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**Working Paper**

## Natural gas pricing GSA Bolivia-Brazil using virtual hub and expected monetary value instruments

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**Institute for Advanced Development Studies**



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expected monetary value instruments**

By:

Jorge L. Gumucio  
Sergio M. Medinaceli

Development Research Working Paper Series  
No. 06/2019

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## Natural gas pricing GSA Bolivia – Brazil using virtual hub and expected monetary value instruments

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*Sergio M. Medinaceli*<sup>†</sup>

*La Paz, november 2019*

### **Abstract**

The purpose of this paper is to show the shortcomings of incentive policies, specifically competitiveness, if they are designed without considering fundamentals of market development such as, level of demand, level of investment, and availability of alternative sources of supply.

We focus on the analysis of the main market, financial, and economic variables in the Bolivia-Brazil Gas Supply Agreement, their relationship, development and dynamics through time and the current situation before the contract is renegotiated in 2019. Our analysis centers on the effective negotiation margin that Bolivia has calculated from the overall production costs of Bolivian gas (using EMV) vis a vis the opportunity cost of Brazil importing LNG. Using 10%-15% as discount rates and WTI prices between \$50 and \$60/bbl, the natural gas price result of EMV is between \$ 4.96 and \$ 7.99/MMbtu. Using the Bolivian tax incentive gas price should be between \$2.29 and \$5.16/MMbtu. Under the assumptions that WTI levels would be around \$ 60/bbl, investors use a 15% discount rate to invest in Bolivia, incentive policy is in place, and the price of LNG is around \$ 6.84/MMbtu; the opportunity cost of Brazil importing gas from Bolivia is \$ -0.55/MMbtu. The same case without incentive policy will yield a \$ -3.38/MMbtu. On the other hand, if the transport tariff is reduced the margin becomes positive under the assumption that the incentive policy is still in place. Therefore, as the price of LNG becomes more competitive through increase in supply (worldwide), Brazil will set its negotiation position around the price that they could import LNG on the short to medium term.

**JEL Classification:** Q31, Q35, F15.

**Keywords:** Netback prices, GSA, Gas Pricing, Gas Contract Negotiation, Virtual Hub, Expected Monetary Value.

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## Resumen

El documento se enfoca en el análisis de las principales variables de mercado, financieras y económicas en el Acuerdo de Suministro de Gas Bolivia-Brasil, en términos de su relación, desarrollo y dinámica a través del tiempo y la situación antes de que el contrato se renegocie en 2019. El análisis se centra en el margen de negociación efectivo que Bolivia ha calculado a partir de los costos generales de producción de gas boliviano (utilizando EMV) con respecto al costo de oportunidad de que Brasil importe GNL. Usando 10%-15% como tasas de descuento y precios WTI entre \$ 50 y \$ 60 / bbl, el resultado del precio del gas natural de EMV está entre \$ 4.96 y \$ 7.99 / MMBtu. Así, el uso del incentivo fiscal boliviano debería estar entre \$ 2.29 y \$ 5.16 / MMBtu. Bajo los supuestos de que los niveles de WTI estarían alrededor de \$ 60 / bbl, los inversores usan una tasa de descuento del 15% para invertir en Bolivia, la política de incentivos está “en su lugar” y el precio del GNL es de alrededor de \$ 6.84 / MMBtu. El costo de oportunidad de que Brasil importe gas desde Bolivia es de \$ -0.55 / MMBtu. El mismo caso sin política de incentivos generará \$ -3.38 / MMBtu. Por otro lado, si se reduce la tarifa de transporte, el margen se vuelve positivo bajo el supuesto de que la política de incentivos todavía está vigente. Por lo tanto, a medida que el precio del GNL se vuelve más competitivo a través del aumento de la oferta (mundial), Brasil establecerá su posición de negociación en torno al precio que podría importar GNL a corto y mediano plazo.

**Códigos JEL:** Q31, Q35, F15.

**Palabras Clave:** Precios de netback, GSA, precios de gas, negociación de contratos de gas, Hub virtual, valor monetario esperado.

## 1. Introduction

The largest commercial Gas Supply Agreement (GSA) in Latin America is about to turn 20 years old and its original terms and conditions are due to be renegotiated in 2019 between the governments of Bolivia and Brazil through their correspondent oil companies Yacimientos Petroliferos Fiscales Bolivianos (YPFB) and Petroleo Brasileiro S.A. (Petrobras).

The history and conceptual structuring of the project has come a long way from the early 1990's when the project was initially conceived. Petrobras started to develop the natural gas market in Brazil in 1988 supplying natural gas (associated gas) to its distribution companies in Sao Paulo. At that time, the overall market penetration for natural gas in Brazil was less than 2%.<sup>1</sup> Meanwhile, Bolivia had started to seek market diversification for its natural gas reserves since the contract with Argentina (in place since 1970s) was going to be negatively affected by new discoveries in the latter. These two conditions led Petrobras and YPFB to sit down and consider the possibility of Bolivian gas supplying the Brazilian market. This agreement was reached in 1993.

For the project to proceed it was necessary to secure a financial structure that allowed, in first place, the pipeline to be built. Petrobras was able to interest British Gas, Tenneco El Paso Energy, and Broken Hill Proprietary to constitute TGB (Transportadora Brasileira Gasoducto Bolivia-Brasil, S.A.). On the Bolivian side, YPFB and Enron reached an agreement to build the pipeline and establish the transport company GTB (Gas Transboliviano) along with Shell and a private equity fund which included proceeds from Bolivian Pension Funds. To secure checks and balances as well as mitigate financial risk allocation, both transport companies (GTB-TBG) allowed each other to have participation on the other.

Uncertainty on some of the basic assumptions (price in Brazil and reserves in Bolivia) of the project forced the financial entities to find creative ways to overcome difficulties. On the Brazilian side, the World Bank and the Inter-American Development Bank were able to finance \$ 380M in soft loans equivalent to 40% of TBG, guaranteeing a competitive gas price to the end user. On the Bolivian side, things were more complex. Despite YPFB being able to raise close to \$ 1 billion of fresh capital for the downstream, the estimations of reserves were not enough to meet minimum quantities of the contract. Accordingly, the

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<sup>1</sup> Peter Law and Nelson de Franco: Public Policy for the Private Sector, International Gas Trade- The Bolivian Brazil Pipeline (May 1998).

pipeline's repayment risk was doubtful. Petrobras had to step in and came up with a prepaid financial option that ensured an 80% turnkey contract to build the pipeline. Repayment was agreed to be made through the "purchase" of a capacity option (TCO) in which volumes transported had zero transport cost. The remaining 20% was financed by shareholder's equity.

The first part of the Bolivia-Brazil pipeline, extending 1,800 kilometers from Rio Grande, Bolivia, to São Paulo, Brazil, was completed in December 1998, and Bolivian gas started flowing to Brazil in July 1999. Currently the pipeline has a throughput capacity of 32.29 MMCMD<sup>2</sup>. The second part of the pipeline, a 1,100-km extension from São Paulo to Porto Alegre, Brazil, was completed in April 2000. With a total length of 3,150 kilometers, the BBPL is the longest pipeline in Latin America. Its total cost was estimated at \$ 2.5 billion.

## **2. The Contract**

On the 16<sup>th</sup> of August 1996, the final Gas Supply Agreement was signed in Rio de Janeiro, after a series of negotiations and inclusions from the original draft. The first draft of the GSA was signed on the 17<sup>th</sup> of February of 1993 in Cochabamba, Bolivia, and the final draft was submitted on August 1995 with all agreed amendments.

The original GSA contract has gone through various modifications by means of 6 Addenda. The Addendum 1 was signed on December 1998, the Addendum 2 on March 2000, the Addendum 3 on February 2001, the Addendum 4 on December 2009, the Addendum 5 on September 2011 and the final Addendum 6 was signed on the 18<sup>th</sup> of August 2014.

### **2.1 Quantity**

The GSA quantity was defined in the 4th Clause of the Contract. The base amount was established as 8 MMCMD for the first year, escalating to 16 MMCMD from 2006 on (see table 1). The quantity schedule is part of Annex 1 of the GSA.

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<sup>2</sup> GTB (ver <http://www.gastransboliviano.com/info/capPres/SitePages/Inicio.aspx>).

