Source: Inter Press Service, 10 April 2015, Plunging Oil Prices Won't Kill Vaca Muerta

¹⁷¹ Reuters, 22 May 2014, Argentina won lottery with Vaca Muerta shale field – Chevron

¹⁷² "Three petroleum systems have been identified in the basin: Los Molles-Tres Esquinas; Vaca Muerta-Sierras Blancas; and Agrio. The liquid rich and wet gas window is between vitrinite reflectance values of 1.2 and 1.5. The gas window starts at approximately vitrinite reflectance values greater than 1.5. The Vaca Muerta source beds represent a classic inverted system (similar to the Austin Chalk and Eagle Ford) with oil up-dip and gas down-dip." Source: Quote from The Colorado School of Mines Department of Geology and Geological Engineering. For more technical information about the geology of the Vaca Muerta shale play, go to their website: http://geology.mines.edu/Vaca_Muerta/index.html



an area with good road access, extensive pipelines, service companies and facility infrastructure in place. These are assets that do not need to be built and that unconventional gas developers can use. Once production starts, the producers will be able to use the more than 30,000 km of gas pipeline network,¹⁷³ the largest network in South America that has been underutilised due to the decline of conventional production, and transport the gas to market centres. The government also promised to YPF a railroad to connect the Vaca Muerta to the rest of the country.¹⁷⁴ Thanks to the pre-existing oil and gas industry activity, the companies also already have geological knowledge and drilling data. While the water requirements of hydraulic fracturing can be a major challenge for shale developers in other parts of the world, this is probably not going to be the case for Vaca Muerta due to the nearby Limay and Colorado rivers. Finally, the shale and tight gas reserves are largely in the lightly populated regions of Patagonia and Neuquén, making environmental and social issues potentially less complicated.

However, this pretty picture is more complex than it first looks. Despite existing geological data and in-place infrastructure, the development of this basin still requires significant capital investment. The government, provincial governments and the country's biggest energy company YPF SA will not be able to fund this without foreign investment, and there are major challenges for attracting private companies. In April 2012, the (re)nationalization of YPF and the revocation of oil and gas concessions, notably in the shale provinces,¹⁷⁵ shocked investors and weakened the country's ability to attract foreign investments. The 2014 \$5 billion settlement with Spain's Repsol in compensation for its expropriated 51% stake in YPF was an important move to restoring some investor confidence.¹⁷⁶ In addition to uncertain regulatory environment, the country's financial difficulties (currency devaluation,¹⁷⁷ high inflation and the defaults on its international debt¹⁷⁸) have hindered the access to financial markets in the 2000s/early 2010s. In April 2016, the country finally settled the dispute with the bondholders that refused to restructure the debt from the \$100 billion default in 2001.¹⁷⁹ The return to international capital markets will be beneficial to the development of unconventional resources. President Macri vowed to end restrictions on access to foreign currency, importing equipment and repatriation of corporate profits in his presidential campaign and promised a shift to market-oriented policy. Reforming the regulatory environment is seen as going in the right direction and to finally dealing with the major obstacle in boosting investment in unconventional formations. In particular, the government increased average wellhead gas prices to around \$5/MMBtu, which was double the price for most existing production while at the same time extending a subsidy program that pays \$7.50/MMBtu for new shale and tight natural gas production projects. Despite these changes seen as welcome by private investors, the arrival of Macri coincided with a difficult period for energy investment in general. The decline of the global oil price will likely slow the pace of development. It is

¹⁷³ The two main companies that control it are Transportadora de Gas del Sur (TGS) and Transportadora de Gas del Norte (TGN).

¹⁷⁴ Casey Research, 25 March 2014, A safe way to play the Vaca Muerta

¹⁷⁵ YPF (2012a) and YPF (2012b)

¹⁷⁶ Financial Times, 25 February 2014, Repsol accepts \$5 billion Argentina

Entering into a partnership is the main route for new players to enter Vaca Muerta, especially with YPF, which holds 75% of wells drilled, 90% of the shale oil production and 80% of the shale gas production. Source: Mares D. (2014), p.17.

Auctions for the limited unlicensed remaining acreage may take place but this is located near the Andes and in the dry gas-prone areas.

¹⁷⁷ Currency devaluation increases the depreciation risk of investments. It can complicate a project by making it harder to collect enough revenue (in the local currency) to meet the scheduled debt payment (typically in a different currency such as USD), increasing the chance of default. When sourcing international funds, developing countries face higher foreign exchange risks, and the private sector is reluctant to provide mechanisms to hedge this risk for less-frequently traded currencies. Source: IDB (2014), p.49

¹⁷⁸ The country defaulted on its debt in July 2014 for the second time in 13 years.

¹⁷⁹ Financial Times, 24 April 2016, Argentina repays holdouts, says ciao to default



also believed that with the oil barrel at \$50, only a few sweet spots in Vaca Muerta are viable.¹⁸⁰ At a time of low oil prices and reduced investment budgets, costs will have to be reduced, especially drilling costs. YPF said it has already cut the cost of drilling a vertical well in Vaca Muerta to \$6.9 million from a previous \$11 million, and it is expected to fall by at least 10% by the end of 2016 by using indigenous sand in fracking.¹⁸¹ Horizontal wells have been drilled at an average cost of \$11 million in January-June 2016 in the onshore Loma Campana block, down from \$13 million to \$14 million.¹⁸² However in 2016, YPF plans to drill only about 54 unconventional wells in Vaca Muerta (about 90% horizontal), a sharp drop compared to the 250 wells drilled in 2015.¹⁸³

Good progress has been made since 2010 when YPF started to develop the unconventional oil and gas resources of Vaca Muerta.¹⁸⁴ Since the takeover in 2012, YPF has been active in finding foreign energy companies to collaborate and every deal –large or small- is an important step forward in the development of the gas resource.¹⁸⁵ Some companies have already begun exploring and a few have already started producing shale oil and shale gas, even if shale gas production on a commercial scale was only just starting in 2015. YPF was the first to enter mass production in a partnership with Chevron. Others have entered pilot production, namely ExxonMobil, Shell, Total and Wintershall. Moving from pilot production to the development phase will be very costly and require additional capital, with most estimates suggesting between \$5 billion and \$12 billion needed per year.¹⁸⁶ After President Macri took office in December 2015, several deals were announced such as the \$500 million agreement with US based Dow Chemical to boost production in an existing shale gas development and the \$500 million deal with US independent American Energy Partners to develop a shale oil and gas pilot project.¹⁸⁷

Despite all these developments, future development of Vaca Muerta –and more importantly the pace of it- is uncertain. The government has been trying to reverse years of declining output and cut back expensive gas imports, but even officials recognise that it will be a long process, and it probably won't have a major impact on the country's gas supply/demand balance this side of 2020. Still, the government expects that by 2020 the production of shale gas will be sufficient to replace imports of

¹⁸⁰ OIES/Kapsarc (2016), chapter 6

¹⁸¹ Costs are between \$4 million-\$5 million/well in shale plays in the US.

¹⁸² Argus Latin America, 9 August 2016, YPF reins in drilling costs

¹⁸³ Argus, 4 March 2016, YPG checks upstream growth expectations

¹⁸⁴ YPF drilled and completed a shale gas discovery in July 2010 in the Loma La Lata area. Shortly thereafter in November 2010, a shale oil discovery was made in the Loma Campana area of Neuquén Province. Source: AAPG Explorer, January 2013, Argentina's Vaca Muerta Draws GTW Spotlight

¹⁸⁵ In 2013, YPF entered in an impressive \$1.4 billion partnership with US Chevron to develop the Loma La Lata Norte and Loma Campana areas. In May 2014, the company announced its intention to invest an additional \$1.6 billion, encouraged by well results and the prospect of lower drilling costs, to warrant additional investment. Source: Reuters, 22 May 2014, Argentina won lottery with Vaca Muerta shale field – Chevron

The second biggest investment was by Malaysia's state-owned Petronas, which signed a \$550 million agreement with YPF in late 2014. Source: Financial Times, 11 December 2014, Petronas signs Argentina shale deal

In both agreements, the foreign IOCs supply the majority of the projects' financing and YPF maintains operational control, and if the initial period is successful, additional investment may be envisaged. Other companies are also active in the country, with smaller commitments. Gas y Petróleo del Neuquén S.A., the company owned by the Argentine province of Neuquén, announced smaller deals with Royal Dutch Shell (\$250 million) and France's Total (\$300 million) to develop other parts of Vaca Muerta. Other companies such as the Argentine company Pan American Energy (PAE), ExxonMobil and Germany's Wintershall are also pursuing pilot production projects in the shale play. In July 2015, the Neuquen province approved four new unconventional upstream contracts with YPF, Pan American Energy (PAE) and Wintershall with the companies expected to invest some \$1.4 billion over the next three years at the projects. These deals were finalized under the amendment to the hydrocarbons law passed in October 2014. Source: Argus News, 21 July 2015, Argentina province approves four upstream deals.

Russia's Gazprom and China's Sinopec are evaluating opportunities The developments in Vaca Muerta have also attracted investments from investors like George Soros for instance, who owns 3.5% of YPF shares. YPF has also entered into partnership with Dow Chemical for a tight gas development in another play.

¹⁸⁶ Platts International Gas Report, 29 June 2015, Vaca Muerta needs capital

¹⁸⁷ Argus, 15 January 2016, YPF signs shale deal with American Energy Partners



gas, which in this author's scenarios seems unlikely. The development of the unconventional reserves, and especially the Vaca Muerta area, is expected to get Argentina closer to its objective of energy self-sufficiency, however until additional exploration is undertaken, one cannot know the scale and characteristics of the resource and therefore how much unconventional gas is potentially recoverable under existing economic and technological conditions.

Brazil is another location with high expectations for future production thanks to large resources of associated gas in the presalt areas and some substantial onshore associated and non-associated resources (both conventional and unconventional). Brazil has large shale gas resources (the 10th largest in the world according to the EIA). However, some of these are located in areas with no gas transportation infrastructure and very far from demand. Some are also in environmentally sensitive areas and in hydroelectric reservoir areas, and hence it would be difficult to obtain environmental permits. The prospects for natural gas production in Brazil are mainly linked to the development of the associated gas in the pre-salt layers discovered in the early 2000s, but there have also been discoveries off the country's northeast coast in post-salt areas since 2012. These finds are closer to shore and could be much cheaper to develop especially due to already existing infrastructure.

First production in the pre-salt layers began in 2008, and additional exploration confirmed hydrocarbon deposits in the presalt areas of the Santos, Campos, and Espírito Santo basins. Estimates vary for total presalt resources with some analysts believing that the presalt recoverable oil and natural gas reserves could be more than 50 billion barrels of oil equivalent.¹⁸⁸ As exploration intensifies, better estimates can be expected. These resources are located in ultra-deep water under thick layers of rock and salt in some of the biggest underground aquifers in the world, on the continental shelves off the coast in south-eastern Brazil between the states of Santa Catarina and Espírito Santo as seen below on Map 4. The area covers about 800 km in length and 200 km in width, of which about 30% has already been allocated for exploration/development.¹⁸⁹

Following the discoveries of the pre-salt resource, the government passed legislation instituting a new regulatory framework and a new fiscal regime in 2008 (production sharing regime) for the so-called presalt polygon.¹⁹⁰ The legislation created a new agency, Pré-Sal Petróleo SA, to administer production from the presalt areas and made Petrobras the sole operator of all pre-salt blocks with a minimum stake of 30%.¹⁹¹ Petrobras is the lead operator in the presalt area already under concession. But several companies (national and international) are exploring and producing both oil and gas in the presalt (and in Brazil generally), mostly in association with Petrobras.¹⁹² Exploration and development of the pre-salt deposits are still in the early stages,¹⁹³ but natural gas production

¹⁸⁸ The fields under production and several other blocks still in exploration were competitively awarded under concession contracts to Petrobras and other companies/consortia, mainly in the 2006 and 2007 auctions. Other areas were non-competitively granted to Petrobras under an agreement by which Petrobras pre-paid a certain volume of reserves to the Government (the so called "cessao onerosa" or "transfer of rights"). Finally, one large area, the Libra field (with potential recoverable reserves of 8 -12 billion barrels) was awarded under the new production sharing regime to a consortium formed by Petrobras, Shell, Total, and China National Petroleum Corporation (CNPC) and China National Offshore Oil Corporation (CNOOC). This consortium submitted the only bid during the first production sharing licensing round, which was concluded in October 2013. Source: Energy Information Administration, 13 November 2013, Recent production growth from presalt resources increases Brazil's total crude output

¹⁸⁹ Petrobras website, Pre-Salt, <http://www.petrobras.com.br/en/our-activities/performance-areas/oil-and-gas-exploration-and-production/pre-salt/> and Gomes (2014a), pp.18-19

¹⁹⁰ Portal Brasil, 27 March 2014, Minas e Energia lança plano decenal para setor de gás

¹⁹¹ Presidência da República (Brazil) (2010)

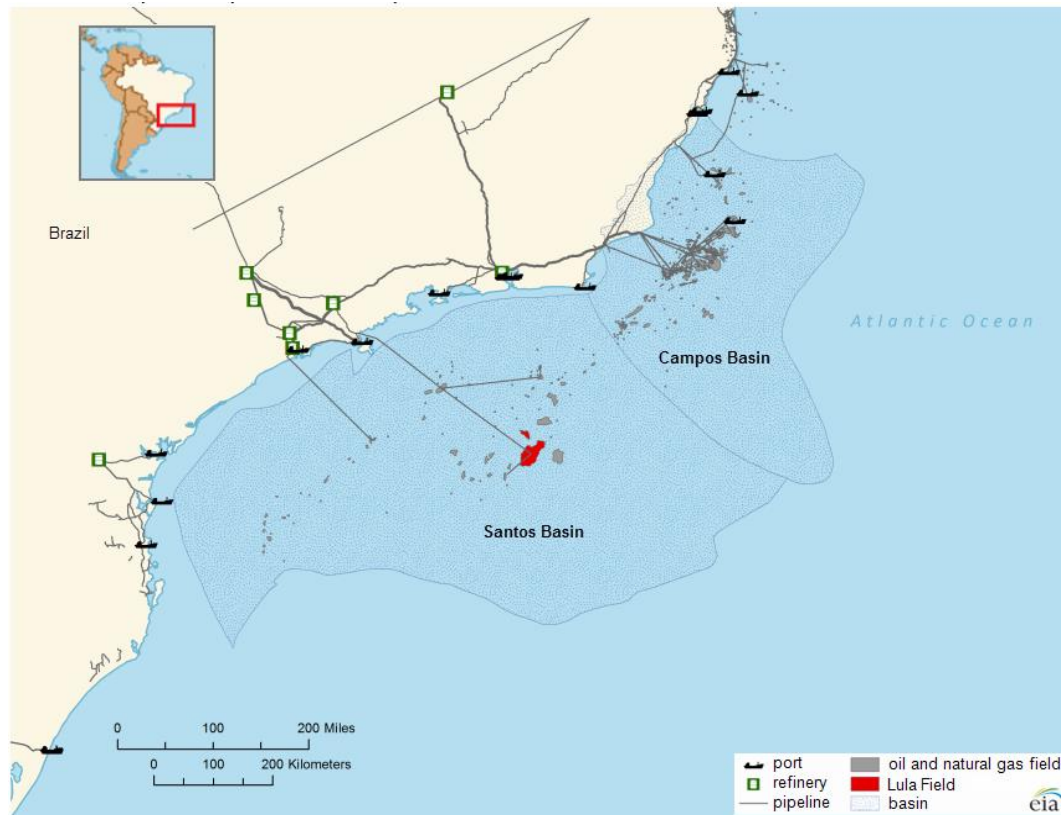
¹⁹² 17 companies were listed by ANP as producing at least 1 mcm/d of natural gas in July 2016. Out of 107.2 mcm/d produced, 99.1 mcm/d came from Petrobras. Source: ANP (2016), p.12

¹⁹³ Out of the 9064 wells drilled for oil and natural gas production in Brazil in April 2015, only 49 were located in the pre-salt areas. For more information and the complete list of the 49 wells and their associated production, see ANP, June 2015, Boletim de Produção de petróleo e Gas Natural – Abril 2015, pp.6-7 and pp.17-18



from the pre-salt has been rising rapidly and represented almost 30% of total gas production in 2016,¹⁹⁴ double that of 2013 and up from 0.5% in 2008.¹⁹⁵

Map 4: Presalt basins in Brazil



Source: Energy Information Administration¹⁹⁶

Petrobras anticipates oil and gas production from the region to account for most of its projected production growth through 2030.¹⁹⁷ However, producing oil and natural gas from the presalt areas is not without challenges. Firstly because of the specific geographic and geological location; the reservoirs are found 200-300 km from the coast, 5,000 to 6,000 metres below the sea level, in ultra-deep water (1,900 m to 2,400 m) under thick layers of salt (up to 2000 metres in some places) as seen in Map 5. This poses technological and logistical problems, such as the need for deep-water drilling and production platforms, the transport of staff and equipment. The ultra-deep water environment also means that special pipes are needed. The thickness of the pipe walls will need to be able to withstand the high pressures and the heavy loads as a result of the larger diameter are also a technological challenge for installation vessels.

¹⁹⁴ Agência Nacional de Petróleo (ANP), Boletim da Produção de Petróleo e Gás Natural, various issues

¹⁹⁵ Energy Information Administration, 9 January 2015, Presalt oil and natural gas provide an increasing share of Brazil's production

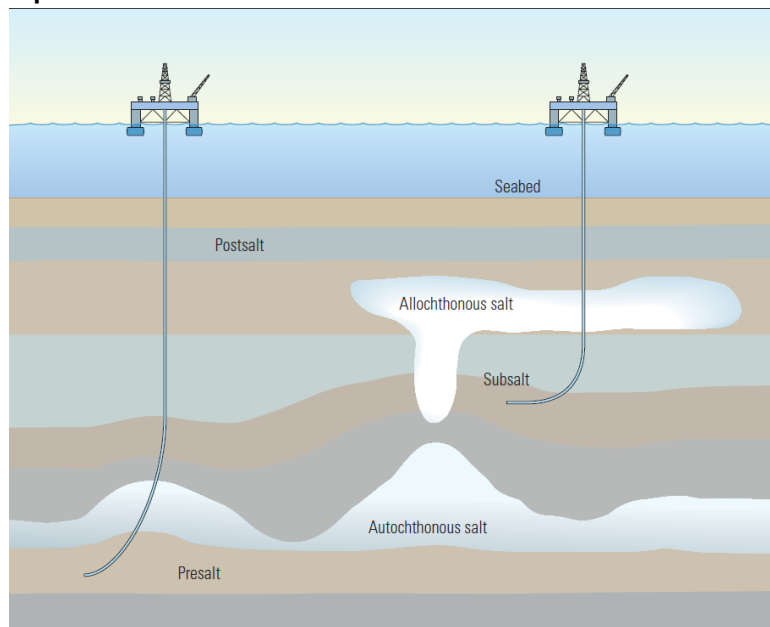
In July 2016, natural gas production was 107.2 mcm/d of which 40.2 mcm/d came from the associated gas in the pre-salt layers. Source: ANP (2016), p.14

¹⁹⁶ Energy Information Administration: <http://www.eia.gov/todayinenergy/detail.cfm?id=13771>

¹⁹⁷ Energy Information Administration, 9 January 2015, Presalt oil and natural gas provide an increasing share of Brazil's production



Map 5: Geology of presalt basins



Source: Schlumberger¹⁹⁸

Drilling is extremely difficult with low penetration rates. In addition, the pre-salt reservoirs are highly corrosive environments with significant amounts of carbon dioxide (CO₂) and hydrogen sulfide (H₂S). Special cement and metallurgy will be necessary throughout the drilling and completion phase. Finally, the reservoirs themselves are described by Halliburton as “complex heterogeneous layered carbonates, which makes accurate reservoir characterization very challenging”.

Developing the pre-salt reservoirs will require specific technologies and capabilities. Along with the technological challenge, comes the economical one. Petrobras announced that the break-even price for the presalt acreage was \$45/bbl, and \$5-7/bbl more for the gas treatment and transport infrastructure.¹⁹⁹ Even if the pre-salt production remains viable at low oil prices, the company would have to cut spending which in turn will at best slow down growth rates or at worst jeopardize production from the pre-salt layer.

Past investments and fully committed ones will sustain production in the mid-2010s but investments are likely to slow in the second half of the decade as a consequence of low oil prices, the ability of Petrobras to recover from its current financial crisis and the corruption scandal,²⁰⁰ the willingness of the government to allow a larger participation of private companies in the presalt, impacts of the economic recession (2014-2016 at least) and of the political situation. This will -at best- cause delays to the start-up of new fields and engender uncertainty regarding the timing and the size of future (oil and) gas production. On the positive side, it is believed that president Temer will carry on a pro-market agenda and intends to renew investors' interests in Brazil's oil and gas sector which accounts for 15% of the country's GDP.

¹⁹⁸ Schlumberger: http://www.slb.com/~media/Files/resources/oilfield_review/ors10/aut10/03_presalt.pdf

¹⁹⁹ Reuters Brazil, 6 January 2015, Petrobras diz que eleva produção no pré-sal de modo viável, apesar de queda dos preços do petróleo

²⁰⁰ Many high ranking politicians have allegedly received payments from mainly domestic firms through inflated Petrobras contracts. The company may have to pay fines, write down assets and/or be restricted in its choice of construction companies due to bans imposed on contractors. Source: Argus Latin America Energy, 27 January 2015, Fighting on two fronts



One of the key proposals that would allow companies other than Petrobras to operate presalt projects had already been passed by the Senate, and in October 2016, the chamber of deputies voted to approve the bill. After a vote on amendments, president Temer will receive the bill and is expected to pass the legislation. Under the proposal, Petrobras would still have the right of first refusal to operate presalt areas,²⁰¹ but this reform would be a key driver to encourage investments from foreign companies that have shown interest in the presalt potential as already seen with Shell's takeover of BG, a move that made Shell the leading foreign operator in Brazil, and also with Statoil's acquisition of 66% of Petrobras' operating stake in a deep-water presalt area in the Santos Basin.²⁰²

Increasing presalt production remains Petrobras' priority in its 2017-2021 business plan, with presalt spending accounting for 2/3 of upstream investments (and the rest allocated at postsalt projects in the Campos Basin).²⁰³ A highly indebted Petrobras, entangled in a massive corruption scandal, is believed to lack the financial capability to develop all the new presalt projects. Its capex plans have been revised downward several times since 2015 as the company intends to reduce its role in the gas industry, especially in midstream and downstream segments and its financial difficulties may still cause delays in the exploration and development of new reserves. This provision would enable the industry to move forward by attracting investment to the country and avoid further disruption in the development of the presalt areas.

Bolivia benefits from large non-associated gas fields that enjoy a high level of productivity. Its gas reserves to production ratios stood at only 13 years, a sharp decline from the 200 years in 2000.²⁰⁴ The nationalization of its hydrocarbons in 2006 caused many international oil companies to limit investments in the country due to political uncertainties and risk of expropriations. As a consequence, the production of the state-owned YPFB dropped, but after several years of efforts to rebuild its output, production started to increase again in 2010. Its indigenous production reached 21.9 bcm in 2015, about six times the level of its national gas demand.²⁰⁵ However, Bolivia will need to find and develop new reserves in order to maintain and expand gas production if it is to fulfil both its existing export commitments and its expectations for additional gas exports.

Boosting gas production and exports will require attracting private investments to the upstream sector. YPFB has several exploration projects under way with various partners (for instance Petrobras, PdVSA, Repsol, BG Group, Total and Gazprom). YPFB and Argentina's YPF have agreed to jointly explore three blocks in Bolivia and share technology for developing shale resources.²⁰⁶ YPFB and Petrobras have also signed a Memorandum of Understanding in 2015 to develop natural gas deposits in the Tarija region over the next 10 years.²⁰⁷ Bolivia's gas reserves, which were adjusted down in 2009 on technical grounds stood at about 0.32 Tcm in 2014. The government expects to boost gas reserves to 0.35 Tcm in 2021 and 0.54 Tcm in 2025.²⁰⁸ Production growth is expected to slow in the second half of the 2010s before starting to fall when some of the largest fields -such as San Alberto, Sabalo and Margarita- enter their decline phase unless new fields are put in production.²⁰⁹ Recent

²⁰¹ Argus Latin America Energy, 11 October 2016, Petrobras close to shedding sub-salt yoke

²⁰² Argus Latin America Energy, 31 August 2016, Temer looks to revive oil and gas sector

²⁰³ Financial Times, 29 June 2015, Petrobras slashes investment to cut debt

²⁰⁴ Calculated from BP (2016)

²⁰⁵ IEA (2016a), p.II.4 and p.II.8

²⁰⁶ Platts International Gas Report, 17 June 2013, Argentina & Bolivia work on E&P

²⁰⁷ The memorandum is the first step to a formal contract for Petrobras to invest about \$2.1 billion in developing gas deposits at San Telmo, Sunchal and Astillero in the province of Tarija through 2025. Source: Platts International Gas Report, 20 April 2015, Brazil primes the gas pumps, pp.3-4

²⁰⁸ These figures include the depletion of existing reserves. Source: Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America

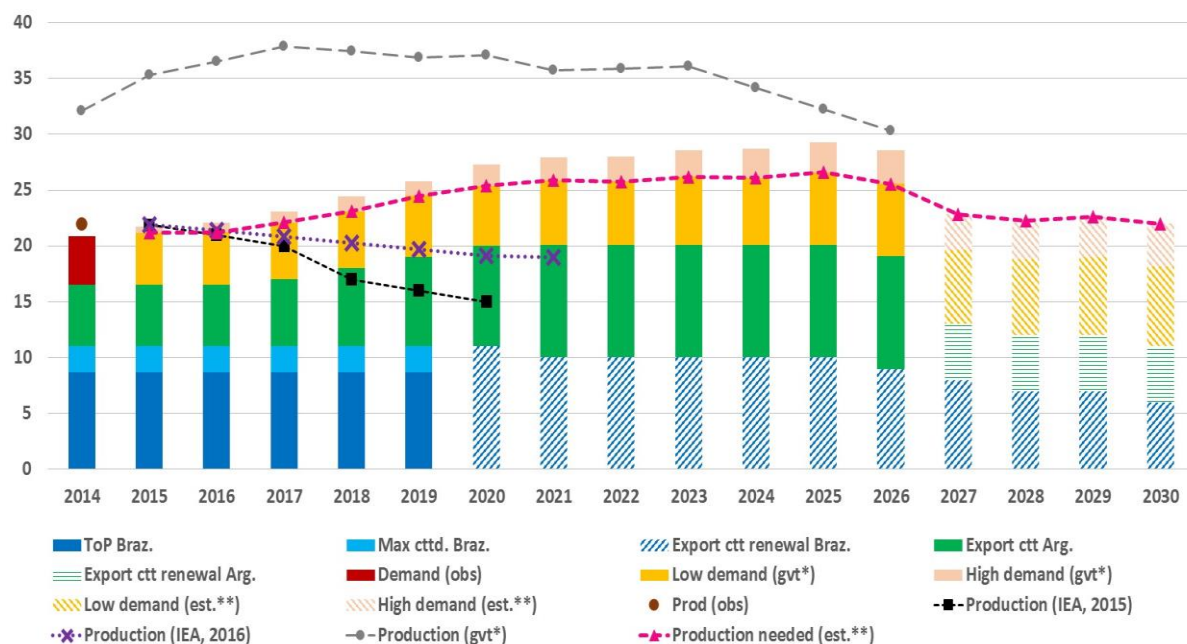
²⁰⁹ These three fields account for 70% of total exports to Brazil and Argentina. Source: IEA (2015d), p.91



discoveries may not be enough to maintain gas production growth even if developing mega fields such as Margarita (operated by Repsol) and Incahuasi (operated by Total) will constitute an important contribution to natural gas supply.²¹⁰

Contrary to government confidence, concerns have risen about Bolivia's continued ability to supply its neighbours beyond the existing contracts. Plans to increase exploration activity have been curtailed by the fall in oil and gas prices. Like others, YPFB made downward revisions to its capital expenditure programme. The government unveiled several decrees in 2015 in order to favour investment,²¹¹ but there are many uncertainties on the level (and the timing) of investment that will be made, especially at times of low oil and as a direct consequence for YPFB due to oil-linked export gas prices. This is an important security issue considering the dependence of Argentina and Brazil on Bolivian gas, at least until they develop their own reserves.

Figure 29: Natural gas balances in Bolivia, 2014-2030 (bcm)



Sources: IEA (2015d) and IEA (2016c), Ministerio de Hidrocarburos y Energia (Bolivia) (2008), p.132; Author's assumptions

This author has chosen to set the future indigenous production of Bolivia at a level that permits fulfilling low national demand expectations and existing export commitments, plus potential additional needs from Brazil and Argentina as seen in Figure 29. These two countries have decreasing need of Bolivian gas in the 2020s thanks to their own indigenous production growth. The assumption that Bolivia will take adequate measures to maintain its production and activate them in time to be able to keep its production at levels that meet national demand and import needs is a gamble. It is therefore important to keep in mind that this may not happen, in which case, the national market will likely be given priority and export markets will come in second, according to the chronological order of the signing of natural gas purchase and sale contracts with YPFB.

²¹⁰ Repsol website, Repsol in Bolivia, http://www.repsol.com/es_en/corporacion/conocer-repsol/repsol-en-el-mundo/bolivia.aspx

²¹¹ Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America



Contrary to other regional importers, **Chile** has no expectations to improve significantly its production. Its small reserves and small production are located in the far south of the country, far away from the main consumption centers and transport network.

In **Colombia**, the major producing fields are in the north-eastern Guajira peninsula and are operated by Chevron, but are slowly declining. The country's upstream sector suffers from a lack of infrastructure, both in the form of transport pipelines and storage, and also from an insufficiently attractive regulatory framework, which acts as a deterrent to major foreign exploration. In an attempt to address the country's problem of reserves replacement, it has taken steps to make terms and conditions more attractive to accelerate exploration activities especially in more costly and risky offshore areas. The policy of restricting gas exports was lifted in 2010,²¹² and 40% royalty discounts for explorers of offshore and unconventional resources²¹³ for both crude and gas were introduced.²¹⁴ However, low oil prices and disappointing early results have been an important setback for offshore exploration. Other challenges remain such as delays in environmental permitting, attacks by leftist guerrillas on crews and pipelines and community blockades which create a difficult operating environment. Without a boost in national production, the country will need to import gas as early as 2017 according to the Colombian oil chamber ACP. The outlook for additional gas production was not optimistic at the time of writing, but reforms in the upstream sector could attract additional investments in the offshore areas in the future.

Peru exports its gas outside of South America in the form of LNG and does not contribute to the regional balance. Sourced by the Camisea field, Peru started exporting its gas in 2010 in the form of LNG. However, the field is located in a remote jungle east of the Andes, 300 miles from Peru's populated coastal areas and even further from potential neighbouring consumers (Brazil, Argentina). Environmental questions and community activism are slowing the development of additional areas. Such unrest is dampening exploration and production growth plans. Nonetheless the Southern gas pipeline (Gasoducto del Sur) started construction in 2015 and was expected to be completed in 2018 (but delays were likely). This 1000 km pipeline will transport the gas to two port cities (Ilo and Mollendo) and to the southern coast providing gas for household demand and power generation (including two gas-fired plants under construction).

In **Uruguay**, the government's objective is to reduce energy imports.²¹⁵ The country does not produce natural gas but expects to make discoveries in the north of the country where there could be significant unconventional resources and has awarded exploration licenses for both onshore and offshore acreage.

Venezuela was a net gas importer between 2007 and 2015, but it expects to increase its own production and eventually export natural gas to Colombia. Associated gas represents about 80% of the reserves and production of natural gas is highly dependent on oil production and the price of crude oil. The country aims at developing additional reserves, especially those located offshore with non-associated gas.²¹⁶ When (if?) these reserves are developed, they will first be directed to the national market as stated in Decreto 310 'Ley Orgánica de Hidrocarburos Gaseosos'.²¹⁷ After several

²¹² Zamora A., Martinez H. (2014), p.19

²¹³ Colombia has important yet to be tapped coal-bed methane resources, and also some shale gas resources. Onshore and shallow-water gas fields and deep offshore gas pay only 80 and 60% of the level of royalties paid by oil fields, respectively

²¹⁴ Platts International Gas Report, 7 April 2014, Colombia tackles replacement problem

²¹⁵ Platts International Gas Report, 1 June 2015, first gas found in north Uruguay

²¹⁶ Platts International Gas Report, 14 July 2014, Perla: Venezuela's big gas hope

²¹⁷ República Bolivariana de Venezuela (1999)



delays, the \$5bn Perla project (see Map 6 below) led by Spain's Repsol and Italy's ENI, started producing natural gas from an offshore non-associated gas field in July 2015 with the first 4.2 mcm/d train of the Cardón IV block, estimated to hold nearly 480 bcm of gas.²¹⁸ Production was expected to ramp up to 12.7 mcm/d by the end of 2015 (4.6 bcma) from thirteen gas production wells that will secure production until the beginning of the second phase.²¹⁹ Production should rise to 23 mcm/d (8.4 bcma) in mid-2017 and reach a peak of 34.5 mcm/d (12.6 bcma) by 2020.²²⁰ Gas will be sold to national oil and gas company PDVSA under a Gas Sales Agreement running until 2036.²²¹ The terms of the agreement have not been disclosed, but the gas will be delivered into the national market and displace some of the costly diesel and other liquid fuels often used to operate power stations, petrochemical plants and other facilities.

Map 6: The Perla project in Venezuela



Source: Enerdata²²²

Part of Perla's production will be exported to neighbouring Colombia to reverse a cross-border gas pipeline that was used to ship Colombian gas to western Venezuela (and to comply with a prior agreement with Ecopetrol).²²³ Exports should have started in January 2016, but that plan was indefinitely postponed in December 2015 due to the severe drought conditions caused by El Niño, which means that Venezuela needs the gas to generate electricity at home. The country's economic problems²²⁴ have worsened with the steep decline in international oil prices since mid-2014. Low regulated gas prices are also an obstacle. In Venezuela, the wellhead price is \$0.127/MMBtu, and \$0.784/MMBtu for the consumer, which is much lower than the wellhead price that the investors need.²²⁵ All this does not augur well for future development of additional (especially offshore)

²¹⁸ ENI, 4 June 2014, Eni signs strategic agreements for Perla super-giant field in Venezuela

²¹⁹ Platts International Gas Report, 1 June 2016, Venezuela to export early 2016

²²⁰ Argus, 17 February 2015, Analysis: Repsol hangs gas pearl on Venezuela

²²¹ Enerdata, 7 July 2015, Eni starts producing gas from Perla giant field offshore Venezuela

²²² Enerdata: http://www.enerdata.net/enerdatauk/press-and-publication/energy-news-001/eni-starts-producing-gas-perla-giant-field-offshore-venezuela_33333.html

²²³ Platts International Gas Report, 14 July 2014, Perla: Venezuela's big gas hope

²²⁴ GDP is expected to contract by 7% in 2015. Source: Argus, 17 February 2015, Analysis: Repsol hangs gas pearl on Venezuela

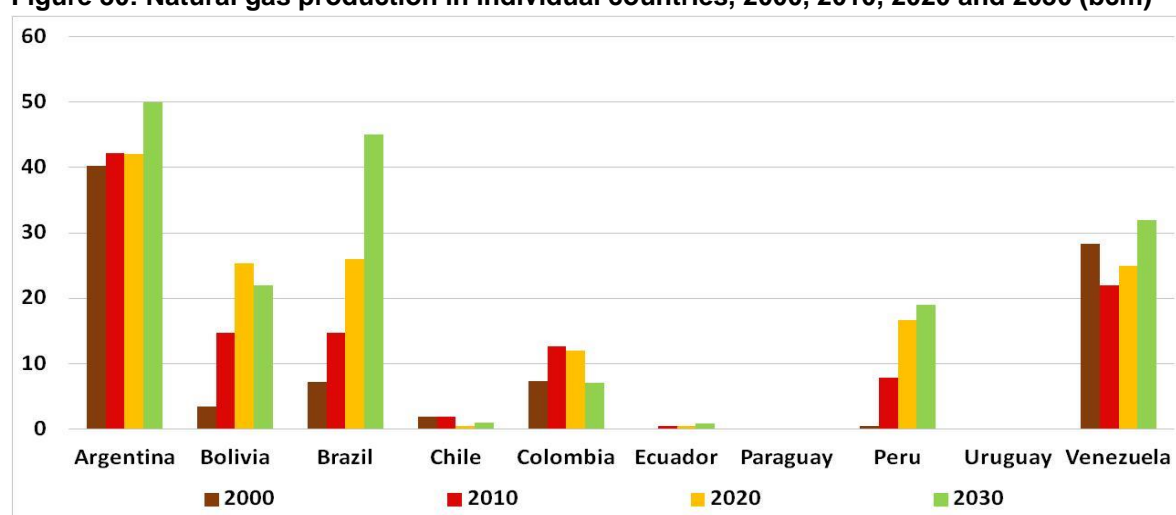
²²⁵ Platts International Gas Report, 14 July 2014, Perla: Venezuela's big gas hope



production, at least this side of 2020. However, political changes and recovery of the oil price could brighten the developments of offshore reserves post 2020.

All in all, the region has lots of resources and reserves, of both associated and non-associated gas, in conventional and unconventional areas. The potential for additional natural gas production in South America is significant, but it is also facing considerable uncertainties on the scale, location and timing of the development. Figure 30 below shows the author's assumptions on natural gas production in individual countries and Table 12 the equivalent average annual growth rates. As for natural gas demand, these scenarios are based on historical trends, official scenarios from national, regional and international entities when available, and/or personal assumptions. Additional details for each country can be found in the Appendix.

