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FERNANDO INTI LEAL

Economic and regulatory analysis of natural gas in Brazil: Electricity generation, infrastructure, and energy integration.

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To my daughters Giovanna and Gabrielle, who were always my source of joy and motivation to pursue personal improvement.

In the memory of my grandfather Eliezer Mendes Pessoa, whose incredible genius and formidable character marked me profoundly, stimulating my love for the Sciences.

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"A little philosophy
inclineth man's mind to
atheism, but depth in
philosophy bringeth
men's minds about to
religion."
Sir Francis Bacon
(1561 – 1626)

"Gloria In Excelsis Deo."

ABSTRACT

Brazil's discoveries of large gas reservoirs in the offshore ultra-deep waters of the pre-salt fields show a promising scenario, along with strategic investment and adequate policy, for the development of natural gas infrastructure and a sustainable transition in the Brazilian electricity mix. Such transition should occur through the use of transnational natural gas pipelines connected to large industrial facilities and power stations, as part of strategic planning to expand industrial usage, and avoid the shortage of electricity supply, with economic and environmental advantages. Since the most important debates of the new millennium are focused on globalization and sustainable development for nations, transnational energy integration in Latin America has been receiving increasingly attention from researchers and policy makers. In this overall context, the purpose of the present research was to develop a model to study, in a comparative manner, the thermoelectric generation, as well as to analyze the effect of legal frameworks and governmental policies on the development of infrastructure and natural gas market in Brazil, with a detailed study of the most relevant market and regulatory mechanisms. A comparison was performed in terms of the most relevant regulatory legislation in Brazil and other relevant Member States of the South American economic block. The study also evaluates the sanctions imposed by ANEEL Resolution n. 583 of 2013 on suppliers, due to the lack of NG supply for thermoelectric utilities, proposing an alternative formula, thought to mitigate the influence of averages and other electricity market parameters, therefore decreasing the sanction value for the NG supplier, without compromising the contract neutrality. Different factors were analyzed in order to determine which technology would be the most efficient in terms of levelized costs. Results indicated that natural gas-fired generators are very competitive and efficient, when compared to other thermoelectric sources in both economic and environmental aspects, even when externalities were included. Also, that further strategic investment and adequate regulatory policy changes are required from the market agents, in order to foster the development of pipeline infrastructure and the expansion of natural gas use in Brazil. The study also demonstrates that the environmental impact of the CH_4 leakage equals that of CO_2 release from combustion at about 4.2% leakage on a mass basis, when methane leakage rises to a level in which natural gas becomes as greenhouse gas intensive as biomass.

Keywords: Energy Integration. Natural Gas. Market Regulation. Thermoelectric power. Levelized Cost of Electricity.

RESUMO

As descobertas de substanciais reservatórios de gás natural no Brasil, localizados em águas ultra profundas após a camada Pré-Sal, demonstram um cenário promissor, aliado a investimentos estratégicos e a políticas públicas adequadas, para o desenvolvimento da infraestrutura de gás natural e uma transição sustentável na matriz elétrica brasileira. Tal transição deveria ocorrer por intermédio do uso de tubulação transnacional de gás natural, conectada a grandes instalações industriais e a usinas termelétricas, como parte de um planejamento estratégico voltado à expansão do uso de gás natural na indústria e a evitar a escassez no suprimento de energia elétrica, com vantagens econômicas e ambientais. Considerando que os debates mais relevantes do novo milênio estão focados na globalização e no desenvolvimento sustentável das nações, a integração transnacional na América Latina tem recebido crescente atenção por parte de pesquisadores e de elaboradores das políticas públicas. Nesse contexto geral, a proposta da presente pesquisa foi a de desenvolver um modelo para estudar, de uma forma comparativa, a geração termelétrica, bem como analisar o impacto do arcabouço jurídico-regulatório e das políticas governamentais no desenvolvimento da infraestrutura e do mercado do gás natural no Brasil, com um estudo detalhado dos mais relevantes mecanismos regulatórios e de mercado. Foi realizado, ainda, um comparativo da legislação regulatória do gás natural no Brasil com outros Estados-Membros relevantes do Mercosul. O estudo também avalia as sanções impostas pela Resolução ANEEL n. 583 de 2013 nos fornecedores, devido a corte no suprimento de gás natural para empreendimentos de geração termelétrica, propondo um cálculo alternativo visando a mitigar a influência das médias e outros parâmetros intrínsecos ao mercado de energia, dessa maneira reduzindo as sanções contratuais para o fornecedor de gás natural, sem prejudicar a neutralidade contratual. Diferentes fatores foram analisados de forma a determinar qual tecnologia seria a mais eficiente em termos de custos nivelados de eletricidade. Os resultados indicaram que as termelétricas a gás natural são muito competitivas e eficientes, quando comparadas com outros tipos de combustível, tanto pelo aspecto ambiental quanto pelo econômico, mesmo quando externalidades são incluídas. Ainda, que são necessárias mudanças nas políticas regulatórias e no investimento estratégico por parte dos agentes do mercado, de forma a incentivar o desenvolvimento de infraestrutura e a expansão do uso do gás natural no Brasil. O estudo também evidencia que o impacto ambiental do vazamento de CH_4 se iguala àquele do CO_2 liberado pela combustão em cerca de 4.2% em base mássica, quando o vazamento de metano atinge um nível em que seu impacto como gás do efeito estufa fica equivalente à biomassa.

Palavras-chave: Integração energética. Gás Natural. Regulação de Mercado. Geração Termoelétrica. Custos Nivelados de Eletricidade.

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LIST OF ABBREVIATIONS AND ACRONYMS

ABEGAS	Associação Brasileira das Empresas Distribuidoras de Gás Canalizado (Brazilian Association of Pipeline Gas Distribution Companies)
ABRACEEL	Associação Brasileira dos Comercializadores de Energia (Brazilian Association of Energy Suppliers)
ACR	Ambiente de contratação regulada (Regulated Contract Environment)
ACL	Ambiente de contratação livre (Free Contract Environment)
AEO	Annual Energy Outlook
ANEEL	Agência Nacional de Energia Elétrica (Brazilian Agency of Electricity)
ANP	Agência Nacional do Petróleo, Gás Natural e Biocombustíveis (Brazilian Agency of Oil, Gas and Biofuels)
CAMMESA	Companhia Administradora del Mercado Mayorista da Argentina (Argentinian Bulk Electricity Market Administration Company)
CCEE	Câmara de Comercialização de Energia Elétrica (Brazilian Chamber of Electric Energy Commerce)
CCGT	Combined Cycle Gas Turbine
CIEN	Companhia de Interconexão Energética (Energy Interconnection Company)
CMSE	Comitê de Monitoramento do Setor Elétrico (Electricity Sector Monitoring Committee)
CONAMA	Conselho Nacional do Meio Ambiente (Brazilian National Council of the Environment)
ECLAC	United Nations Economic Commission for Latin America and the Caribbean
EIA	U.S. Energy Information Administration
ENARGAS	Ente Nacional Regulador del Gas (Argentinian Agency of Gas)
EPA	Environmental Protection Agency
EPE	Empresa de Pesquisa Energética (Brazilian Energy Research Enterprise)