**Table 1. Volumes GSA**

Year	QDC = QDG1		QDG2					Pricing		Transport		
	Original	Addenda2 2000-2006 Current	Original	Addenda2 2000-2006 Current	Addenda2 2000-2006 Total	QDCB	QDCA	QDCB	QDCA	TCQ	TCO	TCX
1999	8.00	8.00	0.00	0.00	0.00	0.00	0.00	8.00	0.00	2.20	0.00	0.00
2000	9.10	9.10	5.50	5.46	5.46	5.46	0.00	9.10	0.00	9.10	0.00	0.00
2001	10.30	13.30	8.20	8.24	8.65	8.65	0.00	10.30	3.00	10.30	3.00	0.00
2002	11.40	20.40	9.10	9.12	14.28	11.40	2.88	11.40	9.00	11.40	6.00	3.00
2003	12.60	24.60	10.10	10.08	18.45	12.60	5.85	12.60	12.00	12.60	6.00	6.00
2004	13.70	30.08	11.00	10.96	24.06	13.70	10.36	13.70	16.38	13.70	6.00	10.38
2005	14.90	30.08	11.90	11.92	24.06	14.90	9.16	14.90	15.18	14.90	6.00	9.18
2006*	16.00	30.08	12.80	12.80	24.06	16.00	8.06	16.00	14.08	16.00	6.00	8.08
2007-2019	**18.08	30.08		14.46	24.06	16.00	8.06	16.00	14.08	18.08	6.00	6.00

Source: Own elaboration from YPFB reports.

**References:**

QDC = Daily Contracted Quantity

QDG1 = Daily Contracted Quantity Guaranteed by YPFB

QDG2 = Daily Contracted Quantity Guaranteed by Petrobras ("Take-or-Pay" Yearly)

QDCB = Base Contractual Daily Quantity – Base Price determined in Original GSA clause 11th

QDCA = Additional Contractual Daily Quantity- Base Price determined to be \$ 1.20/MMBTU

TCQ = Transport Capacity Base

TCO= Transport Capacity Option

TCX= Transport Capacity Additional

In the same clause (4<sup>th</sup>) of the original GSA contract, two very interesting things are mentioned. The first is the establishment of a Transport Capacity Option in favor of Petrobras for 6 MMCMD over a 40-year period. The cost of this option was USD 81,000,000 (eighty-one million USD) and was fully prepaid by Petrobras as part of the financial agreement reached by Bolivia and Brazil to channel funds and move forward with the project. In Addendum 1, the volumes in the TCO, were marginally increased from year 1 to year 7 (2000-2006). However, the volumes from year 8-20 (2007-2019) remained unchanged. It is important to note that validity of the TCO doubles the validity of the contract, and it is not clear if for whatever reason the GSA is not renewed for another 20 years, Petrobras will be eligible for a refund.

The second interesting item that comes up in the 4<sup>th</sup> Clause of the GSA is the creation of an "irrevocable" Purchasing Option in favor of Petrobras, granting preferred rights of acquiring additional volumes of Bolivian gas up to 30 MMCMD. The only condition precedent that would void this option is if the Bolivian internal market demand cannot be met. The duration of this option matches the length of the contract (20 years) and Petrobras can transfer or sell it at any time. It is also determined that YPFB will have the preferential right to supply the volumes established in this option.

The Addendum 1 presents a small modification of volumes with respect to the original contract, with a net increase of 0.02 MMCMD in year 2004. However, Addendum 2 established significant changes in volume since the “additional” quantity is incorporated in the contract. Addendum 2 also establishes a differentiation category for volumes introducing the terms of QDCB and QDCA referring to a “Base” quantity (QDCB) and an “Additional” quantity (QDCA). This is very important since each of these categories has a different base price. Addendum 2 also sets forward the tranches of volumes that should be considered for transportation agreements and tariffs. It is interesting to note that the TCQ and TCO volumes match Petrobras’ TOP level, and that the TCO covers a little less than half of the QDCA volumes.

The only modification to the quantity in the GSA is reflected on Addendum 5 in which additional 2.24 MMCMD are contracted on interruptible basis. This volume is destined to the Cuiaba power plant, formerly an Enron project that, ironically, served as a milestone in breaking Petrobras monopoly of gas supply in Brazil. This additional volume is not part of the QDCA option and has a different price structure (same price as in the Gas Supply Agreement with Argentina).

## 2.2 Price

Clause 11<sup>th</sup> of GSA contract determines the price of the Bolivian gas to be exported to Brazil. The price structure is made up of three components:

- a. Base price for every year of the contract,
- b. A mechanism of adjustment based on competing fuels (alternative sources of energy) and
- c. A mechanism designed to dampen the effect of significant changes in price from one period to another.

The Table 2 summarizes the Base Price for each year. The only change through time on this point was the clarification of the year of starting operations, being that 1999 was for Petrobras year 0 and year 1 for YPF.



**Table 2. Base Price (Addendum 6)**  
(in \$/MMBTU)

1999 -2001	2002-2003	2004	2005 -2006	2007	2008-2009	2010
0.95	0.96	0.97	0.98	0.99	1.00	1.01
2011-2012	2013-2014	2015	2011-2013	2018-2019		
1.02	1.03	1.04	1.05	1.06		

Source: Bolivia Brazil Gas Supply Agreement. Clause 11.1

The adjustment and dampen mechanisms are set by the following formulas:

**GSA Gas Pricing Formula**

*(Heat content = 9,200 kcal/m3)*

**PG = Price of gas per MMBTU in \$ calculated based on:**

- **PG** =  $P_i [(0.5 \cdot FO1/FO1o) + 0.25 \cdot (FO2/FO2o) + 0.25 \cdot (FO3/FO3o)]$
- **Pi** = initial price of gas in \$/ MMBTU based table 7
- **FO1** = 3.5% sulphur, CAGRoes FOB Med Basis Italy (\$/mt)
- **FO2** = 1% sulphur, US Gulf Coast Waterborne (\$/bbl)
- **FO3** = 1% sulphur, CAGRoes FOB NWE (\$/mt)

FO1o, FO2o, and FO3o are the arithmetic averages for the same Fuel Oil as defined above from the average daily price points determined in accordance with the daily higher and lower quotation for each day in the period from 1 January 1990 to 30 June 1992, excluding the period from 1 August 1990 to 31 January 1991, corresponding to:

**FO1<sub>o</sub>**: 66,0577 **FO2<sub>o</sub>**: 13,6744 **FO3<sub>o</sub>**: 89,8493

**Pt** =  $(0.5 \cdot PG) + (0.5 \cdot P_{t-1})$

The formula applies to QDCB and QDCA volumes with the only difference that QDCA has a fixed initial price of \$ 1.20 /MMBTU. The yearly price is calculated as a weighted average price of both volume segments.

The main driver of price variation in the GSA contract is the price of oil. There is a robust correlation factor (>90%) between the price of oil (WTI) and the price of natural gas exported from Bolivia to Brazil. The initial price and the adjustment mechanism in the GSA

were designed with the idea that Bolivian natural gas was going to replace/compete with “dirty” fuel oils and its price should have reflected the opportunity cost of generating energy on a cleaner fuel. Therefore, the GSA gas price reflects a gas to oil competition.

### **Transport Tariffs**

The transportation of natural gas from Bolivia to Brazil is in charge of two companies. In Bolivia Gas Transboliviano (GTB) and in Brazil Transportadora Brasileira Gasoducto Bolivia Brasil (TBG). Both companies have a similar principle in the calculation and adjustment of the tariffs. A base tariff was calculated taking into account Capex, volumes and a rate of return over a period of time. For GTB the tariff was set to \$ 0.3176/MMBTU for capacity and \$ 0.002/MMBTU for transport both set on 1996 as base year and adjusted for 0.5% annually<sup>3</sup>. The current GTB tariff is \$ 0.3549/MMBTU.

For TBG, the tariff was set in segments corresponding to the transport contracts, that is one for TCQ, one for TCO, and one for TCX. For the base volume or TCQ the capacity tariff was set to \$1.14/MMBTU adjusted annually from 1996 at 0.5% and the transport tariff to \$0.002/MMBTU adjusted to the median of IGP-M, IGP-DI, and IPA-DI from the first business day of 1996. For the TCO, or Transport Capacity Option there is only a transport fee of \$0.0020/MMBTU adjusted to the median of IGP-M, IGP-DI, and IPA-DI from the first business day of 1996. For the TCX segment, the capacity tariff was set to \$1.17/MMBTU adjusted to 0.5% and the transport tariff was set to \$0.002/MMBTU adjusted to the median of IGP-M, IGP-DI, and IPA-DI; both adjusted from the first business day of 1996.

<sup>4</sup>The current level of tariffs for TBG are: TCQ \$ 2.0499/MMBTU, TCO \$0.0063/MMBTU and TCX \$2.1036/MMBTU.