Figure 30: Natural gas production in individual countries, 2000, 2010, 2020 and 2030 (bcm)



Source: Author's assumptions

Table 12: Annual average natural gas production growth rates, per country, up to 2030 (%)

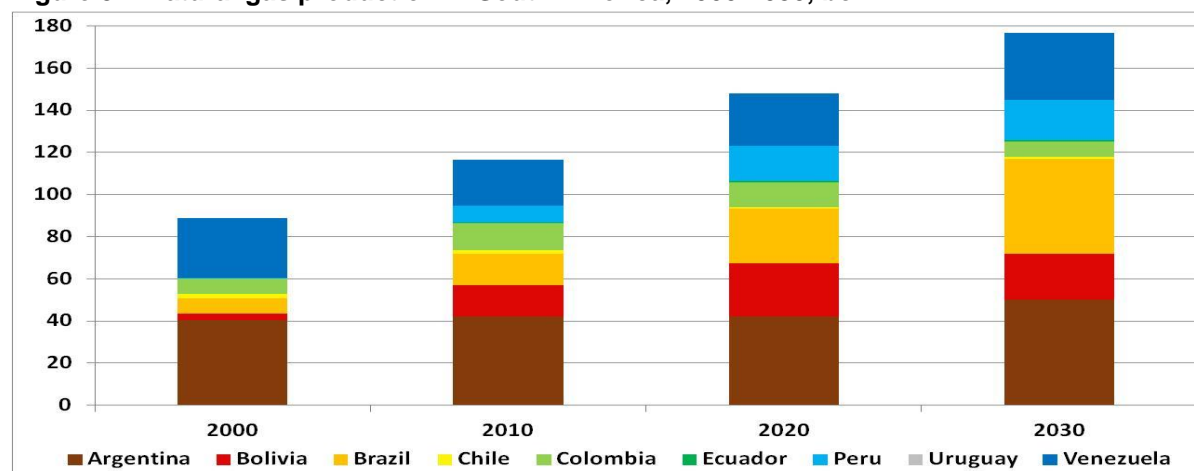
	2000-2010	2010-2020	2020-2030
Argentina	0.5	-0.1	1.8
Bolivia	15.9	5.6	-1.4
Brazil	7.5	5.8	5.6
Chile	-0.3	-12.3	7.2
Colombia	5.6	-0.5	-5.2
Ecuador	n/a	2.1	4.8
Paraguay	n/a	n/a	n/a
Peru	31.5	7.8	1.3
Uruguay	n/a	n/a	n/a
Venezuela	-2.5	1.3	2.5
Total	2.7	2.4	1.8

Sources: 2000-2010: IEA, Natural gas information, various reports, Outlook: author's assumptions

Despite the challenges mentioned, regional production grows from 138 bcm in 2015 to 148 bcm by 2020 and 177 bcm by 2030 as seen on Figure 31 below. Argentina and Brazil are expected to be the largest gas producing countries in the region in 2030, followed by Venezuela, Bolivia and Peru.



Figure 31: Natural gas production in South America, 2000-2030, bcm



Sources: 2000-2010: IEA, Natural gas information, various reports, Outlook: author's assumptions

3.2. Balances and import options

The following paragraphs confront the expectations on future indigenous gas production and future gas demand, with a particular focus on the impacts of these regional and national dynamics on LNG imports.

3.2.1. Regional trends and country specifics

Table 13 offers a recapitulation of natural gas balances per country, historical and expected up to 2030. The scenarios show continued discrepancies in the timeframe considered.

Table 13: Natural gas demand and production per country, in 2000, 2010, 2020 and 2030 (bcm)

	2000		2010		2020		2030	
	Production	Demand	Production	Demand	Production	Demand	Production	Demand
Argentina	40	36	42	46	42	50	50	55
Bolivia	3	1	15	3	25	7	22	10
Brazil	7	9	15	27	26	37	45	51
Chile	2	6	2	5	1	6	1	11
Colombia	7	7	13	10	12	13	7	16
Ecuador	0	0	0	0	1	1	1	1
Paraguay	0	0	0	0	0	0	0	0
Peru	1	0	8	6	17	12	19	15
Uruguay	0	0	0	0	0	1	0	1
Venezuela	28	28	22	33	25	25	32	32
Total	89	88	117	131	148	151	177	191

Source: Author's assumptions

As seen in Figure 32, the evolution of the natural gas balances is different in each country.

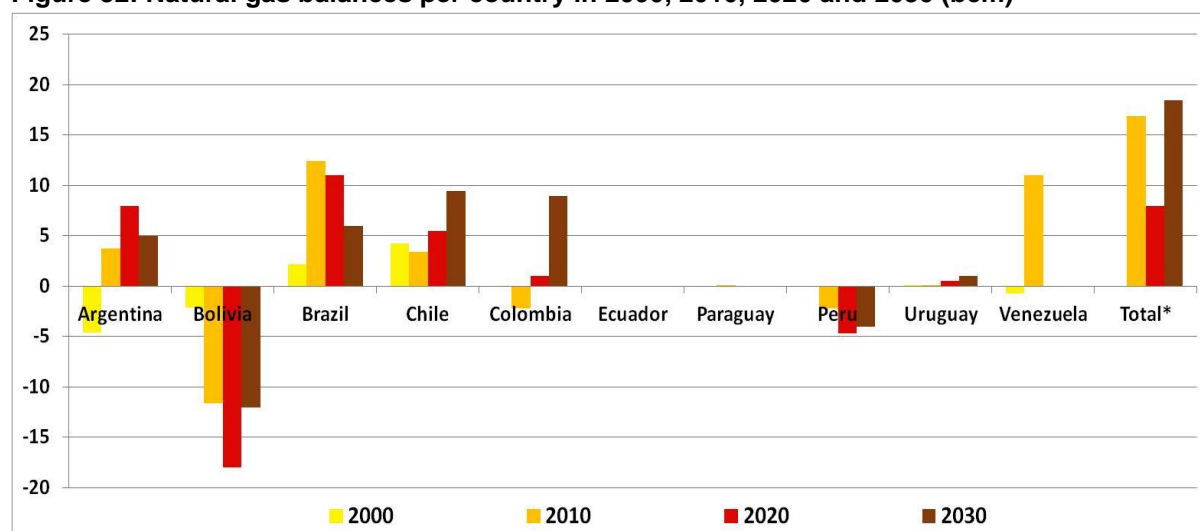
- Argentina is expected to see its imports increase this side of 2020 due to a lack of indigenous production to meet rising demand, but the situation should start to ease in the 2020s with the



development of unconventional resources even if there are great uncertainties with respect to the pace of development of these resources.

- In Brazil, imports will remain important in the second half of the 2010s, but the normalisation of the hydro situation will remove some stress to the system. The doubling of indigenous production in the 2020s is expected to almost annihilate the need for imports in a normal year (i.e. when levels of hydrogeneration are adequate). Despite great uncertainties in the pace of indigenous production development, the largest uncertainty will remain about gas demand.
- In Chile, gas imports are expected to increase as demand grows thanks to economic recovery and switching from more costly and polluting fuels continues. The timing of economic recovery and hence, impacts on energy and natural gas demand is the main uncertainty in this country.
- Limited progress in Colombia's production translates into higher imports in the 2020s. If Venezuela does not manage to develop its own reserves at a level high enough to supply its own market and export to its neighbour, then Colombia will have to turn to LNG imports to find the necessary volumes of natural gas.
- In our scenarios, Venezuela is expected to match its growth in consumption with indigenous production (especially from additional non-associated offshore fields) when the oil price recovers, but will most likely not be able to free enough volumes to supply both its own market and export pipeline gas to Colombia.
- Regarding the two exporters Peru and Bolivia, assumptions in our scenarios have been designed to enable them to fulfil their export commitments. These may be very challenging assumptions considering the hurdles they face to develop their own reserves and the pressing needs to increase their gas production to fulfil their existing commitments. Nonetheless, as both countries need the revenues from their exports, this author has assumed that an adequate (and if needed improved) regulatory environment will be put in place to attract the necessary investments in a timely manner. However, it is important to note the major uncertainties around these assumptions.

Figure 32: Natural gas balances per country in 2000, 2010, 2020 and 2030 (bcm)



Source: Author's assumptions

While the level of exports from Peru will not impact other markets in South America, this is not the case for exporter Bolivia. Figure 29 showed that in the absence of substantial investment in new exploration, Bolivia may soon be unable to supply both its export markets (Brazil, Argentina) and its



own rising internal demand. This seems to be confirmed by the IEA's assumptions on Bolivian gas production,²²⁶ which show a decline in output up to 2020. If we try to match these levels with scenarios on national demand and export commitments, it looks as if the country could be in trouble as soon as 2016. The government expects new fields to be developed with a surplus returning in 2018,²²⁷ especially thanks to the Caipipendi Block, which will start production from 2019. Whether this will be sufficient (and happen as quickly as mentioned by Bolivian officials) is uncertain. This is particularly relevant at a time when Bolivia is negotiating a renewal of its supply contract with Brazil, which expires in 2019. The other importing country, Argentina, has already turned to its neighbour Chile to find additional gas, especially during winter months when its own demand increases due to residential heating. This solution should offer some respite to Bolivia if need be. There are still uncertainties as to how much longer into the next decade Bolivia will be able to sustain exports to Argentina. Any uncertainty on security of supply from Bolivia will contribute to favour the LNG option for additional gas volumes in the future, at least until indigenous production reaches sufficient levels to feed national markets.

3.2.2. Role of LNG

Supply and demand balances show that additional imports to the region will be needed in our timeframe. Due to the geographical location of South America, the only option to import natural gas from external sources is in the form of LNG. The following paragraphs highlight the main evolution of the role of LNG in the region and in key markets at the 2030 horizon.

- Importing countries

The three existing importers will continue to import LNG. **Argentina's** LNG imports will continue to focus during the winter months of June-August, when Argentina routinely suspends industrial gas supply to favour residential consumption that relies on gas for heating, although LNG is and will continue to be imported throughout the year. The level of LNG imports will be dependent on indigenous production growth and the availability of Bolivian gas. In 2020, the gas supply and demand balance is in deficit of about 8 bcm and about 5 bcm in 2030, in a normal year (mild winter). Contracted gas imports from Bolivia should cover the needs in 2020 (contract ends in 2026), but if any delay happens in Bolivia's production development, Argentina will need to cover the gap by additional imports. In May 2016 when Argentinian state-owned Enarsa finalized short-term natural gas supply contracts with its Chilean counterpart Enap, the contract was for or 3mcm/d of gas during the winter months with an option to supply an additional 1 mcm/d depending on availability, through the 9 mcm/d GasAndes pipeline from the Quintero regasification terminal on Chile's central coast. A separate agreement between Engie/Enap and Enarsa was signed to supply another 1.5 mcm/d from the Mejillones regasification terminal on the northern coast, using the 7.1 mcm/d Norandino pipeline. Argentina will pay \$7.20/MMBtu for the central supply, and \$6.90/MMBtu for gas from the north, both prices being tied to diesel, the fuel used in Argentina in the absence of gas.²²⁸ With no storage, the short-term Chilean supply will help to alleviate wintertime gas shortages in Argentina in addition to imports from Bolivia and LNG imported through the Bahia Blanca and Escobar terminals.

²²⁶ IEA (2015d)

²²⁷ Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America

²²⁸ Argus, 12 May 2016, Chile signs Argentina gas supply agreements; Argus, 17 May 2016, Engie launches pipeline gas flow to Argentina



LNG demand will continue to grow in **Brazil** but volumes will be dependent on the levels of hydropower generation, on the timing of the development of its own indigenous gas resources, and levels of imports from Bolivia. Contracted gas imports from Bolivia will end in 2019, and the two countries were already in discussions in 2016 to negotiate a new contract. In 2020, gas supply and demand balances are in deficit of about 11 bcm and about 1 bcm in 2030, in a normal year (high level of hydropower). During years of low hydrogenation levels, higher natural gas demand due to the high level of dispatch from gas-fired plants will need to be fed by LNG imports, much as happened in 2013 – 2016. With no storage capacity in Brazil, most gas production associated with oil, and the flat deliveries in the Bolivian contract,²²⁹ LNG will bring much needed flexibility into the system. With low LNG prices in the second half of the 2010s, power developers and large industrial users have shown interest in building new LNG regasification terminals, in addition to the three owned by Petrobras.²³⁰

In **Chile**, LNG imports will increase and remain at a fairly flat level throughout the year. With very limited indigenous production and no pipeline imports, the only uncertainty to impact the level of LNG imports will be gas demand growth, including switching to natural gas from costlier fuels. In 2020 the gas supply and demand balance is in deficit of about 7.5 bcm and about 11 bcm in 2030. If these scenarios are at least directionally correct, they will need to be supported by the proposed expansion of the existing LNG terminals, as well as by new LNG regasification terminals.

Additional importers will join the three existing LNG importers in our timeframe. First, **Colombia** is expected to start importing LNG in 2017, in order to add much needed volumes to feed its demand, especially in the power sector. As in Brazil, important variations in natural gas demand are expected to follow hydrogenation levels.

The second country to join the LNG importers group will be **Uruguay** sometime this side of 2020. The country has only a small market but it has long been looking for a solution to increase and diversify its gas supply. The country is expecting to export some of its LNG to neighbouring markets, especially Argentina during winter months.²³¹ There is already a 26-km pipeline between Argentina and Uruguay that could be expanded and reversed. LNG re-exports in smaller cargoes to potential regasification terminals in Southern Brazil are also a possibility. However, future gas balances in both countries may not leave much room for Uruguayan LNG, except at times of peak demand when it will be able to play an important role for the security of supply of its neighbors.

Finally, **Ecuador** has also plans to add an LNG terminal in the future to feed its power sector, but the realisation and the timing is uncertain.

- Exporting countries

Peru is expected to remain the only exporter, even if other producing countries have considered the option in the past. LNG exports are expected to remain stable during the duration of the contract with Mexico, although it is unlikely to be expanded in our timeframe due to the growth of demand in Peru.

²²⁹ The contract has a take-or pay clause that allows Brazil to reduce monthly demand to 80% of maximum contracted volume (within the limit of 90% of annual contracted volume)

²³⁰ Three regasification projects stand out because they are integrated LNG/power projects and the power developers have successfully obtained a 25-year power purchase agreement (PPA) in the 2013 and 2014 nation-wide power auctions, which means the projects will have to be ready to generate by 2019 and 2020. See Appendix “Brazil” for more information.

²³¹ In 2013, ANCAP (Uruguay) and YPF (Argentina) signed a Memorandum of Understanding establishing that Uruguay will export to Argentina part of the natural gas it will produce in the regasification plant expected to be built close to Montevideo. Source: República Oriental del Uruguay, 27 August 2013, Uruguay podrá exportar a partir de 2015 gas natural a la República Argentina



Both Venezuela and Bolivia have looked at the possibility of exporting LNG, but **Venezuela** would need to increase its indigenous production above its own needs, which is unlikely at least in our timeframe. LNG exports through Trinidad's facilities have been mentioned, but how the gas would reach such facilities is unclear, as no route exists at the moment. In our scenarios, it already seems challenging for **Bolivia** to meet its contracted pipeline gas exports to Brazil and Argentina. The government has plans to extend sales to its neighbours and further afield.²³² Bolivia's ambition is to develop its role as the gas heart of South America, a position its geography and resources should allow. Bolivia being a land locked country its gas would need access to the sea through either Peru or Chile in the 2000s. The project via Chile was economically the best but was complicated by the difficult political relations between the two countries, which have not had diplomatic relations since the 19th century war that saw Bolivia lose its access to the sea to Chile. The preferred idea seems to be via neighbouring Peru. A pipeline would need to be built to link infrastructure in Bolivia to the new southern gas pipeline (GSP) under construction in Peru.²³³ Around 230km of pipeline would be needed to join transport networks under construction in both countries. The existing Peru LNG plant could be expanded or a second export terminal built on the southern coast at the end of the GSP. This idea would enable Bolivia to reach other markets in addition to the South American ones. Nonetheless, before this could become a reality, new reserves will need to be put into production.

Argentina and **Brazil** are net importers as of 2016, but they both expect to develop their indigenous production and reach self-sufficiency – and maybe even become next exporters - although this seems very unlikely in our timeframe.

In **Colombia**, a small liquefaction project, Pacific Rubiales' Caribbean FLNG, was once envisaged to export LNG at times of high hydropower in the country in order to monetize the gas reserves found in the La Creciente onshore field. However, the project was suspended in February 2015 because of low oil prices and changes in the LNG market.

- Regional integration 2.0

Plans for regional pipeline integration collapsed after Argentina cut exports in the 2000s. Instead, countries focused on supply security and energy diversification, especially via LNG. Although the idea of a region-wide pipeline integration has ended, an interesting development is that a new form of integration could be taking place around LNG terminals and imports, a sort of integration 2.0 at the sub-regional level, recreating energy connections between neighbouring countries such as Brazil importing LNG from Argentina's regas terminal²³⁴ and Chilean LNG imports being redirected to Argentina via empty pipelines that had been fitted with reverse flow technology or the plans to re-export part of the LNG arriving in Uruguay to Argentina or Brazil for instance, or even possibly from Colombia to Venezuela.

In addition, aside from LNG imports from overseas, smaller countries like Ecuador and Bolivia have produced LNG locally to transport domestic gas in lieu of traditional pipelines. Bolivia is even seeking

²³² Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America

²³³ Construction of the \$4bn pipeline began in May 2015. The line will run 1,000km from Peru's central jungle, over the Andes and down to the southern coastal ports of Ilo and Matarani and will be operational in the first half of 2018. Source: Argus News, 24 June 2015, Bolivia looks to export gas through Peru

²³⁴ Brazil imports LNG through the Bahia Blanca regas terminal to supply its Uruguiana thermal power plant in Rio Grande do Sul state. Source: Platts International Gas Report, 23 March 2015, Brazil uses Argentina's regas

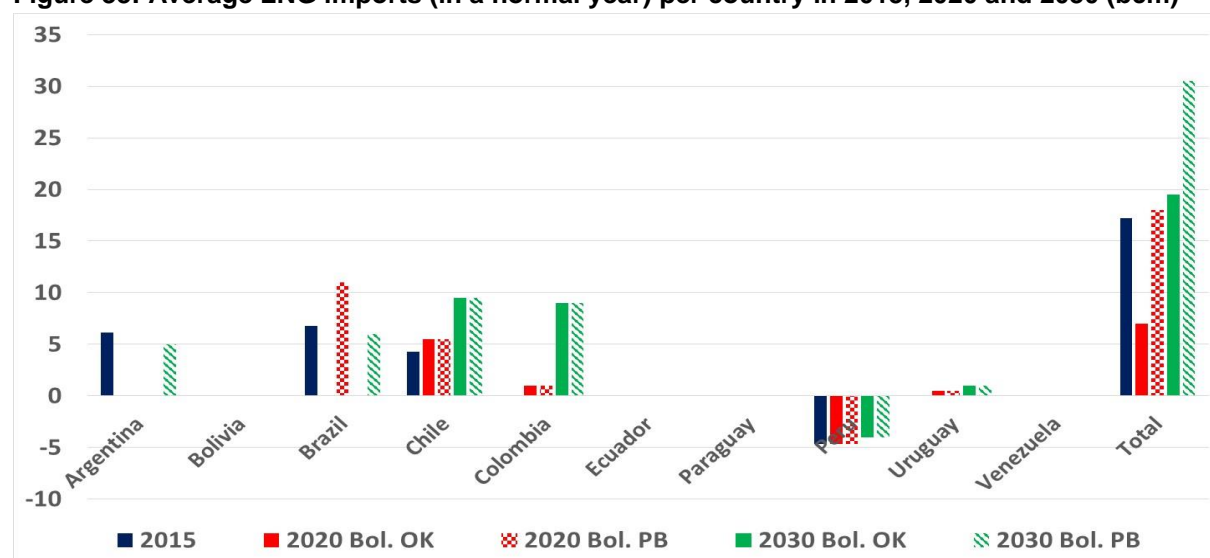


to export trucked LNG to neighbouring Peru and Paraguay, once its roads are repaired.²³⁵ Gas integration could develop in new forms such as LNG trucks or barges (virtual pipelines) but also distribution of natural gas by CNG, or gas by wire (electricity²³⁶).

- How much LNG?

As already mentioned several times, one should proceed with caution when looking at natural gas scenarios for South America. If the scenarios presented in this paper happen, then the levels of LNG imports in the region under 'normal' weather conditions would be around 7 bcma in 2020 if Bolivian export commitments are fulfilled and contracts prolonged [Figure 33]. If the Bolivia-Brazil agreement is not prolonged, then LNG imports could soar to 18 bcma. By 2030, our scenarios under 'normal' weather conditions show a potential of 19.5 bcma of LNG if Bolivia renews its pipeline export contracts at levels allowing Argentina and Brazil to balance their demand, and up to 30.5 bcma if it does not. However, cold winters in Argentina and dry weather could have significant impacts on LNG imports, the major source of flexibility in the region. In Brazil alone, it could add about 35 bcma of LNG imports in a dry year in 2030 (in addition to volumes imported under 'normal' weather conditions).

Figure 33: Average LNG imports (in a normal year) per country in 2015, 2020 and 2030 (bcm)



Note 1: LNG imports per country in this Figure correspond to the LNG volumes consumed in the country only. For instance, some LNG volumes to Argentina may arrive in regasification terminals located in Chile and in Uruguay in 2020 and 2030, but in this Figure, they are shown as LNG imports to Argentina.

Note 2: Total = all LNG imports to the region (Peruvian exports are not taken into account)

Source: Author's assumptions

²³⁵ Argus news, 28 July 2015, Ecuador struggles to resuscitate LNG plant

²³⁶ Large distances, complicated geography and low population density makes alternatives more appealing. In addition to LNG, it could also take the shape of distribution of natural gas by CNG, gas by wire (electricity) but also LNG trucks (virtual pipelines). Power lines are a cheaper and more environmentally friendly option for delivering energy than the pipelines that would otherwise be necessary to transport the gas to market. Further collaboration has indeed been seen in the electricity sector with cross border power lines between Colombia and Ecuador, Colombia and Venezuela, Ecuador and Peru, Argentina and Chile, Argentina and Paraguay, Paraguay and Brazil, Uruguay and Brazil and Uruguay and Brazil. There have also been hydroelectric projects involving bilateral cooperation between neighbouring countries. The Salto Grande power plant between Argentina and Uruguay started operation in 1979, the large Itaipú power plant (14 GW) between Brazil and Paraguay was inaugurated in 1982 and the Yacyretá power plant between Argentina and Paraguay (3.2 GW) was operational in 1998. Source: IDB (2014), p.130. Gas by wire could still be beneficial to natural gas demand if the electricity is generated by CCGTs.



- What role for LNG?

LNG has not been a cheap insurance policy for importing countries, but in a region with high variations of gas demand from one year to another, no storage facilities, associated gas production that cannot fluctuate with natural gas demand and long distance cross border pipelines that operate on rather flat deliveries as seen with Bolivian exports to Brazil and Argentina, LNG will remain necessary to supply much needed flexibility to meet seasonal needs or peak demand. LNG will also provide additional volumes, diversity of suppliers and therefore increased security of supply. LNG imports offer access to areas not covered by the pipeline network. One of the main limiting factors to the development of natural gas is the lack of infrastructure at the national and regional level in South America. This applies for international imports such as in Brazil (Brazilian infrastructure group Bolognesi projects for instance) or even for deliveries within parts of the same country such as envisaged in Peru. LNG imports will continue to be necessary but there are major uncertainties on volumes, prices, timing, location and even direction of LNG flows in our timeframe.



Conclusions

South America has long been isolated from other global natural gas markets. However the region turned to LNG to source additional supply in 2008. Although the volumes imported represent less than 5% of world LNG trade, imports have grown rapidly from 0.5 bcm in 2008 to 17.2 bcm in 2015. If the pace continues, the region could become an important player reducing the scale of flows to Europe, the swing market for LNG. This paper analysed the regional market fundamentals and shows that this is not the most likely outcome. However, two words seemed to summarise the outlook for natural gas by 2030: uncertainty and diversity on demand and on drivers; on supply from indigenous production and imports, but also on many other issues that will influence the expected demand/supply balances such as timescale, policies, competitiveness, generation mix and economic growth, to name but a few. 'The future is uncertain'. While this arguably can be said for any scenarios in any part of the world, it seems even more appropriate in this very diverse region.

In 2015, gas demand reached 145 bcm, a 21% increase over 2010 (+62% since 2000) driven mainly by rapid economic growth, expansion of the grid to areas not previously covered, addition of new gas-fired generation capacity, substitution of gas for oil in industry and the rise of gas use for the transport sector. As the region's economy and population grows, energy demand is expected to continue to increase and become more reliant on natural gas, especially in electricity generation, even if drivers for additional gas demand are as diverse as the markets themselves (size, maturity, infrastructure, generation mix, subsidies and energy policies). Despite the fact that weaker economic growth will slow down energy demand growth in all sectors for the rest of the 2010s, gas demand is still expected to increase. In our timeframe, meeting the needs for both additional generation and additional flexibility will be one of the greatest challenges. Most new generation will be in the form of renewables, especially hydropower, but most new hydro will be run of the river or have small reservoirs. As a result, generation will be even more significantly reduced in dry periods, thus needing more back-up capacity, especially gas plants. In the non-power sectors, there is also some potential for more gas penetration in industry and for additional use of CNG in road transport (but if oil prices remain low, expectations may be over-optimistic). There is virtually no need for space heating in the region, which explains the low expectations in the residential and commercial sector despite plans to develop gas distribution infrastructure. All in all, this author expects gas demand to increase to 151 bcm in 2020 and 191 bcm in 2030. Brazil is one of the major question marks, especially the normalisation of the hydro situation. During wet years, it may be that gas for power will be limited at 8-10 bcm while potentially shooting up to 40-45 bcm during dry years by 2030.

Another major challenge for the region will be how to supply this demand and shortage and/or delay in increasing indigenous production will constrain these scenarios. In addition to total volumes, flexible supply will be increasingly needed in order to match the seasonal and often volatile dispatch of gas-fired power plants, whether from indigenous production (if possible) or from imports, especially LNG. South American countries will have to increase upstream investment and develop new resources in order to boost production. Geopolitical uncertainties, along with economic, geographic, social, and regulatory issues have impacted (and will continue to influence) the pace and the level of natural gas production. Cutbacks in exploration investment after the decline in global oil prices in 2014 rose uncertainties on gas volumes to be produced in the whole region (at least) this side of 2020 and may especially impact high cost unconventional plays (like in Argentina but not only), offshore pre-salt projects in Brazil, and all offshore prospects in general. The ability of Bolivian gas to supply its markets until their own production picks up is uncertain, and could possibly increase the need for LNG in the 2010s and early 2020s, when ample LNG will be available at low prices. The main objective for



most countries with gas resources remains the development of indigenous production to become self-sufficient, but until it happens, LNG will be needed to fill the gap (and will most likely continue to be needed to add flexibility).

For all these reasons, one should be very cautious when looking at natural gas/LNG scenarios for South America. Up to 2030, Brazil, Argentina and Chile will continue to import LNG and will be joined by Uruguay and Colombia. Peru is likely to remain the only LNG exporter. There will be no region-wide pipeline integration, but there is a possibility of sub-regional integration around LNG import terminals, as suggested by projects in Uruguay, Colombia or even LNG arriving in Chile and being sold to Argentina. This author expects that the region will import about 7 bcma of LNG in 2020 under 'normal' weather conditions with Bolivian export commitments fulfilled and contract prolonged. If the Bolivia-Brazil agreement is not renewed, then LNG imports could soar to 18 bcma in 2020 under 'normal' weather conditions. By 2030, scenarios show a potential of 19.5 bcma of LNG under 'normal' weather conditions and if Bolivia's renew both its pipeline export contracts at levels allowing Argentina and Brazil to balance their demand. LNG imports could rise to 30.5 bcma in the case of no Bolivian exports, still under 'normal' weather conditions. However, cold winters in Argentina and dry weather across the region could have significant impacts on LNG imports. In Brazil alone, it could add about 35 bcma of LNG imports (on top of already needed imports) in a dry year in 2030.

As a conclusion, South America is not expected to be a major future LNG market unless there are extreme climatic conditions, which will not happen every year and will not last many years. LNG will remain necessary to supply much needed flexibility, additional volumes, security of supply and reach new markets far from infrastructure, but there are also major uncertainties on volumes, prices, timeframe, location and even direction of the LNG flows as some importers could turn exporters at times of low demand toward the end of the timeframe.



Appendix: Overview of national gas markets in South America

The main text provides a vision of the future of natural gas for South America and consequently, of the future role of LNG in the region. The scenarios are the results of a simple bottom-up methodology based on expected evolution of key factors and on scenarios available in the public domain (with which this author may or may not agree). Some information on the assumptions has already been given in the main text, and the purpose of this appendix is to provide additional details on the individual markets. For each country, it gives details on the energy sector, information on the natural gas industry, explanations of the assumptions used in the scenarios (with highlights on the alternative routes when these are also a strong possibility) and finally the consequences for the role of LNG up to 2030.

Energy and gas markets are evolving rapidly, and the writing of this paper was substantially completed by mid-2016 with information and statistical data available at the time. The trends and scenarios will need to be updated as policies/prices/generation mix evolve in the future. This appendix gives some tools to the reader to “adjust” the scenarios in case of disagreements with this author’s views/assumptions or following a change in the market situation. The more the details, the more chances for differences of opinion... but, at least, hopefully also more usefulness for the reader compared to scenarios with plain numbers at a regional level given with no details of the calculations or the assumptions at the national level.

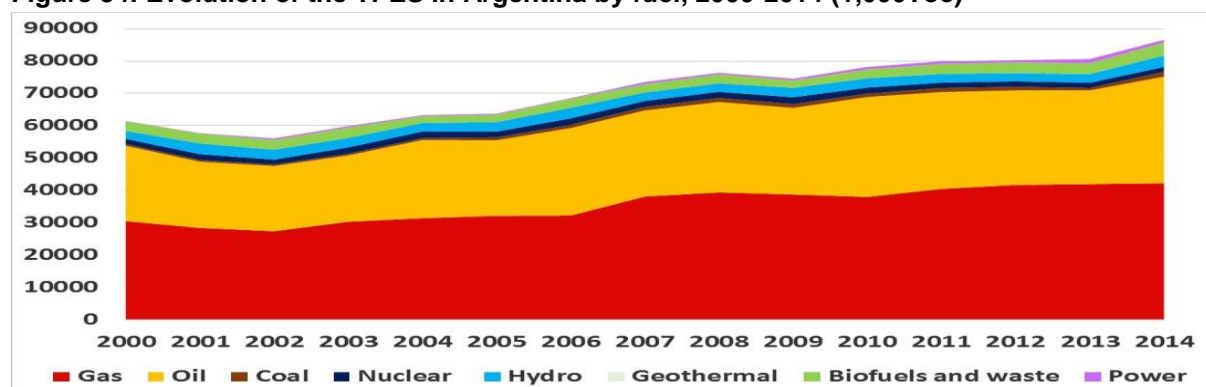


Argentina

Overview of the energy market

Argentina is the second largest energy consumer in South America after Brazil. In contrast to the other regional markets, the country has a gas-intensive economy having started to develop its gas industry from the 1960s. About half of its primary energy demand is covered by natural gas (49% in 2014²³⁷). Oil makes up for another large share (38%) but down from 71% in 1960.²³⁸ Other fuels only contribute to a small share of the Total Primary Energy Supply (TPES) as seen below in Figure 34.

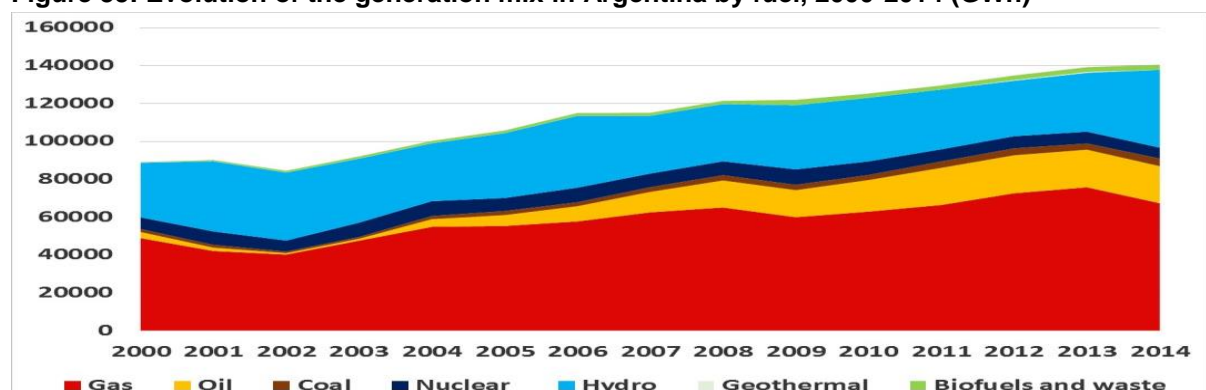
Figure 34: Evolution of the TPES in Argentina by fuel, 2000-2014 (1,000Toe)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

Natural gas has an important role in power generation, accounting for about half of the generation mix (48% in 2014).²³⁹ Hydroelectricity is in second place (29%) followed by oil (14%). Following the 2004 gas crisis, oil has made up an increasing share of power generation as natural gas power plants could not fulfil demand due to supply shortages. The other fuels have a relatively small share as seen in Figure 35, including nuclear power which is only present in two countries in the region: Argentina and Brazil.

Figure 35: Evolution of the generation mix in Argentina by fuel, 2000-2014 (GWh)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

²³⁷ IEA (2016b), p.II.149

²³⁸ Data for 1960: IAPG (2014), p.130

²³⁹ IEA (2016b), p.II.149



In 2014, Argentina had 31.4 GW of installed generation capacity, 46% in the form of natural gas, 34% of large hydro, 13% of oil and diesel, 3% of nuclear, 2% of coal, and 2% of other renewable (1.7% small hydro, 0.6% wind, 0.1% biomass and waste).²⁴⁰ The gas power plants had an annual average load factor of 53%.²⁴¹ As a result the existing plants could potentially generate more electricity and replace the oil-fired plants in the mix (14% or the equivalent of about 4.6 bcm) if and when additional gas supply becomes available. In addition to baseload generation, gas seems to also be acting as a flexibility tool together with oil products, ramping up and down depending on hydro availability.

The natural gas industry

Argentina's gas industry started to develop in the 1960s, and important gas discoveries were made in the 1980s. The liberalisation and privatisation policies put in place in the following decade attracted major capital in the upstream sector, and national production rapidly overtook demand. Argentina looked for ways to monetise its own gas supplies and markets to export its surplus. Between 1996 and 2001, seven pipelines were built between Argentina and Chile: three in the south to meet the increased gas demand resulting from the expansion of the Methanex (methanol) plant, two in the centre to serve large cities (including Chile's capital Santiago) and two in the north which supply the Chilean copper mining industry. In addition to Chile, Argentina started to export gas to Uruguay in 1998 and, in 2000, it started to export gas to Brazil to supply the AES 600-MW thermoelectric power plant built on the Brazil-Argentina border (Uruguaiana). This was intended as the first stage of a more ambitious project to supply Argentine gas to southern Brazil, and compete with Bolivian gas, which started to flow to Brazil at around the same time via the Gasbol pipeline which was finalized between 1999 and 2000²⁴² and was designed to carry 11 bcma.²⁴³

Argentina was exporting pipeline gas to Chile, Uruguay and Brazil when, in 2001, it was hit by a severe economic crisis.²⁴⁴ In order to sustain the economy after the collapse, the government started to subsidize electricity and natural gas prices for households and large consumers.²⁴⁵ While the economy recovered strongly, energy prices remained frozen at very low levels. The consequences were lower investment in exploration and production and at the same time, a rapid growth of energy demand, especially in the industrial and the power sectors. Old reserves were not replaced by exploration and production from maturing fields started to decline. Production fell below national consumption, which triggered the so called "gas crisis" in 2004.²⁴⁶ In order to limit domestic shortages, the government drastically reduced gas exports and suspended all new export authorisations. These breaches of contracts created many problems in the importing countries that had become reliant on Argentina for natural gas supply, especially in Chile which was completely dependent on pipeline gas imports from Argentina, generating tensions between the two countries. Repeated interruptions created major economic problems for the Chilean industry and electricity generators, which had to resort to more expensive alternative fuels to fulfil their needs. The impact of the cut was less severe

²⁴⁰ Bloomberg New Energy Finance (2015), p.149

²⁴¹ Author's calculations

²⁴² The first part was completed in 1999 and starts at Rio Grande in Bolivia and connects with the Brazilian network that supplies the cities of São Paulo, Rio de Janeiro and Belo Horizonte. The second part was completed in March 2000 and links Campinas to Canoas, near Porto Alegre in the state of Rio Grande do Sul. Source: IEA (2003), pp.58-60

²⁴³ A second Bolivia to Brazil pipeline started operating in 2002 mostly to the Cuiabá power station (which was also supplied by Argentine gas for a while). Source: IEA (2003), pp.58-60

²⁴⁴ GDP fell 4.4% between 2000 and 2001 and 10.9% between 2001 and 2002. Source: Mares D. (2012)

²⁴⁵ The government paid the subsidies to gas and power distribution companies. Natural gas prices at the wellhead were frozen at a level of \$0.40/MMBtu for the industry and \$0.66/MMBtu for the residential sector. Source: IEA (2003), pp.58-60

²⁴⁶ See Honoré (2004) for more information for the gas crisis of 2004

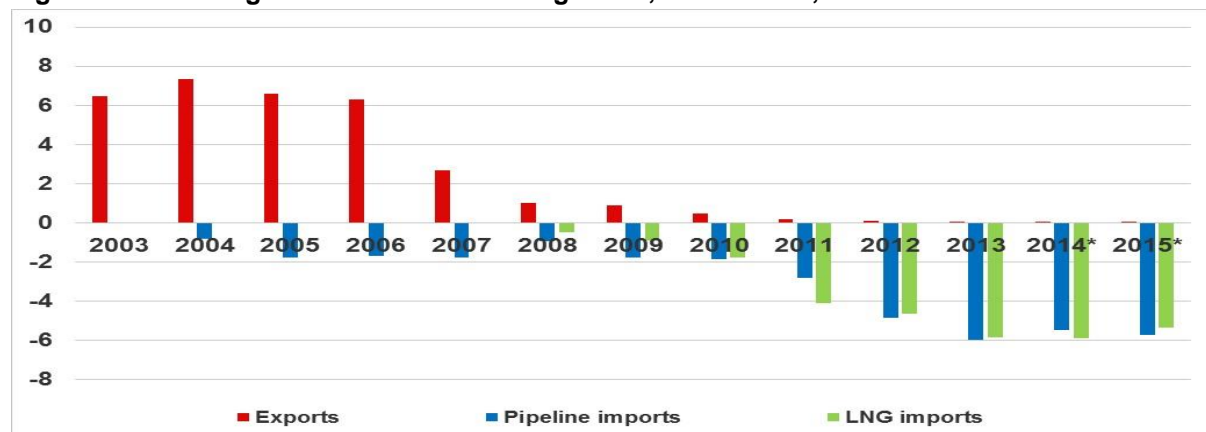


on the Brazilian economy because the volumes were smaller and directed at a single customer (who nonetheless suffered important economic losses),²⁴⁷ and also on Uruguay, which is a much smaller market, and Argentina continued to supply some quantities to residential customers. In addition to creating energy supply constraints, it also generated doubts towards Argentina as a reliable supplier and toward sub-regional integration which had failed to fulfil its obligations to ensure security of supply and cooperation.