EU	European Union
FAEG	Federação de Agricultura e Pecuária de Goiás (Goias Federation of Agriculture and Catlle Raising)
FERC	Federal Energy Regulatory Commission
GASBOL	Gasoduto Brasil-Bolívia
GDP	Gross Domestic Product
GHG	Green House Gas
GWP	Global Warming Potential
IBGE	Instituto Brasileiro de Geografia e Estatística (Brazilian Institute of Geography and Estatistics
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
LACE	Levelized avoided cost of electricity
LCOE	Levelized cost of electricity
LNG	Liquefied Natural Gas
MEM	Mercado Eléctrico Mayorista (Argentinian Bulk Electricity Market)
MME	Ministério de Minas e Energia (Brazilian Ministry of Mines and Energy)
MLCOE	Modified levelized cost of electricity
NG	Natural Gas
ONS	Operador Nacional do Sistema Elétrico (National System Operator)
PDE	Plano Decenal de Expansão de Energia (Decennial Plan for Energy Expansion)
PNE	Plano Nacional de Energia (National Plan of Energy)
PEMAT	Expansion Plan of the Natural Gas Transportation
USP	University of Sao Paulo

LIST OF SIGNS AND SYMBOLS

$\mathbf{Q_{MW}}$	Quantity of electricity generated in MWh in the year *t*
$\mathbf{C_{fuel}}$	Cost of fuel
$\mathbf{P_{MW}}$	Constant price of electricity sold in the year *t*
$\mathbf{C_{inv}}$	Cost of investment
$\mathbf{TR_t}$	Total revenue in year *t*
$\mathbf{C_{eqCO2}}$	Cost of emissions
$\mathbf{TC_t}$	Total costs in year *t*
$\mathbf{C_{trans}}$	Cost of transmission
$\mathbf{C_{op}}$	Cost of operations & management
$\mathbf{C_{leak}}$	Cost of leakage
$\mathbf{P_{fuelX}}$	Price of fuel for a given scenario X
i	Discount rate
$\mathbf{V_{sm}}$	Sanction value, in month *m*, in which the NG supply cut off occurred
$\mathbf{V^*_{sm}}$	Mitigated sanction value, in month *m*, in which the NG supply cut off occurred
$\mathbf{PMED_m}$	Average monthly liquidation price of the differences
j	Number of months
w	Week of the month
$\mathbf{PLD_{max}}$	Maximum regulated liquidation price of the differences
$\mathbf{PLD_w}$	Weekly liquidation price of the differences
$\mathbf{ENP_m}$	Amount of electricity not generated in month *j*
$\mathbf{ENP_w}$	Amount of electricity not generated in week

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1. Introduction

1.1 Research questions and objectives

Natural gas (NG) has been recognized as a clean and efficient energy source, although of fossil fuel origin. The major discoveries of large gas reservoirs in the Brazilian coastal ultra deep waters, especially in the beginning of the 21st century, have opened space for debates concerning the expansion of usage and development of related gas infrastructure. There is a preemptory major inquiry that permeates all the others throughout the present research, and relates directly to the concern if natural gas-fired thermoelectric utilities (UTE-GN) are viable and competitive in Brazil. This considering economic and environmental aspects, as well as other involved externalities, in comparison with their fossil fuel counterparts and other generation technologies as well.

Indeed, the research main focus was to perform a comparative study between the most employed thermoelectric generation technologies: natural gas, biomass, mineral coal, and fuel oil. The analysis included the market conditions in Brazil, in order to obtain the overall generation cost in terms of US$/MWh. The objective was to provide a comprehensive analysis of economic and environmental aspects of each technology, given the actual prices and other relevant variables, through the analysis of the produced data by a levelized cost calculation, with the added impact of methane's leakage as an important externality.

Also, an assessment of the actual Brazilian NG industry legal framework, comprising the most relevant oil & gas law, governmental resolutions, and diplomatic documents, especially concerning energy integration in Latin America, as a secondary goal. In this case, a comparison between the Brazilian and more mature markets such as the Argentinian, by means of current regulation and infrastructure concerning the natural gas production, usage, and distribution to final consumers.

The main emerging hypothesis is that natural gas final consumption and supply security, for different thermoelectric utilities and industrial use, would be improved with the increase in market liberalization and competition, by means of regulatory framework improvements, as well as through the expansion of the South American NG pipeline integration. Also, that natural gas-fired utilities would present themselves as a reliable and more efficient alternative, when compared to their counterparts, even when externalities are included.

This expansion of infrastructure would allow a better allocation of the resources in Latin America, bringing more efficiency and economic advantages of a competitive market, with multiple suppliers and more access to distribution infrastructure. In this case, the development of integration would also bring new possibilities for market growth, especially considering the increase in capillarity and the expansion towards energy integration between Mercosul Member States.

From this point of view, some **research questions** of the present study have been elaborated: *Can natural gas replace, with advantages, other fossil fuels for a sustainable transition in the Brazilian electricity mix, considering most important market, environmental, and financial issues, as well as other externalities?*

And also: "*Is Natural gas actual distribution network and regulatory framework adequate to stimulate distribution to final consumers and to advance infrastructure integration?*"

Aligned with the research questions and the literature review on the subject, the **main objective** of the research can be summarized as: *To study about comprehensive market conditions for thermoelectric generation and regulation towards the natural gas industry in Brazil, and to compare it with Argentina, a more mature gas market, and punctually with other countries.*

From the main objective, it is possible to break it down into the **following specific objectives**:

a) To analyze the thermoelectric generation in Brazil considering most important financial and environmental issues associated, as well as other externalities;

b) To study the natural gas actual distribution network and regulatory framework in Brazil and compare it with Argentina, a more mature gas market, and punctually with other countries, focusing on more developed markets.

c) To study which regulatory policies should be adopted to stimulate private sector investment in the natural gas industry;

d) To analyze the Brazilian regulatory framework concerning the natural gas industry and identify bottlenecks, opportunities, and, if applicable, propose improvements.