## **3. Market Conditions**

### **3.1 Brazil**

#### **3.1.1 Demand**

As time went on, the dynamics of the Brazilian gas market changed. In February 2000 Petrobras created the PPT (Portuguese acronym for Priority Thermoelectric Program) to start diversifying the Brazilian energy matrix by potentially constructing and implementing 55 Thermoelectric plants to add 15 GW of capacity to the power grid (up to June 2015,

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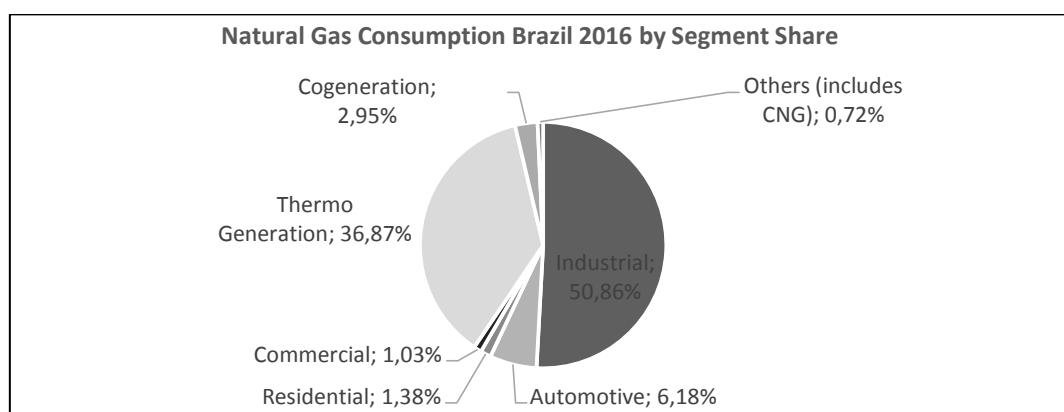
<sup>3</sup> Gastransboliviano (ver [www.gastransboliviano.com](http://www.gastransboliviano.com)).

<sup>4</sup> Boletim Mensal de Acompanhamento da Indústria de Gás Natural – Edição 127 – September 2017.

only 22 plants came into place adding 9.2 GW). The main incentives to invest in this program were: (i) the price of gas, (ii) a guaranteed PPA for the power producer, and (iii) access to soft financing. Before most of the plants came into place, a 20% compulsory rationing was put in place in May 2001 due to a severe drought. This stayed in effect until February 2002 effectively requiring a change on efficiency in the patterns and technology of energy usage, resulting in a permanent decline of power demand in the country<sup>5</sup>.

From 2003-2009 only 20% (on average) of total Thermoelectric capacity was used, which led Petrobras to take aggressive market measures to increase demand for natural gas coming from Bolivia to reduce its exposure on volumes contracted under the TOP clause on the GSA. Petrobras started to offer incentives to the industrial, commercial and vehicular sectors achieving significant growth rates. Currently the overall market segmentation of natural gas in Brazil and respective volumes are shown in Figures 1 and 2.

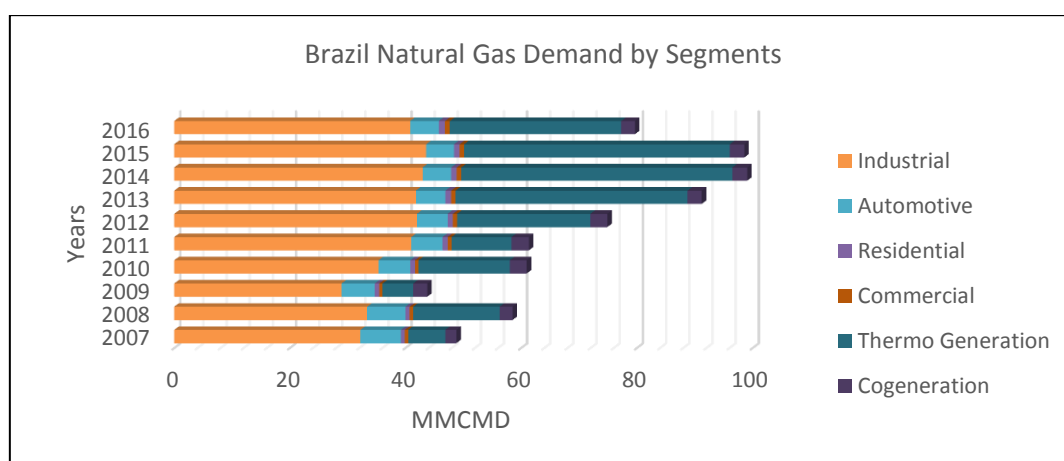
**Figure 1. Natural Gas Consumption Brazil 2016**



**Source:** Own elaboration. Data from BOLETIM MENSAL DE ACOMPANHAMENTO DE INDÚSTRIA DE GÁS NATURAL ([www.mme.gov.br](http://www.mme.gov.br)).

<sup>5</sup> A integração truncada das termelétricas a gás natural no setor elétrico brasileiro free translation (Blog Infopetro 4/19/17).

**Figure 2. Natural Gas Volume Consumption by Segments**

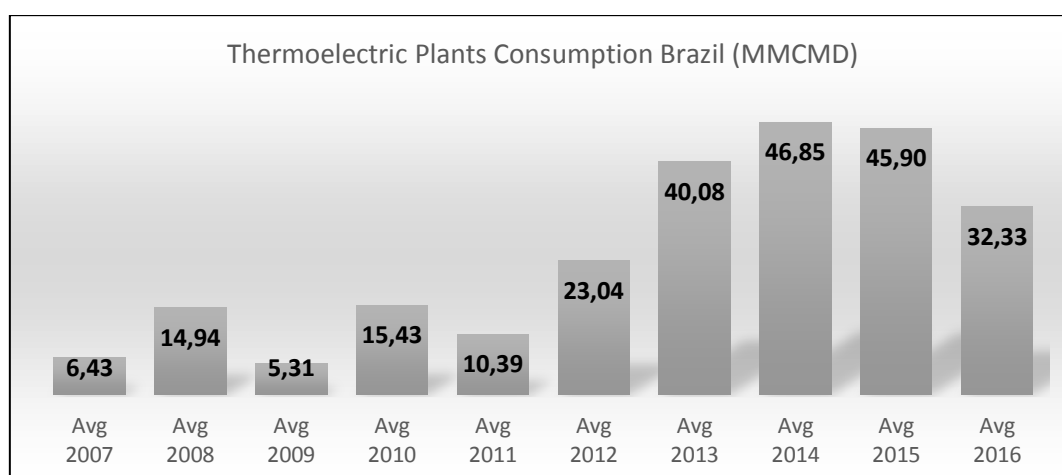


**Source:** Own elaboration. Data from BOLETIM MENSAL DE ACOMPANHAMENTO DE INDÚSTRIA DE GÁS NATURAL ([www.mme.gov.br](http://www.mme.gov.br)).

In 2006, the ONS (Portuguese acronym for National Electric System Operator) decided to change its approach to the Thermoelectric plants' implementation and dispatch. The decision was that expansions in generation were going to be based on competitive biddings for the short and medium term (3 and 5 years respectively). The most competitive bid gets contracted on availability basis, paid a fixed fee on standby plus a variable fee when dispatching. Due to dry conditions, dispatch rates for the Thermoelectric Plants jumped from an average of 20% between 2003-2009 to 56% between 2012 -2014. The peak average dispatch rate was achieved in 2014 at 74%<sup>6</sup>. Figure 3 shows the average consumption for the Thermoelectric sector in Brazil.

<sup>6</sup> A integração truncada das termelétricas a gás natural no setor elétrico brasileiro free translation (Blog Infopetro 4/19/17).

**Figure 3. Thermoelectric Plant Consumption Brazil**



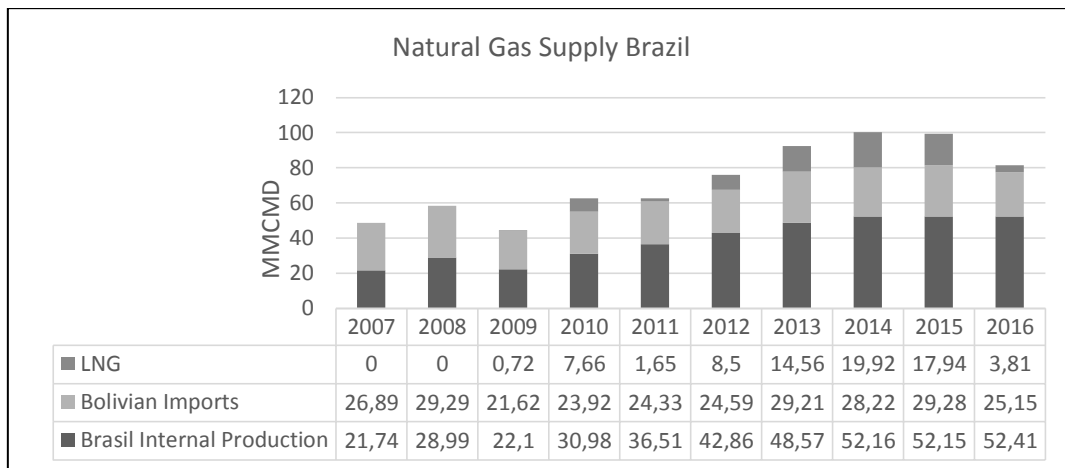
**Source:** Own elaboration. Data from BOLETIM MENSAL DE ACOMPANHAMENTO DE INDÚSTRIA DE GÁS NATURAL ([www.mme.gov.br](http://www.mme.gov.br)).