Argentina's export restrictions were not sufficient, and in order to supply its own market Argentina also had to restart imports from Bolivia in 2004.²⁴⁸ Gas flows were resumed on an interruptible basis for two years, and in 2006, Energía Argentina Sociedad Anónima (ENARSA) signed a new gas supply contract with Yacimientos Petrolíferos Fiscales Bolivianos (YPFB) for the period 2006-2026. In addition, producers were obliged to direct natural gas to meet domestic demand in June 2009. The volumes in the contract were also readjusted by Addendum 1 in March 2010.²⁴⁹ This Addendum established a new ramp-up volume with Delivery or Pay (DoP) and Take or Pay (ToP) commitments and a Daily Contractual Amount (DCA) (maximum) of 7.7 mcm/d at the beginning of the contract and increasing over a period of ten years to reach 27.7 mcm/d in the early 2020s (or when additional pipeline capacity permits it²⁵⁰). This volume would remain until the end of the contract in 2026.²⁵¹ In June 2012, ENARSA and YPFB signed another contract for volumes exceeding the DCA. This interruptible contract provided for maximum volumes of 2.7 mcm/d in 2012 and 3.3 mcm/d in 2013. These volumes can be reviewed until 2026, which is also when the firm contract ends.²⁵²

In addition to Bolivian gas imports, Argentina started to import LNG in the late 2000s. Since 2004, natural gas imports, from Bolivia and LNG, have risen rapidly as seen in Figure 36. Argentina became a net importer again in 2008.

Figure 36: Natural gas trade balances in Argentina, 2003 – 2015, bcm



Sources: IAPG, Argentina Anuario, various reports; Data for 2014 and 2015: IEA (2016a), pp.II.40-47, tables 22, 24 and 25

²⁴⁷ Gomes (2014a)

²⁴⁸ Argentina imported gas from Bolivia to its northern region from 1972 to 1999.

²⁴⁹ "Primera adenda al contrato con Argentina", the contract can be found on the YPFB website (retrieved in 2015)

²⁵⁰ In 2015, the deliveries were about 17 mcm/d. Argentina had secured financing for natural gas distribution networks in the northeast, where the GNEA pipeline was under construction to bring in more supplies from Bolivia. The project involves installing distribution lines in a region of 3.5 million inhabitants who rely on costlier alternatives such as diesel, fuel oil and liquid petroleum gas (LPG). Source: Platts International Gas Report, 27 July 2015, Argentinean pipeline gets finance

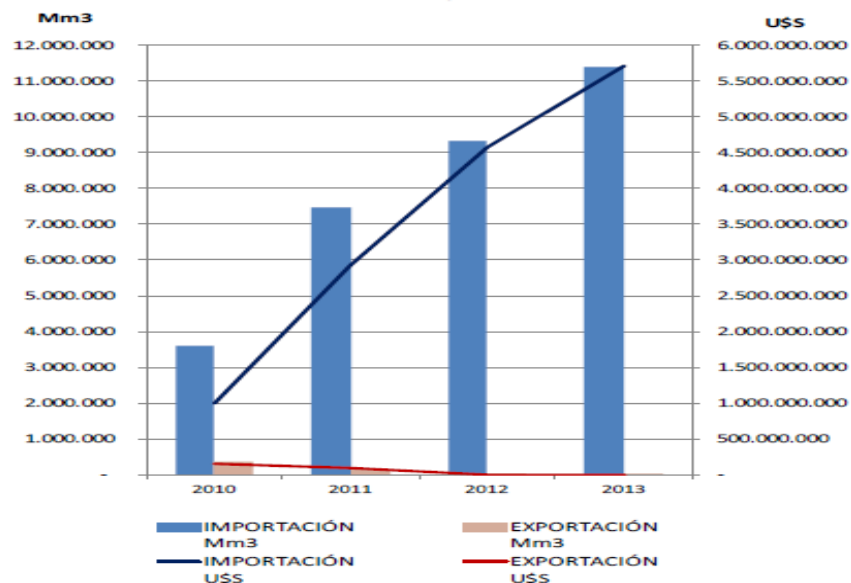
²⁵¹ Note: Winter ToP and DoP volumes are the same, except between 2020 and 2022. Source: Contract "Primera adenda al contrato con Argentina", YPFB website

²⁵² YPFB (2015), p.11



These rising imports (Bolivian gas and LNG) cost billions of US dollars per year (gas import payments are dollar-denominated²⁵³) [Figure 37]. Gas prices from Bolivia are linked to WTI crude oil prices over the previous three months with a three-month lag.²⁵⁴ The price is typically set in US Dollars and exchange rate variations are accounted for in the formula.²⁵⁵ As a result, national currency depreciation or appreciation can increase or decrease the price of gas for importing countries compared to alternative fuels.²⁵⁶ For LNG imports, YPF issues international tenders for the delivery of cargoes for the following weeks/months.²⁵⁷ Argentina secures cargoes from the spot market at a fixed price or a price based on the short-term market (generally Henry Hub) plus a premium in US dollars. Because this index does not link with any other market, the differentials may be (and have been) substantial at about \$10.00/MMBtu or more.²⁵⁸ Despite the great flexibility of LNG to meet seasonal needs, LNG is not a cheap insurance policy. Imports have helped Argentina to meet its demand, but it has also created financial pressure and dependence that the country is looking to get out of.

Figure 37: Argentine natural gas trades: volumes and revenues/costs, 2010-2013 (Mcm and \$)



Source: IAPG (2014), p.57

²⁵³ This has created additional problems for Argentina. For instance in 2014, three LNG carriers were waiting offshore the Argentinean coast unable to be unloaded because of a shortfall of US dollars to pay for the cargoes as the central bank put limits on transferring US dollars to Enarsa as Argentina paid in cash for the supplies because of its poor creditworthiness following a 2001 default on \$100 billion that had not fully been settled then. Source: Hellenicshippingnews, 3 October 2014, Argentina LNG imports delayed on dollar shortage: newspaper

²⁵⁴ YPFB (2011), pp.16-18

²⁵⁵ IEA (2003), p.78

In 2014, mean prices were \$10.1/MMBtu, but due to lower oil prices, mean prices for 2015 (January-August) were \$6.8/MMBtu. Source: Data from Ministerio de Hidrocarburos y Energia website, Reporte Diario Informe de precios, <http://www2.hidrocarburos.gob.bo/index.php/viceministerios/exploracion-y-explotacion-de-hidrocarburos/reportes-de-precios-gas-natural-y-petr%C3%B3leo/category/44-viceministerio-de-exploracion-y-explotacion-de-hidrocarburos.html>

²⁵⁶ Usually hydropower and other fossil fuels in power generation, heavy fuel oil and biomass in industry and electricity and LPG in the commercial and residential sector): Source: IEA (2003), p.74

²⁵⁷ State-owned Enarsa was charged with buying the LNG until the government's 2012 expropriation of a majority stake in YPF from Spain's Repsol. Now YPF runs the LNG tenders on behalf of Enarsa.

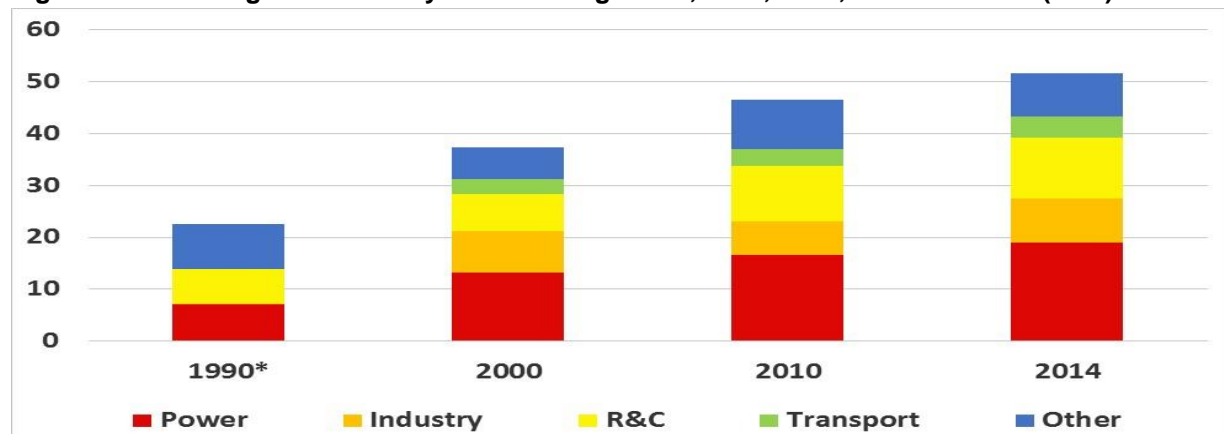
An overestimation of the expected demand can also create some financial pressure such as at the end of 2014 when cargoes had to wait off the coast of Argentina due to a lack of demand (and lack of storage). With each shipment costing about \$50 million, the delays implied a daily fine of \$15,000/ship, a heavy burden for an already indebted country. Source: Bloomberg, 7 October 2014, LNG Ships Accrue Off Argentina as Demand Misses Estimates

²⁵⁸ ICIS/Heren Global LNG Markets, "Trades tables"



The natural gas market of Argentina is the largest in South America. At 52 bcm,²⁵⁹ it represents almost 36% of the regional demand. In Europe it would place Argentina in fourth position at about the size of the Turkish gas market. The power sector is the largest consumer (37%), followed by the residential and commercial (23%), industry (17%), other sectors, which include energy own use and losses (16%) and finally transport (8%) as seen in Figure 38.²⁶⁰ Argentina is one of the world's largest consumers of gas in the transport sector due to high gasoline prices vs. low gas prices, which has boosted the number of car conversions from oil to natural gas.

Figure 38: Natural gas demand by sector in Argentina, 1990, 2000, 2010 and 2014 (bcm)



Source: IEA (1993), IEA (2003a), IEA (2012), IEA (2016b), Individual country tables

Because of the high share of the residential and commercial sector, gas demand is strongly affected by variations in temperature during the year and presents high seasonality patterns. During the Southern hemisphere's coldest months (May to September), residential consumption which is used mainly for heating purposes, increases by about five to six times compared to the summer months as seen in Figure 39. For instance, in 2015, the average consumption for the residential sector in January was about 309 mcm but it was multiplied by more than five in July at about 1.7 bcm.²⁶¹ Due to the already tight supply-demand balance, and even with additional LNG imports, thermal power plants and industry are routinely rationed in order to keep the heating on in the residential market. Thermal power plants are the first to be cut off and are usually forced to switch to diesel, but if this is not enough, then part of the industry sector needs to shut down as well. Plants can be shut down sometimes for days in winter (the curtailments vary from region to region, but cuts can reach 30-40% in the industry sector, and can be as high as 75% during the coldest days²⁶²) or even sometimes during the summer when air conditioning demand rises.

As of 2016, the natural gas market in Argentina was a net importer. Since 2013, natural gas demand has been fairly flat due to a slowdown of economic activity while at the same time gas production seemed to be levelling off. The objective of the country is to focus on its upstream sector, develop new reserves especially its immense unconventional gas resources (shale and tight gas) notably in the Vaca Muerta basin and to become self sufficient again as soon as possible.

²⁵⁹ IEA (2016b), p.II.8, data for 2015

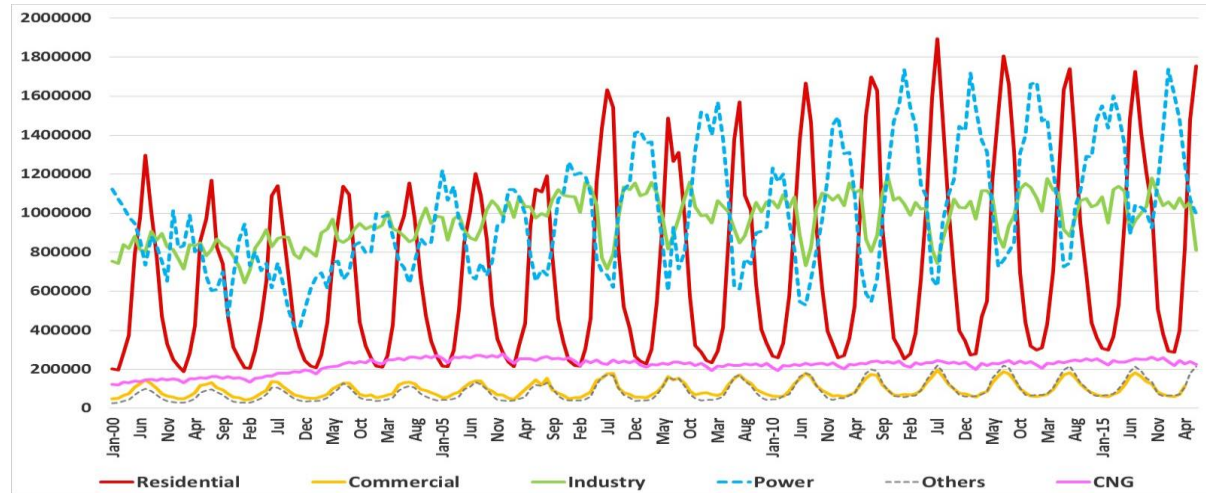
²⁶⁰ IEA (2016b), p.II.149, data for 2014. National statistics up to 2015 can be found in the regulator's report: Enargas (2015), Chapter 4, p.146

²⁶¹ Enargas data, <http://www.enargas.gov.ar/Publicaciones/Informes/Index.php>

²⁶² Argus news, 18 June 2015, Argentina re-imposes gas rationing amid cold snap



Figure 39: Seasonality of natural gas demand in Argentina, January 2001-September 2015 (cm)



Source: Enargas data²⁶³

Scenarios up to 2030

- Demand

A continuous increase in gas demand is expected, but a moderate one due to a combination of slow GDP growth, revision of energy subsidies and higher renewables in the generation mix.

The power sector, the largest user, is expected to grow slowly at least until indigenous gas production picks up: there is significant potential to replace costly oil-fired plants, but it will be limited by the availability of supply (volumes of gas but also network access). The electricity sector is also overstretched after years of subsidies and frozen tariffs that sustained demand growth while curtailing investments. After renewed blackouts due to peak demand over the summer months (2015-16) in Buenos Aires as a result of high temperatures, Argentina awarded power purchase agreements to twenty gas-fired projects as part of a tender launched in March 2016. However, the projects have relatively small capacity (20 projects for a total of 1.9 GW), highlighting the continuous uncertainty over the political decisions despite the arrival of a new elected president Mauricio Macri, the centre right mayor of Buenos Aires, in November 2015. Nonetheless, the government is promoting a \$35billion investment programme with the objective to install 21 GW of new power generation by 2025. This new capacity is expected to be based on gas (5-7 GW) but also renewables to expand efforts to fight climate change and diversify the generation mix. As a result, gas will be more and more in competition with renewables, especially wind.²⁶⁴ The legislation requires clean sources in the mix to increase from about 2% in 2015 to 8% in 2018 and 20% in 2025.²⁶⁵ The previous government was also planning new nuclear plants (1.75 GW backed by China and 1.2 GW by Russia) but uncertainty remained on these projects by mid-2016 as the government reviewed the proposals.²⁶⁶

²⁶³ Enargas data: <http://www.enargas.gov.ar/DatosOper/0302010.php>

²⁶⁴ In the first renewable auction on 7 October 2016, wind projects were the most successful. Source: Argus Latin America Energy, 11 October 2016, Wind cleans up in Argentina auction

²⁶⁵ La Nación, 29 September 2015, Para 2017, el 8% de la generación eléctrica argentina deberá ser de energías renovables

²⁶⁶ Argus Latin America Energy, 5 July 2016, New government sticks to China nuclear plans



In the industry sector, gas demand has been flat since the mid-2000s, essentially due to a shortage of gas supply. In 2014, a weakening economy combined with high inflation started to reduce consumption in this sector. Industrial output declined by almost 8% in July 2016 yoy, the sixth consecutive months with yoy decline.²⁶⁷ The relatively weak economic outlook and the continued financial difficulties will most probably prolong this trend. The transport sector may also be impacted by government measures to reduce interests in NGVs.²⁶⁸ In the residential sector, network coverage of the country is close to 100%, so there will be limited gas demand growth due to a growing client base.²⁶⁹

Lower subsidies will likely promote energy savings and efficiency measures. In 2014, it was reported that consumers only paid about 20% of the cost of natural gas, with the balance being subsidized by the government.²⁷⁰ With growing deficits, tightened fiscal and monetary policy and rampant inflation, eliminating state energy subsidies or at least lowering them significantly, has been high on the government's agenda for several years. Finally in April 2014, the government started to lower natural gas subsidies, which were reduced by 20%. The power sector, industrial consumers and low-income residents were expected to be exempted from the subsidy cuts, while the middle and upper classes would bear most of the burden.²⁷¹ The subsidy cuts were accompanied by measures to encourage efficient energy use. In May 2015, a 44.3% increase in the tariff applicable to the public transportation of natural gas was approved and has been effective since May 2015. These starting points were followed by more drastic measures after the election of president Macri. In April 2016, the government increased wellhead gas prices for residential, commercial and compressed natural gas users by as much as 1,700% (to an average of about \$5/MMBtu). On August 18, the Supreme Court repealed gas rate hikes for residential customers until public hearings were held, while the increases for commercial and industrial users remained. The government then decided to scale back the rise to \$3.42/MMBtu (on average) in October 2016. This measure is to be followed by roll-out adjustments every six months to reach \$ 6.78/MMBtu in October 2019.²⁷² The initial increase had set the price at \$4.72/MMBtu from April 2016. This setback may be significant for hurdles ahead for the government in implementing its market-based measures and therefore adds some uncertainty for investors. Removing price subsidies for energy (gas, power and retails fuels) will help tackle a fiscal deficit of about 7% of GDP, and if these actions are followed through, they should also temper the growth of natural gas demand in our timeframe. For instance, electricity demand fell by 9.4% in March 2016 (yoy) after a power tariff hike in February.²⁷³

All these factors indicate a slow growth scenario for gas demand. However, as indigenous supply availability improves, there is a potential for additional gas demand that has been repressed since the mid-2000s. These uncertainties lead to high variations in expectations and scenarios. The IEA expects about 54 bcm in 2020.²⁷⁴ The IAPG forecasts gas demand at about 97 bcm in 2035 (260 mcm/d) or twice the anticipated average gas demand for 2015 (47.5 bcm).²⁷⁵ The scenario

²⁶⁷ Indec data: http://www.indec.gov.ar/nivel2_default.asp?seccion=E&id_tema=3

²⁶⁸ In 2014, the IEA expected 8 bcm growth between 2012 and 2018 in the sector, but this may also be called into question. Source: IEA (2014a), p.49

²⁶⁹ IDB (2014), p.56

²⁷⁰ Mercopress, 28 March 2014, Argentina begins natural gas and water subsidies reduction in three stages

²⁷¹ Industrial users, low-income consumers receiving social or unemployment benefits, pensioners and inhabitants of the colder southern provinces were exempt from these measures. Source: The Economist, 31 March 2014, Government announces subsidy cuts

²⁷² Argus Latin America Energy, 13 September 2016, Government to reinstate price hikes

²⁷³ Argus Latin America Energy, 26 April 2016, Argentina power demand plummets after tariff hike

²⁷⁴ IEA (2015d), p.51

²⁷⁵ IAPG, 14 July 2015, De Vaca Muerta al hogar de los Argentinos



considered in this paper is more in line with the IEA one of slow growth up to 2020 (50 bcm) as supply shortages and weak economic growth continue to constrain gas demand increases. Despite additional indigenous supply expected in the 2020s, we expect a mix of efficiency measures and growth of renewables to limit gas demand to 55 bcm in 2030. This timeframe is a lot more uncertain, and higher demand can be envisaged.

- Production

Argentina produced almost 40 bcm of natural gas in 2015,²⁷⁶ mostly from the Neuquén, Austral and Noroeste basins. These three areas represent about 85% of production. Offshore production represents only about 13%, mostly from the southern part of the country. The country is at a point of decline in practically all of its conventional fields. A mature producer for its conventional provinces, the country aims to continue the reversal of the decade-long decline of its indigenous oil and gas production (which seems to have halted in 2014).

Argentina is relatively well endowed with hydrocarbon resources, and its world's second-largest shale gas resources have attracted interest from international players, especially in its Vaca Muerta region located in the middle-western Neuquén province. The Neuquén Basin covers 137,000 km² (more than the size of England), of which the Vaca Muerta shale play covers about 30,000 km² (about the size of Belgium). The size is an important factor, but the geology also seems very promising with a 1,000-foot-thick shale formation, which allows higher production with a smaller number of wells. In addition, the Neuquén Basin has been a major producer of hydrocarbons for over 100 years and it is the country's most prolific region for conventional natural gas output (about half of national production).²⁷⁷ As a consequence of being in a mature petroleum-producing region, the Vaca Muerta shale play is located in an area with good road access, extensive pipelines, service companies and facility infrastructure in place. These are assets that do not need to be built and that shale developers can use. Once production starts, the producers will be able to use the more than 30,000 km of gas pipeline network, the largest network in South America that has been underutilised due to the decline of conventional production and transport the gas to the market centres. The government has also promised YPF a railroad to connect the Vaca Muerta to the rest of the country. Thanks to the pre-existing oil and gas industry activity, the companies also already have extensive geological knowledge and well data. In addition, hydraulic fracturing necessitates large amounts of water and while this can be a major challenge for shale developers in other parts of the world, this is probably not going to be the case for Vaca Muerta thanks to the nearby Limay and Colorado rivers, which should avoid the high cost of sourcing far-afield water. Finally, the shale gas reserves are largely in the lightly populated regions of Patagonia and Neuquén, which may make environmental issues less complicated.

YPF started to develop the shale resources of both oil and gas in Vaca Muerta in 2010. The company holds most of the shale acreage that has been licensed, but there are a dozen or so companies with acreage in Vaca Muerta, including major oil and gas companies such as Chevron, Petronas, Shell and Total. The government expects that by 2020 the production of shale gas will be sufficient to replace imports of gas, but this is very uncertain and it will also cost billions of dollars in investments. The government has tried to encourage new investments in E&P activities since the late 2000s with various measures. An important one was the increase of state-controlled prices in 2012 when wellhead prices for new developments were increased to \$7.50/MMBtu, three times the prevailing

²⁷⁶ IEA (2016a), p. II.4, table 3

²⁷⁷ The Neuquén basin includes the country's most prolific natural gas field, Loma La Lata, operated by YPF



average in the Neuquén basin.²⁷⁸ The government also tried to update its oil and gas regime to attract investments to both conventional (mainly offshore) and unconventional exploration and production,²⁷⁹ as well as rebuild investor's confidence after the 2012 renationalization of YPF which shocked investors and weakened the country's ability to attract foreign investments. Uncertain regulatory environment has been one of the major obstacles in the exploration of Vaca Muerta.²⁸⁰ The election of Mauricio Macri started a shift toward a more business friendly economic policy and seems to have renewed investors' interest in upstream investment in Vaca Muerta.²⁸¹ In April 2016, the country finally settled the dispute with the bondholders that refused to restructure the debt from the \$100bn default in 2001.²⁸² The return to international capital markets will certainly be beneficial to the development of the unconventional resources. President Macri vowed to end restrictions on access to foreign currency, importing equipment and repatriation of corporate profits in his presidential campaign and promised a shift to market-oriented policy. Expected regulatory changes have been welcome by private investors, but the arrival of Macri coincided with a difficult period for energy investment in general. The decline of the global oil price since late 2014 will likely slow the pace of development: with the oil barrel at \$50, only a few sweet spots in Vaca Muerta are believed to be viable.²⁸³ At a time of low oil prices and reduced investment budgets, costs will have to be reduced, especially drilling costs. YPF says it has already cut the cost of drilling a vertical well in Vaca Muerta to \$6.9 million from a previous \$11 million, and it is expected to fall by at least 10% by the end of 2016 with the use of indigenous sand in fracking.²⁸⁴ Horizontal wells have been drilled at an average cost of \$11 million in January-June 2016 in the onshore Loma Campana block, down from \$16 million in 2014.²⁸⁵

Nonetheless, progress has been made since 2010 when YPF started to develop the unconventional oil and gas resources of Vaca Muerta.²⁸⁶ Since the takeover in 2012, YPF has been active in finding foreign energy companies to collaborate and every deal –large or small- is an important step forward

²⁷⁸ The government has tried to encourage new investments in E&P activities since the late 2000s starting with the Gas Plus program in 2008. More than sixty projects were approved under this programme which allowed producers to charge around \$4-5/MMBtu for their production from offshore exploration and for gas produced from either new wells or wells that had not been producing since 2004, which was about double the national average price cap at the time of \$2.50/MMBtu. In August 2012, the government went further and set well-head prices at \$7.50/MMBtu.

²⁷⁹ In 2013, Argentina adopted Federal Decree 929/13. This document was drafted to attract investment for both conventional and unconventional hydrocarbon production by including key measures to allow the repatriation of profits (restricted by federal government policy) after a minimum of \$250 million of investment (down from the previous level of \$1 billion), authorizing up to 20% of production (conventional and unconventional oil and gas) to be exported and even up to 60% for offshore production and raising the national price of oil and gas. Source: Boletín Oficial (2013)

The Argentine Congress built on the changes proposed in Federal Decree 929/13, and proposed the Hydrocarbon Reform Law (Law 27.007) which replaced its 1967 Law (Law 17.319) and was promulgated on October 30 2014 and published in the official bulletin on October 31 2014. The objective of this law was to create an attractive environment to increase investment in shale and exploration and production activity in the Vaca Muerta shale oil and gas deposits. The Law limits the power of the oil-producing provinces, which under the constitution own the nation's oil and gas reserves. It also creates standardized rules for companies, which were facing different regulatory frameworks across the various oil-producing provinces. The main measures include a national bidding process, changes in the duration of exploration periods, and standardisation of taxes and royalties. Source: Federal Register of Argentina (2014)

This 2014 New Hydrocarbon Law was repealed after the arrival of president Macri in December 2015.

²⁸⁰ The 2014 \$5 billion settlement with Spain's Repsol in compensation for the expropriation of its 51% stake in YPF was an important move forward to restore some investor confidence. Source: Financial Times, 25 February 2014, Repsol accepts \$5 billion Argentina settlement

²⁸¹ ExxonMobil announced that it would spend a further \$250 mn on a pilot programme. Source: Argus Latin America Energy, 7 June 2016, ExxonMobil to raise shale block investment, p.7

²⁸² Financial Times, 24 April 2016, Argentina repays holdouts, says ciao to default

²⁸³ OIES/KAPSARC (2016), chapter 6

²⁸⁴ Costs are between \$ 4-5 million/well in shale plays in the US

²⁸⁵ YPF (Q2 2016), slide 10

²⁸⁶ YPF drilled and completed a shale gas discovery in July 2010 in the Loma La Lata area. Shortly thereafter in November 2010, a shale oil discovery was made in the Loma Campana area of Neuquén Province. Source: AAPG Explorer, January 2013, Argentina's Vaca Muerta Draws GTW Spotlight



in the development of the gas resource.²⁸⁷ Some companies have already begun exploring and a few have already started producing shale oil and shale gas, even if shale gas production on a commercial scale was only just starting in 2015. YPF was the first to enter mass production in a partnership with Chevron. Others have entered pilot production, namely ExxonMobil, Shell, Total and Wintershall. Moving from pilot production to the development phase will be very costly and require additional capital, with most estimates suggesting between \$5 billion and \$12 billion needed per year.²⁸⁸ After president Macri took office on December 10 2015, several deals were announced such as the \$500mn agreement with US based Dow Chemical to boost production in an existing shale gas development and the \$500mn deal with US independent American Energy Partners to develop a shale oil and gas pilot project.²⁸⁹

The government has been trying to reverse years of declining output and cut back expensive gas imports. Future development of Vaca Muerta –and more importantly the pace of it- is uncertain. In 2016, YPF planned to drill only about 54 unconventional wells in the region (about 90% horizontal), a sharp drop compared to the 250 wells drilled in 2015.²⁹⁰ Officials recognise that it will be a long process, and it probably won't have a major impact on the country's gas supply/demand balance this side of 2020. Still, the government expects that by 2020 the production of unconventional gas will be sufficient to replace imports of gas, but this is unlikely. The development of the unconventional reserves, and especially the Vaca Muerta area, is expected to get Argentina closer to its objective of energy self-sufficiency, however it will require significant investments and until additional exploration is undertaken, one cannot know the scale and characteristics of the resource and therefore how much unconventional gas is potentially recoverable under existing economic and technological conditions.

For all these reasons, our scenarios reflect a cautious optimism of growth, but likely much slower than expected by the government or other institutes. For instance, in its Medium Term Gas Outlook 2015, the IEA expected that before 2020, shale gas would make a minimal contribution to the overall gas production which was seen to increase modestly adding 2.4 bcm between 2014 and 2020.²⁹¹ In its WEO 2015, the IEA planned for 42 bcma of total gas production by 2020 and 71 bcma by 2030.

²⁸⁷ In 2013, YPF entered in an impressive \$1.4 billion partnership with US Chevron to develop the Loma La Lata Norte and Loma Campaña areas. In May 2014, the company announced its intention to invest an additional \$1.6 billion, encouraged by well results and the prospect of lower drilling costs, to warrant additional investment. Source: Reuters, 22 May 2014, Argentina won lottery with Vaca Muerta shale field – Chevron

The second biggest investment was by Malaysia's state-owned Petronas, which signed a \$550 million agreement with YPF in late 2014. Source: Financial Times, 11 December 2014, Petronas signs Argentina shale deal

In both agreements, the foreign IOCs supply the majority of the projects' financing and YPF maintains operational control, and if the initial period is successful, additional investment may be envisaged. Other companies are also active in the country, with smaller commitments. Gas y Petróleo del Neuquén S.A., the company owned by the Argentine province of Neuquén, announced smaller deals with Royal Dutch Shell (\$250 million) and France's Total (\$300 million) to develop other parts of Vaca Muerta. Other companies such as Argentine Pan American Energy (PAE), ExxonMobil and Germany's Wintershall are also pursuing pilot production projects in the shale play. In July 2015, the Neuquen province approved four new unconventional upstream contracts with YPF, Pan American Energy (PAE) and Wintershall, with the companies expected to invest some \$1.4 billion over the next three years. These deals were finalized under the amendment to the hydrocarbons law passed in October 2014. Source: Argus News, 21 July 2015, Argentina province approves four upstream deals

Russia's Gazprom and China's Sinopec are evaluating opportunities. The developments in Vaca Muerta have also attracted investments from investors like George Soros for instance, who owns 3.5% of YPF shares. YPF has also entered into partnership with Dow Chemical for a tight gas development in another play.

²⁸⁸ Platts International Gas Report, 29 June 2015, Vaca Muerta needs capital

²⁸⁹ Argus, 15 January 2016, YPF signs shale deal with American Energy Partners

²⁹⁰ Argus News, 4 March 2016, YPG checks upstream growth expectations

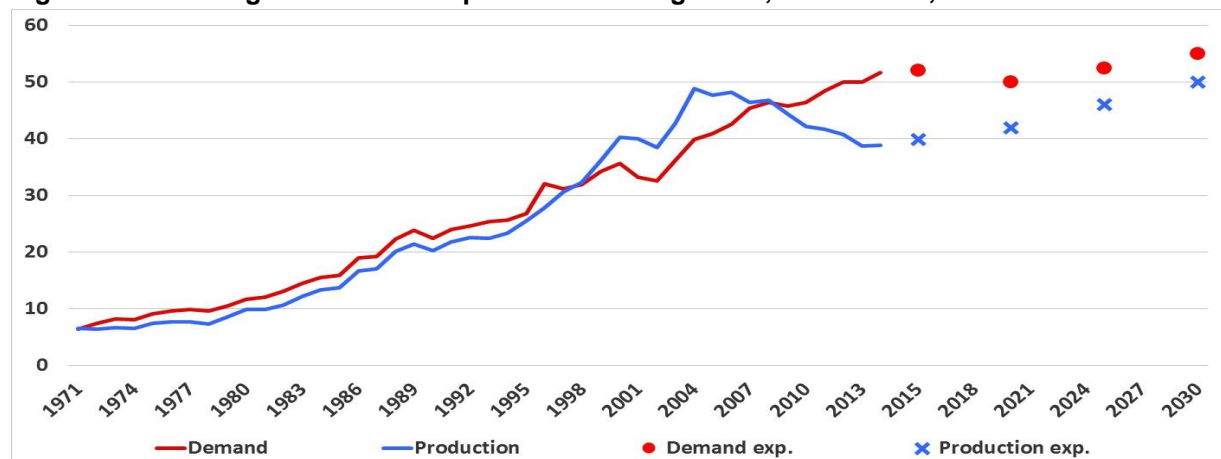
²⁹¹ IEA (2015d), p.90



- Balances

Despite expectations of rebalancing gas supply and demand fundamentals, Argentina is likely to continue to import gas for at least the next 10 years, as confirmed by YPF chief financial officer Daniel Gonzalez in 2016.²⁹² Scenarios of gas demand and indigenous production show a continued need for imports for even longer as seen in Figure 40.

Figure 40: Natural gas demand and production in Argentina, 1971 – 2030, bcm



Sources:

1971-2015: IEA, Natural gas information, various reports

2016-2030: Author's estimates

What future role for LNG?

The first LNG terminal, the Bahía Blanca FSRU, (3.7 bcma later expanded to 5.1 bcma), 643 km southeast of the capital Buenos Aires, came on line in 2008 and the country became the first South American country to import LNG later in the year. The second LNG terminal, the Escobar LNG FSRU, (5.1 bcma), on the Paraná River 48 km from Buenos Aires, was inaugurated in 2011. LNG imports rapidly increased from 0.5 bcm in 2008 to 5.5 bcm in 2015 (with a peak of 6.4 bcm in 2013).²⁹³ A third LNG terminal, the Cuatros terminos, has been envisaged, near the existing Bahia Blanca terminal with a proposed capacity of 25 mcm/d (9.1 bcma).²⁹⁴

LNG was initially imported only during the winter when demand for gas soars to meet residential heating demand. By 2016, the peak during winter months still existed but LNG was imported whole year round [Figure 41].

LNG cargoes are imported on a spot basis and prices can vary significantly. For instance, in the first half of 2016, the LNG import price ranged from \$12.59/MMBtu (to Bahia Blanca in January) to \$4.18/MMBtu (to Bahia Blanca in June), which was below the domestic gas price set at an average of \$5/MMBtu (and even \$7.5/MMBtu for new production).²⁹⁵

²⁹² Argus Latin America Energy, 9 August 2016, YPF reins in drilling costs, p.5

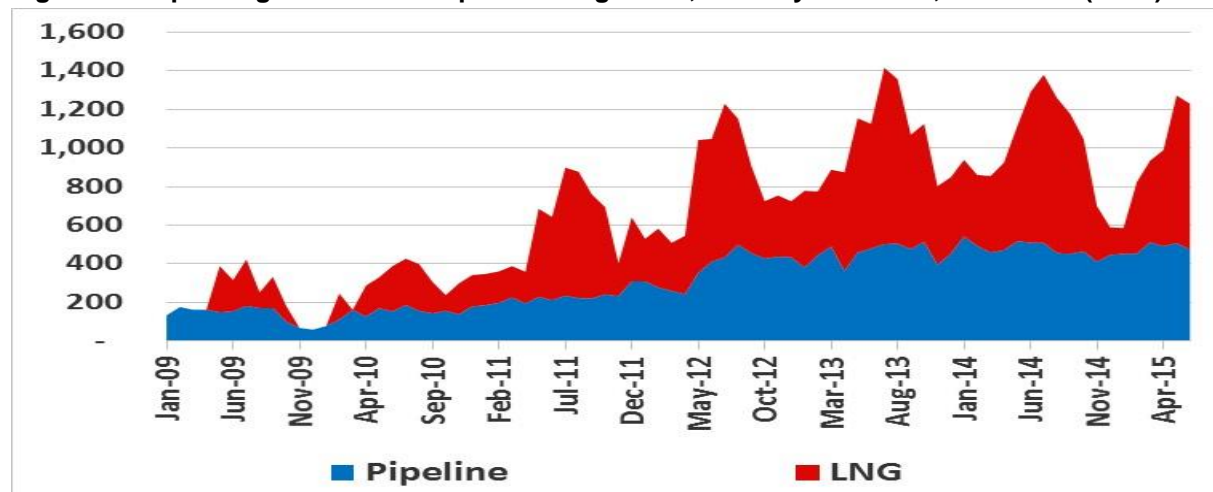
²⁹³ GIIGNL, The LNG industry, annual reports

²⁹⁴ Argus, 25 October 2011, Argentina to launch tender for at least 60 LNG cargoes

²⁹⁵ The regulated price is part of measures decided to encourage upstream investments and boost production.



Figure 41: Pipeline gas and LNG imports to Argentina, monthly evolution, 2009-2015 (mcm)



Sources: YPF, Boletín Estadístico Gestión, several issues and Platts, LNG data

In winter 2016, Argentina started imports of regasified LNG from Chile using both the Norandino pipeline and the GasAndes pipeline.²⁹⁶ Deliveries via the Norandino pipeline started on May 17 (1.5 mcm/d) at a price of \$6.90/MMBtu. The gas was imported under a short term contract with Engie (until August 5). On June 3, Chile state-owned Enarsa, Endesa and Metrogasvia began deliveries of 4.5 mcm/d via the GasAndes pipeline at a price of \$7.2/MMBtu.²⁹⁷ The price of gas imported from Chile was linked to diesel, making this gas more expensive than the imports from Bolivia (at around \$3/MMBtu in early 2016) and even LNG imports at around \$6.5/MMBtu.²⁹⁸ The reason behind this move was the expected shortness of available Bolivian gas²⁹⁹ but also the fact that both Argentine LNG import terminals run at full capacity during winter months. These expensive imports from Chile have created controversy, but the alternative – diesel - would be even more expensive. Other proposed options to increase gas imports include buying LNG from the terminal under construction in Uruguay, once it starts operation.

The future of LNG imports will depend on the level of Argentine gas demand and production and on available gas from Bolivia; especially post 2026 when the export contract expires. In 2020, it appears that the gap between production and demand in our scenarios can be covered by pipeline gas already contracted from Bolivia. In 2030, if pipeline gas is cheaper than LNG and if Bolivia has enough gas to export, then it is possible that pipeline gas will also be enough cover Argentina's needs. If LNG is cheaper or if Bolivian gas is not available, then the gap between production and demand would need to be covered by about 5 bcm of LNG.

President Macri expects that it will take "5-6 years" for Argentina to be able to supply its market without LNG imports, which are expensive.³⁰⁰ However, LNG imports may be cheaper than develop the infrastructure needed to be able to meet peak demand with unconventional resources, even if the objective of the government is to regain self-sufficiency in its energy (oil and gas) markets. The

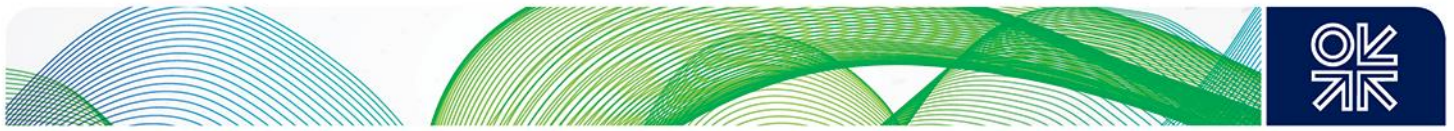
²⁹⁶ Both pipelines were built in the 1990s originally to send Argentina gas to Chile.