1.2 Research structure

The dissertation was structured in a way that each Chapter relates to a specific issue of the problematic in study. Chapter 1 - *Introduction* is divided into two items. In Item 1.1 – "*Research Questions and objectives"* the problematic is briefly addressed and the emerging questions and corresponding objectives are discussed. Also, how they relate to some of the study's hypotheses. Item 1.2 – "*Research Structure"* is where the actual research structure is discussed.

Chapter 2 – *"Literature Review"* presents a literature review of the natural gas regulation and economic related studies, as well as the most relevant data obtained in the referenced literature concerning the electricity sector, infrastructure, and regulatory framework.

In Chapter 3 – *"Methods"*, the general methodologies employed in the research are addressed, and a bit more detailed approach was made available then in the corresponding published articles. The discussion regarding aspects of both analyses was contained in Chapter *4 "Discussion"*, divided into four items in the present text.

The first one, Item - *4.1 "Thermoelectric generation financial assessment"* privileges the discussion concerning the aggregate costs methodology analysis employed to assess the cost of electricity generation by thermoelectric utilities.

The second part, Item - 4.2 "*Natural gas and the electricity market",* discusses thermoelectric generation MLCOE results and compares them to other methods' results, addressing some related information

The discussion furthers on Item - *4.3 "Regulatory analysis of NG market towards infrastructure and energy integration"*, where the regulatory historical background in Brazil and Argentina are studied, how they developed in recent years, including the energy integration agenda and supply cut-off sanctions to the natural gas supplier of thermoelectric utilities.

Item 4.4 – *"Infrastructure assessment and energy integration"* focuses on the infrastructure study, especially when it refers to energy integration and its correlate international agenda.

The three interconnected outcomes from each part of the study are summarized in Chapter 5 – *"Conclusions"*, in which the conclusions achieved and final considerations are presented. Item - 5.1 highlights some limitations of the current work and gives suggestions for future research, especially concerning the incorporation of volatility to the calculations.

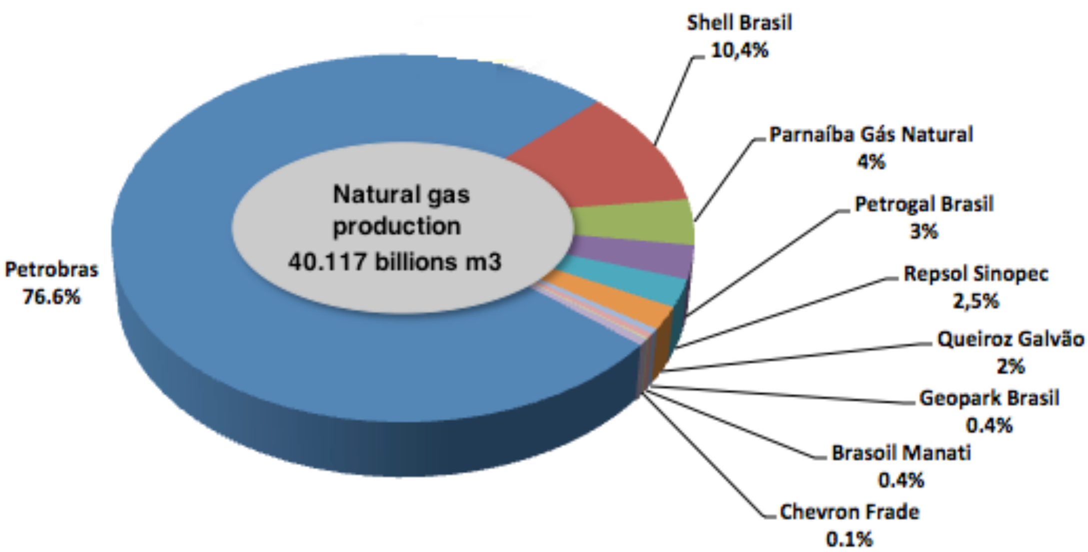
2. Literature Review

2.1 Natural gas and the electricity sector

In 2016 natural gas (NG) accounted for 13.7% of internal energy supply, being the third energy source in Brazil in consequence (EPE, 2017). The main destinations of the commodity are usually thermoelectric utilities, domestic energy demand, petrochemical, and fertilizer industries. The industrial sector remains as the major consumer, accounting for 50.8% of NG final consumption. In the Brazilian natural gas balance, the domestic supply, or internal offer, corresponds to the sum of imports and internal production, discounted of adjustments, flare burning, losses, reinjection, and exports.

The average daily NG production in 2016 was of 103.8 million m^3/day, and the volume imported was an average of 32.1 million m^3/ day, or about 30% of the total. (EPE, 2017). In 2017, the natural gas production was of 40.117 billions of m^3 and the major producers are those depicted in Figure 1. The internal natural gas offer was of 39.16 billions of m^3 in the year. From this total, about 70% were destined to sales and 24.5% were destined to own consumption (i.e. production, refining, and processing) (ANP, 2018).

Figure 1 – Natural Gas Production in Brazil by concessionary in 2017



Source: ANP (2018)

Table 1 – Natural Gas Balance in Brazil

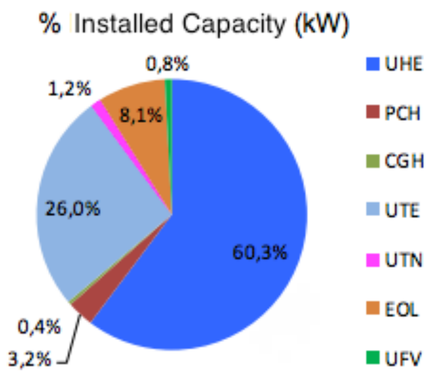
Specification	Natural Gas Balance in Brazil (millions m³) 2011	2012	2013	2014	2015	2016	2017	17/16 %
Imports	10,481	13,143	16,513	17,398	19,112	13,321	10,643	-20.11
Exports	50	312	37	90	2	517	135	-74.00
Production	24,074	25,832	28,174	31,895	35,126	37,890	40,117	5.88
Reinjection	4,038	3,543	3,883	5,740	8,867	11,069	10,077	-8.97
Burning & Losses	1,756	1,445	1,303	1,619	1,398	1,484	1,377	-7.21
Total Own Consumption[1]	7,803	8,850	9,078	9,335	10,851	9,360	9,593	2.49
LGN[2]	1,287	1,281	1,337	1,505	1,381	1,541	1,851	20.13
Sales[3]	19,307	23,284	28,784	30,768	31,502	27,224	27,717	1.81
Adjustments and Losses	314	260	266	235	237	15	11	-29.32

Source: ANP (2018)

Regarding Brazil's electricity sector, it includes a large group of stakeholders who provide services through distinct electricity generation, transmission, and distribution for different classes of final customers. It also includes several governmental agencies that regulate the sector. In the second semester of 2018, there were 7,097 electric utilities in operation in the country, resulting in a total installed capacity of around 160 GW (ANEEL, 2018).