The Brazilian natural gas market has experienced meaningful growth, not only in absolute volume consumed but also in its ability to penetrate different market sectors in addition to the power generation. The thermal power generation experienced a 16.5% CAGR (Compound Average Growth Rate) due to an accentuation of dry periods from 2012 to 2015, whereas the industrial sector has had a steady growth over the last decade, with a CAGR of 2.4% from 2007 to 2016.

### 3.1.2 Supply

Natural gas supply in Brazil comes basically from three sources: national production, imported gas from Bolivia and LNG. As shown in the Figure 4 there's a steady increase in national production from 21.74 MMCMD in 2007 to 52.41 MMCMD in 2016 representing a 9.20% CAGR. On the other hand, we have imported Bolivian gas which over the years has lost market share, -0.61% CAGR (10-year period). Two main factors contributed to this loss. First, it is constrained by the fixed capacity of the BBPL (32 MMCMD) in a market that has been growing at a 5.09% CAGR in the last decade and the "game changer" factor, the inclusion of LNG in the Brazilian natural gas market.

**Figure 4. Natural Gas Supply Brazil**



**Source:** Own elaboration. Data from BOLETIM MENSAL DE ACOMPANHAMENTO DE INDÚSTRIA DE GÁS NATURAL ([www.mme.gov.br](http://www.mme.gov.br)).

In 2006, Brazil prioritized the construction of LNG terminals to add flexibility to the natural gas supply and to expand potential Thermoelectric generation. The current regasification capacity of all LNG terminals is 41 MMCMMD, 37% more than the GSA contract. These plants alone could provide enough gas for the average 2016 demand in the South and South-East regions.

Currently, LNG regasification plants are controlled and operated by Petrobras. However, this situation could change soon if Petrobras decides to include private partners that could develop integrated energy projects, such as the projects being developed by Genpower Energy in Porto de Sergipe and the Bolognesi group in Pernambuco y Rio Grande.<sup>7</sup>

The natural gas supply in the Brazilian market has not kept up with the demand, despite the continuous growth of national production over the last decade. However, the introduction of LNG has given Brazil the ability and the flexibility to deal with peak demand when extraordinary hydro conditions (low reservoir levels) may happen. We believe that Brazil could potentially increase its natural gas production in the coming years when the Pre-salt fields come in full production, effectively decreasing dependency on imported gas from Bolivia.

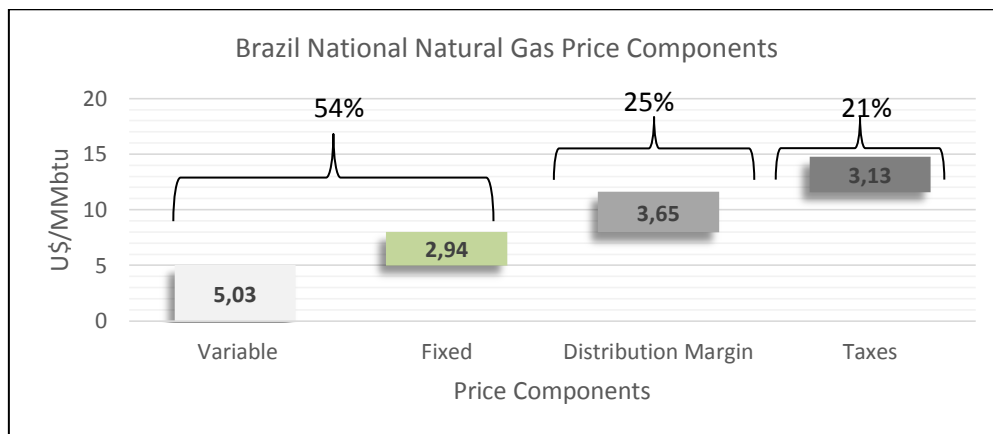
<sup>7</sup> A integração truncada das termelétricas a gás natural no setor elétrico brasileiro (Blog Infopetro 4/19/17).

### 3.1.3 Prices

Prices in the Brazilian market have been determined by the cost of supply (national + imported) as well as by the policies adopted to foster gas consumption over other sources of energy (heavy fuels), especially in the industrial and vehicular segments.

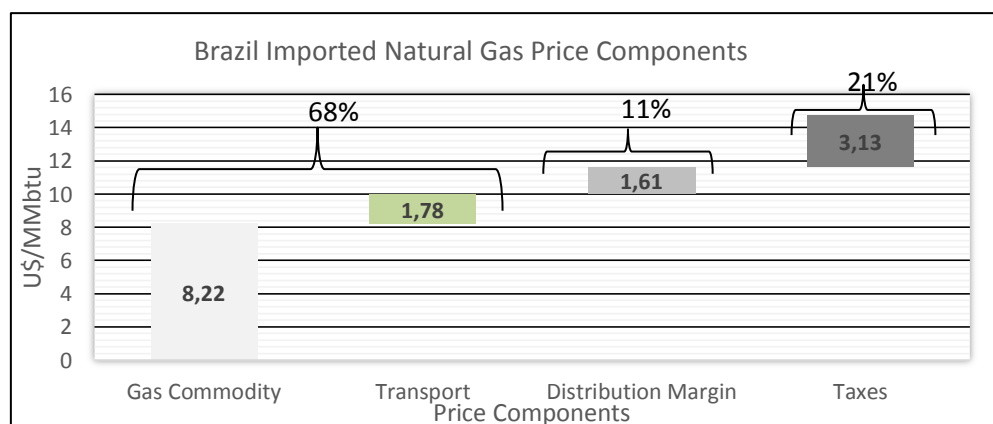
From the price formation structure shown in Figure 5 and, is clear that adjustments in the final price are controlled through changes in the distribution margins, a cheaper national gas (commodity + transport) can generate higher distribution margins and can be adjusted (lowered) to obtain a lower price for end customers. Maybe this mechanism was used by Petrobras to offer a discounted gas price from 2012 to November 2015 in the South and Southeast regions. Figure 6 shows the imported gas structure in the country.

**Figure 5. Brazil National Gas Cost Structure**



**Source:** Own elaboration. Data from BOLETIM MENSAL DE ACOMPANHAMENTO DE INDÚSTRIA DE GÁS NATURAL (MME 2013).

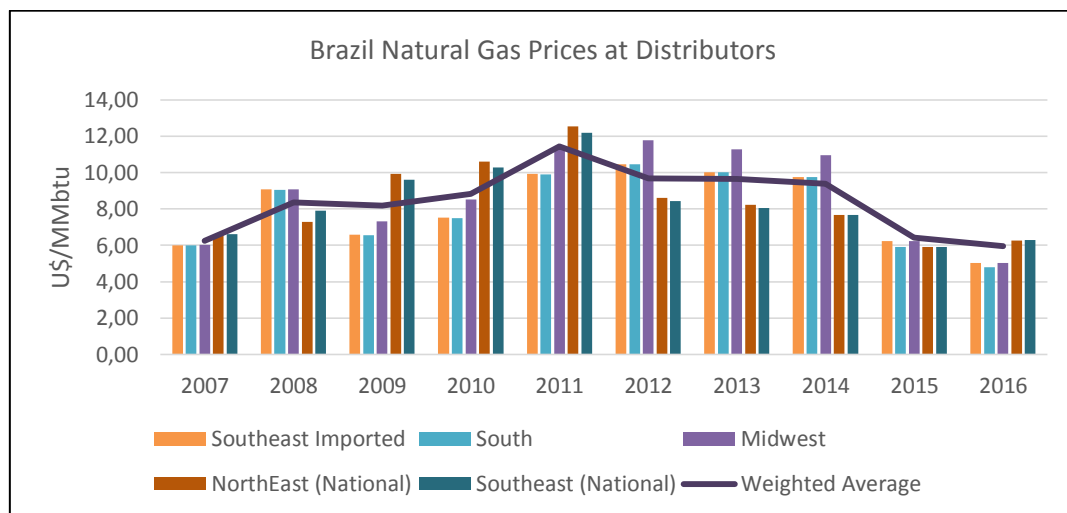
**Figure 6. Brazil Imported Gas Cost Structure**



**Source:** Own elaboration. Data from BOLETIM MENSAL DE ACOMPANHAMENTO DE INDÚSTRIA DE GÁS NATURAL (MME 2013).

The Brazilian natural gas market is segmented in four regions: Northeast, Midwest, South and Southeast. The imported gas from Bolivia is destined to the Southeast region where a significant portion of Brazilian industry and population are located. Figure 7 shows the pricing policy implemented by Petrobras in these four regions, in which the more expensive gas is sold in the Midwest (less developed region in Brazil) and the cheaper gas in the South and Southeast. This figure clearly shows the need for Petrobras to maintain competitive prices (below the overall weighted average price) in these two regions by equating the Brazilian gas and Bolivian gas prices through a discount mentioned in the previous paragraph, to foster consumption.