²⁹⁷ Argus Latin America Energy, 21 June 2016, LNG imports cheaper than domestic gas

²⁹⁸ Argus Latin America Energy, 10 May 2016, Exports to Argentina to start

²⁹⁹ As expressed by Argentinean energy minister Juan Jose Arganguen. Source: Argus Latin America Energy, 10 May 2016, Exports to Argentina to start

³⁰⁰ Argus Latin America Energy, 9 August 2016, YPF reins in drilling costs



Argentine Oil and Gas Institute (IAPG) considers that it would be uneconomic to invest in production and transport infrastructure to meet peak winter demand because of the cost of keeping the capacity in working order for only about three months per year which the Institute estimates at \$1.1 billion per year for pipeline and related infrastructure through 2035 and \$620 million/year needed to expand distribution networks.³⁰¹ This would mean that even when unconventional gas production is developed, LNG imports may still be needed to cover peak demand in winter (June-August).

³⁰¹ Platts International Gas Report, 27 July 2015, Argentina set for long-term imports

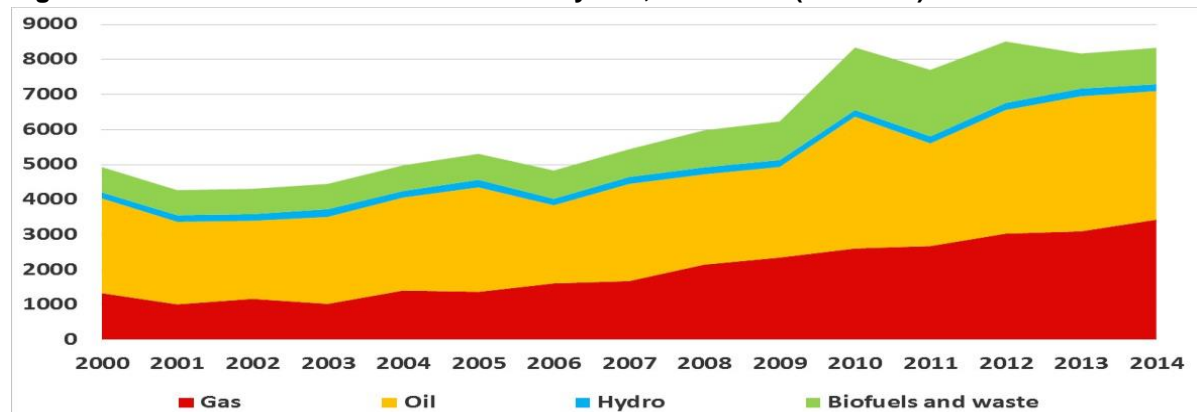


Bolivia

Overview of the energy market

Bolivia is a relatively small energy market, representing about 1.5% of regional primary energy supply. Its TPES is heavily reliant on oil (44%³⁰²) and on natural gas (41%). Biofuels and waste makes up for the other large share (12%) while hydro is minimal in the mix as seen below in Figure 42.

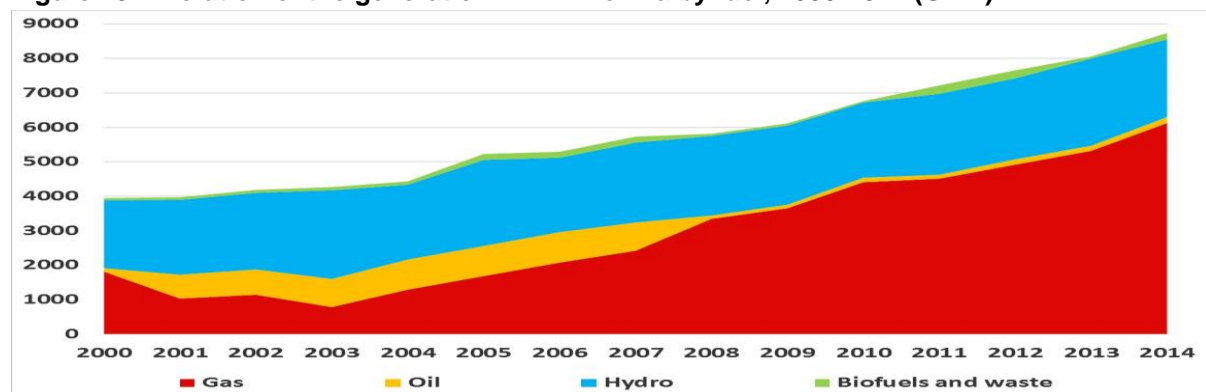
Figure 42: Evolution of the TPES in Bolivia by fuel, 2000-2014 ('1000Toe)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

Bolivia is heavily reliant on natural gas to produce its electricity (70%³⁰³) as seen in Figure 43. This share has risen quickly since the mid-2000s due to rapid expansion of gas-fired capacity to meet the increase in power demand and also to replace more expensive oil plants.

Figure 43: Evolution of the generation mix in Bolivia by fuel, 2000-2014 (GWh)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

In 2014, Bolivia had 2.1 GW of installed generation capacity, 54% in the form of natural gas, 18% of other fossil fuels, 16% of other renewable (14% small hydro, 2% biomass and waste, 0.1% wind), 10% of large hydro, and 2% of oil and diesel.³⁰⁴ The gas power plants had an annual average load

³⁰² IEA (2016b), p.II.163, data for 2014

³⁰³ IEA (2016b), p.II.163, data for 2014

³⁰⁴ Bloomberg New Energy Finance (2015), p.157



factor of 62%,³⁰⁵ which means some additional electricity could be generated from the existing plants, for instance to back up hydropower in times of drought.

The natural gas industry

Bolivia has abundant non-associated gas reserves, which it is eager to export to neighbouring countries. It started to export natural gas to Argentina in 1972, but the development of its natural gas industry really began following liberal economic policy implemented in the 1980s, the structural reforms adopted by the country in 1985,³⁰⁶ and the privatisation of the gas industry in 1996.³⁰⁷ Significant gas reserves were discovered in the Sábalo (1990), San Alberto and Margarita (1998) mega fields (which still accounted for about 70% of the country's production of natural gas in 2014). Gas production increased rapidly after 1999 when Bolivia started to export natural gas to Brazil, a potentially very large market. Exports to Argentina, which ended in 1992, were resumed in 2004.

The liberal policies and export-driven growth -through hydrocarbons and other products- started to be contested in the early 2000s. Severe monetary and fiscal policies, high unemployment and low income triggered social and political unrest against President Sánchez de Lozada (2002 to 2003). The economic wealth which should have come from monetising the natural gas resources was not passed down to the country's economy and contributed even less to the prosperity of the majority of Bolivians. By 2003, the country was in a difficult situation, which became known as the "Gas War". This major popular revolt even led to the president's resignation. Vice-President Carlos Mesa assumed the government. In 2004, he launched a referendum about the creation of a new Hydrocarbon Sector Law. The project was approved, harshly debated and the law was promulgated.³⁰⁸ This law changed the legal framework, with increased state control and government take, raising taxes on oil and gas from 18% to 50%. Evo Morales won the presidential elections in the first round in December 2005. His government focused on land reform and the nationalisation of key sectors of the economy, including hydrocarbons. The nationalizations of the oil and gas industries and the revision of contracts with multinational companies were important objectives of the newly elected president. Supreme Decree 28701 was issued on May 1st, 2006.³⁰⁹ The new regime gave exclusive exploration rights to the state-owned oil company YPFB (Yacimientos Petrolíferos Fiscales Bolivianos), concession based contracts were transformed into service contracts between YPFB and private companies, all property rights of oil and gas production were transferred to YPFB, which also gained responsibility for the commercialisation of the products both nationally and for exports. Finally, the Decree also raised the government's take from 50% to 82% (a reversal from the previous 18% for the state and 82% for the companies).

After difficult negotiations with the government, most of the international oil companies with interests in the country agreed to sign the new contracts and continued to produce from the fields under production. However, political uncertainties and risk of expropriations caused many international oil companies to limit new investments in the country. As a consequence, the production of YPFB and the country's proven reserves dropped considerably, suggesting possible problems in sustaining

³⁰⁵ Author's calculations.

³⁰⁶ The so-called Supreme Decree 21060. For more information on the measures and policies developed in the 1980s in Bolivia, see WorldBank (1995)

³⁰⁷ Cedib (1996)

³⁰⁸ Cedib (2005)

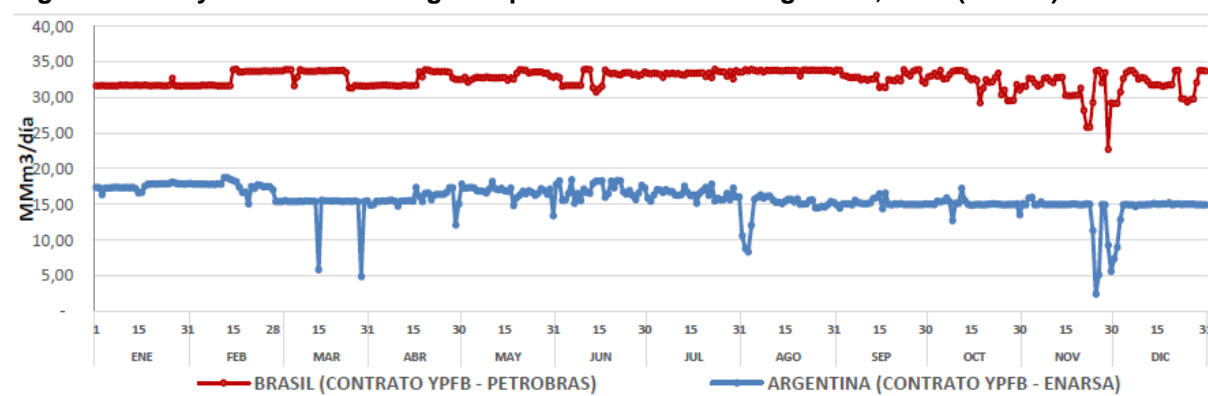
³⁰⁹ A reversal from the privatisation of the gas industry that happened in 1996. Source: see McNeish J.A., Borchgrevink A. and Logan O. (2015) for additional information



future rates of production and export commitments. However, after several years of efforts to rebuild its output, production started to increase again in 2010 and after five years of continued growth, natural gas production reached a new record in 2015 at 22 bcm.³¹⁰ However, very few new discoveries were made and put into production, with the important exception of the Itau field (Total, Petrobras and YPFB Chaco). Bolivia's gas reserves were adjusted down dramatically at the end of the 2000s on technical grounds, but the country will need to find and develop new reserves in order to maintain and expand gas production if it is to fulfil both its existing commitments and its expectations of additional gas and energy exports.

Bolivia has long term contracts with Brazil and Argentina. The 20-year contract between Bolivia and Brazil provides for the import of ToP volumes of 8.7 bcma and a maximum contractual volume of about 11 bcma until 2019.³¹¹ YPFB signed an additional temporary supply contract for 0.8 bcma for the Cuiabá gas power plant in Brazil at the end of 2013. The contract had an initial duration of one month but was extended for 2 years. Details of pricing under the new agreement were not released but it may be slightly higher than the price in the 20 year contract but with greater flexibility in volumes.³¹² The 20-year contract between Bolivia and Argentina provides for the imports of volumes that will ramp up to about 10.1 bcma in the early 2020s, when the GNEA to North East Argentina is finalised, and ends in 2026.³¹³ An additional interruptible contract was signed in 2012 for a possible additional amount of about 3.3 bcma, also until 2026. Both deliveries (to Brazil and to Argentina) are fairly flat through the year, and do not reflect the seasonality of Argentine demand or the peak in power generation in Brazilian demand, as seen below in Figure 44.

Figure 44: Daily Bolivian natural gas exports to Brazil and Argentina, 2014 (mcm/d)



Source: YPFB (2015), p.8

The revenues from these exports play a crucial role in the trade balance of Bolivia, which is one of the poorest countries in South America. Hydrocarbon exports represented \$6.6 billion to the trade balance in 2014, of which \$5.9 billion came from natural gas alone (46% of the country's total exports).³¹⁴ These incomes finance the development of the country and social programmes including subsidies for national energy prices. The mean prices for the national market were \$1.15/MMBtu in

³¹⁰ IEA (2016a)

³¹¹ 24 mcm/d and 30 mcm/d respectively. Source: "Addendum número 4 al contrato de compra venta de gas que celebraron, el 16 de agosto de 1996, por una parte Petrobras y por otra parte", the contract can be found on the YPFB website

In addition to this large contract, there are two smaller contracts to deliver natural gas to a thermo power plant in Cuiaba and in Puerto Suárez on the border to Brazil. Source: Andersen L.E., Meza M. (2001), p.11

³¹² Gas to Power journal, 8 October 2014, YPFB discusses gas supply extension with Brazil

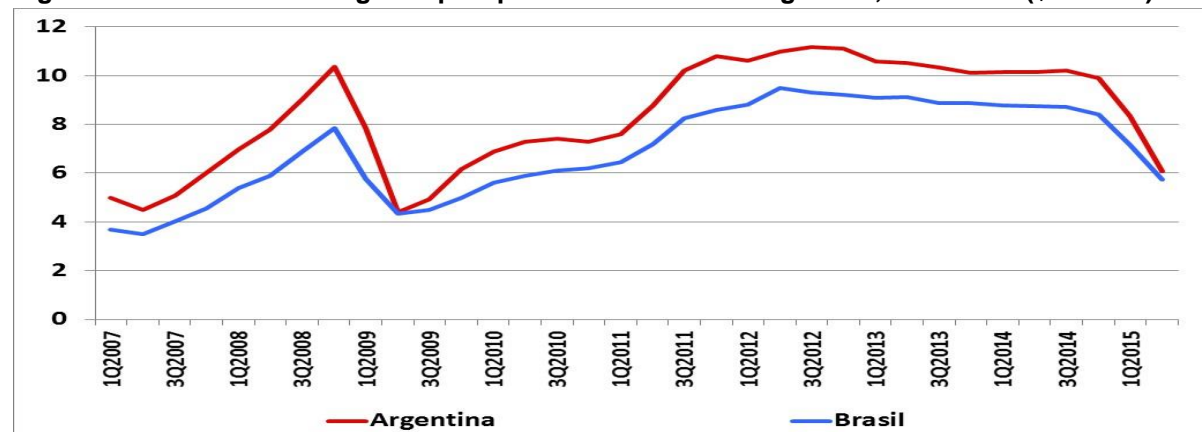
³¹³ "Addendum número 4 al contrato de compra venta de gas que celebraron, el 16 de agosto de 1996, por una parte Petrobras y por otra parte", YPFB website, retrieved in 2015

³¹⁴ Camara Bolivian de Hidrocarburos y Energia, 12 August 2015, Ingresos del gas caen 36



2014,³¹⁵ very low compared to the prices charged to the rest of the production which is exported to Brazil and Argentina which are linked to WTI crude oil prices over the previous three months with a three-month lag as seen in Figure 45.³¹⁶ & ³¹⁷ Given that export contracts to Brazil and Argentina are tied to international oil prices, the decline in global oil price has severely affected the country's exports on which the government and many regions have come to rely to finance popular welfare and poverty relief programmes. For instance, in the first five months of 2015, the revenues from natural gas exports fell by 34.4% raising only \$1.81 billion compared to \$2.86 billion in the same period in 2014.³¹⁸

Figure 45: Bolivian natural gas export prices to Brazil and Argentina, 2007-2015 (\$/MMBtu)



Source: YPFB, Boletín Estadístico, several reports

Bolivia has been looking at new ways to monetise its resources. Exports to Uruguay and Paraguay have been envisaged, but this would require the construction of new pipeline(s) and/or the use of Argentine pipelines for transit. The country also had ambitions to export part of its production in the form of LNG but, being a land locked country, it would have needed access to the sea through either Peru or Chile. The project via Chile was economically the best but was complicated by the difficult political relations between the two countries which haven't had diplomatic relations since the 19th century war that saw Bolivia lose its access to the sea to Chile. Both options were finally abandoned in the 2000s due to the high cost of the project and political turbulence in Bolivia.

Bolivia is a small gas market, which only consumed 3.8 bcm in 2015. Gas demand rose rapidly in the 2000s due to robust economic growth, supportive energy policies in all the sectors of consumption and very low domestic prices. Massive additions in gas-fired capacity made the power sector the main consumer of gas (43%³¹⁹) as seen in Figure 46. The industry share (22%) also rose thanks to energy policies in the petrochemical sector. The transport sector represents an impressive 17% of total gas demand, with about 331,550 CNG vehicles as of the first semester of 2015 (about 23% of the national fleet). Since 2010, the government offers free conversions from oil to gas, which are financed by

³¹⁵ YPFB (2015), pp.12-13

³¹⁶ YPFB (2011), pp.16-18

³¹⁷ In 2007, after complicated negotiations, it was decided that *state-owned* Brazilian oil company Petrobras would remunerate YPFB at international market prices for the fractions of butane, propane and other products of greater value than methane present in the gas delivered.

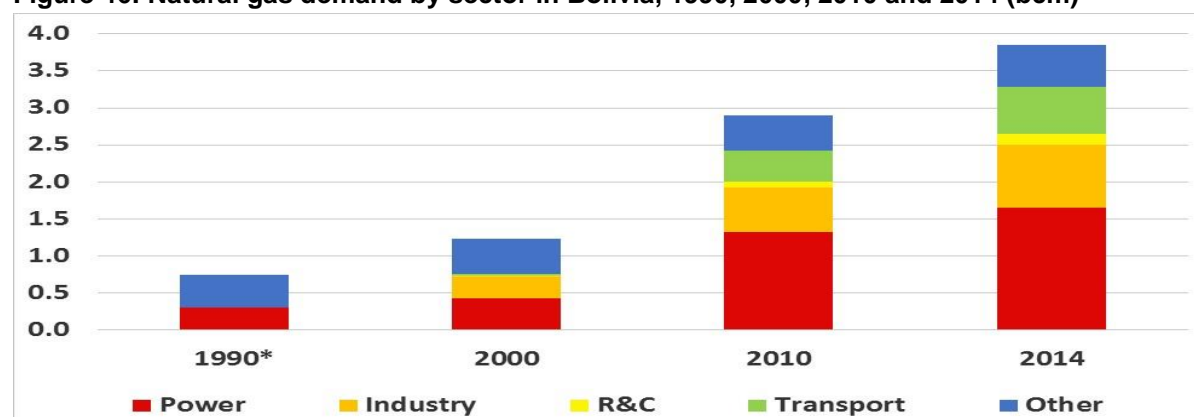
³¹⁸ Platts International Gas Report, 27 July 2015, Bolivian gas revenues drop

³¹⁹ IEA (2016b), p.II.163, data for 2014



revenues from gas sales.³²⁰ The residential and commercial is limited (4%) but rising thanks to national programmes to improve the geographical coverage of the country. The other sector, which includes energy own-use consumes about 14%.

Figure 46: Natural gas demand by sector in Bolivia, 1990, 2000, 2010 and 2014 (bcm)



Source: IEA (1993), IEA (2003a), IEA (2012), IEA (2016b), Individual country tables

As of 2016, the natural gas market in Bolivia was a net exporter with important commitments under long term contracts to its neighbours, but in a context of slowing indigenous production growth. National demand is also facing a slowdown due to the bleak economic activity.

Scenarios up to 2030

- Demand

A continuous increase in gas demand is expected, driven by economic growth and energy policies in favour of gas consumption.

In the power sector, the focus will be to diversify the generation mix in favour of renewables including hydro. Bolivia has 2.1 GW of installed capacity and has a target of 13.4 GW in 2025, mostly from new hydroelectric plants.³²¹ Natural gas will be the natural back up to hydropower and will account for some growth in power generation, especially thanks to low gas prices for power plants which have been fixed since 2001. However, additional gas for power demand will come from the country's plans to have electricity cover 100% of its territory by 2025,³²² from only about 87% in 2014.³²³ Bolivia would also like to build power generation capacity and develop electricity exports to Brazil and Argentina, which would be more profitable than exporting raw natural gas. By 2020, the government is planning to increase gas-fired capacity to around 4,800 MW from the 1,600 MW in 2013. If run baseload, these plants would use about 4 to 5 bcma of gas.³²⁴

³²⁰ Camara Boliviana de Hidrocarburos y Energia, 14 August 2015, Un 23% del parque automotor es a GNV

³²¹ Argus News, 24 July 2015, Bolivia to open protected areas for exploration

³²² Molina Ortiz F. (2014)

³²³ The penetration rate is better in cities (97%) compared to rural areas (67%). Source: Bloomberg New Energy Finance (2015), p.157

³²⁴ Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America



Bolivia expects to develop exports of processed products and is also making investments in several petrochemical plants to develop an industrial base founded on gas.³²⁵ The government intends to develop three main projects; a petrochemical plant, a polyethylene plant and a fertiliser plant in the coming decade.³²⁶ The decline of global oil prices will however complicate this plan by limiting revenues and therefore potential investments to realise these ambitions.

Transport is also expected to grow with a target of 500,000 CNG vehicles by 2020.³²⁷

The latest hydrocarbons energy plan on the government's website dates back to 2008 and covered the period 2008-26.³²⁸ These scenarios are disconnected from the 2016 reality and do not provide a good perspective on future potential growth. In 2015, the IEA expected gas consumption to increase robustly and reach 7.4 bcm by 2020,³²⁹ a scenario that corresponds roughly to the "high" demand trend on the 2008-2026 plan.³³⁰ We follow the IEA's estimates for 2020 (7.4 bcm) and expect gas demand to reach 10 bcm in 2030 in our scenario.

- Production

Production growth is expected to slow in the second half of the 2010s before starting to fall when some of the largest fields -such as San Alberto, Sabalo and Margarita- enter their decline phase.³³¹ Recent discoveries³³² may not be enough to maintain gas production growth even if developing mega fields such as Margarita (operated by Repsol) and Incahuasi (operated by Total) would constitute an important contribution to natural gas supply.³³³

Bolivia has large non associated gas fields that enjoy high levels of productivity, but it needs to find and develop new reserves in order to maintain and expand gas production if it is to fulfil both its existing commitments and its expectations of future exports, which are crucial for its economy. For this to happen, the country needs to build up investors' confidence that their interests will be preserved in the future if they decide to invest billions of dollars into the upstream gas sector. The state-owned company is trying to develop its E&P partnerships with foreign companies further³³⁴ and look for new areas to exploit including in national parks and other protected areas but the consultations with the local populations could at the very least complicate these projects.³³⁵

The Bolivian government has launched a series of incentives aiming at promoting private investment in exploration, but it was too early at the time of writing (mid 2016) to say whether these new

³²⁵ Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America. Additional details on the projects can be found in Molina Ortiz F. (2014)

³²⁶ YPFB (2013)

³²⁷ Argus News, 24 July 2015, Bolivia to open protected areas for exploration

³²⁸ Ministerio de Hidrocarburos y Energía (Bolivia) (2008)

³²⁹ IEA (2015d), p.52

³³⁰ Ministerio de Hidrocarburos y Energía (Bolivia) (2008), p.116

³³¹ These three fields account for 70% of total exports to Brazil and Argentina. Source: IEA (2015d), p.91

³³² For more information, see EFE, 2 May 2015, Spain's Repsol makes new gas discovery in Bolivia

³³³ Repsol website, Repsol in Bolivia, http://www.repsol.com/es_en/corporacion/conocer-repsol/repsol-en-el-mundo/bolivia.aspx

³³⁴ YPFB has several exploration projects under way with various partners. For instance, YPFB and Argentina's YPF have agreed to jointly explore three blocks in Bolivia and share technology for developing shale resources. Source: Platts International Gas Report, June 17, 2013, Argentina & Bolivia work on E&P

YPFB and Petrobras also signed a memorandum of Understanding in 2015 to develop natural gas deposits in the Tarija region over the next 10 years. The memorandum is the first step to a formal contract for Petrobras to invest about \$2.1 billion in developing gas deposits at San Telmo, Sunchal and Astillero in the province of Tarija through 2025. Source: Platts International Gas Report, 20 April 2015, Brazil primes the gas pumps

³³⁵ Even if the government expects that it would only represent a very small percentage of the protected areas, at about 0.04 %. Source: Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America



measures will be sufficient to reverse the trend. Bolivia's gas reserves, which were adjusted down in 2009 on technical grounds stood at about 0.32 Tcm in 2014. The government expects to boost gas reserves to 0.35 Tcm in 2021 and 0.54 Tcm in 2025.³³⁶ The government projections also point to a rising surplus from 2018³³⁷ especially thanks to the Caipipendi Block which will start production from 2019 and is even targeting peak production of 31.8 bcma in 2022.³³⁸ However, plans to increase exploration activity have been curtailed by falling oil and gas prices. Like others, YPFB made downward revisions to its capital expenditure programme for 2015-2019 to \$2.42 billion/year, from \$3.03 billion envisaged in its previous programme for 2014-2018.³³⁹

There are many uncertainties on the level (and the timing) of investment that will be made, and contrary to government's confidence, there are concerns about the ability to continue to supply its neighbours beyond the existing contracts. This is particularly relevant at a time when Bolivia is negotiating a renewal of its supply contract with Brazil, which expires in 2019. In the absence of substantial investment in new exploration in Bolivia, Bolivia could soon be unable to supply both its export markets (Brazil and Argentina) and its own rising internal demand. The other importing country, Argentina, has already turned to its neighbour Chile to find additional gas, especially during winter months when its own demand soars due to residential heating. This solution should offer some respite to Bolivia if need be.

- Balances

Facing all these factors of uncertainty, this author has chosen to set the future indigenous production of Bolivia at a level that permits it to fulfil low national demand expectations and existing export commitments, plus potential additional needs from Brazil and Argentina. These two countries have decreasing needs in the 2020s thanks to their own indigenous production growth, which will limit their Bolivian imports as time goes by and free some gas for the growing national market as seen in Figure 47. The assumption that Bolivia will take adequate measures to maintain its production and activate them in time to be able to keep its production at levels that meet national demand and import needs is a big gamble. It is therefore important to keep in mind that this may not happen, in which case, Bolivia will likely prioritise its own market and curtail exports to its neighbours, potentially creating security of supply problems for Brazil and Argentina.

In its Medium Term Gas Outlook 2015, the IEA expected natural gas production in Bolivia to decline sharply between 2015 and 2020³⁴⁰ (black line in Figure 47 below). In 2016, the expectations were slightly less pessimistic, but still showing a relative decline (purple line).³⁴¹ If new reserves are not developed and indigenous production does not increase (and even declines), it appears that Bolivia will not be able to supply both its national demand and its contractual commitments to Brazil and Argentina by 2016. The start of regasified LNG imports from Chile to Argentina for the winter months (June-August) could be a first sign of this tightness of available Bolivian gas.

For all these reasons, we have not considered the possibility of additional exports in our timeframe.

³³⁶ These figures include the depletion of existing reserves. Source: Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America

³³⁷ Financial Times, 26 October 2015, Bolivia wants to become the energy heart of South America

³³⁸ Argus News, 24 July 2015, Bolivia to open protected areas for exploration

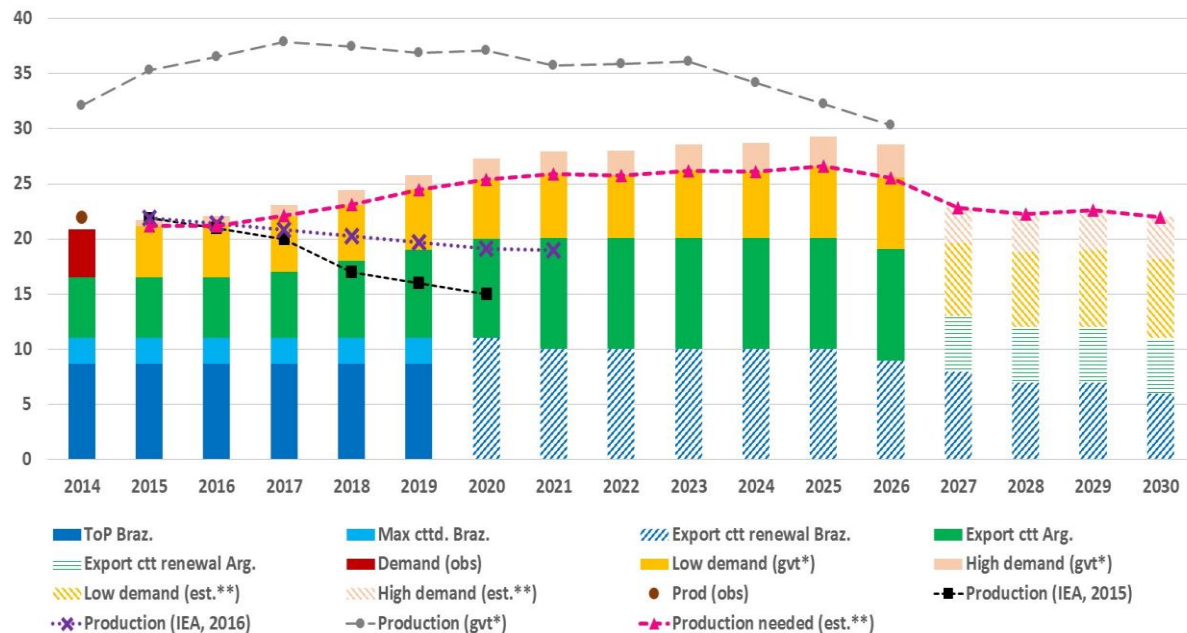
³³⁹ Platts, 6 January 2015, Latin America Oil Outlook 2015

³⁴⁰ IEA (2015d), p.91

³⁴¹ IEA (2016c), p.81. There are no specific details in this report for Bolivian gas production decline, contrary to the 2015 report.

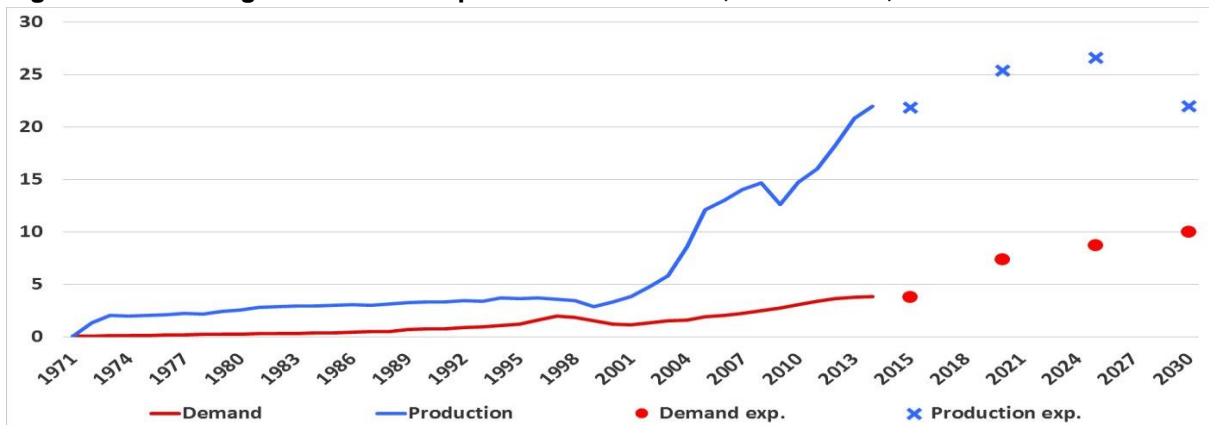


Figure 47: Natural gas balances in Bolivia, 2014-2030 (bcm)



Source: IEA (2015d), IEA (2016c); Ministerio de Hidrocarburos y Energia (2008); Author's assumptions

Figure 48: Natural gas demand and production in Bolivia, 1971 – 2030, bcm



Sources:

1971-2015: IEA, Natural gas information, various reports

2016-2030: Author's estimates

What future role for LNG?

In these scenarios, it already seems challenging for Bolivia to meet its contracts to supply gas to Brazil and Argentina. Nonetheless, the government has plans to extend sales to its neighbours and further afield. Bolivia's ambition is to develop its role as the gas heart of South America, a position its geography and resources should allow. In the 2000s, the prospect of exports to Chile was raised, which considering the political relations between these two countries, seemed very far-fetched. The preferred idea was to export LNG via neighboring Peru. This idea was renewed in the 2010s. There would be a need to build a 230km pipeline to link infrastructure in Bolivia to the new southern gas



pipeline (GSP) under construction in Peru.³⁴² The existing Peru LNG plant could be expanded or a second export terminal built on the southern coast at the end of the GSP. This idea would enable Bolivia to reach many more gas markets. However, before this could become a reality, new reserves will need to be put into production. For these reasons, we haven't envisaged new exports from Bolivia to other markets, including in the form of LNG via Peru's coast to the global market but also LNG to Peru and Paraguay via trucks and road transport (i.e. a virtual pipeline) as suggested by president Morales in May 2016.³⁴³

³⁴² Construction of the \$4 billion GSP began in May 2015. The line will run 1,000km from Peru's central jungle, over the Andes and down to the southern coastal ports of Ilo and Matarani and is expected to be operational in the first half of 2018, however, delays are possible. See Appendix on Peru for more information.

Source: Argus News, 24 June 2015, Bolivia looks to export gas through Peru

³⁴³ Newsbout, 7 May 2016, Bolivia plans LNG export agreements with Peru, Paraguay

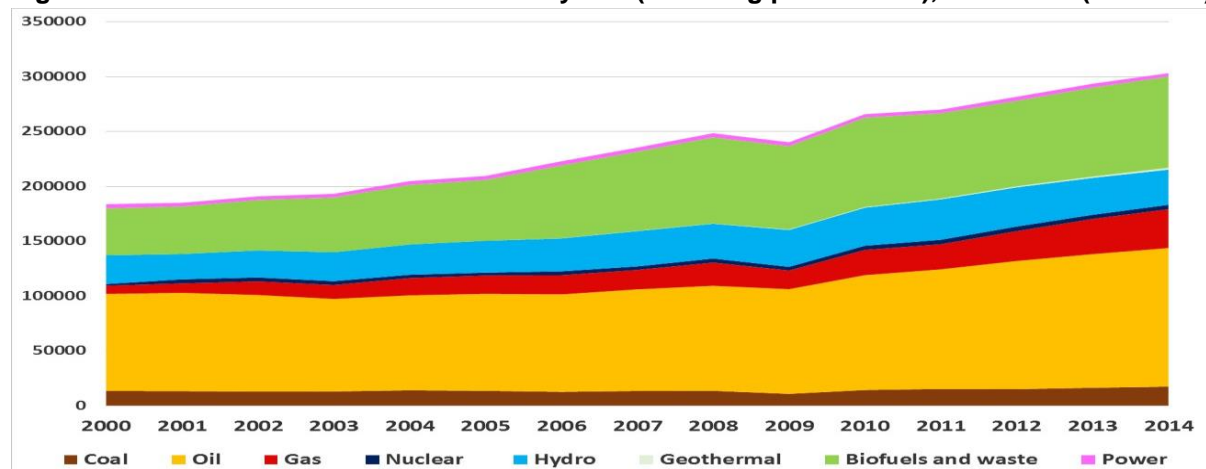


Brazil

Overview of the energy market

Brazil is the largest energy and gas market in South America. It is by far the largest energy consumer, representing almost half of the primary energy supply on its own. Still, natural gas plays a relatively modest role in the mix, accounting for about 12%³⁴⁴ as seen below in Figure 49. This is due to the predominant role of oil (42%) used primarily in the transportation and residential sectors and biofuels and waste (28%), but also hydroelectricity (11%) in the generation mix. The relatively undeveloped gas infrastructure across the country and government subsidies for LPG (the main fuel used for cooking) have also constrained the development of the gas market.

Figure 49: Evolution of the TPES in Brazil by fuel (including power trade), 2000-2014 ('1000Toe)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

Brazil is heavily reliant on hydropower to produce its electricity, and it represents more than 75% of its total domestic power generation under normal climatic conditions. As a result, the mix is highly concentrated and the other fuels cover only a very small share [Figure 50]. Gas, renewables, oil, coal and also nuclear (Brazil is one of the two nations with nuclear power plants with Argentina) complete the generation mix.

During dry seasons, the generation mix is altered as seen several times since the early 2000s. In the most recent episode in 2013-2016 (still ongoing in the North-Northeast as of mid-2016), the country faced the consequences of the worst drought in eight decades which dried up reservoirs at hydro-dams.³⁴⁵ Fossil fuel power plants were called in to supplement power generation. In 2014, hydropower only supplied 64% of the mix while gas covered 14%, biofuels and waste 8%, oil 6%, coal 5% and nuclear 2%.³⁴⁶

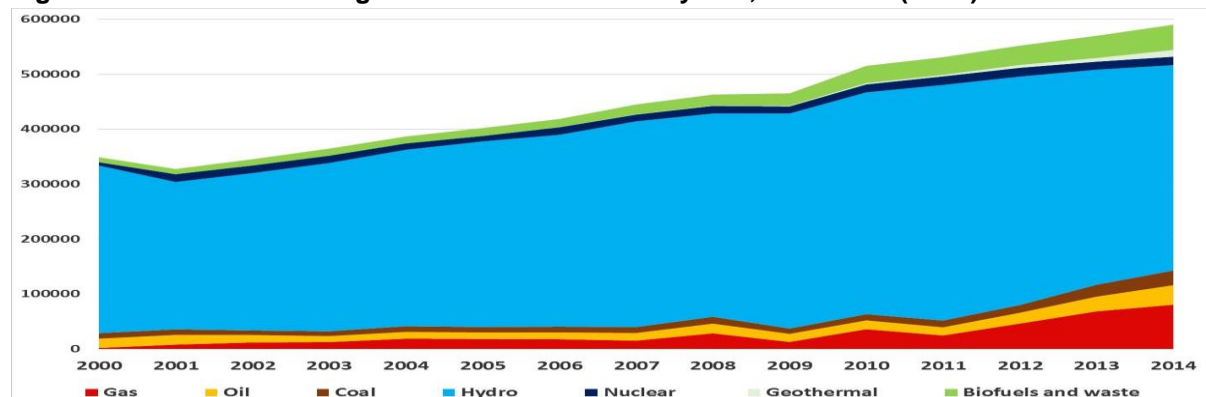
³⁴⁴ IEA (2016b), p.II.169, data for 2014

³⁴⁵ In 2014, the marginal operating cost rose to \$1,126/MWh (three times the 2013 level of \$392.46/MWh). Consequently, even the most costly diesel-fuelled thermal plants were dispatched to meet power demand. Shortly after, electricity imports from Argentina were authorised in order to meet peak-hour demand. Source: Platts International Gas Report, 23 February 2015, Petrobras sets record for LNG

³⁴⁶ IEA (2016b), p.II.169, data for 2014



Figure 50: Evolution of the generation mix in Brazil by fuel, 2000-2014 (GWh)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

In 2014, Brazil had 138.4 GW of installed generation capacity, 62% in the form of large hydro, 18% from other renewable (10% from biomass and waste, 4% small hydro and 4% wind), 9% from natural gas, 7% from oil and diesel, 3% from coal, and 1% from nuclear.³⁴⁷ The gas power plants had an annual average load factor of 74% in 2014³⁴⁸ as gas plants were running on base load to make up for the lack of hydropower generation.