The predominant power source in this electricity mix is hydraulic, which accounts for about 63.9% of the total. The thermoelectric generators participation is of approximately 27.2%, included among that percentage: natural gas, nuclear, coal, biomass, and other fossil fuels (See Fig. 2 – ANEEL, 2018).

Figure 2 – Electricity mix in Brazil – Installed Capacity [4]



Source: ANEEL (2018)

[1] Refers to own consumption in refineries, production areas, transportation and storage.
[2] Gas volume consumed in gas processing units (UGPNs)
[3] Includes sales to distributors, fertilizers factories and thermoelectric utilities.
[4] Type of generating asset: UHE – Hydroelectric; PCH – Small hydroelectric; CGH – Hydroelectric Generating Central; UTE – Thermoelectric; UTN – Thermonuclear; EOL – Aeolian/Wind; UFV – Photovoltaic.

In this scenario, natural gas-fired power plants contributed to about 8.1% of the total installed capacity, or 12,597MW. The overall thermoelectric participation in the National Interconnected System (SIN) has jumped from 25,210MW in 2006 to 36,080MW in 2017, an increase of 43% or an average annual growth rate of 3.92%. Hydroelectric power has increased at a similar pace, from 73,430 MW in 2006 to 105,406 MW, for the same period (ONS, 2018).

Considering the importance of natural gas as supply for thermoelectric generation, a first consideration was made in order to investigate if existing comparative studies in IEA/OECD have demonstrated a high standard deviation from average in results, regarding levelized cost of electricity[5] per country.

Garson (2015) has shown a large variation within the possible results for the levelized cost of electricity for each country, varying up to 101% for natural gas and up to 52% for mineral coal. The ample dispersion of that index and the fact that no single technology can be said to be the cheapest under all circumstances, indicate that market structure and the policy for the environment also play strong role in determining the final cost for any investment.

In this matter it is important to observe that some gas markets are regionalized and not all consumers are capable of using LNG, therefore a considerable part remains restricted to gas pipeline.

One of the most important planning tools for the national energy sector is the Decennial Plan for Energy Expansion (PDE), elaborated by the Energy Research Agency (EPE) for the Ministry of Energy. It contributes to the design of national development strategies in the short and mid-term periods. The plan also incorporates an integrated view of the supply and demand expansion for different energy sources in a ten-year period.

The most recent version of the PDE 2026 (EPE, 2017) presents a forecast where the aggregate demand annual growth rate for the period of 2016-2026 is of 3.5% per year. This projected increase demonstrates the relevance of strategic planning, in order to avoid the shortage of supply, based on reliable and non-intermittent power sources. This becomes more relevant considering the overcome of the 2015-2016 commodity crisis that affected emerging economies, with the consequent re-heating of economic activity.

Thermoelectric power plants, mainly the natural gas-fired ones, present themselves as an alternative to diversifying the electricity mix in Brazil, due to their reliability and easy

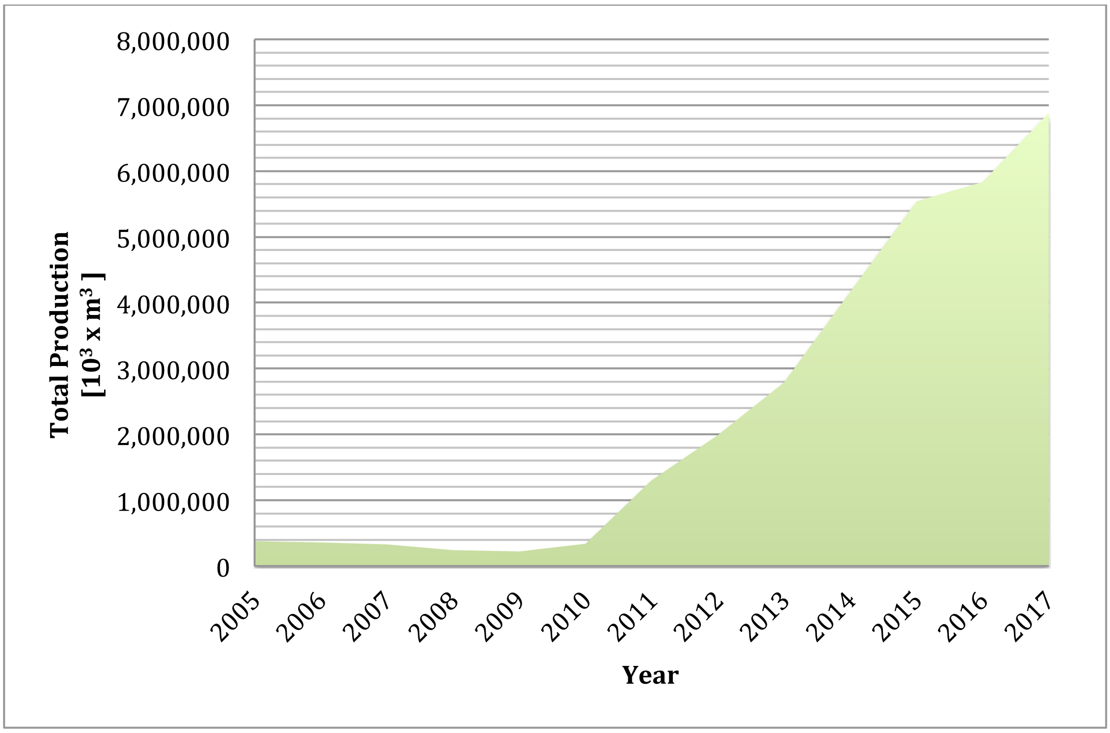
[5] The levelized cost of electricity (LCOE) is the net present value of the cost of electricity over the lifetime of a generating asset. It is considered to be the average price that the generating asset must receive in a market to break even over its lifetime. It is a first-order economic assessment of the cost competitiveness of an electricity-generating system that incorporates most relevant costs over its lifetime.

dispatch. They are able to provide sufficient capacity to attend demand growth, aiming to decrease the risk of shortage in supply due to adverse climatic conditions, reservoir depletion, and intermittence that might affect some renewables. In this context, thermoelectric power plants have received more attention from policy makers in the last decade, because there is a need to address the increase in demand, along with a lack of places for new large hydraulic projects, since most productive basins are close to full capacity.