**Figure 7. Brazil Natural Gas Prices at Distribution**



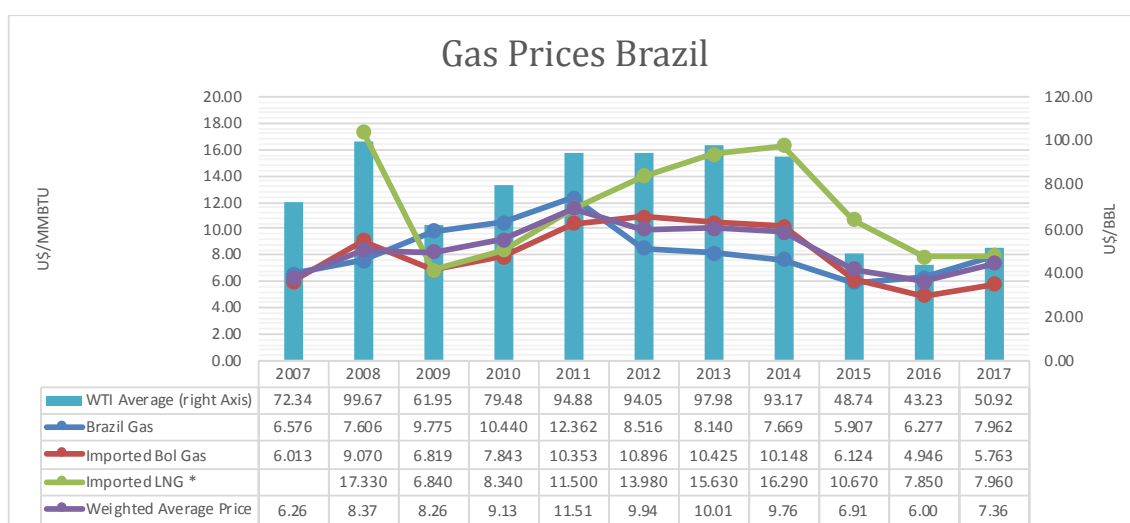
**Source:** Own elaboration. Data from BOLETIM MENSAL DE ACOMPANHAMENTO DE INDÚSTRIA DE GÁS NATURAL ([www.mme.gov.br](http://www.mme.gov.br)).

It seems that at higher crude price (WTI) levels there is a larger difference between Brazilian gas (more expensive) and Bolivian gas. However, this trend is reverted with the discount policy adopted by Petrobras from 2012 up to the end of 2015. We can expect that at lower crude prices, both, the Brazilian and Bolivian gas will be at practically the same level.

The prices in which Brazil has bought LNG also reveals that Petrobras is willing to pay higher natural gas prices to satisfy peak demand without going into long term contracts. From Figure 8 we can infer that Petrobras has been buying LNG at spot prices, and that at lower crude prices it is a viable and competitive option to Bolivian gas.



**Figure 8. Gas Prices Brazil**



**Source:** Data from BOLETIM MENSAL DE ACOMPANHAMENTO DE INDÚSTRIA DE GÁS NATURAL ([www.mme.gov.br](http://www.mme.gov.br)).

Figure 9 shows the end consumer prices (with taxes) for each segment of consumption, where we can see that there is a cross subsidy structure in favor of thermoelectric generation.

**Figure 9. End Consumer Natural Gas Prices Brazil**



**Source:** Data from BOLETIM MENSAL DE ACOMPANHAMENTO DE INDÚSTRIA DE GÁS NATURAL ([www.mme.gov.br](http://www.mme.gov.br)).

In December 2016, the weighted average cost of gas was \$7.35/MMBTU and the average price for the thermal power generation sector was \$3.94/MMBTU resulting in a gross margin of \$-2.02/MMBTU. On the other hand, the weighted average price for the residential, industrial and automotive is \$13.17/MMBTU resulting in a \$5.82/MMBTU gross margin.

If we were to apply matching and marginal cost principles on effectively allocating natural gas supply to demand, we can assume that we have a base demand that is made up of the industrial, residential and automotive sectors (Industrial sector). These three sectors have a steady growth rate that generally accompanies the economic growth of the country. On the other hand, we have the thermal power generation sector where demand depends upon several factors: seasonal, cyclical and political (impossible to model). Therefore, a long-term (on volumes destined to supply thermal power generation plants) supply contract increases the risk of having an uncovered position, gas bought and paid for without demand.

Given these conditions, we believe that a long-term commitment on supply should be channel to the base demand (industrial sector) where the risk of TOP is minimized. Meanwhile, the thermal power generation sector should be partly supplied with gas contracted under interruptible contracts and partly with spot purchases options (LNG).

### 3.2 Bolivia

In Bolivia, there were several events that took place in the last decade that had an impact on the dynamics and commercial relationship within the GSA. In May 2005, a new Hydrocarbon Law (Law 3058) was enacted. The most significant changes related to:<sup>8</sup>

- Change the ownership definition (the State of Bolivia is the rightful owner of all hydrocarbon produced within the country).
- Implementation of new contract structures (Production Sharing Agreements, Service Contracts), voiding the Joint Venture agreements in place at that time.
- Tax increase by implementing a direct tax (IDH) of 32%.
- Participation of YPFB on earnings through Operation Contracts.

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<sup>8</sup> Generacion, Distribucion y Uso del excedente de Hidrocarburos en Bolivia Programa de Investigacion Estrategica en Bolivia (Del granado, Mokrani, Medinaceli, Gumucio).

- New role of YPFB (administrator and aggregator).
- Implementing new contract structures.

A year later, in May 2006, through Presidential Decree 28701, “Heroes del Chaco”, Bolivia nationalizes the hydrocarbon industry, taking effective control of the entire supply chain. YPFB, representing the Bolivian State, acquired (buyout settlement)<sup>9</sup> majority ownership rights in upstream and downstream assets (transport and refineries).

Additionally, YPFB assumed the role of sole aggregator and seller of hydrocarbons in Bolivia. All upstream companies were obligated to sign service contracts with YPFB, and to hand in their production to YPFB, who in turn, after paying taxes, royalties and participations, repays operational costs and distributes profits.

On December 2015<sup>10</sup>, Law 767 - Exploration and Exploitation Incentives - was enacted to promote investments in the exploration and exploitation in Bolivia. This law basically creates a compensatory fund made up of 12% of the IDH, and it benefits crude production, associated liquids (natural gas condensate), and additional production of the latter. This indirect subsidy (incentive to the production of gas by subsidizing the production of natural gas condensate) works within a range of prices (related to the WTI price), and its application is tied to location and size of the production field<sup>11</sup>. The net effect of the application of this law, basically reduces the overall government take. Under different price and production scenarios this subsidy could surpass the budgeted amount (12% of IDH collection) in which case, the government will issue NOCRES (Tax Credit Notes) in favor of the producer, that could distort cash flows of producers and negatively affect the tax revenues (beyond the already low government take) of the government.

To keep the internal market and export markets supplied, Bolivia depends on the production of its mega fields of San Alberto, San Antonio and Margarita. However, low investment in exploration and faster than expected decline curves are now constraining Bolivia’s capacity and credibility to supply all markets at current levels.