The natural gas industry

Natural gas is a fairly recent addition to the country's energy mix. Before the inauguration of the Bolivia-Brazil (GASBOL) pipeline in July 1999 and the arrival of Bolivian imports, natural gas' share in the TPES never surpassed 4%.³⁴⁹ It became important to develop a gas market once imports added up to 11 bcma of gas to the indigenous production, which was about half that amount at the time, and even more so with additional resources discoveries in the late 1990s and early 2000s.³⁵⁰

In 2001, an acute episode of dry weather conditions lowered hydropower generation dramatically and caused severe power shortages and electricity rationing. In order to alleviate the crisis, the country had to rely on generation capacity that could be build up fairly rapidly. The government decided on an emergency power programme (PPT) which offered lower gas prices for 20 years to power plants commissioned by December 31, 2004.³⁵¹ The consequence was the mass construction of gas-fired stations to back up hydro generation, and in the 2000s, demand for natural gas in power generation rose quickly due to several episodes of severe drought-induced power crisis, under-investment in new hydropower capacity and the increasing use of gas-fired power plants to stabilize the system.

Gas consumption displayed strong growth in all sectors, but the most rapid growth was in the power sector [Figure 51]. From 2012/2013, the country had to face the consequences of the worst drought in more than 80 years, with major impacts on hydropower availability. All idled thermal power plants were restarted to back up hydropower and address the crisis, boosting natural gas demand (and

³⁴⁷ Bloomberg New Energy Finance (2015), p.159

³⁴⁸ Author's calculations

³⁴⁹ MME (2016)

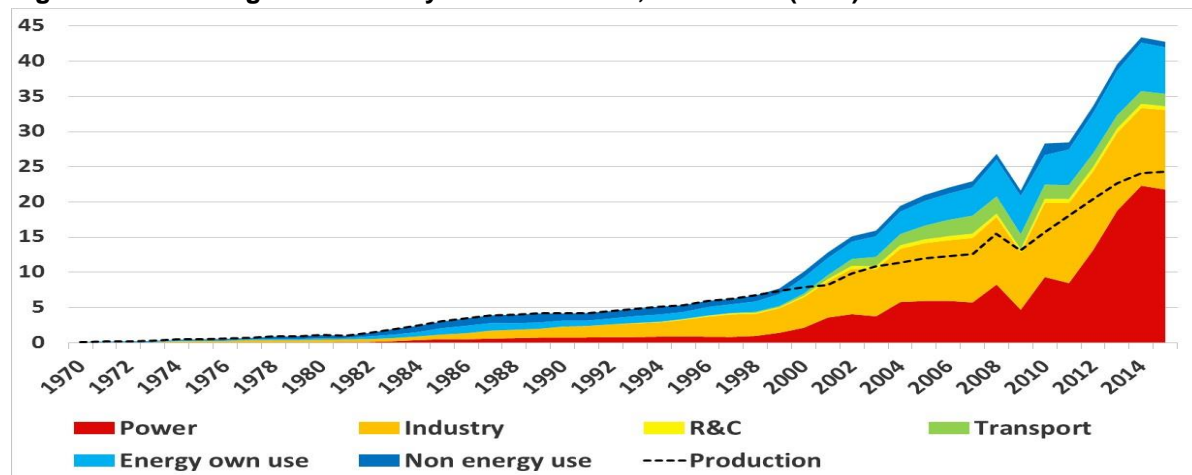
³⁵⁰ The discoveries of the Congoá-Peroá (1997), Manati (2000), Jubarte (2001) and Mexilhão (2003) fields. For more info on this period, see Vilas Boas, M.V. (2004)

³⁵¹ The gap between electricity wholesale prices and the regulated PPT prices contributes to the losses of state owned oil company Petrobras. For more information on the PPT program, see Almeida E., Pinto Jr. H. (2004)



imports of LNG). As a result of high levels of dispatch of the gas-fired plants, for the first time in 2013, gas for power became the biggest consumer of gas (44%³⁵²), before the industrial sector (29%) which has traditionally been the largest consumer thanks to sustained GDP growth in the 2000s. However, industrial demand for gas has stagnated since 2011 owing to gas-price competitiveness and the morose economic situation. The transport sector accounted for an impressive 7% of the total. Brazil has the second largest fleet of CNG vehicles behind Argentina with 1.8 million vehicles (but only about 2% of the total vehicles, due to sugarcane-based ethanol competition). Demand in the residential and commercial sector is limited to less than 2% of the gas. Of the approximately 62.8 million households, only about 2.44 million are served with natural gas.³⁵³ The low penetration can be explained by the mild climate (no need for heating), the lack of urban infrastructure for natural gas, the competition from subsidised LPG, which is more attractive than higher gas prices, and finally the limited transport network to bring the gas to consumption centres with a large part of inland Brazil not supplied at all, although this is (very) slowly improving.³⁵⁴

Figure 51: Natural gas demand by sector in Brazil, 1970-2015 (bcm)



Source: MME data³⁵⁵

Natural gas (marketed³⁵⁶) production is also rising but it has not followed demand growth. More than 70% of gas reserves are associated with oil and produced as a result of oil production. In addition, more than 80% of reserves are located offshore, which makes them more complicated and costly to produce. Natural gas production reached a record high 24.3 bcm in 2015³⁵⁷ due to growing output from the Mexilhão, Uruguá-Tambaú, Sapinhoá and Lula fields, but also improved interconnections between wells and platforms.

After Bolivian imports started in 1999, Brazil began importing natural gas from Argentina in 2000 and finally in the form of LNG in 2009. Natural gas imports covered 47% of needs in 2015 (32.5% from Bolivia and 18% in the form of LNG) as seen in Table 14.³⁵⁸ The 20-year contract between Bolivia and Brazil provides for the import of ToP volumes of 8.7 bcma and a maximum contractual volume of

³⁵² IEA (2015e), p.II.64

³⁵³ Gomes I. (2014a)

³⁵⁴ MME (2015b), p.31

³⁵⁵ MME data, retrieved in June 2016, <http://www.mme.gov.br/web/guest/publicacoes-e-indicadores/balanco-energetico>

³⁵⁶ Only about 65% of gas production is marketed, while the rest is reinjected (to boost oil production), flared (due to the lack of infrastructure to transport the gas from the fields to the market centres) or used as a fuel on the platforms.

³⁵⁷ IEA (2016a), p.II.4

³⁵⁸ MME (2016b), p.2



about 11 bcma.³⁵⁹ YPFB signed an additional temporary supply contract for 0.8 bcma for the Cuiabá gas power plant in Brazil at the end of 2013. The contract had an initial duration of one month but was extended for 2 years. The country also increased its LNG imports since 2012/2013 to supply the additional demand from the power sector.

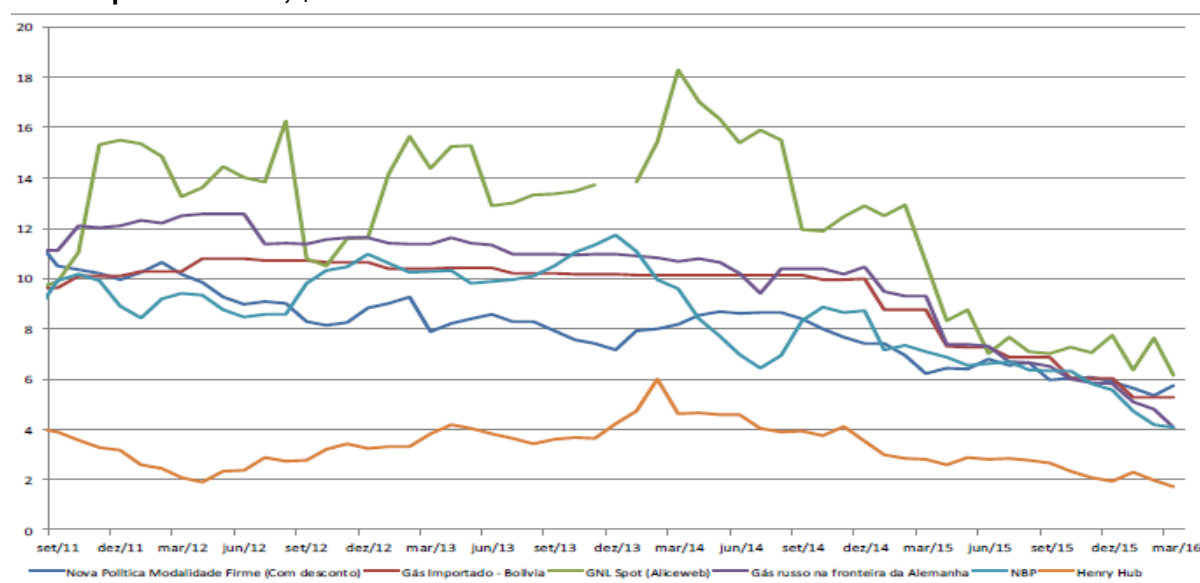
Table 14: Annual natural gas balances in Brazil, 2010-2015 (bcm)

	Production (total)	Supply				Demand
		Production (marketed)	Bolivia	Argentina	LNG	
2010	22.9	10.2	9.8	0.0	2.8	22.5
2011	24.1	12.3	9.8	0.0	0.6	22.4
2012	25.8	14.5	10.0	0.0	3.1	27.4
2013	28.2	17.7	11.6	0.1	5.3	33.3
2014	31.9	19.1	12.0	0.1	7.3	36.2
2015	35.1	19.1	11.7	0.2	6.5	36.0

Source: MME (2013), p.2 and MME (2016), p.2

These imports have had an impact on gas prices in Brazil which are a mix of (cheaper) domestic production plus the price of Bolivian imports indexed against oil prices and the price of LNG bought on the spot market at a price high enough to attract cargoes away from the highest alternative market. Figure 52 below shows the various prices: the dark blue line is for the national price, the red line represents the price of Bolivian gas and the green line is the LNG price to Brazil (the purple line represents the price of gas at the German border, the light blue line is NBP and the orange line is Henry Hub).

Figure 52: Comparison between natural gas prices in Brazil and in the rest of the world, April 2011-September 2015, \$/MMBtu



Source: MME (2016a), p.24

³⁵⁹ 24 mcm/d and 30 mcm/d respectively. Source: "Addendum numero 4 al contrato de compra venta de gas que celebraron, el 16 de agosto de 1996, por una parte Petrobras. y por otra parte", the contract can be found on YPFB website.



Except in the case of PPT plants, end-user prices are not subsidised. All costs, including margins and taxes can be passed through. As a result, end-user gas prices in Brazil are high compared with those in other South American markets. In March 2016, industrial consumers paid between \$11.05 and \$13.1/MMBtu (depending on size of consumption), whereas residential consumers paid \$23.69/MMBtu and commercial consumers paid \$18.9/MMBtu. PPT power plants paid only \$3.8/MMBtu.³⁶⁰ Other gas-fired plants were supplied with LNG and had to pay the price of LNG imports.

As of mid-2016, several gigawatts of thermal plants had been suspended since the beginning of the year based on higher reservoir water levels in southeast/centre-west subsystems (70% of hydroelectric generation potential), lower demand due to the economic recession and additions to generating capacity.³⁶¹ It is interesting to note that during the 2013-2016³⁶² exceptional drought period, the dispatch of thermal power plants was not based on the merit order but on a weekly stochastic calculation done by the national power System National Operator (ONS) that takes into account how much water there is in the reservoirs and, based on demand projections, the probability that there will be enough water to cover power demand in the next 24 months. After some normalization of hydro reservoir levels in the southern and southwestern/centre west subsystems in 2016, the ONS began to use operational costs rather than the availability of hydropower supply to decide the dispatch of thermal plants that were still running in these subsystems. As a result, any plants that could not sell power at or below the spot price would not be able to run, which should trigger some additional closures in 2016. The northern and northeastern subsystems remained low on hydro availability, which translated into sustained LNG imports (84% of the LNG deliveries to Brazil are in January-June).³⁶³

Scenarios up to 2030

- Demand

Scenarios for future natural gas balances in Brazil are particularly complicated to establish. The biggest uncertainty comes from the reliance on hydropower, and the large variations from one year to another due to water levels in reservoirs. Between 2009 and 2015, gas-fired generation surged, increasing gas demand in the power sector from 3 bcm to more than 20 bcm.³⁶⁴ By mid-2016, normalisation of hydropower generation contributed to lower the need for gas-fired power plants in the generation mix. As an illustration of the impact of normalisation of the hydro level on gas/LNG demand, it is worth noting that in January-June 2016, Brazil imported 1.9 mt of LNG, down 45% compared with the same period in 2015 due to hydro level recovery in the southeast/centre-west subsystem.³⁶⁵ Over the same period, thermal output went down from 14.6 GW/h to 9.5 GW/h.³⁶⁶ The recovery in water levels at hydroelectric reservoirs, increase total power generation (including hydro and wind capacity), and declining power demand will continue to normalize the situation in the gas for power sector in the second half of the 2010s.

³⁶⁰ MME (2016b), p.23

³⁶¹ Argus Latin America Energy, 12 July 2016, Impors slide in frist half, p.4

³⁶² As previously stated, it was still ongoing at the time of writing in the North/Northeast region (early 2016)

³⁶³ Argus Latin America Energy, 12 July 2016, Imports slide in first half, p.4

³⁶⁴ IEA (2016c), p.46

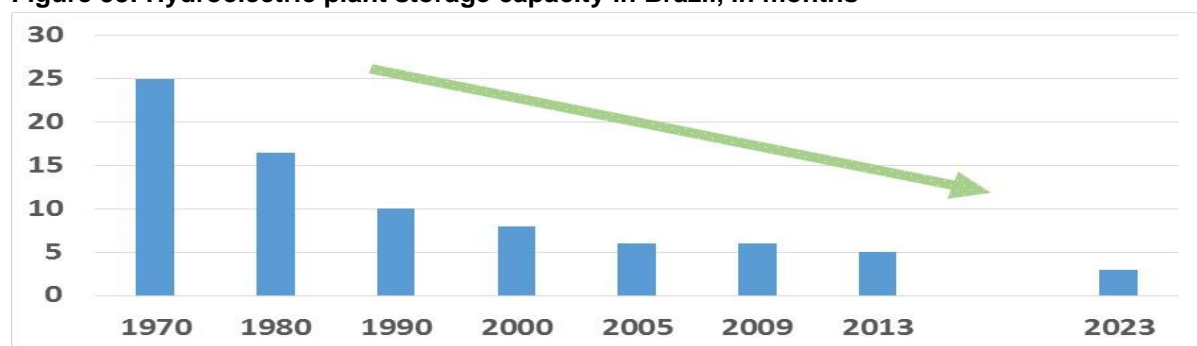
³⁶⁵ Platts LNG data: www.platts.com

³⁶⁶ Operador Nacional do Sistema Elétrico (ONS) data, <http://www.ons.org.br/home/>



What will be the utilisation rate of gas-fired plants in the future is unknown. They may only be called up to back up hydropower during episodes of low reservoir levels, but at the same time, these events could multiply in the future. First, the new hydro projects are highly concentrated, and any delays in one or two of these projects may cause serious problems.³⁶⁷ Second, even if the projects do start on time, they will have smaller reservoirs (most anticipated growth in hydrogeneration will be “run of the river”) as it becomes increasingly difficult to build large reservoir hydroelectric plants due to stricter environmental regulations (most the remaining hydropower resources are in the Amazon region, where large projects will be highly controversial). This has already changed the shape of hydropower generation, with less and less storage available as seen in Figure 53. Smaller reservoirs mean that hydro generation will become more volatile (instead of being assimilated to a firm capacity, as it was the case in the past) and dependent on natural and seasonal variations. Instead of using hydropower to balance the system, thermal power generation will need to fill this role more often in the future. Natural gas-fired generation is already an important source of flexibility, and it is expected that this trend will continue and even develop (in addition to wind in the northeast and bioenergy in the southeast which will also increasingly help to balance the system).

Figure 53: Hydroelectric plant storage capacity in Brazil, in months



Note: Maximum stored electricity (MW) / electricity load (average MW)

Sources: Petrobras, Operador Nacional do Sistema Elétrico (ONS) and Agência Nacional de Energia Elétrica (ANEEL)

The development of wind capacity, which has already reached grid parity with conventional sources,³⁶⁸ and later on of solar will squeeze gas out of the power system at times of high availability and will also reinforce the need for back up capacity in the system (hydropower, bioenergy and natural gas).

The government is expected to encourage the use of natural gas for balancing power generation as part of its new regulatory framework for gas. As Petrobras pulls back from the gas market, Brasilia looks to stimulate investments and competition. In April 2016 auction, 36 gas-fired projects participated but only one won a contract (representing 5.5 MW on a total of 18.7 GW). The requirements for gas-fired plants to participate in an auction act as a barrier for generators, such as the provision that generators must have long term gas supply contracts in place for the duration of their power purchase agreements. At the same time, the already oversupplied market may not need new natural gas fired plants this side of the 2020.³⁶⁹ Finally, the government is considering converting

³⁶⁷ Three projects represent about 76% (more than 21.6 GW) of all hydro projects planned for 2015-2024 (28.3 GW). Source: MME (2015a), p.85

³⁶⁸ Bloomberg New Energy Finance (2015), p.159

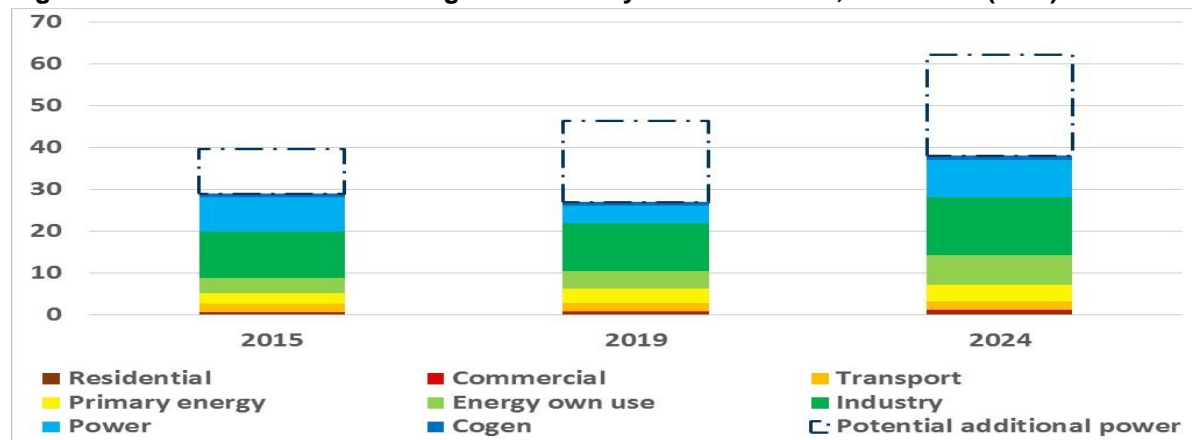
³⁶⁹ Argus Latin America Energy, 6 September 2016, Brazil cool on new gas-fired power generation: AES



diesel and fuel oil-operated power plants to LNG in an effort to reduce operating costs, which will contribute to boost gas for power demand in the future.³⁷⁰

For the reasons explained above (both drivers and constraints to gas for power), it will be more complicated in the future to make gas demand scenarios in Brazil as illustrated by the scenarios published by the Ministry of Mines and Energy (MME) and prepared annually by the EPE, the body that is responsible for forecasting long term energy demand as well as organising auctions for three and five year power capacity and availability. These scenarios show that during wet years, gas for power demand in the period 2015-2024 could be limited to 8-10 bcma under normal weather conditions while possibly shooting up to 30-35 bcma during episodes of dry weather conditions as seen in Figure 54. If we extrapolate these numbers to cover our timeframe, gas for power demand could oscillate between 9.5 bcm and 43 bcma in 2030, depending on water level availability. These wide possibilities will be largely unpredictable more than a few months ahead and are likely to be covered by LNG imports.

Figure 54: EPE scenarios: natural gas demand by sector in Brazil, 2015-2024 (bcm)



Source: MME (2015a), p.51

Natural gas demand in the industrial sector is not expected to increase much in our timeframe. Gas prices have been too high to keep the sector competitive with other parts of the world and the country's economic performance is not showing signs of rapid recovery in 2016/2017.³⁷¹ The effects of lower import prices from Bolivia (indexed on oil prices) and lower LNG prices until the early 2020s on national gas demand are expected to be limited as these will be happening after the end of price discounts by Petrobras in late 2015.³⁷² Some limited growth is expected later in the 2020s, tracking the economic cycle. Some growth could come from developing the network and adding some industrial and residential and commercial customers. However, due to the size of the country, its geographical specificities (Amazonian forest) and the already well developed electricity network, it may make more sense to develop the gas-by-wire option rather than the pipeline network.

In the transport sector, the outlook is uncertain too. Gas prices are sold at a discount to gasoline, but low oil prices are not a strong incentive to convert to CNG. A modest growth is expected and it will

³⁷⁰ Argus, 10 February 2015, Brazil resumes LNG imports through Argentina. Note: If this happens, it would increase gas demand for power by a maximum of about 5 bcm in years like 2014 (author's calculations).

³⁷¹ IMF (2016)

³⁷² There has been a 20% reduction on the gas prices since 2011 as part of fuel subsidies. Source: Abegas, 18 September 2015, Fim de desconto tira competitividade do gás



depend on government support due to the abundance and cost competitiveness of sugar cane-based ethanol and also on gas availability.³⁷³

Natural gas demand in Brazil is also hindered by a lack of infrastructure. Low populated areas are not covered by the grid, and most onshore pipelines are located near the coasts in populated areas but far from large deposits.

Finally, the economic recession in the mid-2010s will also have an impact, especially on the industrial and power sectors. The economy is expected to recover up to 2020,³⁷⁴ but gas demand is likely to only start to grow again post 2020, and the outlook will be lower than previously envisaged as we expect a mix of energy saving measures and growth of renewables to limit gas demand. Finally, at the time of writing, it was yet unclear how the corruption scandal at Petrobras³⁷⁵ and the prolonged political crisis³⁷⁶ would impact the energy sector and investments along the chain in the longer run.

All these uncertainties and specificities make it difficult to produce scenarios. The Energy Matrix for 2030 on the MME website is useless because it dates back to 2007, before the pre-salt findings.³⁷⁷ The EPE proposes scenarios but the ones published in 2015 only go as far as 2024. The IEA comes up with confusing scenarios too. In its Medium Term Outlook 2015, gas demand in 2020 reaches 44.5 bcm (higher than 2014), while in the World Energy Outlook 2015, it only goes to 37 bcm in 2020 (lower than in 2014). The WEO gives 51 bcm for 2030.³⁷⁸ In this paper, we take the WEO 2015 scenarios: 37 bcm in 2020 and 51 bcm in 2030.³⁷⁹ The latter is also close to Petrobras' expectations as shown in its 2030 Strategic Plan.³⁸⁰

- Production

The great potential for additional gas supplies in the short term lies in the still largely unexploited presalt areas. In 2007, a consortium of oil companies (Petrobras, BG and Petrogal) made an important discovery in the Santos Basin off the coast of Brazil. First production began in and around the field in 2008, and additional exploration confirmed hydrocarbon deposits in the presalt areas of the Santos, Campos, and Espirito Santo basins. Exploration and development of the presalt layer is still

³⁷³ IEA (2015d), p.51

³⁷⁴ IMF (2016)

³⁷⁵ High ranking politicians in president Rousseff's PT party and political allies have allegedly received illicit payments through inflated Petrobras contracts (but Rousseff is not under investigation for corruption at Petrobras, which she chaired in 2003-10). Petrobras is already a highly indebted company and in order to try and recover some control of its heavy debt, the company was looking to sell \$14.4 billion worth of assets in 2016, but the political uncertainty has complicated the situation and makes it difficult for the company to finalise negotiations.

³⁷⁶ On 17 April 2016, the lower House of Congress voted to open impeachment proceedings against President Dilma Rousseff following claims that Rousseff breached fiscal laws by using state-run banks to cover spending gaps in 2013-2014 (i.e. ahead of her re-election in October 2014), claims that she denies. Additionally, separate requests have been filed at Brazil's Supreme Court to open inquiries into president Rousseff and her predecessor Luiz Inacio Lula da Silva based on claims that they tried to influence the investigation into the Petrobras corruption scandal to protect politicians linked to the scheme. On 31 August 2016, the senate voted by 61 to 20 to remove her from office and former vice-president, Michel Temer, who had been interim president since May, was sworn in to serve out the remaining 28 months of her term. Sources: Argus Latin America, 10 May 2016, Rousseff ensnared in Petrobras probe, p.1 ; The Economist, 3 September 2016, Time for Temer, The new president takes over a country in crisis

³⁷⁷ MME (2007)

³⁷⁸ The scenarios published in the WEO 2015 are also much lower than in the WEO 2014, probably taking into account the grimmer picture of the economy and Petrobras' situation.

³⁷⁹ IEA (2015c), tables with New Policy Scenarios

³⁸⁰ Assumptions on Brent Prices: \$ 105 in 2014, declining to \$ 100 by 2017 and to \$ 95 in the long term. Source: Petrobras, 29 June 2015, 2015-2019 Business and Management Plan, Press Conference



at the beginning, but natural gas production has been rising rapidly and represented about 35% of total gas production in mid-2016, up from 30% in 2015, about 15% in 2013 and 0.5% in just 2008.³⁸¹

The challenges facing the pre-salt region to develop its hydrocarbon production are important. First, the specific geological location is complex. The reservoirs are found 5,000 and 6,000 metres below the sea level, in ultra-deep water (1,900 m to 2,400 m) under thick layers of salt (up to 2,000 metres in some places).³⁸² This poses logistical problems, such as the transport of people and of the materials for instance. The ultra-deep water environment also means that special pipes are needed. The drilling is extremely difficult with low penetration rates. In addition, the pre-salt areas are a highly corrosive environment with significant amounts of carbon dioxide (CO₂) and hydrogen sulfide (H₂S). A special cement and metallurgy will be necessary throughout the drilling and completion phase. The reservoirs themselves are described as complex heterogeneous layered carbonates, which makes accurate reservoir characterization very challenging. Finally, two sub-sea pipelines to transport presalt gas from the offshore Campos and Santos basins have been built but gas transport plans scheduled for 2020 face delays following the shift of focus of Petrobras to oil production. Reinjection, which already represented about 44% in the Santos basin by mid-2016 is expected to continue to rise in the future to maintain reservoir pressure.³⁸³

Petrobras still enjoys a de facto monopoly along the gas chain, even if its legal monopoly ended with the 1997 Petroleum Law³⁸⁴ and the 2009 Gas Law³⁸⁵ that followed. Many private and state-controlled companies have been allowed to explore, produce, transport and distribute, import and export hydrocarbons, build LNG terminals and gas-fired plants,³⁸⁶ but Petrobras has been the sole operator of all presalt blocks with a minimum stake of 30%.³⁸⁷ In addition to regulatory constraints, the ability to attract investment and develop the presalt reserves will also be impacted by the political situation. President Dilma Rousseff was suspended on May 2016 for impeachment proceedings, which ended on August 31 with a vote from the Senate to remove her from power. Interim president Michel Temer had announced plans for more pro-market political and economic measures when he took over in May. As president, it is believed that he will carry on a pro-market agenda and intends to renew investors' interests in Brazil's oil and gas sector which accounts for 15% of the country's GDP.

One of the key proposals that would allow companies other than Petrobras to operate presalt projects had already been passed by the Senate, and in October 2016, the chamber of deputies voted to approve the bill. After a vote on amendments, president Temer will receive the bill and is expected to pass the legislation. Under the proposal, Petrobras would still have the right of first refusal to operate presalt areas,³⁸⁸ but this reform would be a key driver to encourage investments from foreign companies that have shown interest in the presalt potential as already seen with Shell's takeover of BG, a move that made Shell the leading foreign operator in Brazil, and also with Statoil's acquisition of 66% of Petrobras' operating stake in a deep-water presalt area in the Santos Basin.³⁸⁹

³⁸¹ MME, Boletim Mensal de Acompanhamento da Indústria de Gás Natural, several reports

³⁸² See Map 4

³⁸³ Argus Latin America Energy, 2 August 2016, Energy ministry plans new gas framework

³⁸⁴ Congresso nacional (1997)

³⁸⁵ Câmara Dos Deputados (2009)

³⁸⁶ Gomes I. (2014a)

³⁸⁷ After the significant discoveries in the pre-salt areas in 2008, Lula's administration then halted auctions of blocks in these areas. A new investment regime for unlicensed pre-salt acreage was designed: the reform made Petrobras the operator of all pre-salt projects, limited private and foreign participation in new E&P projects to less than 50%, created a separate state entity to oversee the basins, and increased domestic content requirements. Source: Mares D. (2012)

³⁸⁸ Argus Latin America Energy, 11 October 2016, Petrobras close to shedding sub-salt yoke

³⁸⁹ Argus Latin America Energy, 31 August 2016, Temer looks to revive oil and gas sector



Increasing presalt production remains Petrobras' priority in its 2017-2021 business plan, with presalt spending accounting for 2/3 of upstream investments (and the rest allocated at postsalt projects in the Campos Basin).³⁹⁰ A highly indebted Petrobras, entangled in a massive corruption scandal, is believed to lack the financial capability to develop all the new presalt projects. Its capex plans have been revised downward several times since 2015³⁹¹ as the company intends to reduce its role in the gas industry, especially in midstream and downstream segments and its financial difficulties may still cause delays in the exploration and development of new reserves. This provision would enable the industry to move forward by attracting investment to the country and avoid further disruption in the development of the presalt areas.

Additional governmental reforms to create a new regulatory framework for the natural gas industry were envisaged while, at the same time, oil producing provinces were considering new taxes to cover budget deficits due to lower oil prices and investment cuts from Petrobras,³⁹² making it very difficult for investors to plan for the long term. It was too soon at the time of writing to judge the impacts of these ongoing changes and political uncertainties on future indigenous gas production. One thing is certain, Brazil will face major competition from other parts of the world to attract shrinking investment potential into its potentially great but high cost -and technically challenging- oil and gas presalt regions.

In addition to conventional gas resources, Brazil has also large shale gas reserves (the 10th largest in the world according to the EIA). However, these are located in areas with no gas transportation infrastructure and very far from demand. Some are also in environmental conservation areas and hydroelectric reservoirs, which means that it would be difficult to obtain environmental permits. Interest in shale gas development has been scarce, especially after the discovery of the pre-salt potential.

All in all, given the large resources of associated gas in the presalt and other onshore resources (both associated and non-associated resources, and both conventional and unconventional), there is some potential for additional gas production in Brazil. However, there is important uncertainty about the pace of these developments. The outlook remains positive (thanks to investments already made) albeit lower than previously expected. Future production will depend on the recovery of the world oil price, Petrobras' ongoing legal and financial challenges,³⁹³ and change in the policies to allow private companies a wider participation of in the presalt and to support onshore upstream investments.³⁹⁴ Uncertainty over gas reinjection volumes and the quality of presalt gas are also important factors of doubt for future (marketed) production in our timeframe. For all these reasons, our scenarios are lower than expected in the IEA World Energy Outlook 2015 scenarios: 26 bcm in 2020 (28 bcm in the WEO) and 45 bcm in 2030 (59 bcm in the WEO).³⁹⁵

³⁹⁰ Financial Times, 29 June 2015, Petrobras slashes investment to cut debt

³⁹¹ Reuters, 1 March 2016, Exclusive: Petrobras to cut five-year investment plan one-fifth to \$80 billion

³⁹² Petrobras reduced planned investments from \$130.3 billion to \$98.4 billion between 2015 and 2019 in January 2016, with planned 2016 investments of \$17.5 billion versus \$27 billion expected a year earlier. Sources: Financial Times, 12 January 2016, Petrobras cuts 5-year investment budget 25

³⁹³ Corruption scandal involving former Petrobras executives ("Operation Car Wash" scandal), construction companies and politicians and high debt presented in Petrobras' 2015 audit. For more information, see Financial Times, 23 April 2015, Brazil's Petrobras takes \$17 billion hit

³⁹⁴ The upstream sector has been opened to private companies since the mid-1990s, but Petrobras is still the dominant company in oil and gas production.

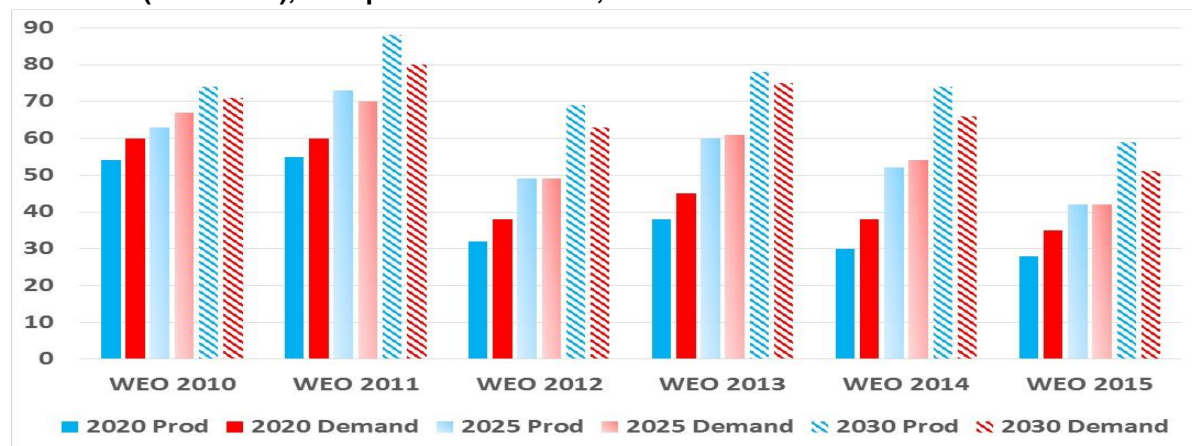
³⁹⁵ IEA (2015c), p.206



- Balances

All these conflicting factors complicate the scenarios, which may vary greatly if any or several changes happen. For example, we show below in Figure 55 the IEA scenarios published in its annual WEO series over the period 2010-2015 at the horizons 2020, 2025 and 2030.

Figure 55: Natural gas demand and production in Brazil for 2020-2025-2030 in the IEA scenarios (2010-2015), New policies scenarios, bcm

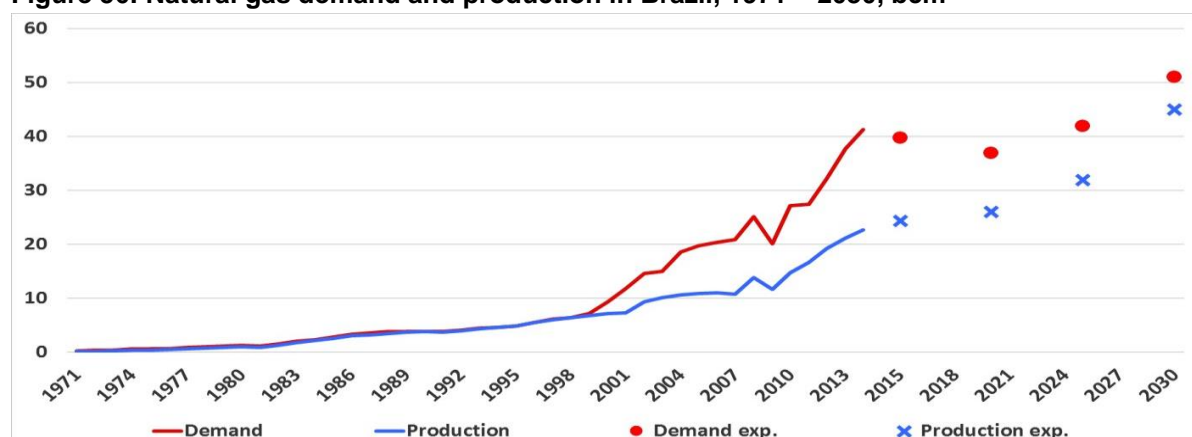


Source: IEA, World Energy Outlook 2010 to 2015, Chapters on Natural Gas Market Outlook

By 2015, expectations on both additional demand and production were significantly lower than in previous years, reflecting the economic and political situation in the country as well as the impact of global lower oil prices. Expectations for 2020 show demand still higher than production, while the market balances by 2025 thanks to a more rapid growth of production compared to consumption. This trend continues in the rest of the decade and the market turns to a surplus of almost 10 bcm of gas in 2030.

Our scenarios are more cautious on gas production and, as a result, Brazil does not show a surplus in the timeframe considered [Figure 56] but a continuous need for gas imports, albeit a declining one.

Figure 56: Natural gas demand and production in Brazil, 1971 – 2030, bcm



Sources:

1971-2015: IEA, Natural gas information, various reports

2016-2030: Author's estimates



What future role for LNG?

The Pecém LNG terminal, the first world floating storage and regasification terminal (FSRU),³⁹⁶ was developed by Petrobras and opened in mid-2008 with 5 bcma of capacity. The first LNG cargo was delivered the same year. The second LNG terminal, the Guanabara Bay FSRU terminal in Rio de Janeiro, opened in January 2009, with an initial capacity of 2.5 bcma, later increased to 7.2 bcma. The third (Bahia) LNG terminal (2.5 bcma), is located in the northeast and started in early 2014. As of 2016, Brazil had a regasification capacity of about 15 bcma. Petrobras was the operator and the only user of these terminals (there is no requirement for third-party access to these terminals), but had expressed interest in leasing out capacity.³⁹⁷ In addition, in June 2016, Petrobras announced a “competitive process” to sell two of its three LNG regas terminals (Guanabara and Pecem) and the associated power plants (with a total capacity of 2.2 GW) as part of its two-year and \$15.1 billion asset sale program to reduce its enormous debt (the largest debt load in the oil industry).³⁹⁸

LNG is mostly used to deal with peaks in gas demand, which does not display the traditional winter/summer seasonality like in Argentina as a result of the low penetration in the residential and commercial market, but is extremely variable due to the power sector. Because most gas production is associated with oil, there is very limited flexibility in the indigenous gas supply system. The import contract with Bolivia offers a TOP clause,³⁹⁹ but the deliveries are rather flat all through the year as seen in Figure 57. Pipeline imports are therefore not well suited to react to changes in gas demand, especially the surge in power demand. There is also no storage capacity in Brazil that could help to cope with demand variations. As a result, the country will continue to need LNG for flexible supply at times of high gas-for-power demand even if the unpredictable consumption of the power sector makes it difficult for private generators to develop independent projects and secure long-term gas supplies.⁴⁰⁰

Some investors have nonetheless expressed interest in building LNG for power projects, encouraged by low LNG prices expected in the second half of the 2010s. Brazil’s Bolognesi Group plans to install two LNG receiving terminals and two associated power plants with more than 2,400MW of total generating capacity.⁴⁰¹ The two new regasification terminals would be the first in Brazil not be owned by Petrobras. Each FSRU are expected to have regasification capacity of 5.1 bcma, of which 2.2 bcma would be used to fuel the plants. The remainder of the LNG could be sold to local industries. The starting date for the terminals was to be in the first half of 2018. The gas-fired plant projects gained 25-year power purchase agreement (PPA) in the 2013 and 2014 power auctions, which means that the projects will have to be ready to generate by 2019 and 2020. However, the plants are

³⁹⁶ Golar LNG Energy (2009)

³⁹⁷ Argus Global LNG, March 2016, Brazil supply deal to help break Petrobras monopoly

³⁹⁸ The power plants have long term power purchase agreements indexed against US Henry Hub gas prices, which could become a serious problem for investors at times of high LNG spot prices, which must be paid to attract the LNG to Brazil. Source: Argus Latin America Energy, 14 June 2016, Petrobras starts terminal sale

³⁹⁹ The take-or pay level is at 80% of the maximum contracted volume but limited to 90% of annual contracted volume. The contract can be found on the YPFB website (retrieved in 2015).