The life cycle analysis performed by (Miranda, 2012) suggests that due to its better efficiency the natural gas produces fewer emissions, such as carbon dioxide and other GHG (Green House Gases in $kgCO_2eq.$), when compared to other fossil fuels. This aspect was incorporated to this study as the variable cost of emission.

Another relevant aspect is the strategic expansion of the natural gas share in the electricity market, as a bridge fuel for a sustainable transition in the Brazilian electricity mix, in order to replace more polluting or inefficient technologies, such as fuel oil and mineral coal. This becomes more prominent when considering the recent discoveries of large natural gas reservoirs in the pre-salt layer, like the Lula Oil Field, and most recently the Sapinhoá Oil Field, both in the Santos Basin, Sao Paulo State (See Fig. 3).

Figure 3 – Total Production of NG in the State of Sao Paulo



Source: ANP (2018)

The Brazilian natural gas transport network is primarily distributed along the Atlantic Ocean coastline, with ramifications in the Center-West axis through the Brazil-Bolivia pipeline, which is 3,150 km in length and transports about 33MMm^3/day. As depicted in Fig. 4, the gas pipelines in study would go from the South, interconnected with the hub in the city of Uruguaiana, border of Argentina and Uruguay, up to the Brazil-Bolivia pipeline in the city of Campo Grande, aiming to reach the Northeast of Brazil (ABEGAS, 2016).

Figure 4 - Operating and projected gas ducts in Brazil

Source: ABEGAS (2016)

The fact is, that in the Northeast of Brazil there are already several large wind power facilities, which have been developed mostly in the last five years, especially along the coast of the States of Ceará, Rio Grande do Norte, and in the interior of Bahia. The question that remains to be answered is if this region would benefit from additional gas pipelines, beyond those already in operation, to compete with several projects of wind power, due to the strong winds at the region.

De Jong et al., (2015) concluded that such wind power farms have attractive total costs ranging from US$35.00 – 40.00/MWh. In this particular matter, however, the average sales price achieved for wind facilities in the 28th Energy Auction promoted by CCEE in September, 2018 was of about US$33.86/MWh (CCEE, 2018), which would locate the price very closely to their total cost.

Besides, Busch and Gimon (2014) discussed the problematic of CH_4 emissions to the atmosphere and methane's higher impact as a GHG throughout the production chain, due to leakage or venting in compressors, pipelines, and other equipment. In order to obtain the cost of the natural gas leakage, the EPA findings in the National Inventory of Greenhouse Gas Emissions and Sinks (EPA, 2014), estimate overall natural gas system leakage at 1.5% on a mass basis, which was adopted as the standard rate for calculations.

Methane's cumulative forcing of Global Warming Potential - GWP over a 20-year time period is estimated by (IPCC, 2014) to be 84 times larger than an equivalent mass of CO_2 and about 28 times over a 100-year period. Since the lifetime of a natural gas-fired power plant is typically between 20 to 30 years, and the adopted price for carbon was of US$ 15.00/ton of eq.CO_2, the corresponding cost of CH_4 leakage was considered to be of US$ 1,260.00 / ton of CH_4. In order to assess and include the effects of such aspect, CH_4 was incorporated into this study as the variable cost of leakage.

2.2 Regulatory framework and infrastructure

Infrastructure investment and regulation discussions date back to the 1960s and there is no consensus regarding the effects of regulation on infrastructure investment (Von Hirschhausen, 2004). Theoretical and empirical work has been developed about the dynamic nature of regulated investment, as in Hausman and Myers (2002) who suggested that relying on traditional regulation to establish competitive prices may lead to adverse effects on innovation and new investment.

In traditional liberal economic theory, the market is a self-regulated system, capable of achieving equilibrium on its own, without major deviations, in accordance with Adam Smith's image of the "invisible hand" and Jean-Baptiste Say's "law" that production creates its own demand given that the economy is in "perfect competition" (Piketty, 2014). In this case there would be no need for government intervention in the freedom of economic decisions of the agents, because the market would accommodate itself through the prices mechanism for resource allocation.

However, there are situations where the market alone does not lead to an efficient allocation of resources, where "market failures" involving externalities, information asymmetries, and market power held by one (monopoly) or some (oligopoly) agents, cause distortions in the market. In this situation, there is the need of action by means of government intervention through regulatory measures.

The word "regulation" in Brazil has appeared with the movement of State reforms, especially when, due to the privatization of State companies and the introduction of the idea of competition between public service concessionaries, it was necessary to "regulate" the activities that were subjected to concession to private companies (Di Pietro, 2004).

Levy and Spiller (1996) state that regulation is needed in the energy utility industry in general, because the mentioned monopolistic nature of its services normally gives a single local utility or a limited group of utilities (oligopoly) uncontrolled power over consumers or distribution.

Concerning specifically the natural gas infrasctructure, Hopper *et al.* (1990) observed that most of the pipeline in the Mercosul countries could be characterized as monopolies, similar to what were most the U.S and the European structures in the 1990s. This situation has not changed considerably after almost thirty years, especially in Brazil.

Gomes (2014), when discussing the issue, has concluded that Brazilian authorities need to change power auction rules in order to make natural gas projects compete more effectively and to develop policies to promote the development of domestic gas and encourage existing producers to sell their gas to the market.

Thus, one important issue to address is how energy integration must be conducted and which regulatory framework has to be adopted to further ensure supply security, quality of services, and reasonable prices for the end-consumer.

After the so called "economic lost decade" in the 1980s, result of the financial crisis that affected many Latin American economies, economic integration regained popularity back in the 1990s, as means of promoting sustainable development in the developing world (Mares and Martin, 2012). In Latin America, several market liberalization and pro-market presidents proliferated in that decade, marked by Collor's and Cardoso's administration reforms in Brazil and Menem's administration in Argentina.

Therefore, it is not a coincidence that the first attempt to regulate and promote the development of the natural gas industry occurred in the same period, since the first legal mark of NG legislation in Brazil was Law n. 9,478 of 1997, promulgated during the first Cardoso administration.

The increase of production and importance of the natural gas supply and final consumption in Brazil and throughout the world is expanding due to, mainly, increasing environmental concerns, since it is considered to be an efficient and clean energy source when compared to other fossil fuel alternatives (Leal et al., 2017).

Additionally, the shale gas boom occurred in North America and the Russian-Ukrainian conflict effects on decreasing supply to Europe, both increased the importance of natural gas supply and destination studies. Richter and Holz (2015) use a model-based approach to analyze the consequences of supply disruptions of Russian natural gas on the European market, concluding that Eastern European countries are the most vulnerable.