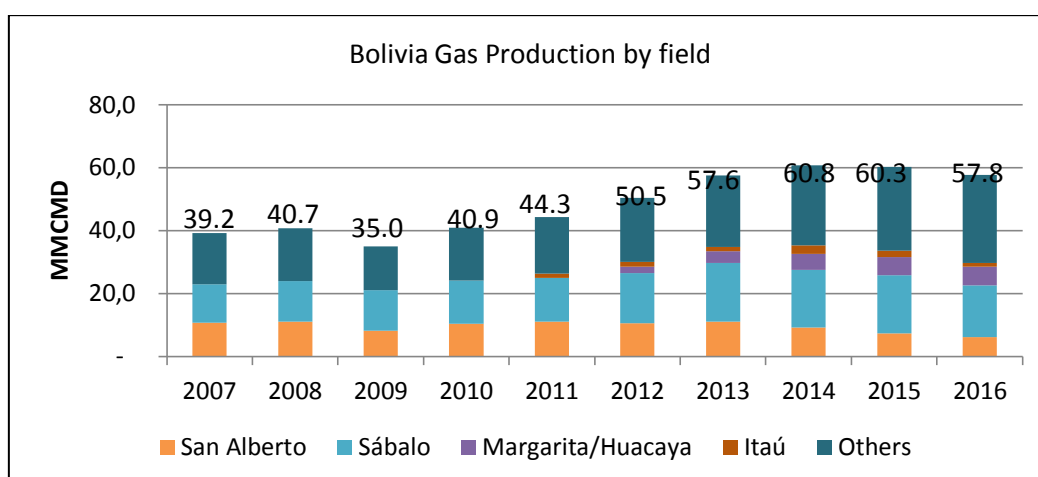
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9 YPFB paid Petrobras U\$ 106MM for 44.5% of Transierra, U\$ 112MM for two refineries. YPFB paid U\$ 241MM to Ashmore and Shell for Transredes (main hydrocarbon transport company) (Periodico La Razon, [http://la-razon.com/index.php?url=/economia/nacionalizacion-costo-us-millones\\_0\\_1287471279.html](http://la-razon.com/index.php?url=/economia/nacionalizacion-costo-us-millones_0_1287471279.html)).

10 Law 767 (<http://www.lexivox.org/norms/BO-L-N767.xhtml>).

11 Regulation to law 767 (<http://extwprlegs1.fao.org/docs/pdf/bol157310.pdf>).

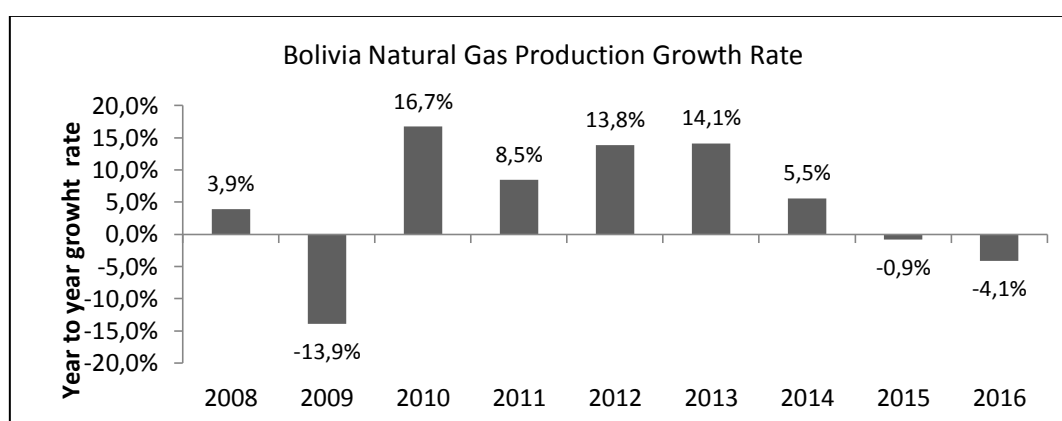
**Figure 10. Bolivia Gas Production by Field**



**Source:** Own elaboration. Data from Mauricio Medinaceli presentation for Fundacion Milenio (2017).

Figure 10 shows the declining participation of San Alberto and Sábalo on the total production and, from 2011, the introduction of Margarita and Itaú as complementary fields, which we believe are in “plateau” production and will soon start to decline as well. It is also important to analyze the year to year production growth rate that it has recently been declining as shown in Figure 11.

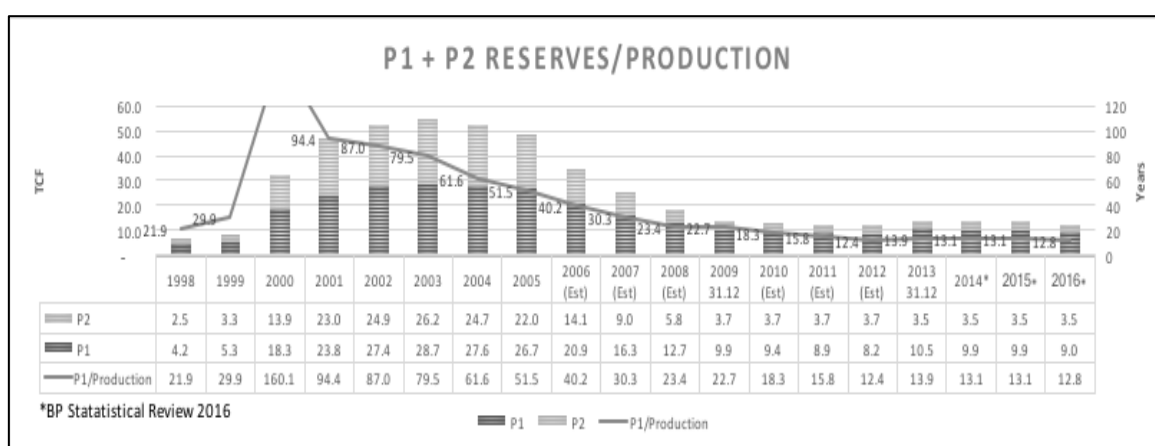
**Figure 11. Bolivia Natural Gas Production Growth Rate**



**Source:** Own elaboration. Data from Mauricio Medinaceli presentation for Fundacion Milenio (2017).

These two trends should be worrisome. The decline in production of the so-called Mega fields and the decrease in production on a year to year basis lead us to believe that Bolivia has not been able to discover new fields and therefore is unable to replace its reserves. Figure 12 shows the decrease in reserves (P1 + P2) and the consequent decline in the reserve production ratio.

**Figure 12. Reserve Production Ratio**



**Source:** Own elaboration. Data from YPFB and BP Statistical Review (2016).

One of the main concerns regarding the calculation of current natural gas reserves in Bolivia is that the last certification was performed in 2013 by GLJ Petroleum Consultants, estimating 10.45 TCF as P1 (Proven Reserves), equivalent to 13.9 years at 2013 production levels. The last estimation of reserves reported by BP Statistical Review situated Bolivian natural gas reserves at 9.0 TCF, enough to supply all markets (at 2016 production levels) for 12.8 years. However, if we consider the internal market growth rate, and the industrialization projects that reserve production ratio will be lower and Bolivia will be in no position to negotiate a contract with Brazil with same conditions as the current GSA (20 years, 30.08 MMCMMD).

## 4. The model

### 4.1 Assumptions and methodology

This section presents the main assumptions regarding the upstream models used to evaluate the main economic and finance conditions in the hydrocarbons sector in Bolivia. Also, we will present the methodology to estimate the break-even natural gas price to operate different scale gas fields in the country.

#### Cost and technical assumptions

- Four types of fields ( $i$ ) with initial proved reserves ( $R_{0,i}$ ) of 0.50; 1.00; 2.00 and 5.00 TCF
- Exploration cost of \$ 70 million for each type of field  $i$

- For 0.50 and 1.00 TCF fields the drilling cost development well is \$ 15 million
- For 2.00 TCF field the drilling cost development well is \$ 30 million
- For 5.00 TCF field the drilling cost development well is \$ 75 million
- The well productivity ( $\delta_i$ ) in 0.50 and 1.00 TCF fields is 20 MM scf per day
- The well productivity ( $\delta_i$ ) in 2.00 TCF field is 30 MM scf per day
- The well productivity ( $\delta_i$ ) in 5.00 TCF field is 75 MM scf per day
- The calorific content is 1.034 MMbtu/MCF
- Only for fields of 1.00; 2.00 and 5.00 TCF the processing plant cost is \$ 1.00 million for each 1.00 MM of scf per day processed gas
- For each type of field, the evaluation periods are 20 years
- The natural gas production profile ( $V_{t,i}$ ) at time  $t$  for each field  $i$  is:<sup>12</sup>

$$V_{t,i} = \frac{R_{0,i} \cdot \alpha_t}{\left[ 5 + \sum_{h=1}^9 \alpha_h + \sum_{j=1}^6 \left( \frac{1}{(1-d)^{-\frac{1}{b}}} \right)^j \right]} \quad t = 1 \dots 9$$

$$V_{t,i} = \frac{R_{0,i}}{\left[ 5 + \sum_{h=1}^9 \alpha_h + \sum_{j=1}^6 \left( \frac{1}{(1-d)^{-\frac{1}{b}}} \right)^j \right]} \quad t = 10 \dots 14$$

$$V_{t,i} = \frac{R_{0,i}}{\left[ 5 + \sum_{h=1}^9 \alpha_h + \sum_{j=1}^6 \left( \frac{1}{(1-d)^{-\frac{1}{b}}} \right)^j \right]} \cdot \left( \frac{1}{(1-d)^{-\frac{1}{b}}} \right)^{t-14} \quad t = 15 \dots 20$$