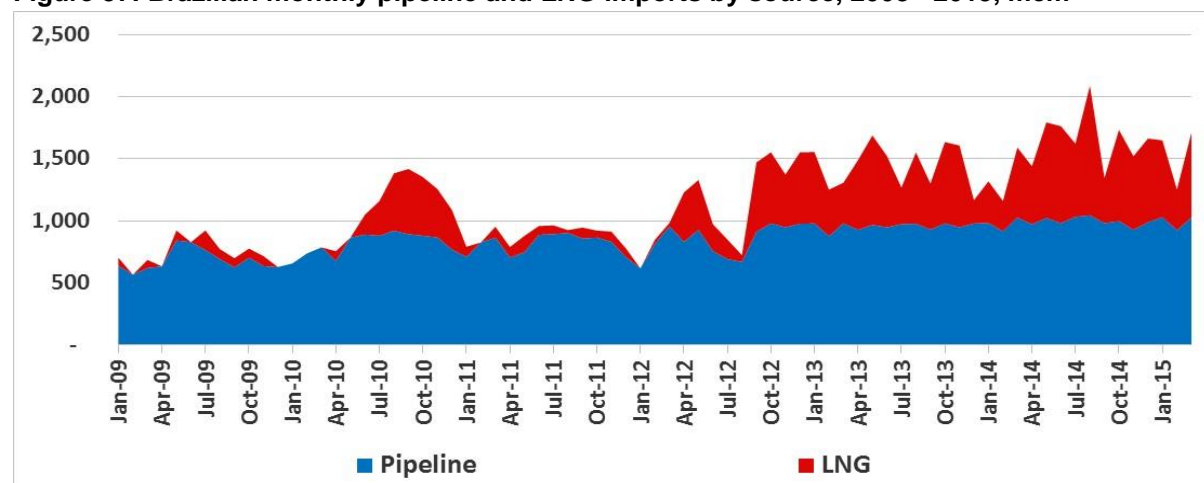
⁴⁰⁰ To qualify to participate in the auction, gas projects require to present 25-year gas supply agreements and to demonstrate that the gas supplier possesses reserves that will meet the 25-year supply obligation; the latter doesn’t fit well with LNG portfolio suppliers which source LNG from various projects. As of 2016, Petrobras was the only company importing and selling LNG in Brazil.

⁴⁰¹ Brazilain company Bolognesi plans to install the Novo Tempo plant in the north eastern state of Pernambuco (1,238 MW) and the UTERG plant in Rio Grande do Sul state in the south (1,238 MW). Source: Argus, 28 November 2014, Bolognesi to build two LNG terminals in Brazil



likely to be delayed.⁴⁰² By October 2016, the plants had not received the necessary permits and construction had not started, which made it unlikely to be completed on schedule. As a result, Brazil's electricity regulator ANEEL had started to revoke the licences for the two plants, which would lead to the suspension of the PPAs won at an auction in November 2014.⁴⁰³ Genpoweris is also looking to develop an LNG/power project with a 2.6 bcma regas terminal due to start of operations in 2020.⁴⁰⁴ The Brazilian natural gas distributor Comgas was also working with the Sao Paulo state government to develop a 5.8 bcma LNG terminal in the port of Santos or Sao Sebastiao.⁴⁰⁵ French company Engie was considering the option of an LNG terminal in Espirito Santo. The project would start operating in 2018 with a capacity of 0.7 bcma, providing feedstock to two power plants. Environmental licenses are believed to have been secured.⁴⁰⁶ By mid-2016, two additional projects had been suggested: Golar LNG presented a project to the state of Para in the Amazon basin to provide LNG to areas with no access to the natural gas grid and another terminal has been proposed at Porto Central in the Southern State of Espirito Santo, and would supply two CCGTs.⁴⁰⁷

Figure 57: Brazilian monthly pipeline and LNG imports by source, 2008 - 2015, mcm



Sources: YPFB, Boletín Estadístico Gestión, several issues and Platts, LNG data

The lack of a countrywide national transmission system (networks are located mainly in the south-east and the north-east regions) also adds additional value to importing LNG to regions not connected to the network but which need to supply their growing energy demand.

Provided the weather normalises and hydropower generation gets back to traditional levels, our scenarios show a gap between demand and production of about 11 bcm in 2020 and 6 bcm in 2030 (in a normal year). Imports could come from an extension of the existing contract from Bolivia.⁴⁰⁸ Preliminary discussions for contract renewal started in 2015.⁴⁰⁹ Petrobras signalled that it would try to

⁴⁰² Bolognesi Energia has requested a postponement for the start date of the gas-fired power plants due to delays in receiving the necessary environmental permits. Source: Argus Latin America Energy, 17 May 2016, Bolognesi to delay LNG power projects

⁴⁰³ Argus Latin America Energy, 18 October 2016, Eletrobras faces further write-downs

⁴⁰⁴ The project won a 25-year PPA in 2015 for a 1.5 GW power plant to be located in Santo Amaro das Brotas, in the state of Sergipe. Source: Argus, 30 April 2015, LNG power project among Brazil auction winners

⁴⁰⁵ Argus, 7 May 2015, Another Brazilian firm eyes LNG import option

⁴⁰⁶ There is also another plan for a terminal at Acu Port in the state of Rio de Janeiro (5.5 bcma). Source: Argus Latin America LNG, 21 June 2015, Engie looks to deepen presence

⁴⁰⁷ Argus Global LNG, June 2016, Investors mull new Brazil regasification projects

⁴⁰⁸ The 20-year supply contract (11 bcm) expires in 2019. The contract can be found on the YPFB website.

⁴⁰⁹ Argus, 11 December 2015, Bolivia, Brazil start talks to renew gas supply



reduce the volumes of gas contracted to take under the new agreement by up to 50% (Brazil imports a minimum of 24 mcm/d and a maximum of 30.1 mcm/d).⁴¹⁰ There is uncertainty about the future level of production in Bolivia and consequently, on the available gas volumes for exports from Bolivia. If Bolivia cannot renew the contract (and/or send any gas to Brazil post 2019⁴¹¹), then imports will be in the form of LNG. If Bolivia can deliver the gas at prices competitive (with low LNG prices), then the volume of LNG imports will be limited during periods with normal water reservoir levels. However, as explained earlier, fluctuations from hydropower availability are expected to rise in the future, as well as the need to back up rising wind generation, and therefore, looking ahead, LNG imports will continue to be important to offer flexibility and stability to the system. Large month-to-month and year-to-year variations are to be expected, with differences of gas for power demand from 8-10 bcm during wet years but as high as 40-45 bcm during dry years in 2030, and these variations will have to be covered by LNG (directly from imports from Brazil's terminals or regasified LNG from Chile and even from Uruguay later on).

⁴¹⁰ Argus Latin America Energy, 2 August 2016, Brazil steps up Bolivia gas talks

⁴¹¹ Without major investment in new exploration in Bolivia, there is a risk that the country will be unable to meet its export commitments to Brazil and Argentina and also supply its own demand. Once the Bolivia-Brazil contract expires in 2019, Argentina will have priority over Brazil.

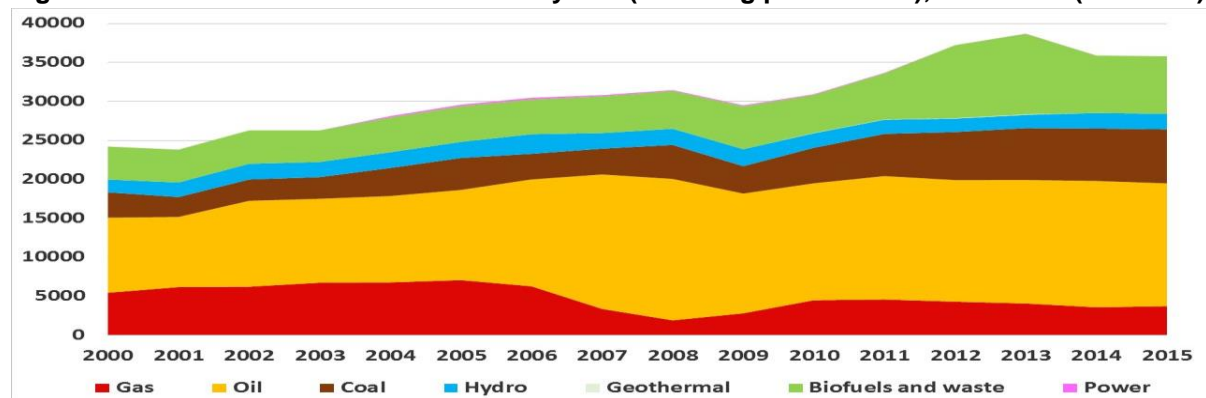


Chile

Overview of the energy market

Following the cuts in exports from Argentina in the mid-2000s, Chile turned to oil products but also coal and renewables to replace natural gas. This explains the sharp decline during 2007-2009 until LNG imports started, as seen below in Figure 58. The TPES is still heavily reliant on oil (44%⁴¹²). Biofuels and waste make up about 20% of the total, followed by coal (19%) and natural gas (10.3%). Despite developing two LNG terminals, the energy sector moved towards cheaper coal in the early 2010s to diversify its primary supply, which explains the relatively high share of coal in the mix compared to the rest of South America. New coal projects have faced increasing local opposition on environmental grounds⁴¹³ and the coal expansion is expected to slow down in the future.

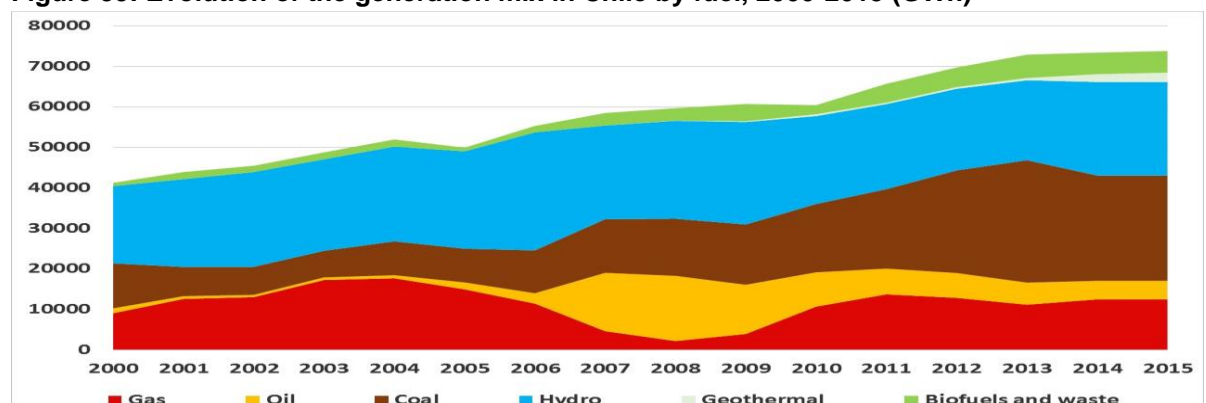
Figure 58: Evolution of the TPES in Chile by fuel (including power trade), 2000-2015 ('1000Toe)



Source: IEA, Energy Balances of OECD Countries, Editions 2003 to 2016, Individual country tables

In power generation, Argentina export cuts also had major impacts as seen in Figure 59. Chile first turned to oil and then to cheaper coal. In 2015, coal was the largest contributor with 35% of the mix, although declining since 2013 to allow for higher hydro, which made up about 31%. Natural gas only represented 17% of the total, still lower than its potential.

Figure 59: Evolution of the generation mix in Chile by fuel, 2000-2015 (GWh)



Source: IEA, Energy Balances of OECD Countries, Editions 2003 to 2016, Individual country tables

⁴¹² IEA (2016b), p.II.52, data for 2015

⁴¹³ Platts International Gas Report, 21 April 2014, Chilean market 'uncompetitive'



In 2014, Chile had 19.2 GW of installed generation capacity, 29% in the form of large hydro, 21% from natural gas, 21% from coal, 15% from oil and diesel, 13% from other renewables (4% small hydro, 4% wind, 3% solar, 2% biomass and waste) and 1% other fossil fuels.⁴¹⁴ The gas-power plants had an annual average load factor of 36% in 2014,⁴¹⁵ which leaves some room to produce more electricity from existing gas-fired plants if natural gas supply challenges can be overcome.⁴¹⁶

The natural gas industry

Contrary to most countries in South America, Chile has limited fossil energy resources. The country has some gas reserves, but located in the far south of the Magallanes Basin, far from demand centres. As a result, the development of the natural gas industry has been based on imported natural gas from Argentina (and later from LNG).

The country started importing gas from Argentina - which at the time had abundant production available at relatively low prices- in 1996⁴¹⁷ via seven pipelines (all built between 1996 and 1999). Natural gas demand increased very rapidly in the central part of the country and imports grew until 2004 when Argentina started to restrict natural gas exports to supply its own market.⁴¹⁸ The imports were gradually curtailed (from 5.2 bcm in 2004 to about 0.6 bcm in 2008), which caused important economic problems for the industry sector and electricity generators which had no alternative sources of gas imports.

The Argentine price of gas at the Chilean border seems to have been the addition of the price of gas at the wellhead, legal fees and transport to the border. The gas was relatively cheap and competitive with other fuels, including coal in power generation. In 2004, at the beginning of the Argentine crisis, a natural gas export tax of 20% was added. In 2006, following the signature of the long-term contract between Argentina and Bolivia, Argentina passed on the 40% increase of the gas price it imported from Bolivia to its own exports to Chile, Uruguay and Brazil⁴¹⁹ by doubling its tax on natural gas exports.⁴²⁰ As a result, in addition to being scarce, Argentine gas also became more expensive.

Despite being a neighbour country to net exporters Peru and Bolivia, the centres of consumption in the north and the south of Chile are still quite far away from gas reserves. In addition, diplomatic relations between these three countries are difficult to non-existent following unresolved territorial disputes during the Pacific war in the 19th century. These reasons prevented any gas to flow to Chile from these two net gas exporters, and the country had to resort to alternative fuels, such as coal and more expensive liquid fuels in order to meet its national demand.⁴²¹ Chile also decided to look for other sources of secure natural gas supply and built two regas terminals. LNG imports enabled

⁴¹⁴ Bloomberg New Energy Finance (2015), p.163

⁴¹⁵ Author's calculations

⁴¹⁶ Author's calculations from data on capacity from Bloomberg New Energy Finance (2015)

⁴¹⁷ Chile signed an economic agreement with Argentina in 1991 and added the Protocol N.15 relative to the regulation of natural gas interconnections and supplies in July 1995. Twenty-five export permits were authorized for a total volume of 34 million cm/d. Sources: Sistema de información sobre comercio exterior (1991); Sistema de información sobre comercio exterior (1995); Ministra de Minería y Energía (2006), p.1

⁴¹⁸ See Honoré (2004) for more details on the Argentine gas crisis

⁴¹⁹ Except for exports from Tierra del Fuego (about 3.4 mcm/d). Source: Ministra de Minería y Energía (2006), p.3

⁴²⁰ Bloomberg, 25 July 2006, Argentina doubles tax on natural gas exports to Chile

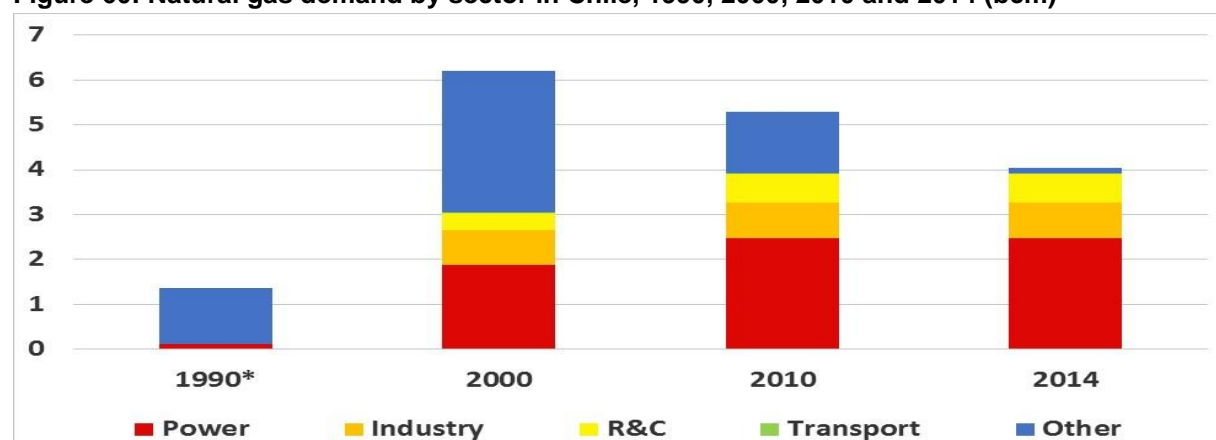
⁴²¹ IEA (2011b)



natural gas to recover part of its market share lost to diesel oil and other fuels and gas demand grew from 2.7 bcm in 2008 to 4.8 bcm in 2015.⁴²²

While natural gas does not play a major role in electricity generation, the power sector accounts for about 61%⁴²³ of the gas used as shown below in Figure 60 as new gas-fired plants with high efficiency gradually replace old and polluting oil-fired and coal-fired power plants. The residential sector is increasing (16%), but with only about 25% of the population covered, there is room for additional demand to be fulfilled if or when secure and affordable gas supply becomes available.⁴²⁴ Despite cold temperatures in winter in the south of the country, gas demand does not display an obvious seasonal pattern due to limited coverage in the residential and commercial sector. Consumption growth in the industrial sector (20%) has been slow probably due to high gas prices in the internal market which are the LNG import prices, except in the region of Magallanes, where prices are regulated.⁴²⁵

Figure 60: Natural gas demand by sector in Chile, 1990, 2000, 2010 and 2014 (bcm)



Source: IEA (1993), IEA (2003a), IEA (2012), IEA (2016b), Individual country tables

Scenarios up to 2030

- Demand

Chile is dependent on LNG imports to fulfil 100% of its gas needs and about two thirds of its energy needs.⁴²⁶ It is highly exposed to gas price volatility on international markets and to possible shortfalls in supply due to market imbalances, political events or climate change.⁴²⁷ Nonetheless gas is needed to develop the economy and diversify away from more expensive imported oil products. Natural gas demand has still not recovered from the crisis with Argentina, and there is much room for additional gas consumption from new gas-fired power plants but also from the residential and commercial and the industrial sectors.

⁴²² IEA (2016a)

⁴²³ IEA (2016b), p.II.51, data for 2014

⁴²⁴ Ministerio de Energía (2014), p.15

⁴²⁵ Ministerio de Energía (2014), p.34

⁴²⁶ Data from Energía Abierta website, data from Balance Nacional de Energía: <http://energiaabierta.cne.cl/balance-energetico/>

⁴²⁷ Ministerio de Energía (2014), p.12



The government's Energy Plan Strategy published in 2014, which focuses on 2015-2019 (but also sets longer term targets), strongly promotes the use of LNG in power generation as new gas-fired generation capacity comes on line in order to feed growing power demand, substitute gas for diesel and coal and also to be used in conjunction with the growing capacity of intermittent and unpredictable renewable energies (solar & wind).⁴²⁸

Gas demand for the power sector could increase rapidly in the short term as the country already has significant idle gas-fired installed capacity, the legacy of cheap Argentine imports in the early 2000s, and replacing the existing oil-fired power plants by gas-fired plants in the mix could create an additional gas demand of about 1.2 bcma (data for 2014) and 6.7 bcma of additional natural gas to replace coal plants.⁴²⁹ Examples of measures implemented to date include promoting ENAP's offer to generators for greater gas volumes from the Quintero terminal and supporting new private gas-fired generation projects. Chile has implemented a tax of \$5/t of CO₂ equivalent on coal-fired generation over 50 MW, which will likely promote the use of natural gas compared to coal.⁴³⁰ In the longer term, delays to get environmental approval and cancellations of new coal-fired and hydroelectric projects will leave room for other fuels in the mix: natural gas but also renewables, especially wind power as seen in the 2016 auctions. In August 2016, the largest-ever auction for long-term electricity supply was dominated by renewables and only one conventional generator was successful. The average price of the awards fell to \$47.552/MWh, too low a price to cover the cost of LNG or even coal. These developments are in line with National Strategy for the Energy Sector published in February 2012. The document repeats the target of (minimum) 10% of electricity from non-conventional renewable sources by 2024 as stated in Law 20257, but it also add a target of 45% to 48% for hydroelectricity, limiting the share for thermoelectric plants to a maximum of 45%.⁴³¹ As a result, natural gas will be more and more in competition with renewable energies in the future, but (new) gas-fired plants will also be needed to back up these intermittent sources.

Gas demand is expected to grow in the industrial sector as copper mining projects expand in Northern Chile and also in the residential sector. However, economic growth expectations have been cut for 2016-2017, which is likely to slow gas demand growth in all sectors. The central bank scenarios for GDP growth oscillated between 1.25% and 2.25% for 2016, with a small recovery the following year to 2-3% growth.⁴³²

- Production

Unconventional gas resources have also been discovered in the same Basin where conventional natural gas reserves are in decline, especially in southern Chile. State-owned oil company Enap is expanding unconventional drilling. Boosting domestic gas production is among the main objectives of Enap's strategic plan, but whether it will make a difference in the rest of the country is uncertain.⁴³³ Following the traditional approach to the economy, the government is leaving development of its shale gas potential to the market.⁴³⁴

⁴²⁸ Ministerio de Energía (2014), pp.36-38,

⁴²⁹ Author's estimates

⁴³⁰ Argus Latin America Energy, 31 August 2016, Colombia develops carbon tax plans, p.11

⁴³¹ Ministerio de Energía (2012), p.12

Note: Law 20257 (Non-Conventional Renewable Energy Law was enacted on 1 April 2008). The quota came into force at the start of 2010, and until 2014 required 5% of electricity to come from non-conventional renewable energy sources. Starting from 2015, the obligation was increased by 0.5% annually, reaching 10% in 2024.

⁴³² Argus Latin America Energy, 24 May 2016, CNE trims auction call, p.7

⁴³³ Argus News, 16 June 2015, Enap steps up tight gas drilling in southern Chile

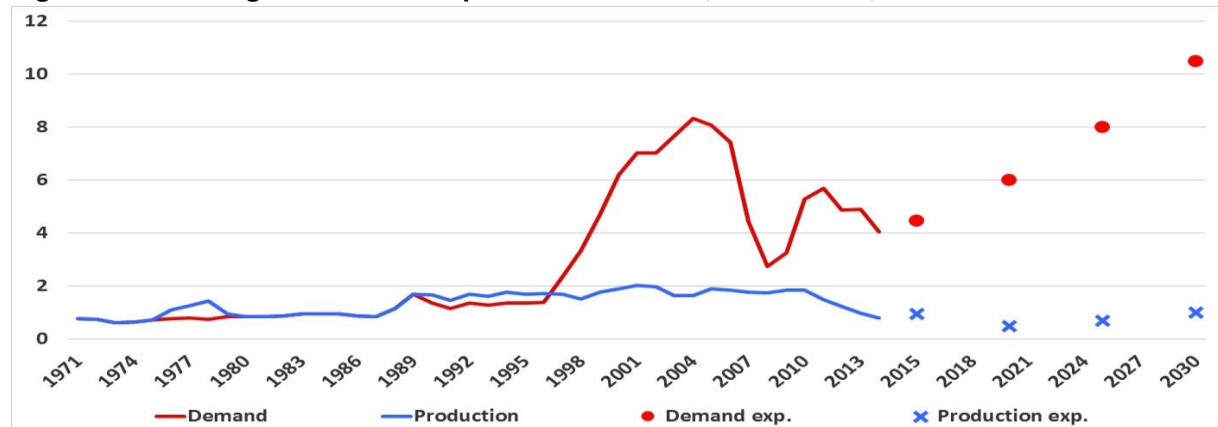
⁴³⁴ Economía y Negocios, 6 May 2012, El revival del gas desata guerra entre empresas en Chile



- Balances

In our scenarios [Figure 61], we expect gas demand to return to pre-crisis levels by 2025 helped by lower LNG prices. With low levels of production to continue, our scenarios show a growing gap between demand and production, which will be filled by LNG imports.

Figure 61: Natural gas demand and production in Chile, 1971 – 2030, bcm



Sources:

1971-2015: IEA, Natural gas information, various reports

2016-2030: Author's estimates

What future role for LNG?

The Quintero LNG terminal (3.7 bcma then expanded to 5.5 bcma in 2015), close to the country's capital Santiago, came on line in 2009 and the first commercial LNG cargo was delivered the same year.⁴³⁵ The terminal, which provides gas for the nearby power plant and a copper smelter, was the first land-based LNG regasification terminal to be constructed in South America. Chile signed a 21-year contract with BG for the supply of LNG equivalent to 2.2 bcma of gas up to 2030.⁴³⁶ The price of LNG in the contract with BG was indexed to (Brent) crude oil, using a slope of 13%,⁴³⁷ but in 2012, an option included in the contract was activated allowing GNL Chile –the buyer- to choose a Henry Hub-indexed contract.⁴³⁸ GNL Chile can contract incremental supply above the contracted volumes with BG, and bought its first spot cargo in October 2011.⁴³⁹ GNL Quintero plans a second capacity expansion in order to boost the LNG deliveries by up to 30%. A final investment decision was expected by late 2016 or early 2017.⁴⁴⁰ The second LNG terminal, at Mejillones (2 bcma), is in the north of the country and came on line in 2010 and supplies mostly power generation for the mining industry.⁴⁴¹ LNG supply to Mejillones works on shorter contracts. A proposed third LNG terminal secured an environmental permit late in June 2016. The FSRU project planned by US Cheniere,

⁴³⁵ BG website, 13 July 2009, BG Group delivers first LNG cargo to Chile

⁴³⁶ Platts International Gas Report, 19 November 2012, Chile seeks LNG elsewhere

⁴³⁷ ICIS/Heren Global LNG Markets, 14 October 2011, Market Report

⁴³⁸ Business news Americas, 14 October 2008, GDF Suez official: Mejillones LNG price tied to project cost

⁴³⁹ ICIS/Heren Global LNG Markets, 14 October 2011, Market Report

⁴⁴⁰ Argus Global LNG, May 2016, Chile terminal eyes new expansion

⁴⁴¹ GIIGNL (2010), p.11



French EDF and domestic investors would be located to the south of Santiago, and would supply a planned 640 MW CCGT. A final decision was not expected before the end of 2016.⁴⁴²

Our scenarios show LNG imports rising from 3.7 bcm in 2015 to 5.5 bcm in 2020 and 9.5 bcm in 2030. This growth will be supported by the proposed expansion of the existing LNG terminals and by new proposed regasification capacity. Post 2020, the Quintero LNG terminal is expected to be expanded (to 7.3 bcma) to serve two additional CCGT plants.⁴⁴³ The investment would also allow the terminal to load smaller ships to transport LNG to other points in the country.⁴⁴⁴ ENAP is expected to develop a new LNG terminal in the central-south region, but no indication of size or timing was given in the Ministry's plan.⁴⁴⁵ New expansions of existing regas plants and extension of virtual pipelines to the north/south of the country will constitute the most probable solutions in the short and medium term. There are also plans by Octopus LNG (Cheniere) for a third terminal in the south of the country, probably near the industrial area around Concepcion.⁴⁴⁶

However, Chile's economy, largely based on copper mining, is expected to be morose for –at least- 2016-2017. Lower copper prices, higher costs and local opposition have already delayed the expansion plans in the Atacama Desert. LNG import growth in the region, like the power plant projects, will most likely be postponed, begging questions on the pace and level of LNG needs this side of 2020. Nonetheless, some additional demand for LNG is expected to be triggered by the agreement to sell gas to Argentina to help the country meet peak demand during winter months (May-August) using both the Norandino pipeline and the GasAndes pipeline. Both pipelines were built in the 1990s to originally send Argentine gas to Chile. Deliveries via the Norandino pipeline started on May 17 2016 with 1.5 mcm/d for a cost of \$6.90/MMBtu. The gas was imported under a short term contract with Engie (until August 5). On June 3, Chile state-owned Enarsa, Endesa and Metrogasvia began deliveries of 4.5 mcm/d via the GasAndes pipeline at a cost of \$7.2/MMBtu.⁴⁴⁷

⁴⁴² Argus Latin America Energy, 5 July 2016, Proposed third Chilean LNG terminal secures permit

⁴⁴³ Quintero LNG regasification terminal has secured an environmental permit to expand capacity further. Final investment decision at the end of 2016 year or in early 2017, for completion by late 2020 or early 2021. Source: Argus Latin America Energy, 10 May 2016, Quintero LNG to decide on expansion by early 2017

⁴⁴⁴ Platts International Gas Report, 18 May 2015, Chile applies to expand capacity, pp.32-33

⁴⁴⁵ Ministerio de Energia (2014), p.38

⁴⁴⁶ Octopus LNG (Cheniere) announced that it had signed a 20-year contract for a FSRU to be installed near Concepcion, in the south of the country, in the second quarter of 2018. The contract is subject to Octopus completing financing and securing environmental permit approvals. The other project is being proposed by ENAP in Baia de San Vicente. The southern region is not interconnected with the Centre and receives CNG by truck from the Quintero LNG terminal. Source: Platts International Gas Report, 19 May 2014, GDF Suez eyes Chilean market

⁴⁴⁷ Argus Latin America Energy, 21 June 2016, LNG imports cheaper than domestic gas

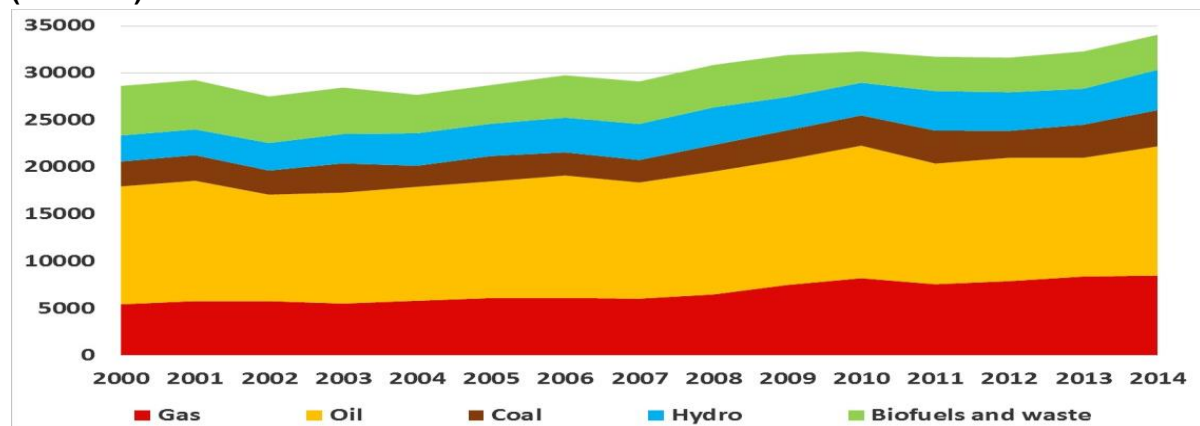


Colombia

Overview of the energy market

In Colombia, the TPES is dominated by oil (40%⁴⁴⁸) as seen below in Figure 62. Natural gas has an important role and provides 25% of the energy mix. Biofuels and waste (11%), hydro (13%) and coal (11%) make up the rest. Colombia is a major coal producer, but the fuel is mostly exported.

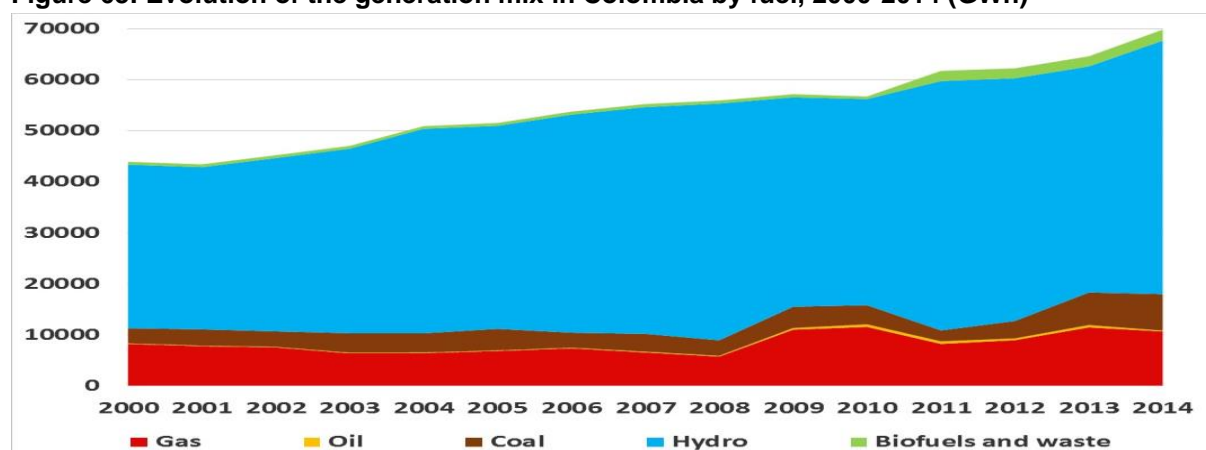
Figure 62: Evolution of the TPES in Colombia by fuel (including power trade), 2000-2014 ('1000Toe)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

Hydroelectric power contributes a large share of Colombia's power generation at about 71%, with thermal plants filling most of the remainder: gas 15% and coal 10%.⁴⁴⁹ Extended periods of drought during El Nino years force the thermoelectric power plants to ramp up (and decline when hydro availability improves) [Figure 63].

Figure 63: Evolution of the generation mix in Colombia by fuel, 2000-2014 (GWh)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

⁴⁴⁸ IEA (2016b), p.II.181, data for 2014

⁴⁴⁹ IEA (2016b), p.II.181, data for 2014



During periods of dry conditions, gas demand for power generation can more than triple from 2.8 mcm/d to 9.8 mcm/d.⁴⁵⁰ Therefore at times of low hydro, natural gas demand can increase by up to 2 bcm/a in the power sector, as seen in 2009-2010 and again in 2013-2014.⁴⁵¹ Gas supply restrictions to industrial users have been enforced in the past in order to guarantee supplies to power generators. In late 2015-early 2016, when hydroelectric power generation was again constrained, many generators even had to turn to diesel to use in their plants because of a shortage of indigenous gas in the country.

In 2014, Colombia had 15.5 GW of installed generation capacity, 67% in the form of large hydro, 11% from natural gas, 11% from oil and diesel, 6% from coal and 5% from other renewables (4% small hydro, 1% biomass and waste and 0.1% in wind).⁴⁵² The gas power plants appeared to have had an annual average load factor of 72% in 2014.⁴⁵³

The natural gas industry

In the 1990s, the Colombian government launched the successful “Natural Gas Expansion Programme” to boost the natural gas market.⁴⁵⁴ Natural gas demand and supply have grown at the same pace until the late 2000s when production overtook consumption. Colombia’s state-controlled Ecopetrol started to export the surplus from the Guajira gas field to neighbouring Venezuela via the Antonio Ricaurte cross-border pipeline from 2007. The gas was sold by Colombia (specifically Chevron) to PdVSA with a price formula indexed to the fuel oil price in Colombia - the same pricing basis as the gas could be sold in Colombia.⁴⁵⁵ The exports helped to support investment in the new fields and the plan was to reverse the flow in 2012 and obtain gas from Venezuela at prices that would be more competitive than those on the international market.⁴⁵⁶ Instead of a reverse flow, Colombia carried on exporting gas to Venezuela until its own balances worsened due to rising demand and plateauing production. These volumes were subject to suspension if needed in the domestic market, and in 2014, Ecopetrol temporarily suspended gas exports to Venezuela because of drought conditions reducing hydroelectric power capacity and forcing it to conserve gas for its own power plants.⁴⁵⁷ Exports were definitely stopped in 2015 and the gas was redirected to the national market. In mid-2015, Venezuela announced the start of production in the giant offshore Perla gas field and the objective to start exporting gas to Colombia in January 2016. However, this was postponed in December 2015 due to the severe drought conditions in Venezuela, and like Colombia in 2014, Venezuela needed the gas to generate electricity for its own market. As of mid-2016, exports were expected to start in December 2016 (515 mcma) to comply with a prior agreement with Ecopetrol.⁴⁵⁸

In 2015, gas demand reached 10.9 bcm.⁴⁵⁹ The power sector uses about 30% of the gas, industry 21%, residential and commercial 16%, the transport sector 9% and the “other sector” –which includes energy own use- 24%⁴⁶⁰ [Figure 64].

⁴⁵⁰ ICIS news, 4 March 2015, Colombian generators eye late 2016 start for LNG imports

⁴⁵¹ IEA, Energy Balances on Non-OECD Countries, several reports

⁴⁵² Bloomberg New Energy Finance (2015), p.165

⁴⁵³ Author’s calculations

⁴⁵⁴ See details on the Ministry website (Ministerio de Minas y Energia): <https://www.minminas.gov.co/gas-natural1>

⁴⁵⁵ Authors’ research

⁴⁵⁶ Argus, 18 February 2015, Gas-short Colombia will need LNG by 2017: chamber

⁴⁵⁷ Platts International Gas Report, 1 June 2015, Venezuela to export early 2016

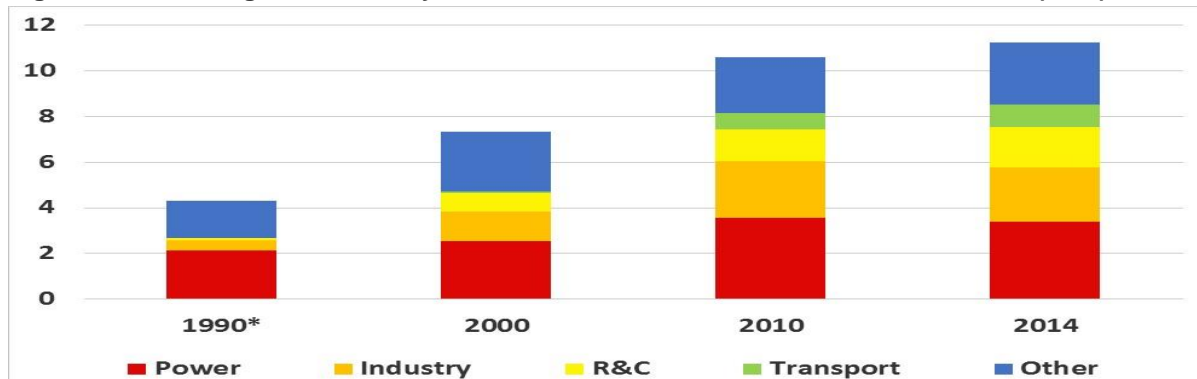
⁴⁵⁸ Platts International Gas Report, July 14, 2014, Perla: Venezuela’s big gas hope

⁴⁵⁹ IEA (2016a), p.II.8

⁴⁶⁰ IEA (2016b), p.II.181. Data for 2014



Figure 64: Natural gas demand by sector in Colombia, 1990, 2000, 2010 and 2014 (bcm)



Source: IEA (1993), IEA (2003a), IEA (2012), IEA (2016b), Individual country tables

More than half of the total production is reinjected into oil fields to keep the pressure up, and only about a third reaches the market. The major producing fields are in the north eastern Guajira peninsula and are operated by Chevron, but they are slowly declining. The country's upstream sector suffers from a lack of infrastructure, both in the form of transport pipeline and storage, but also from an insufficiently attractive regulatory framework for foreign exploration. In 2013, Colombia fully deregulated its gas market by eliminating price controls on gas produced in La Guajira and Cusiana, a move that regulator CREG said reduced prices by 30%.⁴⁶¹ Instead, a price increase would have been necessary to maintain the viability and reliability of operations.