For them, the surcease of Russian supply could be compensated by an increase in domestic production, imports of LNG, and pipeline gas being brought from other regions, thus requiring further EU internal infrastructure integration.

In the same context, NG consumption in South America has been increasing rapidly at average growth rates of 3.6% from 2004 to 2015 (BP, 2016). Brazil's natural gas market has grown at a faster pace in recent years, with the commodity having increased its share in the national primary energy consumption from 9.4% to 13.7% between 2005 and 2016.

On the internal demand side, the industrial demand for natural gas increased 2.5% over 2015, especially in iron and steel (18.1%) and chemical sectors (9.9%). The thermal power generation with natural gas, including self-producers and public service power plants, reached a level of 79.5 TWh (MME, 2016).

Energy integration in Latin America has been considered a key factor for the promotion of economic development at the region, ever since the issue was brought up in the United Nations Economic Commission for Latin America and the Caribbean (UN-ECLAC) and other instances in the post-war era. One of the most relevant issues is which projects should be implemented in order to maximize the wealth of Latin America, through the comparative advantages of its countries in the use of their natural resources.

Calogeras *et al.* (2016) point out that the Mercosul area has a huge potential to create and stimulate the mutual cooperation between its members, including their relative power of bargain with other economic blocs. It also has the potential to form one of the biggest economic and energy integration blocs in the world, as its Member States, including former member Venezuela, have a substantial share of 316.6 Billion Barrels of oil proved reserves (EIA, 2015), as well as a gigantic amount of natural resources that can be converted into energy and electricity.

Since 2010, the Brazilian pre-salt basins are increasingly producing natural gas and the overall production has experienced a boost in the period, due to the recent discoveries of large gas reservoirs in the pre-salt layer, like the Sapinhoá Oil Field in the Santos Basin. The crude oil production has increased almost 24 times from the 41,000 barrels per day, in 2010 to the level of 1,000,000 barrels per day in mid-2016's (ANP, 2016).

There is also the regulatory and market environment in South America, especially in the Mercosul, where Member States present extensive potential of regional integration and interconnection between natural gas consuming and producing markets. This either from the point of view of the necessity of consumers in assuring supply for their markets, or suppliers with the need to monetize their reserves (See Table 2).

Table 2 - Proved natural gas reserves ranked by country for the 7-largest-resource holders in Latin America

Total Proven Reserves[6]	Trillion cubic meters	Share of South America	Share of Total	Total Production[7]	R/P ratio
Argentina	0.3	4%	0.2%	36.5	9.1
Bolivia	0.3	4%	0.2%	20.9	13.5
Brazil	0.4	5.3%	0.2%	22.9	18.5
Colombia	0.1	1.3%	0.1%	11.0	12.2
Peru	0.4	5.3%	0.2%	12.5	33.1
Trinidad & Tobago	0.3	4%	0.2%	39.6	8.2
Venezuela	5.6	74.7%	3.0%	32.4	173.2
Other S. & Cent. America	0.1	1.3%	0.05%	2.6	24.0

Source: BP (2016) as of 31st December 2015

Also, the seasonality of demand in some countries, such as Argentina and Chile, who rely deeply on natural gas for heating during the winter and electricity generation, is an opportunity for resources reallocation in the region. It can be noticed at Table 3 that Argentinian and Chilean annual consumptions have remained somehow stable throughout this decade, with averages of 45.9 and 5.4 billions of m^3 respectively, as happened analogously to other South American countries, whereas in Brazil, the steady increase in consumption observed up to 2015 was recently reverted, especially due to the retraction of industrial activity during the 2015 – 2017 economic crisis.

Trinidad and Tobago, the largest oil and gas producer in the Caribbean, has been involved in the petroleum sector for over one hundred years, exporting nowadays super-chilled natural gas (LNG) all over the world. There, the energy sector accounts for more than one third of Gross Domestic Product (GDP) and the electricity sector is fueled entirely by natural gas. [8]

Table 3 – Natural gas consumption ranked by country in 2017

Country	**Natural gas consumption per country (billions of m3)**								**17/16 %**
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	
United States	648,2	658,2	688,1	707,0	722,3	743,6	750,3	739,5	-1,44
Russia	422,6	435,6	429,6	423,0	423,6	409,6	420,2	424,8	1,09
China	108,9	135,2	150,9	171,9	188,4	194,7	209,4	240,4	14,80
Iran	150,6	159,8	159,1	160,4	180,9	191,9	201,4	214,4	6,50
Japan	98,9	110,4	122,4	122,3	120,5	118,7	116,4	117,1	0,57
Canada	88,7	95,6	92,8	98,0	103,2	102,9	109,5	115,7	5,74
Saudi Arabia	83,3	87,6	94,4	95,0	97,3	99,2	105,3	111,4	5,80
Germany	88,1	80,9	81,1	85,0	73,9	77,0	84,9	90,2	6,21
Unt. Kingdom	98,5	81,9	76,9	76,3	70,1	71,8	81,0	78,8	-2,69
Arab Emirates	59,3	61,6	63,9	64,4	63,4	71,0	72,5	72,2	-0,44
Italy	79,7	74,8	71,9	67,2	59,4	64,8	68,0	72,1	5,97
India	59,5	61,3	56,7	49,8	49,6	46,4	50,8	54,2	6,62

[6] Total proved reserves at the end of 2015. More data available at: https://www.bp.com/content/dam/bp/pdf/energy-economics/statistical-review-2016/bp-statistical-review-of-world-energy-2016-full-report.pdf
[7] Natural gas production data expressed in billion cubic meters per day.
[8] http://www.energy.gov.tt/our-business/oil-and-gas-industry/

South Korea	45,0	48,4	52,5	55,0	50,0	45,6	47,6	49,4	3,62
Argentina	**42,2**	**44,0**	**45,7**	**45,8**	**46,2**	**46,7**	**48,3**	**48,5**	**0,27**
France	49,6	43,0	44,5	45,2	37,9	40,8	44,6	44,7	0,41
Indonesia	44,0	42,7	42,9	41,4	41,5	41,0	38,3	39,2	2,36
Brazil	**28,0**	**28,0**	**33,1**	**39,0**	**41,3**	**43,7**	**37,7**	**38,3**	**1,65**
Venezuela	**32,2**	**32,6**	**34,0**	**32,9**	**32,9**	**36,5**	**38,3**	**37,6**	**-1,80**
Spain	36,2	33,6	33,2	30,3	27,5	28,5	29,1	32,0	9,91
Trin. Tobago	**22,5**	**22,7**	**21,6**	**21,8**	**21,4**	**20,9**	**18,6**	**18,5**	**-0,68**
Colombia	**8,7**	**8,5**	**9,5**	**10,5**	**11,4**	**11,2**	**10,6**	**10,0**	**-6,01**
Peru	**4,9**	**5,4**	**6,0**	**5,9**	**6,7**	**7,1**	**7,6**	**6,7**	**-11,33**
Chile	**5,7**	**5,8**	**5,3**	**5,3**	**4,4**	**4,8**	**5,9**	**6,0**	**1,37**