Where:

$\alpha_t$  of fields with 0.5 and 1.0 TCF starts at 0.10 and linearly ends at 0.9

$\alpha_t$  of fields with 2.0 and 5.0 TCF starts at 0.25 and linearly ends at 0.9

$d = -0.03$

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<sup>12</sup> Expressed in TCF per year.

$$b = -0.20$$

- The condensate production profile is:

$$v_{t,i} = \alpha_i \cdot V_{t,i} \cdot 10^6$$

Where:

$\alpha_i$  = the condensate yield.<sup>13</sup>

- Operation expenses ( $Opex_t$ ) per barrel of oil equivalent (Boe) come from the following expression:

$$Opex_t = 2 \cdot \left[ 179 \cdot \left( \frac{V_{t,i} \cdot 10^9}{365 \cdot 6} + \frac{v_{t,i}}{365} \right)^{-0.5119} \right]$$

- Total operation expenses ( $OPEX_t$ ) are:

$$OPEX_t = Opex_t \cdot \left[ \left( \frac{V_{t,i} \cdot 10^9}{6} + v_{t,i} \right) \right]$$

- Wellhead revenues ( $R_{t,i}$ ) come from the following expression:<sup>14</sup>

$$R_{t,i} = p \cdot V_{t,i} + q \cdot v_{t,i}$$

Where:

$p$  = natural gas wellhead price

$q$  = condensate wellhead price

- Based in the natural gas production profile and each wellhead production productivity ( $\delta_i$ ), the number of wellheads drilled in each year by each field's size is:

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<sup>13</sup> For fields of 0.5; 1.0 and 2.0 TCF this yield is 20 barrels of condensate for each MM cubic feet of natural gas; fields of 5.0 TCF the factor is 50.

<sup>14</sup> This equation doesn't present the conversion factors.

**Table 3. Drilling Time Profile by each field's size**  
(# wellheads)

Year	0.5 TCF	1.0 TCF	2.0 TCF	5.0 TCF
-5	-	-	-	-
-4	-	-	-	-
-3	-	-	-	-
-2	-	-	-	-
-1	-	-	-	-
0	1	2	4	4
1	1	1	1	1
2	-	1	1	1
3	1	1	1	1
4	-	1	1	1
5	1	1	1	1
6	-	1	1	1
7	1	1	1	1
8	-	1	2	2
9	1	1	1	1
10	-	-	-	-

Source: Medinaceli (2007), Medinaceli (2009), Medinaceli (2010) and Medinaceli (2016).

### Economic assumptions

- In Bolivia the hydrocarbons production must pay a 18% royalty plus a 32% production tax.<sup>15</sup> The expression used in the model is:

$$RT_{t,i} = 50\% \cdot R_{t,i}$$

- Based in current exploration and production contracts in Bolivia<sup>16</sup> the most likely scheme in the future is a profit sharing contract with 10% YPFB<sup>17</sup> participation.

$$YPFB_{t,i} = (R_{t,i} - RT_{t,i} - OPEX_{t,i} - dep_{t,i}) \cdot 10\%$$

- Income tax ( $IT_{t,i}$ ) is 25% and remittance tax ( $RT_{t,i}$ ) is 12.5%, according:

$$IT_{t,i} = (R_{t,i} - RT_{t,i} - OPEX_{t,i} - dep_{t,i} - YPFB_{t,i}) \cdot 25\%$$

$$RT_{t,i} = (R_{t,i} - RT_{t,i} - OPEX_{t,i} - dep_{t,i} - YPFB_{t,i} - IT_{t,i}) \cdot 12.5\%$$

- Wellhead prices  $p, q$  are constant over the project's life<sup>18</sup>
- All condensate and natural gas production is exported

<sup>15</sup> For a detailed description of the Bolivian fiscal system is in Medinaceli (2007), Medinaceli (2009), Medinaceli (2010) and Medinaceli (2016).

<sup>16</sup> Medinaceli (2006).

<sup>17</sup> Yacimientos Petrolíferos Fiscales Bolivianos, Bolivian state oil company.

<sup>18</sup> The difference between the wellhead oil Price and WTI Price in Bolivia is assumed 8 \$/Barrel.



- The depreciation rates ( $dep_{t,i}$ ), for income tax and YPFB participation in the profit sharing contract are: 5 years for drilling expenses; 8 years for processing plants and 10 years for other expenses.
- Other capital expenses are 10% of total exploration expenses plus 10% of total processing plant cost.
- Baseline discount rate ( $dr$ ) is 10%.
- Baseline probabilities are: 25% for success exploration ( $p_e$ ); 80% to discover a 0.5 TCF field ( $p_{0.5}$ ); 10% for 1.0 TCF ( $p_{1.0}$ ); 5% of 2.00 TCF ( $p_{2.0}$ ) and 5% of 5.0 TCF ( $p_{5.0}$ ).
- In 2015 Bolivia's Government approved an incentive act called "*Ley de promoción para la inversión en exploración y explotación hidrocarburífera*"<sup>19</sup>. This new legal act provides a cash incentive for condensate production associated with natural gas production. The estimation of this incentive can be modelled with the following expressions:

$$i_{t,i} = (-0.03 \cdot WTI_t^2 + 0.1479 \cdot WTI_t + 48.173) \cdot v_{t,i}$$

Where:

$WTI_t$  = International WTI price under "spot average" denomination publish by the Platts Oilgram Report

For  $WTI_t \leq 0$  and  $WTI_t \geq 106.29$  the incentive ( $i_{t,i}$ ) is zero.

For  $i = 0.5$  and  $i = 1.0$  the incentive is valid for 20 years; for  $i = 2.0$  is 18 years and for  $i = 5.0$  is 7 years.

## **Methodology**

The evaluation criteria for the natural gas/condensate oil developing field in Bolivia is the Expected Monetary Value (EMV) which equals the "*sum of the probability of unsuccessful exploration multiplied by expected after tax NPV loss from failed exploration costs, and the probability of each type of successful discovery multiplied by the expected after tax positive NPV from successful projects.*"<sup>20</sup> The usual expression for the net present value (NPV) of the total cash flow is:

<sup>19</sup> Incentive act for the promotion of investment in exploration and exploitation of hydrocarbons in Bolivia. The specific regulation is in Supreme Decree N° 2830 for July 6th. 2016.

<sup>20</sup> Daniel et al. (2010), p. 198.

$$NPV_i = - \sum_{t=-5}^0 \frac{I_{t,i,e} + I_{t,i,d} + I_{t,i,p} + I_{t,i,o}}{(1 + dr)^{5+t}} + \sum_{t=1}^{20} \frac{(R_{t,i} - RT_{t,i} - OPEX_{t,i} - YPFB_{t,i} - IT_{t,i} - RT_{t,i} + i_{t,i})}{(1 + dr)^{5+t}}$$

Where:

$I_{t,i,e}$  = Exploration investment<sup>21</sup>

$I_{t,i,d}$  = Wellhead drilling investment

$I_{t,i,p}$  = Processing plant investment

$I_{t,i,o}$  = Other investment<sup>22</sup>

The EMV for the investment decision is:<sup>23</sup>

$$EMV = p_e \cdot p_{0.5} \cdot NPV_{0.5} + p_e \cdot p_{1.0} \cdot NPV_{1.0} + p_e \cdot p_{2.0} \cdot NPV_{2.0} + p_e \cdot p_{5.0} \cdot NPV_{5.0} - (1 - p_e) \sum_{t=-5}^0 \frac{I_{t,i,e}}{(1 + dr)^{5+t}}$$

One of the objectives of this section is to find the natural gas wellhead price that generates an  $EMV = 0$  under different assumptions with main economic variables, e.g. the WTI price, the discount rate or the incentive applied in Bolivia for new exploration natural gas and condensate fields.

## 4.2 Results

Table 4 presents different levels of natural gas wellhead prices (in Bolivia)<sup>24</sup> under several values of discount rates and international WTI prices. Following Kaiser (2007), using 10% and 15% as discount rates and international oil WTI prices between 50 and 60 \$/Barrel, the natural gas price result is between \$ 4.96 and \$7.99/MMbtu. Table 5 shows that using the incentive the gas price should be between \$2.29 and \$5.16/ MMbtu.

<sup>21</sup> \$ 70 million.

<sup>22</sup> Equal to 10% of total investment during period t=-5 to t=0.