Scenarios up to 2030

- Demand

The Unidad de Planeación Minero Energética (UPME) considered in 2016 that levels of gas used in the power sector should remain high between 2015 and 2018 (with possible peaks) but will decrease post 2019 with the start of hydropower plants (for instance, Ituango and Porvenir). From 2024 onwards, gas for power demand rises slowly and gets close to 2015 levels in 2030 (average levels, excluding peaks).⁴⁶² The industrial, residential and commercial sector and the transport sector (taxis, buses and cars) are also expected to expand due to additional infrastructure. In total, UPME expects that gas demand will grow at an annual average of 2.2% between 2015 and 2035.⁴⁶³ Declining indigenous supply may constrain additional gas demand growth (or at least until LNG imports are fully developed).

- Production

In an attempt to address the country's problem of reserves replacement (including with unconventional such as coal-bed methane and shale gas resources), the country has taken steps to make terms and conditions more attractive to accelerate exploration activities especially in more

⁴⁶¹ Platts International Gas Report, 24 March 2014, Colombia plans regas plant

⁴⁶² UPME (2016), p.25

⁴⁶³ UPME (2016), p.27



costly and risky offshore areas. For instance, the restriction of gas exports was lifted in 2010,⁴⁶⁴ and 40% royalty discounts for explorers of offshore and nonconventional resources for both crude and gas were introduced.⁴⁶⁵ Oil companies would welcome a more competitive tax system as part of fiscal reforms planned for end-2016.⁴⁶⁶

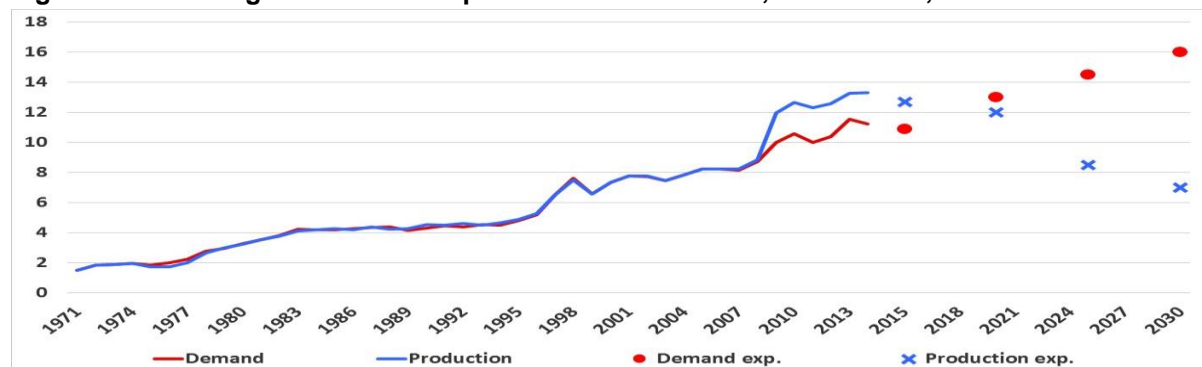
Discoveries in offshore deep-water areas⁴⁶⁷ could prove significant for Colombia but many challenges remain. Delays in environmental permitting, attacks by leftist guerrillas on crews and pipelines and community blockades create additional difficulties for investors. Significant cutbacks in exploration investments were decided following the decline in global oil prices in 2014, which impact the revenues of independent oil companies' and the country. State-controlled Ecopetrol planned to invest \$3 billion - \$3.4 billion in 2016 compared to \$6.5 billion in 2015.⁴⁶⁸ In October 2016, the revised plan for 2017-2020 was published and cut the projected capital expenditure (capex) to about \$3.25 billion per year over the period (assuming \$50/bbl).⁴⁶⁹

For all these reasons, gas production is expected to decline in the second half of the 2010s and the limited supply availability may also constrain gas consumption. Without any clear vision on expected levels of production, our scenarios follow the official one published in the Balance de Gas Natural 2016-2025.⁴⁷⁰ Gas production declines from 12.9 bcm in 2015 to 12 bcm in 2020 and 7 bcm in 2030.

- Balances

According to the Colombian oil and gas chamber (ACP),⁴⁷¹ imports will be needed as early as 2017. This is illustrated in Figure 65 below. The gap between demand and production grows quickly in the 2020s, from 1 bcm in 2020 to 6 bcm in 2025 and 9 bcm in 2030.

Figure 65: Natural gas demand and production in Colombia, 1971 – 2030, bcm



Sources:

1971-2015: IEA, Natural gas information, various reports

2016-2030: Author's estimates

⁴⁶⁴ Zamora A., Martinez H. (2014), p.19

⁴⁶⁵ Platts International Gas Report, 7 April 2014, Colombia tackles replacement problem

⁴⁶⁶ In 2014, the new tax regime lowered to 34% taxes paid on oil and gas profits, which were due to increase to 43% by 2018. Source: Argus Latin America Energy, 28 June 2016, Colombia ceasefire deal offers limited relief

⁴⁶⁷ In August 2015, Anadarko's Kronos-1 well in the Fuerte Sur block found a net pay of 40-70m of gas-bearing structures. The discovery adds to a deepwater find by a consortium led by Petrobras in December 2014 at the nearby Tayrona block. Source: Argus News, 4 August 2015, Growing Latin American prospects beckon drillers

⁴⁶⁸ Argus Latin America Energy, 23 August 2016, Ecopetrol bets on offshore gas, asset sales

⁴⁶⁹ Argus Latin America Energy, 4 October 2016, Ecopetrol trims capex plans

⁴⁷⁰ UPME (2016), p.11

⁴⁷¹ ACP (2016), p.2 and Argus, 18 February 2015, Gas-short Colombia will need LNG by 2017



What future role for LNG?

In addition to indigenous production growth, Colombia is also planning for a regasification terminal funded by a consortium led by Colombian gas distributor Promigas. The FSRU terminal was expected to start by late 2016 or early 2017 with a capacity of 4.1 bcma to be located near Cartagena on the Atlantic coast in the north. It will supply a group of thermal generators (Grupo Termico).⁴⁷² LNG imports should bring some relief for the power generation sector which was charged around twice as much as the industrial sector for gas amid a looming gas shortage in 2015.⁴⁷³ In late 2015 and early 2016, most generators had also been forced to turn to more costly (and less efficient) diesel due to declining indigenous gas production and low water levels as a result of a drought constraining hydropower generation.

Because Colombia is short of gas during El Niño, but potentially in surplus at other times due to changes in reservoirs levels and therefore hydropower availability, the country has also looked at a liquefaction plant, but as of mid-2016, the FLNG project with capacity of 0.7 bcma was dormant due to lower oil prices.⁴⁷⁴

Gas imports in 2020 will be around 1 bcma, in a normal year (average hydro levels), which could easily be filled by LNG or even by Venezuelan gas if exports happen. If only the LNG option is available, it appears that the 4.1 bcma terminal will not be enough by 2024. If Venezuelan exports start, then the country will still need additional regasification capacity as LNG imports are expected to rise to about 9 bcma by the end of the decade.

⁴⁷² Argus Latin America Energy, 7 June 2016, Colombia to commission LNG terminal by October

⁴⁷³ Argus news, 23 June 2015, Colombian thermal generators vexed over gas price

⁴⁷⁴ IEA (2015d), p.127

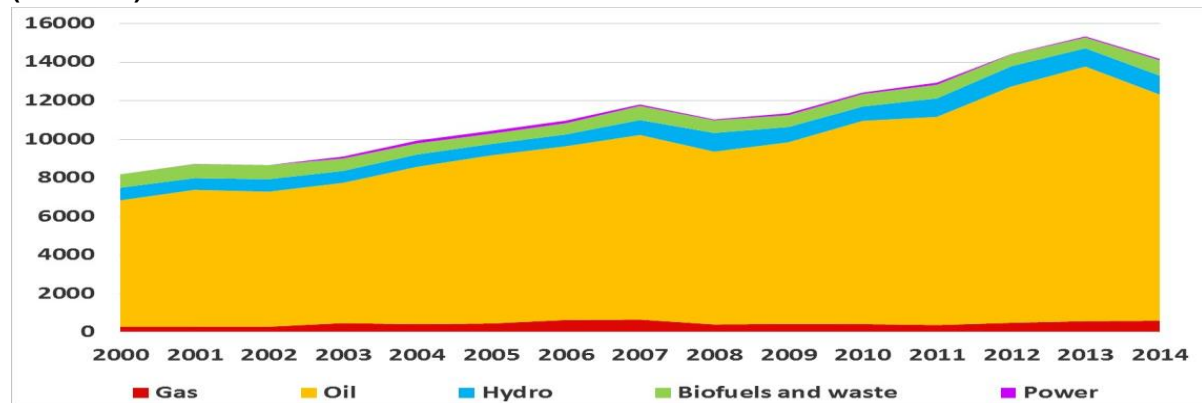


Ecuador

Overview of the energy market

Being an oil producer (and an OPEC member), the Ecuadorian TPES is logically heavily reliant on oil (83%⁴⁷⁵) as seen in Figure 66. Hydro accounts for 7%, biofuels and waste for 6% and gas for 4%.

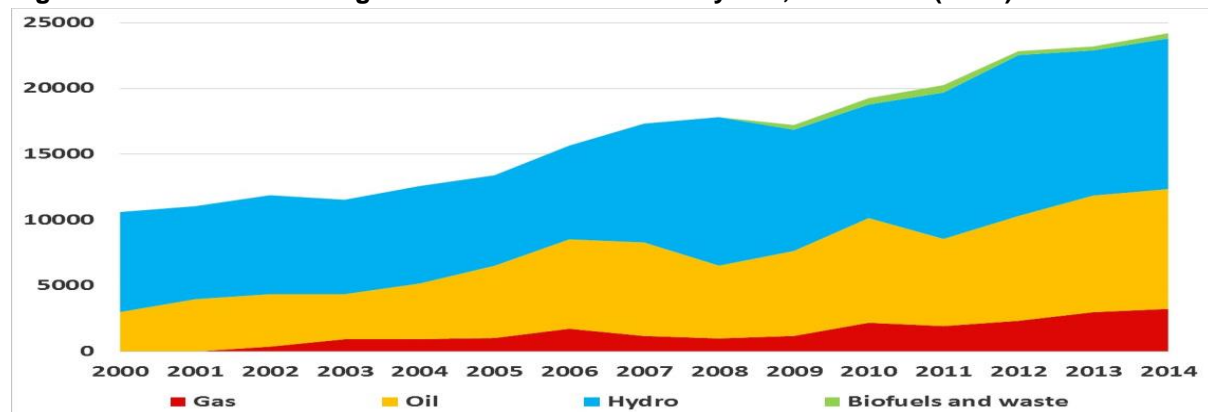
Figure 66: Evolution of the TPES in Ecuador by fuel (including power trade), 2000-2014 ('1000Toe)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

Hydropower makes up for about half of power generation (47%), followed by oil (38%).⁴⁷⁶ Natural gas' share is rising and but only accounts for about 13% [Figure 67].

Figure 67: Evolution of the generation mix in Ecuador by fuel, 2000-2014 (GWh)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

In 2014, Ecuador had 5.4 GW of installed generation capacity, 43% in the form of oil and diesel, 35% from large hydro, 10% from other renewables (7.6% small hydro, 2.5% biomass and waste, 0.4% in wind and 0.2% solar), 6% from natural gas and 6% from other fossil fuels.⁴⁷⁷ Thermoelectric plants offer additional power to the electric grid but also quick back up to hydro power changes. The long

⁴⁷⁵ IEA (2016b), p.II.203, data for 2014

⁴⁷⁶ IEA (2016b), p.II.203, data for 2014

⁴⁷⁷ Bloomberg New Energy Finance (2015), p.171

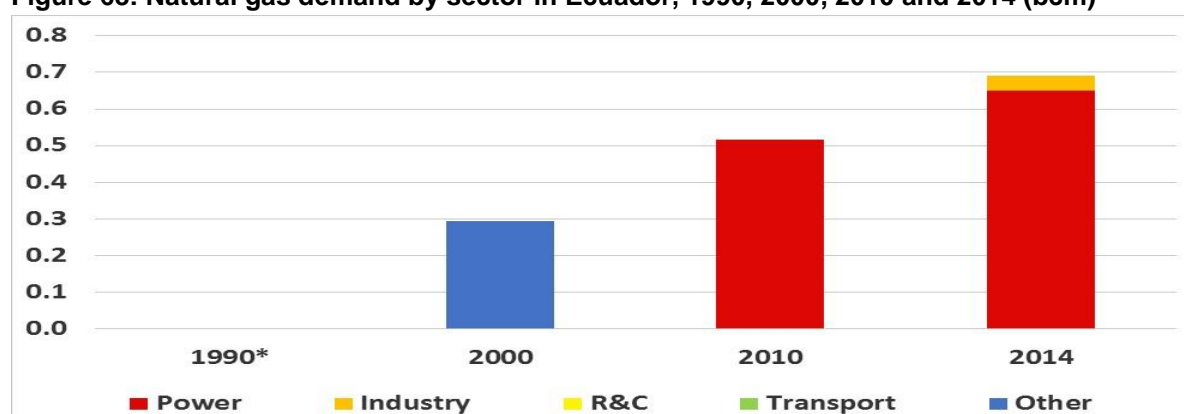


distance from the location of the hydroelectric facilities (inland) to the coastal cities, such as Guayaquil adds for the requirement to keep thermal plants in the system.

The natural gas industry

Natural gas demand is very small at about 0.7 bcm in 2014.⁴⁷⁸ It is highly concentrated in the power sector as seen in Figure 68. There is also a small quantity of gas used in the production process of natural gas from the Amistad field, which in the IEA data was classified in industry, “non-specified” but is really an “energy own use” demand.

Figure 68: Natural gas demand by sector in Ecuador, 1990, 2000, 2010 and 2014 (bcm)



Source: IEA (1993), IEA (2003a), IEA (2012), IEA (2016b), Individual country tables

Ecuador has significant proven gas reserves but they are largely associated with oil. Marketed production comes from the non-associated gas field Amistad, which flows to the Machala gas-fired power plant (130 MW) that supplies electricity to the Guayaquil region.⁴⁷⁹

Ecuador is a small and balanced gas market which is still relatively young. Natural gas prices are not the main issue when it comes to natural gas demand as the lack of infrastructure is essentially the main constraint.

Scenarios up to 2030

The economy is heavily dependent on oil revenues, and was already suffering from lower global oil prices⁴⁸⁰ when an earthquake devastated parts of the country on April 16, 2016.

- Demand

Ecuador anticipates an increase in gas demand, especially in the power sector. Our scenario follows the official one,⁴⁸¹ and expects 0.5 bcm in 2020 and 0.8 bcm in 2030.

⁴⁷⁸ IEA (2016b), p.II.203. Data in thousand tonnes of oil equivalent (596 ‘1000Toe)

⁴⁷⁹ Cedigaz (2013), p.44

⁴⁸⁰ The economy is also fully dollarized and therefore also hit by real exchange rate appreciation.

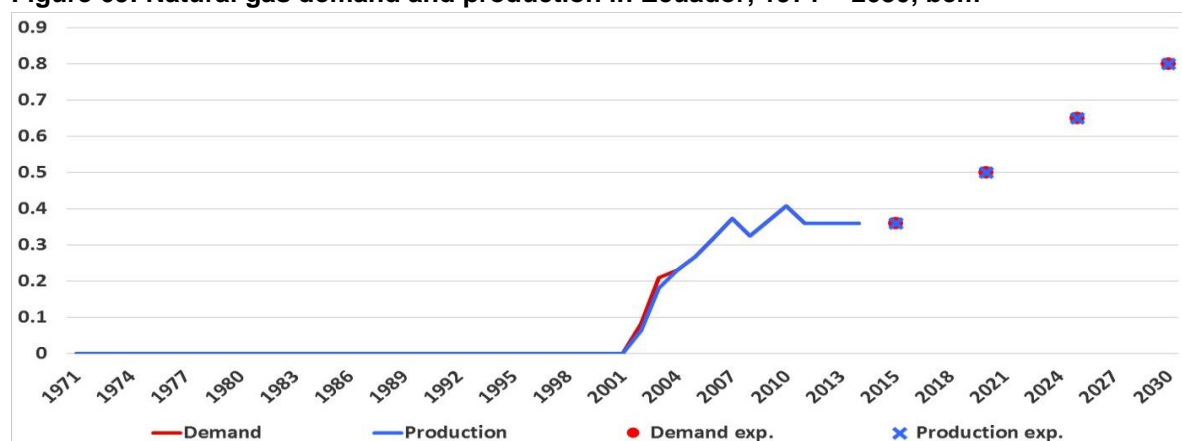
⁴⁸¹ CONELEC (2013), p.27



- Production and balances

Ecuador has plans to increase production of gas (and the necessary infrastructure) to meet growing power demand. We anticipate national production to follow gas demand growth in our timeframe, limiting the need for imports [Figure 69].

Figure 69: Natural gas demand and production in Ecuador, 1971 – 2030, bcm



Sources:

1971-2015: IEA, Natural gas information, various reports

2016-2030: Author's estimates

What future role for LNG?

There have been discussions about building an LNG terminal along Ecuador's coastline as LNG would be both cheaper than the diesel burned in power plants (and subsidised by the government) but also cleaner. A 2 bcma LNG regasification terminal would be located at Puerto Bolivar on the Pacific coast and would be used to supply 700 MW thermoelectric plants that currently run on diesel. As of mid-2016, no decision had been taken on this project.

Ecuador does not import LNG from the global market, but gas has been liquefied and transported as LNG instead of in traditional pipelines. This example highlights the way in which small scale LNG can penetrate industrial sectors through "virtual pipelines" in small markets using cryogenic trucks, and replacing oil products. The Bajo Alto LNG system, which included the liquefaction plant, 10 cryogenic trucks, a water treatment plant and communications infrastructure started operating in November 2011, but has never reached full capacity.⁴⁸² At the time of writing (mid 2016), state-owned PetroEcuador was struggling to resuscitate this small but strategic natural gas liquefaction plant in order to replace more costly oil products in the industry.⁴⁸³

⁴⁸² The LNG was transported to an industrial park in Cuenca in cryogenic trucks in order to replace diesel and LPG at ceramic manufacturing plants.

⁴⁸³ Argus News, 28 July 2015, Ecuador struggles to resuscitate LNG plant

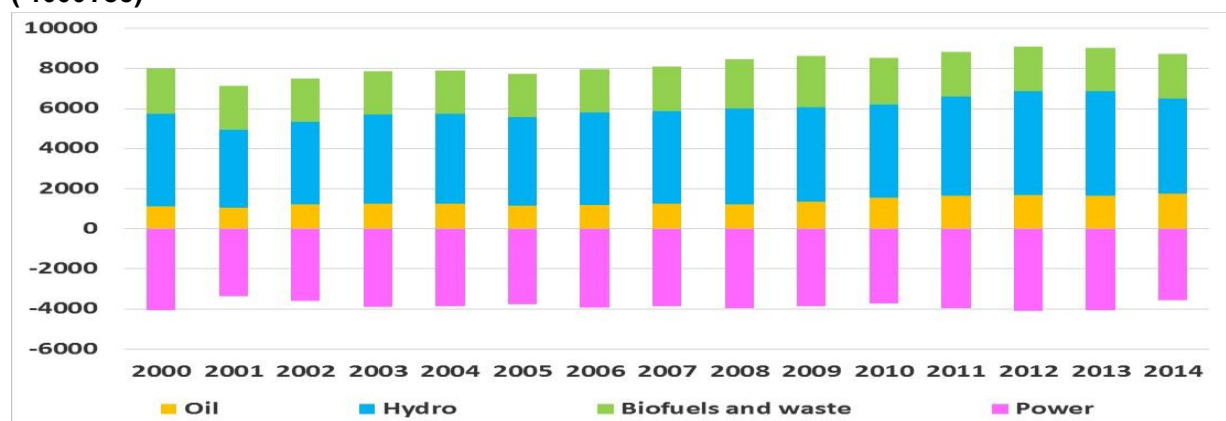


Paraguay

Overview of the energy market

Paraguay is a small energy market. It is heavily reliant on hydropower (54% of its internal TPES, excluding its electricity exports⁴⁸⁴) as seen below in Figure 70. Biofuels and waste (26%) and oil (20%) made up for the rest of the energy supply. The country does not use natural gas in its energy mix.

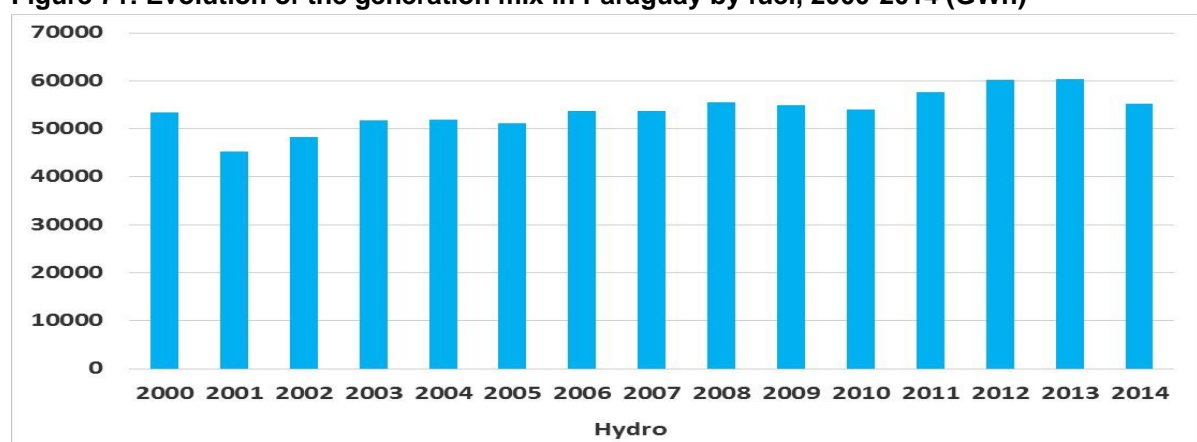
Figure 70: Evolution of the TPES in Paraguay by fuel (including power trade), 2000-2014 ('1000Toe)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

Paraguay relies on hydropower to generate electricity [Figure 71]. The 9 GW binational Itaipú dam is co-owned with Brazil. Paraguay uses only about 10% of the electricity produced while Brazil uses 90%.⁴⁸⁵

Figure 71: Evolution of the generation mix in Paraguay by fuel, 2000-2014 (GWh)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

⁴⁸⁴ Without power

⁴⁸⁵ Mares D. (2012)



In 2014, Paraguay had 8.8 GW of installed generation capacity, almost 100% in the form of large hydro with limited oil and diesel (0.3%).⁴⁸⁶

The natural gas industry

Paraguay is not a gas market, but it has been included in this paper because of its geographical position between Bolivia, Argentina and Brazil. Despite some technically recoverable shale gas reserves, there has been no interest on the part of government or the private sector to develop either a national gas market or exports as it is surrounded by countries with far more potential in conventional and/or unconventional gas.

⁴⁸⁶ Bloomberg New Energy Finance (2015), p.193

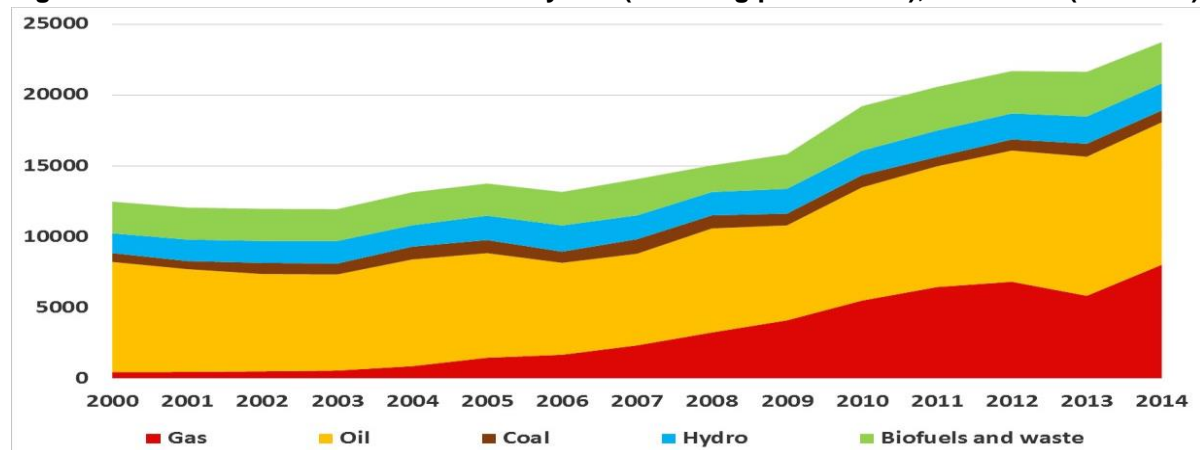


Peru

Overview of the energy market

Primary energy in Peru primarily comes from oil (43%), but the discovery and production of the Camisea reserves in the second half of 2000 transformed the energy mix radically as seen below in Figure 72 with gas representing 34% of the TPES.⁴⁸⁷

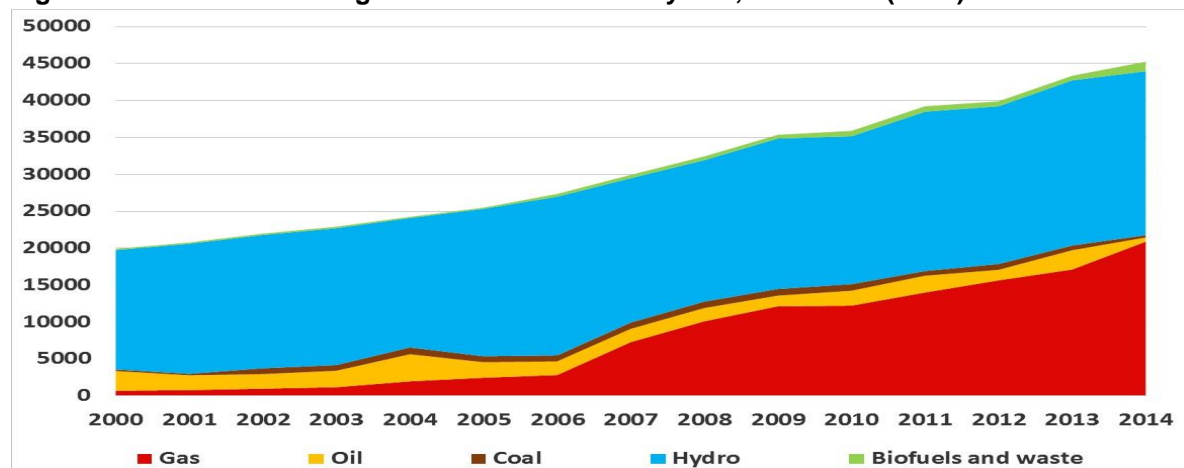
Figure 72: Evolution of the TPES in Peru by fuel (including power trade), 2000-2014 ('1000Toe)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

Important changes also happened in the generation mix as seen in Figure 73. Hydropower represents about half of electricity generation (49%), but the share of natural gas has rapidly increased to reach about 46% of the mix in 2014.⁴⁸⁸

Figure 73: Evolution of the generation mix in Peru by fuel, 2000-2014 (GWh)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

⁴⁸⁷ IEA (2016b), p.II.297, data for 2014

⁴⁸⁸ IEA (2016b), p.II.297, data for 2014



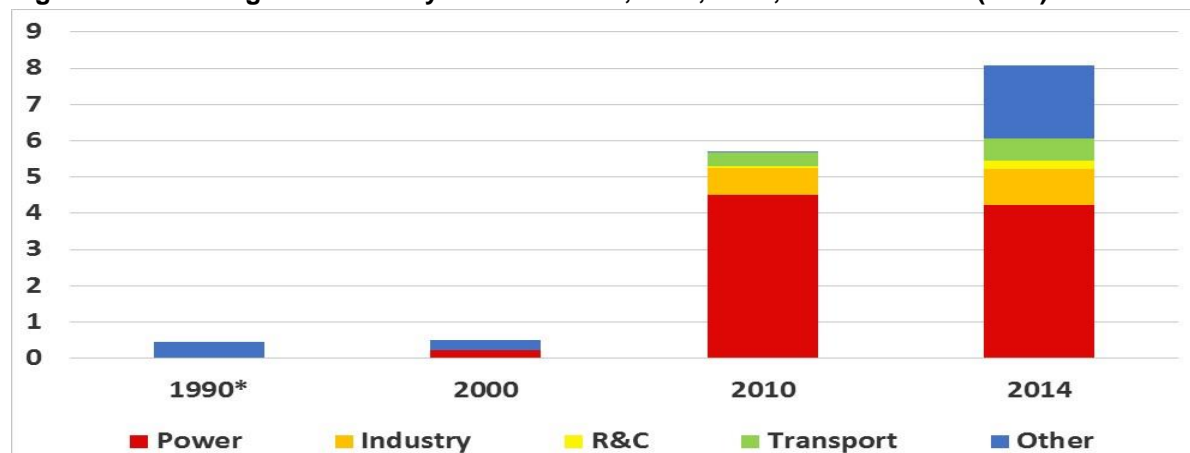
In 2014, Peru had 10.8 GW of installed generation capacity, 27% in the form of large hydro, 24% from natural gas, 23% from oil and diesel, 14% from other fossil fuels, 11% from other renewables (7% small hydro, 2% wind, 1% biomass and waste and 0.9% solar) and 1% from coal.⁴⁸⁹ The gas power plants appeared to have an annual average load factor of 92% in 2014.⁴⁹⁰

The natural gas industry

Production from the giant Camisea gas field started in 2004. This triggered a rapid growth in natural gas production, consumption and exports. The field supplies gas to Lima, the country's capital and main industrial centre and a liquefaction plant from which LNG is exported outside of South America. Low gas prices,⁴⁹¹ government incentives, economic growth and new gas-fired power plants boosted the national gas market with demand rising to 8.4 bcm in 2015 and production to 13.2 bcm.⁴⁹²

Gas consumption is split between the power sector (52%), industry (12%), residential and commercial (3%) and the transport sector (8%).⁴⁹³ The other sector which among others include the energy sector own use (LNG production), non-energy use and losses, represent about a fifth of total consumption (25%) as seen in Figure 74.

Figure 74: Natural gas demand by sector in Peru, 1990, 2000, 2010 and 2014 (bcm)



Source: IEA (1993), IEA (2003a), IEA (2012), IEA (2016b), Individual country tables

Scenarios up to 2030

- Demand

Peru's government increased the fuel oil tax and introduced a coal levy in early 2016, a follow up on its policy of tighter emissions standards.⁴⁹⁴ The country has only one coal-fired station -135 MW Ilo21-

⁴⁸⁹ Bloomberg New Energy Finance (2015), p.195

⁴⁹⁰ Author's calculations

⁴⁹¹ The government owns a large share of the pipeline capacity from Camisea to Lima, which enables it to offer gas at very competitive prices to industrial customers and power generation developers.

⁴⁹² IEA (2016a), p.II.8, table 6 and p.II.4, table 3

⁴⁹³ IEA (2016b), p.II.297, data for 2014

⁴⁹⁴ Argus Latin America Energy, Lima hikes fuel oil tax and introduces coal levy



which traditionally accounts for a very small share of electricity generation (less than 1%), but the move will likely promote the use of natural gas rather than coal in future projects.

Natural gas demand is expected keep on rising, and will be boosted by the completion of the Gasoducto del Sur Peruano (GSP). The pipeline project will transport gas from the ethane-rich Camisea gas field in the central jungle, over the Andes, down to two port cities (Ilo and Mollendo) and to the southern coast providing gas for household demand and power generation (including for two gas-fired plants under construction). The initial capacity of the pipeline will be 5 bcma and the government has allocated 28 bcm of gas reserves from the Camisea field block 88 (blocks 57 and 58 could also be earmarked for the line).⁴⁹⁵ In mid-2016, the newly elected president Pedro Pablo Kuczynski said he supported the project, which is expected to help develop the natural gas market in Peru, including with new petrochemical complexes and eventually copper refineries.⁴⁹⁶ The initial project for a second LNG export terminal –associated with the pipeline– seemed to have been abandoned at the time of writing, most likely because of lower US gas and LNG prices. The construction of the GSP began in May 2015, and 30% of the project was completed before construction came to a halt in April 2016 because of uncertainty over the project's ownership structure.⁴⁹⁷ The pipeline is expected to be operational in the first half of 2018, but uncertainties over the completion date of the pipeline are rising. Concerns over the level of demand (and also supply) to justify the pipeline have also been expressed.⁴⁹⁸

In its Plan Energético Nacional 2014-2025, the government still expects gas demand to continue to increase and reach 14.5-15 bcma in 2020 (depending on the assumptions about GDP growth and including the gas needed for reinjection) and to 20.6-23.3 bcma in 2030. This seems very optimistic, especially in view of the difficulty of developing new gas reserves. The GDP growth expectations in the latest available IMF outlook (April 2016) are also lower than in the scenarios considered in the National Energy Plan. For these reasons, we assume gas demand will rise from 8.4 bcm in 2015 to 12 bcm in 2020 and 15 bcm in 2030.

- Production

There are a large number of private and foreign companies working in the upstream oil and gas sector in Peru and some areas in the central jungle see high expectations for finding gas or oil and are strategically located near the Camisea gas fields. However, plans to explore for natural gas have been facing turbulence due to environmental awareness and community activism which have limited the development of additional areas. The Camisea field is located in the south-east of the Amazon, in a remote jungle east of the Andes, 300 miles from Peru's populated coastal areas and even further from potential neighbouring consumers (Brazil, Argentina or even the consumption centres in Chile if one wanted to look at the –unlikely– option). As a result, new reserves have not been developed⁴⁹⁹ and large field production has started to decline.

⁴⁹⁵ Argus Latin America Energy, 31 August 2016, Sempra leads race to acquire gas pipeline

⁴⁹⁶ Argus Latin America Energy, 14 June 2016, New president backs southern pipeline

⁴⁹⁷ The contract was originally awarded to Odebrecht in 2014, but the company decided to sell its stake because of its alleged involvement in Petrobras corruption scandal in Brazil.

⁴⁹⁸ Argus Latin America Energy, 27 September 2016, Uncertainty shrouds Peru's southern gas line

⁴⁹⁹ As of mid 2016, the last upstream tender in Peru was in 2010. Source: Argus Latin America Energy, 14 June 2016, Kuczynski faces difficult term



In its Plan Energético Nacional 2014-2025, the government expects total gas production (marketed plus volumes for reinjection) to rise to about 20.5 bcma in 2020 and between 28-30 bcma in 2030.⁵⁰⁰ Our views are a lot more cautious, for all the reasons explained. Peru has large potential for natural gas, but it needs investments. Nonetheless, we assume that the country will find a way to supply its growing national demand while at the same time exporting the LNG volumes as planned by the contract with Mexico: our scenarios show about 16 bcm of marketed production in 2020 and 20 bcm in 2030.

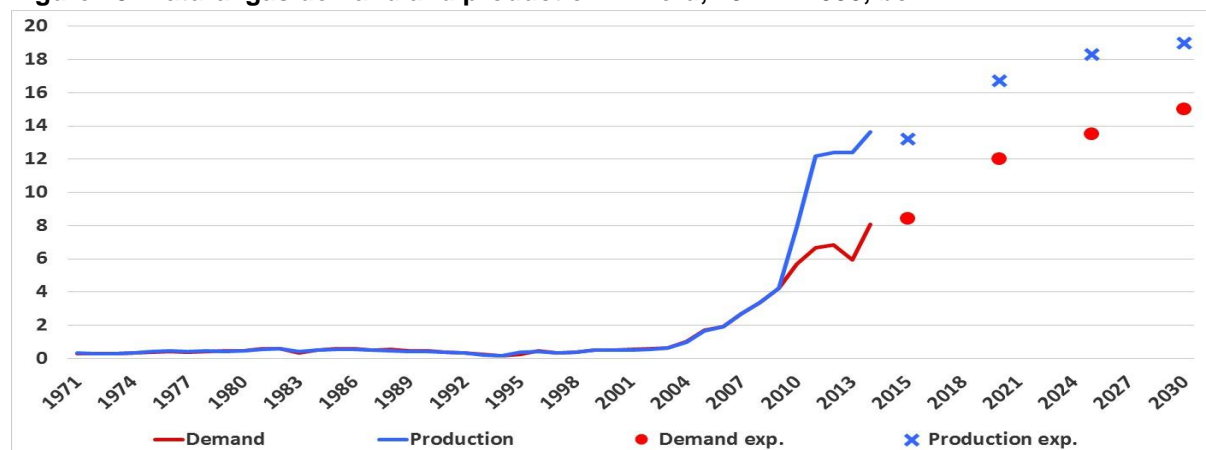
- Balances

With rising national demand and stagnating upstream activities, there are concerns about future availability of natural gas to supply both the domestic market and LNG exports.

If our assumptions on gas production do not happen, LNG exports will be constrained to give priority to the national market until additional production comes on line. However, it is unlikely that a curtail of Peruvian LNG exports to Mexico will have any kind of consequences on the importer, which can source natural gas from its US neighbor and is also focusing on developing its own reserves or on the other markets in South America.

Natural gas balances in Peru as shown in Figure 75 below. 'Demand' does not take into account contracted LNG volumes to be exported to Mexico.

Figure 75: Natural gas demand and production in Peru, 1971 – 2030, bcm



Sources:

1971-2015: IEA, Natural gas information, various reports

2016-2030: Author's estimates

What future role for LNG?