Source: BP Statistical Review of World Energy (2018)

The experience of regional integration in North America, between Canada and the United States (US), presents some good examples of successful projects. TransCanada has long been one of the major natural gas transmission companies in North America, operating a 91,500 km network of pipelines, which supplies more than one quarter of the NG consumed daily across North America. Moreover, the recent expansion of the Northern Border Pipeline into Chicago and the development of the Alliance Pipeline, which delivers more than 1.6 billion cubic feet per day of natural gas from western Canada into the Chicago market.

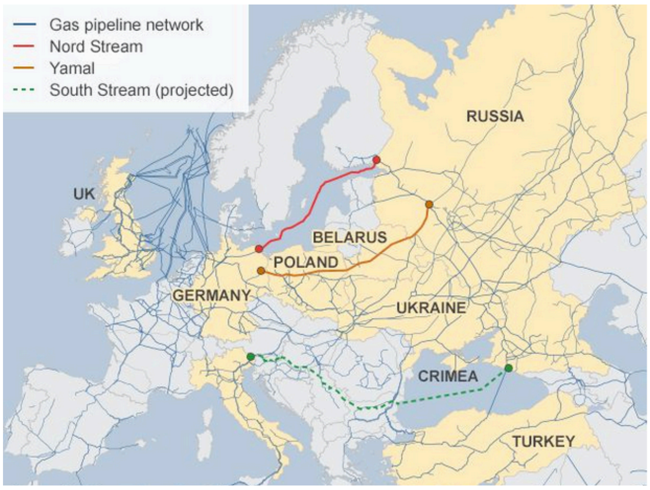
The continuous development of the Marcellus and Utica shales is being supported by the extension of pipeline infrastructure from the Appalachian region to ship more gas to markets in the Northeast, Midwest, and Southeast regions of the United States and in Eastern Canada. The US gas output is expected to grow by 2.9% per year by 2022, adding around 140 billions of m^3 to global production. Moreover, it is expected that by 2022, the US will produce approximately 890 billions of m^3, or 22% of the total gas produced worldwide (IEA, 2017).

Additionally, although NG markets are approaching saturation in many parts of the developed world, consumption continues to grow in the US, the largest gas-consuming country in the world. Coal plants deactivation and NG switching in the power generation grid acted as the main driver of gas demand growth in the recent past (IEA, 2017).

In the European market, where demand rose in 2016, due to lower prices and coal plant retirements, after four years of decline from 2010, natural gas relies heavily on large-scale infrastructure across several European Union (EU) Member States and outside the block as well (See Figure 5).

In this particular case, pipelines to other Member States trade a fifth of the internal production in the EU. Furthermore, pipeline supplies from Russia, Norway, and Algeria supply almost half of the Union's gas consumption (Aalto and Temel, 2014).

Figure 5 - Natural gas pipelines interconnecting Russian and European Markets.



Source: GIE, Gazprom (2014).

Russia's share of EU-28 imports of natural gas has increased from 34.6% to 39.5%, between 2005 and 2016, as Norway remained the second largest supplier of European Union's imports, with its share rising from roughly 20% in 2005 to 34.4% in 2016. In 2016, more than three quarters (89%) of the EU-28 States' NG imports came from Russia, Norway, or Algeria[9]. Therefore, comparatively to the European or the North American experiences, still remains a lot to be developed in transnational natural gas infrastructure integration in South America. As depicted in Figure 6, the continent has little infrastructure of gas transport, in such a way for internal supplying or regional interconnection.

Figure 6 - Natural gas pipelines interconnecting Bolivia with Brazil and Argentina.

Source: ANH (2013), ENARGAS (2012), TBG (2015) in. Garaffa, R. *et al.,* (2016).

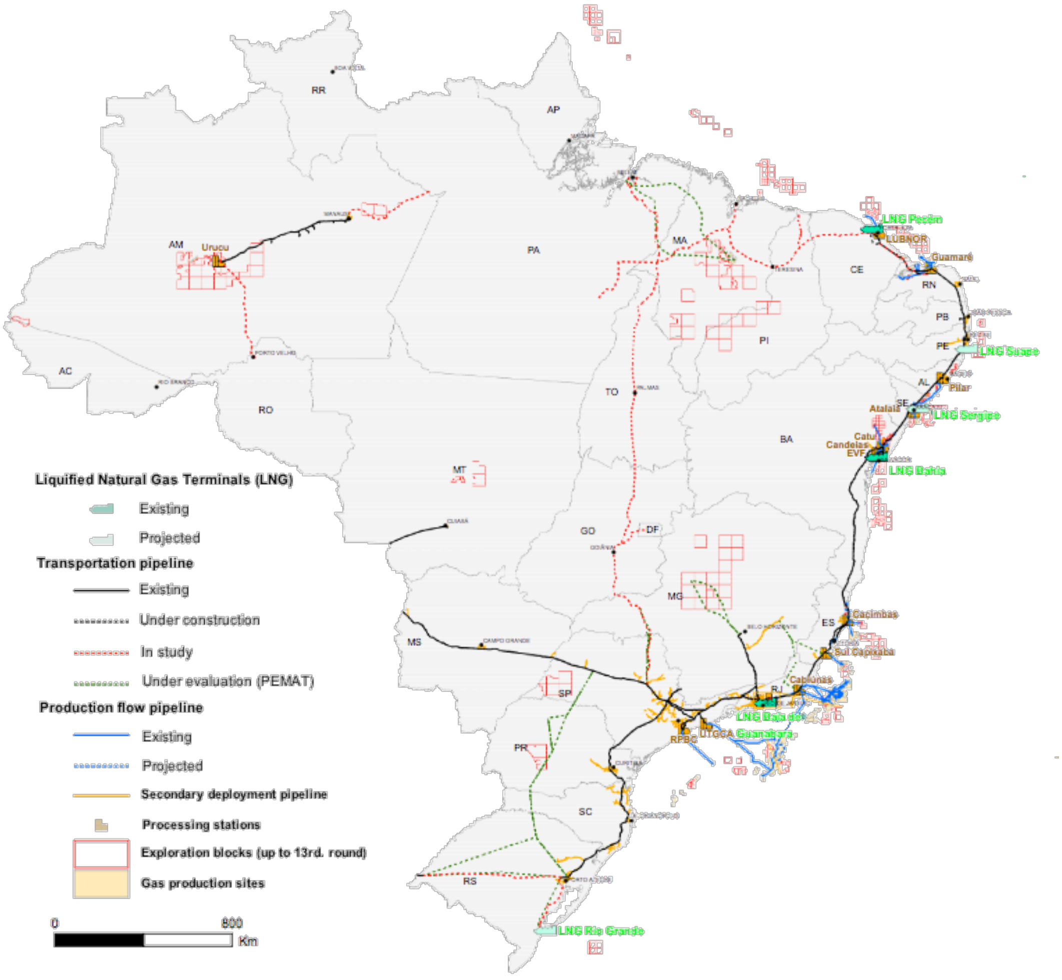
[9] More information regarding the EU energy imports can be found at: http://ec.europa.eu/eurostat/statistics-explained/index.php