<sup>23</sup> An extensive discussion of this methodology can be found in Newendorp & Schuyler (2000), Mian (2002), and Johnston (2003).

<sup>24</sup> As mentioned before, the result is the natural gas price that generates an  $EMV = 0$ .

**Table 4. Natural gas wellhead prices – Without incentive**  
(\$/MMbtu)

Discount rates	International Oil WTI Price (USD/Barrel)								
	20	30	40	50	60	70	80	90	100
0%	2.17	1.89	1.61	1.34	1.06	0.78	0.51	0.23	*
5%	3.57	3.29	3.01	2.74	2.46	2.19	1.91	1.64	1.36
10%	5.80	5.52	5.24	4.96	4.68	4.40	4.12	3.84	3.56
15%	9.11	8.83	8.55	8.27	7.99	7.70	7.42	7.14	6.86
20%	13.78	13.50	13.21	12.93	12.65	12.36	12.08	11.79	11.51
25%	20.10	19.81	19.52	19.24	18.95	18.67	18.38	18.09	17.81

\* Prices are negative

**Source:** Results from Model.

**Table 5. Natural gas wellhead prices – With incentive**  
(\$/MMbtu)

Discount rates	International Oil WTI Price (USD/Barrel)								
	20	30	40	50	60	70	80	90	100
0%	2.17	*	*	*	*	*	*	*	*
5%	3.57	0.82	0.58	0.36	0.17	0.01	*	*	*
10%	5.80	2.74	2.50	2.29	2.11	1.96	1.85	1.77	1.72
15%	9.11	5.78	5.54	5.33	5.16	5.03	4.93	4.87	4.84
20%	13.78	10.24	10.00	9.80	9.63	9.50	9.42	9.37	9.36
25%	20.10	16.37	16.13	15.93	15.77	15.65	15.57	15.53	15.54

\* Prices are negative

**Source:** Results from Model.

To estimate the range of prices that Brazil will be willing to negotiate the new contract, we have structured a “virtual hub” which will reflect the opportunity cost of buying Bolivian gas *vis a vis* buying LNG (gas to gas). Basically this “hub” reflects the price of imported LNG (FOB prices) plus a fee (\$1.40/MMbtu) that covers transportation regasification and transport within Brazil and compares to the price of imported Bolivian gas considering all its price components required to get to the hub.

For finding out the order of magnitude of negotiation margins (for price), the price of Bolivian gas based on the following assumptions is:

- The average level of WTI and discount rate;
  - \$50/MMbtu @ 10%
  - \$60/MMbtu @ 15%
- Both cases with and without incentives.
- Both cases with transport tariffs calculated using current contract formula.<sup>25</sup>

<sup>25</sup> Current transport tariffs calculated using escalator factor stated in current transport contract and projected for 10 more years.

- Both cases with discounted tariffs.<sup>26</sup>
- Average WTI prices for 2009 = \$ 60/bbl => LNG \$ 5.44/MMbtu (FOB)<sup>2728</sup>
- Average WTI prices for 2017 = \$ 50/bbl => LNG \$ 6.56/MMbtu (FOB)

Table 6 summarizes the calculations based on the netback (from the hub to the wellhead) of the LNG price and how it compares to the producer price in Bolivia. Although there is non-robust historical correlation between LNG prices and WTI prices, we believe that this correlation will get even weaker as the supply of LNG becomes more available specially from sources in US and Africa creating an effective decoupling of prices, making the LNG alternative less volatile in relation to crude. In our calculations we show that at WTI price of \$60/MMbtu and a discount rate of 15%, Bolivian gas price will not be competitive (\$ -0.55/MMbtu) with the alternative of importing LNG, even if the current incentive policy is in place. Therefore, if Brazil is able to lock an LNG price between \$7.50 and \$8.50/MMbtu that would effectively set the “ceiling” price for negotiation. On the other hand, one of the viable alternatives that Bolivia has, is to lower the transport tariff by adjusting its tariff base and/or the return rate of the GTB pipeline in order to have a more competitive price in the hub.

**Table 6. Negotiation Margins**

		GTB Transport			TBGTransport		LNG Prices Brazil	Negotiation Margin (4)	Negotiation Margin (5)
		Wellhead Price (\$/Mmbtu)	As per current contract (1)	Discounted Tariff (2)	As per current contract (1)	Discounted Tariff (3)			
<b>Without Incentives</b>									
WTI Level (\$/bbl)	50	4.96	0.3675	0.2128	1.8666	1.0810	7.96	0.77	1.71
Discount Rate	10%								
WTI Level (\$/bbl)	60	7.99	0.3675	0.2128	1.8666	1.0810	6.84	-3.38	-2.44
Discount Rate	15%								
<b>With Incentives</b>									
WTI Level (\$/bbl)	50	2.29	0.3675	0.2128	1.8666	1.0810	7.96	3.44	4.38
Discount Rate	10%								
WTI Level (\$/bbl)	60	5.16	0.3675	0.2128	1.8666	1.0810	6.84	-0.55	0.39
Discount Rate	15%								

**Source:** Results from Models

#### References:

- (1) GTB prices calculated keeping the current contract formula and projecting for a 10 years.  
(2) Discounted tariff calculated under the following assumptions;  
Recovery of the terminal value of the pipeline  
Ten year contract  
Weighted average tariff on 26 mmcmd  
14 mmcmd firm  
12 mmcmd on interruptible basis  
IRR set to 16%  
(3) Tariff estimated mirroring discount on the GTB side  
(4) Calculated using transport tariffs as per current contract  
(5) Calculated using assumptions in point (2)

<sup>26</sup> Discounted tariffs calculated using assumptions of: shorter term (10 years), reduced volume of 26 MMcmd (14 MMcmd firm + 12 MMcmd interruptible), recovery base equals to salvage value after original contract is finished, no significant investments needed, 16% IRR.

<sup>27</sup> Ali ceweb – MDIC.

<sup>28</sup> Ver [http://www.mme.gov.br/documents/1138769/0/Boletim\\_Gas\\_Natural\\_nr\\_131\\_JAN\\_18.rev.pdf/9ccf8f67-c7d3-4ea6-95bd-cca719c62e5b](http://www.mme.gov.br/documents/1138769/0/Boletim_Gas_Natural_nr_131_JAN_18.rev.pdf/9ccf8f67-c7d3-4ea6-95bd-cca719c62e5b).

## 5. Conclusions

In 2019 the Bolivia – Brazil gas supply agreement is up for renegotiation. During the validity of the agreement, several events took place that changed the supply and demand conditions in both countries.

In Brazil, the rapid economic growth and lack of rain led to a major spike in natural gas consumption opening the door for Bolivia to export the full BBPL capacity (32MMCMD). However, as time went on, Brazil increased its own natural gas production, rain came, demand slowed down, and LNG showed up; effectively changing fundamental variables under which the gas supply agreement was conceived. Meanwhile in Bolivia, political events and decisions in the last decade postponed investments and increased domestic demand, effectively reducing the level of reserves going beyond 2019.

Using 10% and 15% as discount rates and international oil WTI prices between \$50 and \$60/bbl, the natural gas price result is between \$ 4.96 and \$ 7.99/MMbtu. **¡Error! No se encuentra el origen de la referencia.** shows that using the incentive the gas price should be between \$ 2.29 and \$ 5.16/MMbtu.

To begin with, Bolivia does not possess reserve-ready quantities of natural gas in order to supply a 20-year contract at current conditions. Furthermore, in our analysis developed through this paper we concluded that Brazil will demand around 14 MMCMD in firm (current industrial consumption level) and 12 MMCMD on interruptible basis for 10 years. Regarding the price, we believe that the current formula will be changed in order to reflect a gas to gas competition rather than a gas to oil competition currently in place. For this reason, we have structured the idea of a “virtual hub” that reflects how competitive Bolivian natural gas is in comparison to the LNG that Brazil imports. The difference between these two prices (LNG and Bolivian Gas) at the hub (in netback prices), represents the margin of negotiation (or lack of it) that Bolivia may have, that is, the LNG price will set the “ceiling” price.

Under the assumptions that WTI levels would be around \$ 60/bbl, investors use a 15% discount rate to invest in Bolivia, incentive policy is in place, and the price of LNG is around \$ 6.84/MMbtu (DES virtual hub); the opportunity cost of Brazil importing gas from Bolivia is \$ -0.55/MMbtu. The same case without incentive policy will yield a \$ -3.38/MMbtu. On the other hand, if the transport tariff is reduced (by lowering tariff base and/or lowering

expected IRR) the margin becomes positive under the assumption that the incentive policy is still in place. Therefore, as the price of LNG becomes more competitive through increase in supply (worldwide), Brazil will set its negotiation position around the price that they could import LNG on the short to medium term.

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