Peru is the only LNG exporter on the continent. Peru LNG, a 6 bcma export capacity, started operations in June 2010. Most of the LNG is shipped to Mexico as seen in Figure 74.⁵⁰¹ It is

⁵⁰⁰ Ministerio de Energía y Minas (2014)

⁵⁰¹ Platts LNG data

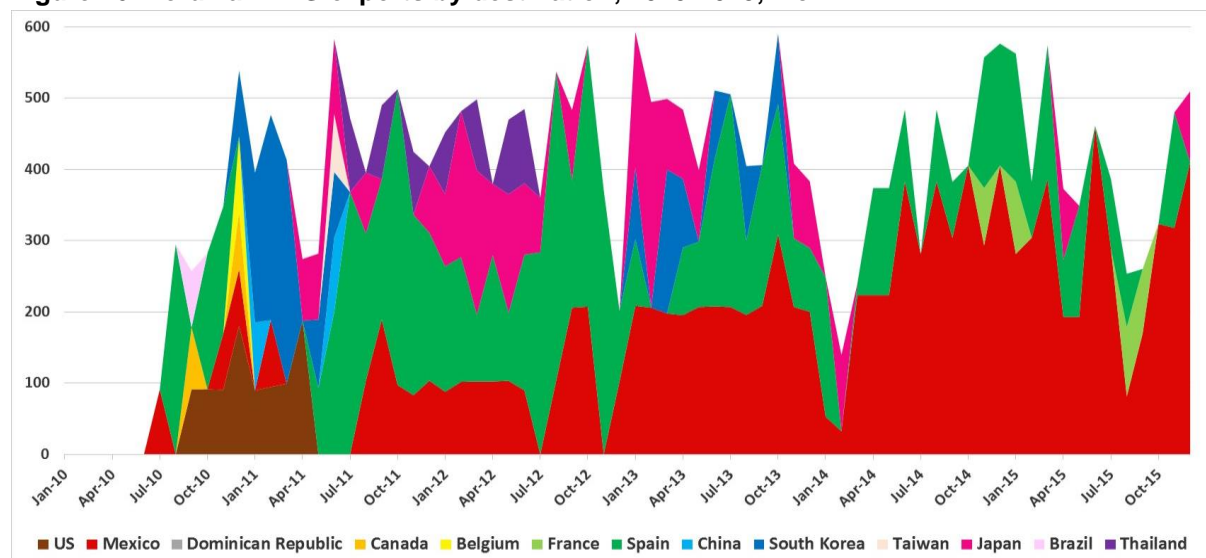


interesting to note that the country chose the LNG option rather than pipeline exports to neighbour markets, especially to gas-hungry Chile as a result of political tensions since the 19th century.

Long-term sales from Peru to Mexico are based on a contract that runs from 2004 to 2028 for about 4.7 bcma and the price is a percentage of the Henry Hub price. The price formula may change with the destination of exports (Atlantic LNG sales to Spain for instance). Spot cargoes will be based on the highest gas price level achievable in either Asia or the Atlantic Basin.⁵⁰² Peru's new government is looking to reduce its LNG exports to Mexico in order to free some LNG to export to higher-priced markets. This would require the renegotiation of the existing contracts between Peru LNG, Shell⁵⁰³ and Mexican state-owned utility CFE, which is not a done deal, but with new cross border gas pipelines between the US and Mexico and better interconnections in the country, the needs for LNG imports from Peru are likely to be reduced in the future.

Peru's LNG exports are expected to remain stable in our time frame, albeit potentially constrained by growing national demand (and eventually gas-based electricity exports⁵⁰⁴) and challenges to increase indigenous production. We do not expect Peruvian gas to make a (any) contribution to the regional supply/demand balances (LNG volumes are likely to be sent to Asia-Pacific or European markets). Therefore Peru will continue to have limited impacts for the other South American countries.

Figure 76: Peruvian LNG exports by destination, 2010-2015, mcm



Source: Platts, LNG data

⁵⁰² See OIES/KAPSARC (2016) for more details

⁵⁰³ Royal Dutch Shell exports Peru's LNG and the consortium Peru LNG operates the liquefaction plant.

⁵⁰⁴ Peru is considering exporting electricity to its neighbour Chile. It is yet uncertain how this will develop considering the difficult political relations between the two countries and the fact that the idea of a power transmission line has been in discussion since 2012 without any major progress as of 2016. Source: Argus Latin America Energy, 2 August 2016, New government promotes exports

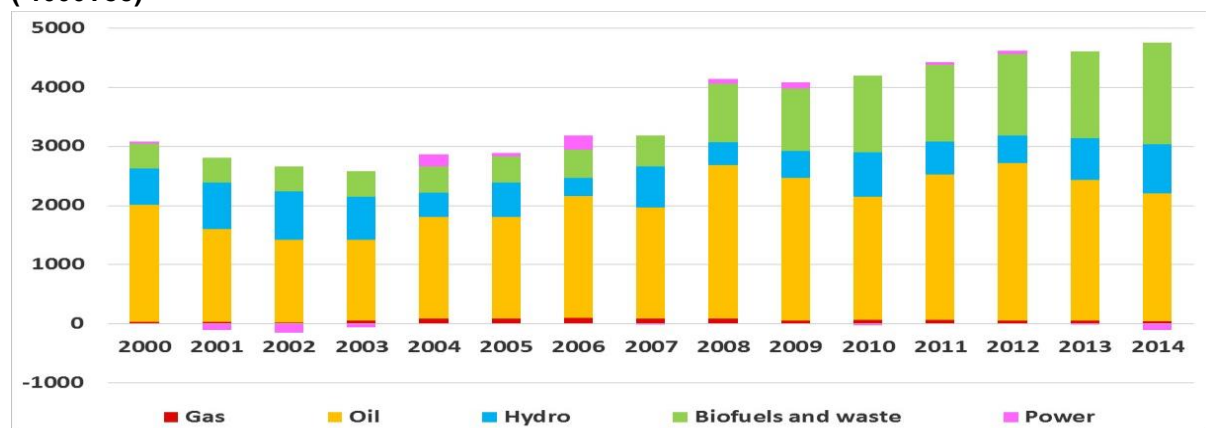


Uruguay

Overview of the energy market

Uruguay has limited hydrocarbon resources. Its TPES is heavily reliant on oil (45%),⁵⁰⁵ and the remaining shares are mostly covered by renewables: biofuels and waste (36%) and hydro (17%). The role of natural gas is minimal at about 1% as seen in Figure 77.

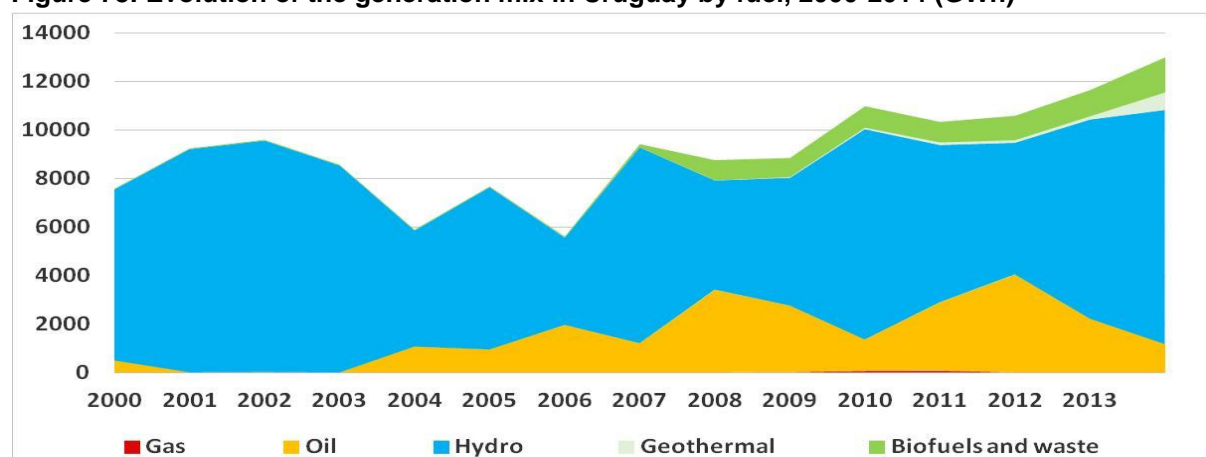
Figure 77: Evolution of the TPES in Uruguay by fuel (including power trade), 2000-2014 ('1000Toe)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

The generation mix focuses on hydropower (74%)⁵⁰⁶. Other sources of renewable generation have started to develop in the late 2000s, and represent about 17% of the mix. Changes in hydro availability are made up by oil plants, which as a consequence show large variations in utilisation year on year (9% in 2014 vs 19% in 2013 for instance). The natural gas contribution is almost non-existent as seen in Figure 78.

Figure 78: Evolution of the generation mix in Uruguay by fuel, 2000-2014 (GWh)



Source: IEA, Energy Balances on Non-OECD Countries, Editions 2003 to 2016, Individual country tables

⁵⁰⁵ IEA (2016b), p.II.347, data for 2014

⁵⁰⁶ IEA (2016b), p.II.347, data for 2014

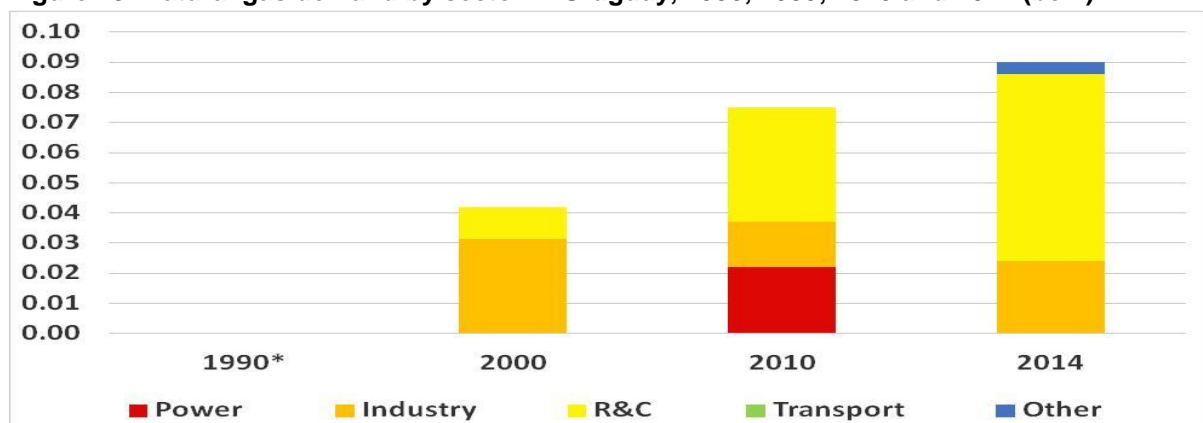


In 2014, Uruguay had 3.7 GW of installed generation capacity, 42% in the form of large hydro, 34% from oil and diesel and 24% from other renewables (13% wind, 11% biomass and waste and 0.1% solar).⁵⁰⁷

The natural gas industry

Uruguay decided to turn to natural gas at the time of cheap available gas from Argentina in the 1990s. Two pipelines were built leading to rapid gas demand growth albeit to very small levels. Consumption is concentrated in the residential and commercial and in the industry sector as seen in Figure 79.

Figure 79: Natural gas demand by sector in Uruguay, 1990, 2000, 2010 and 2014 (bcm)



Source: IEA (1993), IEA (2003a), IEA (2012), IEA (2016b), Individual country tables

Uruguay does not produce natural gas and all demand (0.05 bcm⁵⁰⁸) is met by importing gas from Argentina, which did not cut exports following its gas crisis in the mid-2000s, but volumes have been kept to a minimum.

Scenarios up to 2030

- Demand

The government launched a 25-year energy plan in 2005.⁵⁰⁹ The main objective was to reduce the risk of shortages and limit the need for imported oil. In order to achieve this, the proposition was to ramp up power generation from renewable energies and back them up with gas-fired capacity. There are plans to convert some of the oil-fired power plants and build a new 530 MW CCGT.⁵¹⁰ We expect gas demand to keep on rising, especially after the opening of the LNG regas terminal, which was also part of the strategy. However, national gas consumption will remain (very) small and our scenarios account for 0.5 bcm in 2020 and 1 bcm in 2030.

⁵⁰⁷ Bloomberg New Energy Finance (2015), p.201

⁵⁰⁸ IEA (2016b), p.II.347, data for 2014. Data in thousand tonnes of oil equivalent (45 '1000Toe)

⁵⁰⁹ MIEM (2005) p.11

⁵¹⁰ The plant may have to be initially fuelled with diesel due to delays with the LNG terminal. Source: Mercopress, 20 December 2012, Uruguay diversifies energy mix with 530 MW combined-cycle-gas-power plant



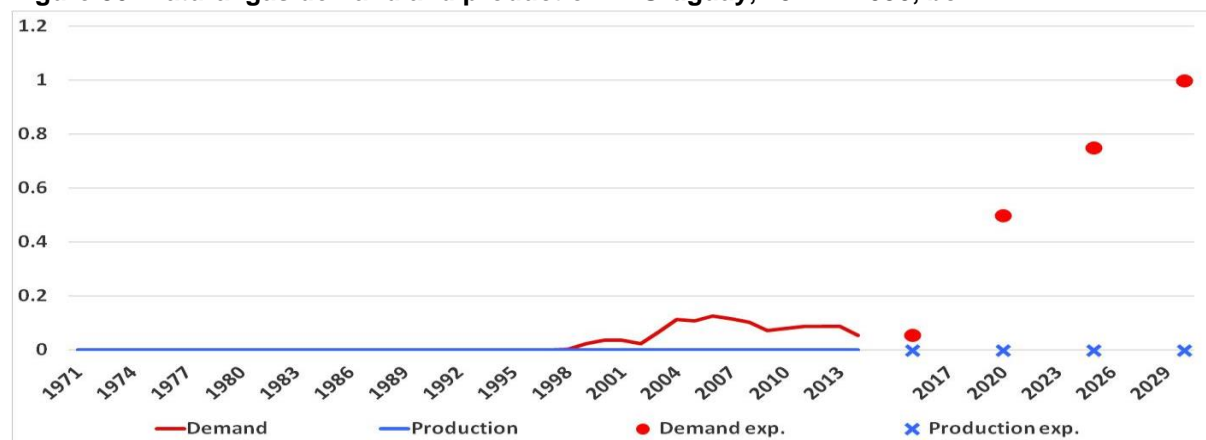
- Production

Uruguay does not produce natural gas, but exploration efforts are taking place both onshore and offshore and some future discoveries are a possibility (conventional and unconventional). However, due to the uncertainty around volumes and timescale, we do not account for a rise in indigenous gas production by 2030.

- Balances

The growing gas demand post 2020 as seen in Figure 80 will be supported by the opening of the LNG terminal in the late 2010s and LNG imports to supply the national market and eventually exports of regasified LNG to neighbouring countries.

Figure 80: Natural gas demand and production in Uruguay, 1971 – 2030, bcm



Sources:

1971-2015: IEA, Natural gas information, various reports

2016-2030: Author's estimates

What future role for LNG?

Uruguay decided to turn to LNG to diversify and supplement its natural gas imports. The FSRU terminal, GNL del Plata, will be situated in Punta Sayago off the coast of Montevideo down the river from Buenos Aires with a capacity of 3.65 bcma, expandable to 5.5 bcma.⁵¹¹ The regas terminal will allow the country to diversify its sources of gas supply, reduce its consumption of more expensive fuels (diesel and fuel oil) and rapidly respond to any sudden increase in gas for power demand due to low hydro availability.

The country is expecting to monetise its surplus supply from the LNG import terminal and to become a regional hub by selling LNG, pipeline gas or gas-based power during winter months to its neighbours: Argentina and eventually Brazil.⁵¹² In May 2016, Argentina and Uruguay settled a preliminary gas purchase agreement where Argentina would buy spare gas from the terminal for 10

⁵¹¹ Enerdata, 3 October 2013, GDF SUEZ will develop Uruguay's first LNG import terminal

⁵¹² Platts International Gas Report, 1 December 2014, Uruguay to sell surplus LNG



years when it starts operations.⁵¹³ After several hurdles and delays,⁵¹⁴ the LNG terminal is still going ahead although some uncertainty remains on its opening date. Uruguay expects exports to Argentina sometime in 2017,⁵¹⁵ but the terminal may face new delays and an opening date sometime around 2020 is not unlikely.

⁵¹³ Argus Latin America Energy, 23 August 2016, Long-delayed project set to restart

⁵¹⁴ The FSRU was initially planned for mid-2017. Source: LNG World Shipping, 5 October 2015, Mitsui OSK and Gas Sayago agree to continue Uruguay FSRU project

⁵¹⁵ Argus Global LNG, January 2016, Argentina and Uruguay advance gas supply plans

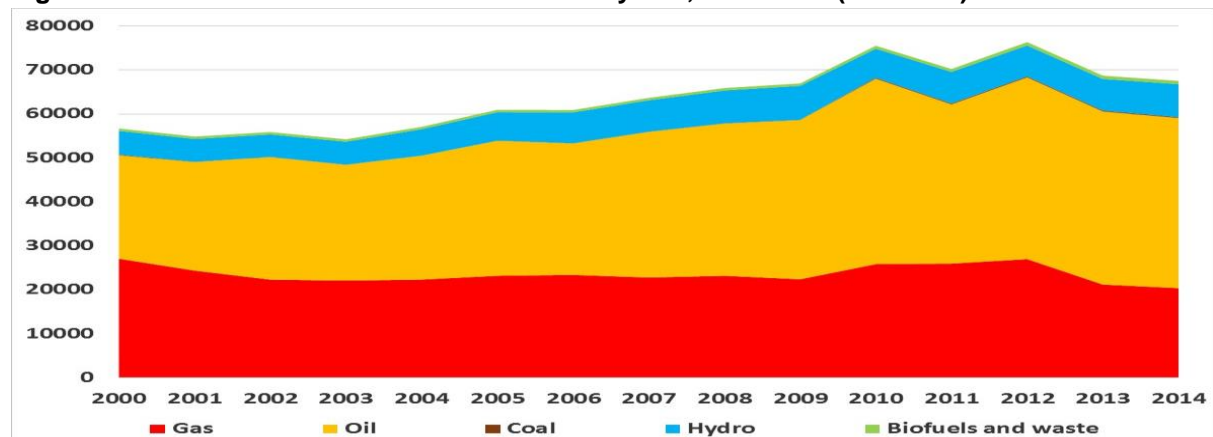


Venezuela

Overview of the energy market

Venezuela is a major oil producing country and an OPEC member. Its TPES remains heavily reliant on oil (57%⁵¹⁶) as seen below in Figure 81. Natural gas made up for the other large segment with 30%, while hydropower accounted for 11%.

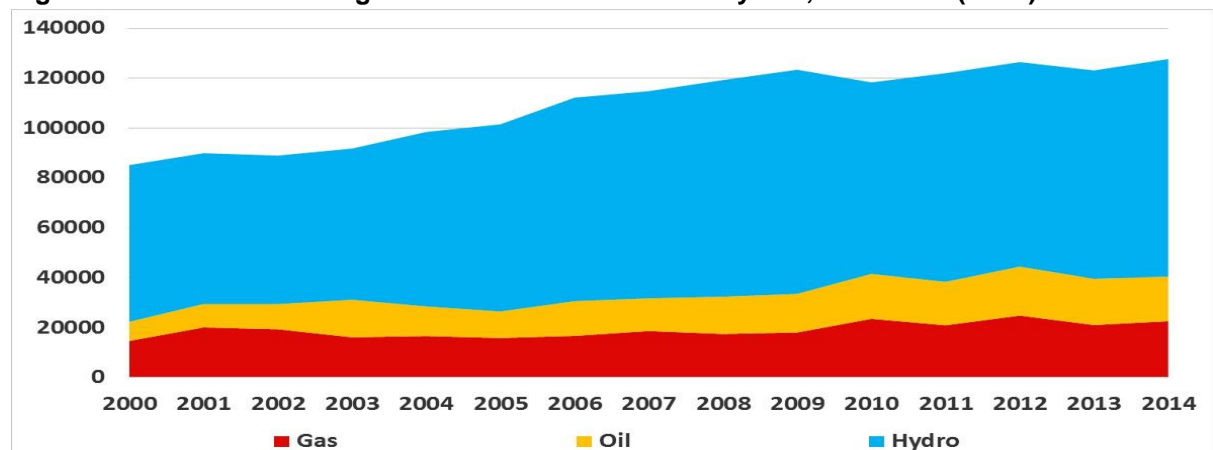
Figure 81: Evolution of the TPES in Venezuela by fuel, 2000-2014 ('1000Toe)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

Venezuela depends on hydroelectricity for about two thirds of its power needs (68% in 2014⁵¹⁷) as seen in Figure 82. The share of natural gas varies over the years as gas power plants ramp up and down at times of low/high hydro levels. Gas represented 17% in 2014, followed by oil (15%). Oil power plants, like gas plants, are also used as flexible generation to back up hydro power.

Figure 82: Evolution of the generation mix in Venezuela by fuel, 2000-2014 (GWh)



Source: IEA, Energy Balances of Non-OECD Countries, Editions 2003 to 2016, Individual country tables

⁵¹⁶ IEA (2016b), p.II.351, data for 2014

⁵¹⁷ IEA (2016b), p.II.351, data for 2014



Low water levels at the dams, especially at the giant 10 GW Guri (Simon Bolivar) hydroelectric power plant which provides most of the country's electric power, are more and more frequent and result in widespread power rationing.⁵¹⁸ The record-low water levels in 2009-10 forced the government to implement blackouts and reduce industrial production. The latest example happened in March 2016 when a two and a half day working week in the public sector was decided in order to save energy at times of very low hydro power availability. The measure was softened in June 2016 with a five-day working week reinstated but keeping shortened working hours of 8:00-13:00.⁵¹⁹

Better availability of natural gas supply would certainly create a demand by replacing oil and oil products in power generation and by backing up hydro power variability. In 2014, Venezuela had 30 GW of installed generation capacity, 49% in the form of large hydro, 26% with oil and diesel and 25% for gas plants.⁵²⁰ These gas power plants had an annual average load factor of 35%,⁵²¹ and could therefore in theory generate additional electricity. There have been some difficulties in getting all existing installed capacity operational due to equipment breakdowns and (natural gas and diesel) supply shortfalls.⁵²² Faster electricity consumption growth compared to installed capacity in the 2000s left the power grid stretched. Additional capacity and demand-reductions policies will be needed, especially at times of major droughts.

The natural gas industry

Most of the upstream focus in Venezuela has been on developing oil reserves, but the country also holds by far the largest gas reserves in South America. These reserves have grown by half over the past two decades to 5.6 Tcm in 2015⁵²³ thanks to exploration activities especially in the south east of the country. However, more than 80% of the reserves are associated gas. These reserves are more costly to process than non-associated gas and the level of gas production depends on the level of oil production, which in turn is constrained by OPEC oil production quotas and influenced by global oil prices. About 40% of Venezuela's gas production is reinjected to maintain pressure and bolster production in its mature oil fields. In addition, due to a lack of gas infrastructure to bring the gas to the market, about 10% of additional volumes are flared. Counting additional losses or uses, marketed production only represents about 35% of the gross production.⁵²⁴

In 2015, Venezuela's dry marketable production reached 24.8 bcm while its consumption was 25.2 bcm.⁵²⁵ The industry sector was the largest consumer (37%),⁵²⁶ followed by the "other" sector which includes energy own use⁵²⁷ (29%) and the power sector (29%) as seen in Figure 83. Like in most of South American markets, gas consumption in the residential and commercial sector is limited (5%).

⁵¹⁸ Platts International Gas Report, 8 November 2010, Venezuela: anyone but Washington

⁵¹⁹ Argus Latin America Energy, 21 June 2016, Power cuts ease as hydro levels recover

⁵²⁰ Bloomberg New Energy Finance (2015), p.203

⁵²¹ Author's calculations

⁵²² Argus News, 4 April 2016, Venezuela tries to dig out of power crisis

⁵²³ BP (2016), p.20

⁵²⁴ Cedigaz (2013), p.44

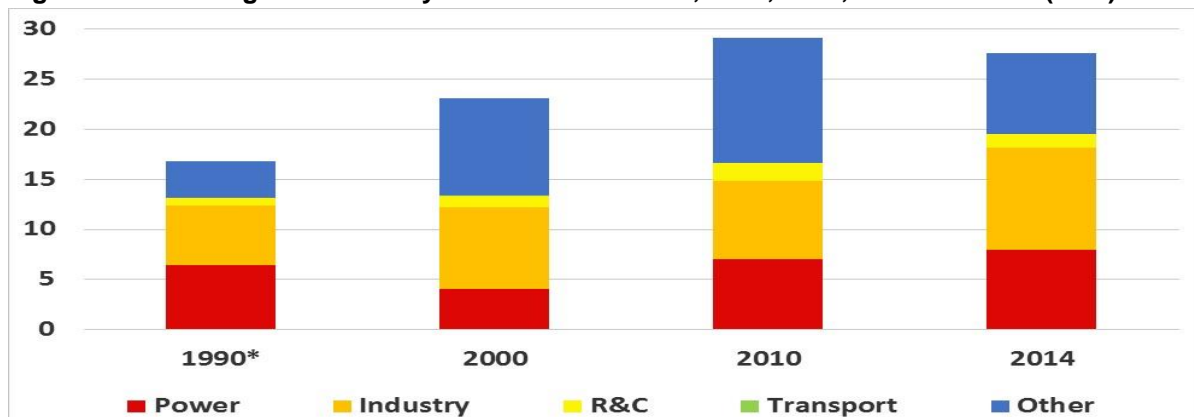
⁵²⁵ IEA (2016a), p.II.4 table 3 and p.II.8 table 5

⁵²⁶ IEA (2016b), p.II.351, data for 2014

⁵²⁷ Natural gas used in the oil industry: refineries and in heavy oil upgrade plants



Figure 83: Natural gas demand by sector in Venezuela, 1990, 2000, 2010 and 2014 (bcm)



Source: IEA (1993), IEA (2003a), IEA (2012), IEA (2016b), Individual country tables

Venezuela started importing natural gas from Colombia in 2007 after the inauguration of the Antonio Ricaurte 225 km pipeline between the Guajira field in north eastern Colombia and Maracaibo in western Venezuela. The gas was primarily meant for reinjection in order to help Venezuela boost oil production in the region. The deal was that Colombia would export just over 1 bcma until 2011, and then the pipeline flow would be reversed in 2012 to allow Venezuela to ship its own future excess gas to its neighbour. However, delays in developing reserves in Venezuela made this impossible, and in late 2011, Colombia agreed to continue to supply gas to its neighbour and the deal was extended for three additional years.⁵²⁸ In June 2014, the contract was extended for another year.⁵²⁹ Despite some existing political tensions between the two countries,⁵³⁰ the security of gas supply has been relatively good until 2015⁵³¹ (particularly since May) when Colombia had to reduce gas exports to meet its own gas for power demand growth. Shortages engendered irregular supply with frequent problems and exports were even at times turned off altogether.⁵³² The contract terminated on 30 June 2015 and was not renewed.

After several delays, the \$5 billion Perla project led by Spain's Repsol and Italy's ENI, started producing natural gas from offshore non-associated gas in July 2015 with the first 4.2 mcm/d train of the Cardon IV block, estimated to hold nearly 480 bcm of gas.⁵³³ Production was expected to ramp up to 12.7 mcm/d by the end of 2015 (4.6 bcma) thanks to thirteen gas production wells that would secure production until the beginning of the second phase.⁵³⁴ Production is expected to rise to 23 mcm/d (8.4 bcma) in mid-2017 and reach its peak of 34.5 mcm/d (12.6 bcma) by 2020.⁵³⁵ Gas will be sold to state-owned national oil and gas company Petroleos de Venezuela (PDVSA) under a Gas

⁵²⁸ Platts International Gas Report, 9 April 2012, Colombia aims at regional status

⁵²⁹ Argus, 18 February 2015, Gas-short Colombia will need LNG by 2017: chamber

As shown for instance in 2008 when Venezuelan President Hugo Chavez called for the mobilisation of troops at the Colombian border, or in July 2010 when President Chavez accused Colombia of allowing the US to launch a future attack against his country (and Ecuador and Nicaragua). In turn, Colombia accused President Chavez of aiding and giving refuge to left-wing Colombian guerrilla groups such as the FARC and ELN. Both countries have also major economical differences with Colombia embracing free market economics while Venezuela prefers a more socialist approach of its economy with more state control. Source: Platts International Gas Report, 2 August 2010, Colombia pipes gas to Venezuela

⁵³¹ A severe drought in Venezuela/Colombia in 2009 even saw gas supplies from Colombia temporarily reduced as Bogota prioritized its domestic demand. Source: Platts International Gas Report, 8 November 2010, Venezuela: anyone but Washington

⁵³² Zamora A., Martinez H. (2014), p.20 ; Enerdata, 15 June 2015, PDVSA (Venezuela) will stop importing gas from Colombia ; Interfax, 15 June 2015, Venezuela will not renew gas import contract from Colombia

⁵³³ ENI Website, 4 June 2014, Eni signs strategic agreements for Perla super-giant field in Venezuela

⁵³⁴ Platts International Gas Report, 1 June 2016, Venezuela to export early 2016

⁵³⁵ Argus, 17 February 2015, Analysis: Repsol hangs gas pearl on Venezuela



Sales Agreement running until 2036.⁵³⁶ The terms of the Agreement have not been disclosed, but the gas will be delivered into the national market and displace some of the costly diesel and other liquid fuels often used to operate power stations, petrochemical plants and other facilities. Part of Perla's initial production is also planned to be exported to Colombia (515 mcma from 1 December 2016) to comply with a prior agreement with Ecopetrol.⁵³⁷

Venezuela has been keen to export natural gas for several decades to its neighbouring countries or further south via the north-south pipeline project (which was never built), Central America, or even further away in the form of LNG. In 2009, the government announced a "Socialist Gas Revolution" with the aim of doubling natural gas production and start exporting by 2015. However, the reality has been very different.

Scenarios for natural gas balances up to 2030

- Demand

There is some potential for gas demand growth in our timeframe but the continued economic, social and political turmoil in the country may -at best- delay gas demand growth. The government aims to develop the national gas market in all sectors, with a special focus for industrial, residential and commercial uses. It also plans to increase access to natural gas and develop the national gas infrastructure to cover the whole country.

In the power sector, Venezuela will need more gas to displace some of the diesel and other liquid fuels used in power stations, petrochemical plants and other facilities.⁵³⁸ Investment priorities since the mid-2000s have focused on developing new gas-fired generation in order to reduce reliance on hydropower and based on the assumption that state-owned PDVSA would rapidly increase its natural gas production. However, the company's persistent financial problems since 2009 have delayed its plans to develop offshore gas, and the state power company Corpoelec had to use higher-cost (and more polluting) diesel as an alternative in power generation. But as a result of continuous gas supply constraints, Venezuela is expected to expand hydroelectric capacity in the future,⁵³⁹ even if high reliance on hydrogenation has created problems at times of low hydro availability.

In the 'other sector', which includes energy own-use, natural gas will also be needed to support PDVSA's plans to increase production of light and medium crudes in mature oil fields in the western parts of the country, where Colombian gas used to flow until 2015 and where wells need gas injection to raise the pressure.⁵⁴⁰ With the declining output from its mature fields, gas use to enhance oil recovery is expected to keep on growing, at least until new fields can be developed.

Fuel demand has lowered with the economic recession,⁵⁴¹ but the extreme tightness in the market balances remain. In this paper, the scenario for additional gas demand follows the direction proposed

⁵³⁶ Enerdata, 7 July 2015, Eni starts producing gas from Perla giant field offshore Venezuela

⁵³⁷ Platts International Gas Report, July 14, 2014, Perla: Venezuela's big gas hope

⁵³⁸ PDVSA website, Gasificación Nacional

⁵³⁹ Argus, 14 July 2015, Venezuela plans new hydroelectric complex

⁵⁴⁰ Platts International Gas Report, 14 July 2014, Perla: Venezuela's big gas hope

⁵⁴¹ GDP is expected to contract by 7% in 2015. Source: Argus, 17 February 2015, Analysis: Repsol hangs gas pearl on Venezuela



by the IEA in 2015⁵⁴² and expects about 25 bcm in 2020 (flat compared to 2015⁵⁴³). Slow growth in energy own use, industry and in the power sector owing to economic difficulties is likely and gas demand reaches about 32 bcm in 2030 in our scenario.

- Production

Scenarios for gas supply up to 2030 will be influenced by the evolution of the economic (social and political) situation of the country, and the ability to attract upstream investment in order to develop its large reserves. The steep decline in international oil prices since 2014 has accelerated the economic problems in a country that depends on oil export revenues for more than 95% of annual hard currency revenue.⁵⁴⁴ It has also reduced PDVSA's ability to fund its upstream capital expenditure plans. Falling revenues mean suspended or cancelled upstream investments, leading to well closures and lower production for the national market and exports. The country's political instability remains a major challenge for international companies to invest billions of dollars in the upstream sector.⁵⁴⁵

The country aims to develop additional reserves, especially those located offshore with non-associated gas.⁵⁴⁶ While gas in associated fields can only be produced by the state, private operators are allowed to own 100% of non-associated gas projects, for which they also benefit from lower royalties and income tax.⁵⁴⁷ However, developing non associated gas, located mostly offshore, requires major investment in exploration and production but also to build the infrastructure to bring the gas to market. Locating and producing such reserves has been delayed due to the lack of investment.

Low international oil prices are an issue and too low national gas prices are also an obstacle. PDVSA has a monopoly of gas sales in Venezuela, so all production must be sold to it at a price which it sets. This is not a market price because natural gas prices in Venezuela are highly subsidized. After the Gas Law was introduced in 2001, the gas price agreed with the private gas producers was fixed at \$0.60-0.90/MMBtu for lower cost onshore gas production. In 2014, the wellhead price was \$0.127/MMBtu and for the consumer it is \$0.784/MMBtu. PdVSA bears the difference between the cost of gas and the domestic sales price. The argument is that the gas is being used in power plants (electricity prices are also subsidized), and frees up diesel and fuel oil for export at international prices, providing revenues to support the subsidies. It is understood that for the country's first offshore gas development, PdVSA has agreed a higher price, with Repsol/ENI being paid \$3.69/MMBtu.⁵⁴⁸

- Balances

We consider that natural gas demand will follow natural gas production as seen in Figure 84. Limited supply is likely to constrain gas demand growth but we do not anticipate the need for imports except during dry seasons. The possibility of exporting gas in our timeframe is even less likely.

⁵⁴² IEA (2015d), pp.50-52

⁵⁴³ IEA (2016a), p.II.8

⁵⁴⁴ Annual inflation reached triple digits in 2015 and the local currency has plummeted in value with respect to the US dollar. The country also has high foreign debt, which reached \$10 billion in 2015. Source: Argus news, 26 Nov 2014, Venezuela faces 'difficult times': PdV

⁵⁴⁵ PDVSA exploits most natural gas, but private companies are also active on the market such as Repsol-YPF, Chevron and Statoil

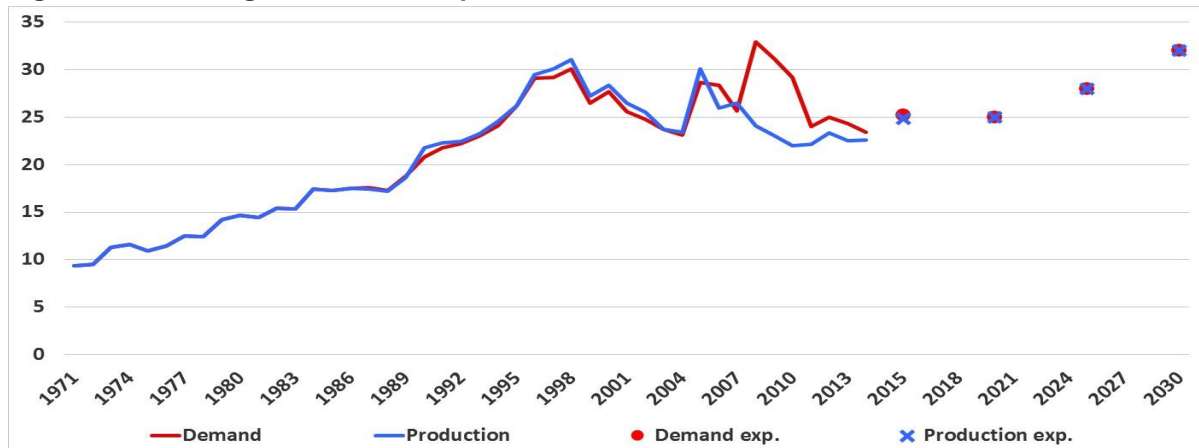
⁵⁴⁶ Platts International Gas Report, 14 July 2014, Perla: Venezuela's big gas hope

⁵⁴⁷ The regulatory regime that applies to oil and gas exploration and production includes several provisions, the main ones can be found in the Constitution of the Bolivarian Republic of Venezuela (Special Official Gazette No. 5.908, 19 February 2009), Organic Hydrocarbons Law (Special Official Gazette No. 5.453 24 March 2000, reprinted in Official Gazette N° 38.493, August 2006) (OHL) and Organic Gaseous Hydrocarbons Law (Official Gazette No. 36.793 23 September 1999) (OGHL)

⁵⁴⁸ Platts International Gas Report, 14 July 2014, Perla: Venezuela's big gas hope



Figure 84: Natural gas demand and production in Venezuela, 1971 – 2030, bcm



Sources:

1971-2015: IEA, Natural gas information, various reports

2016-2030: Author's estimates

What future role for LNG?

During dry seasons and limited hydro availability, thermal power plants, especially gas-fired will be needed to balance the system. In these periods, Venezuela is likely to remain a net gas importer if it does not want to face power shortages. At the time of writing, the only option was imports from neighbour Colombia, with which cross border capacity already exists. Colombia is planning to import LNG from 2017 (or as soon as its regas terminal starts operation) and some volumes of regasified LNG could potentially end up in the Western part of Venezuela using the existing pipeline capacity.

Venezuela has been examining the possibility of LNG exports with different international oil companies since the 1980s but has made little progress, changing its policy on LNG exports several times. In September 2011, PdVSA announced its latest position in that it was freezing all its LNG export projects due to falling prices that made investments uneconomic. It also stipulated that offshore gas projects would focus on feeding the growing national market.⁵⁴⁹ Production from the Perla field is expected to rise quickly, but it probably will not be enough to develop exports.⁵⁵⁰

In May 2016, Venezuela reached a preliminary agreement with Trinidad and Tobago to discuss a joint venture to market LNG produced at Trinidad's Atlantic complex using gas from the Venezuelan side of the cross border offshore Loran-Manatee field. The discussions were at preliminary state at the time of writing (mid 2016), and it was too soon to tell the impacts or even if the project would go ahead.⁵⁵¹

⁵⁴⁹ As stated in Decreto 310 'Ley Orgánica de Hidrocarburos Gaseosos'. Source: Gaceta Oficial (1999)

⁵⁵⁰ Argus, 17 February 2015, Analysis: Repsol hangs gas Pearl on Venezuela

⁵⁵¹ Argus Latin America Energy, 1 June 2016, Port of Spain to pay for Dragon pipeline



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