From a technical perspective, the natural gas transportation system in Latin America is still a low integrated network. The Brazilian pipeline network total length is of about 11,696 km and primarily distributed along the Atlantic Ocean coastline (ANP, 2016). It has ramifications in the Center-West axis through the Bolivia-Brazil pipeline (GASBOL), which is 3,150 km in length and transports about 33MMm^3/day.

Currently, most pipelines in study would go from the South, interconnected with the hub in the city of Uruguaiana, border of Argentina and Uruguay, up to the city of Campo Grande, connecting to the GASBOL, aiming to reach the Northeast of Brazil (Figures 6 and 7). The Bolivian natural gas exports to Brazil and Argentina were an average of 28.33 million m^3/day and 15.50 million m^3/day, respectively, in 2016, which represents more than ¾ of Bolivia's production (Ministerio de Hidrocarburos, 2018).

This low-density market, which occurs in most of South American countries, implies a series of monopolies at the national and regional levels. Indeed, there is virtually no competition anywhere within the Mercosul between alternative gas suppliers, except mostly at local level in Brazil, where distributors of LNG compete for retail sales.

Figure 7 - Operating and projected natural gas infrastructure in Brazil



Source : EPE (2016)

A case regarding energy integration in the energy utility industry that deserves to be briefly addressed is the CIEN, or Energy Interconnection Company. It was founded in 1998 to be in charge of operating the power lines between Brazil and Argentina, since at that time the latter had an electricity surplus originated from its natural gas thermoelectric facilities, and Brazil already projected a deficit in generation at that time.

About US$ 700 million were invested in the construction of two converter substations, named Garabi I and Garabi II, and two power lines of 500km each, with an overall capacity of 2,200 MW. The first substation started to operate in the beginning of June 2000, and the second in the beginning of August, 2002. The Brazilian National Agency of Electricity (ANEEL) issued Resolution nº 129 in 1998 and authorized the CIEN to import up to 1,100MW from the "Mercado Eléctrico Mayorista – MEM" in Argentina (Santos et al., 2002).

The confirmation by the Electricity Sector Monitoring Committee (CMSE), in the beginning of 2004, that there was risk of electricity shortage in the South Region of Brazil motivated the testing of real availability of the power line operated by CIEN. Tests were conducted by the National System Operator (ONS) and ANEEL, along with the Companhia Administradora del Mercado Mayorista da Argentina (CAMMESA). They demonstrated the evident incapacity of CIEN to import the contracted energy associated to the enterprise, the power line was "dry".

This is an indication that the natural gas in Argentina, which is destined for electricity generation, is not able to produce a surplus able to be sold to its neighboring countries. This might even be a demonstration that the power lines administrated by CIEN might eventually be used more often on the opposite way they were intended, with Brazil selling electricity surplus to Argentina.

3. Methods

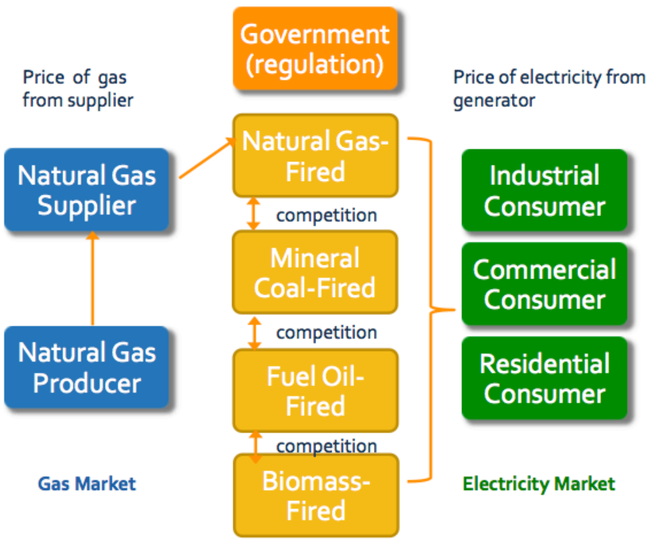
3.1 Thermoelectric generation financial assessment

The research combined quantitative, mostly present in the financial analysis, and qualitative analysis, more present in the regulatory framework evaluation. The model for financial assessment presents a more analytical propositional profile, in which the problematic is addressed in a comparative manner.

The analysis of thermoelectric generation in Brazil was designed in order to adequately measure comparatively the different generating technologies, by means of costs and other relevant aspects between the major competitors or substitutes for the natural gas in the thermoelectricity generation chain (See Fig. 8).

In this context, a long-term levelized cost of electricity analysis was employed for new power plants running on different fuels. The most relevant costs involved are included in the comparative analysis, such as investment, fuel, operations & management, emissions, among others.

Figure 8 – Natural gas for electricity generation integrated chain.



Source: Adapted from Tian *et al.* (2015)

The LCOE methodology is based on a lifetime levelized cost analysis, between different technologies, employing a discounted cash flow method for a given discount rate. It uses technological and country specific assumptions for the various parameters involved in the calculation. It reflects both the capital and operational costs of installing and running new generation power plants of any given kind. Although, as observed by EIA (2018), its direct comparison across different technologies, to determine the economic competitiveness of various generation alternatives is problematic and could be potentially misleading.

As well noted by Garson (2015), this method is more efficient for the study of monopolistic regulated markets, with captive consumers. In Brazil this would imply the energy contract under the Regulated Contract Environment (ACR – Brazilian acronyms). The relevance and applicability of such assumption is discussed with more detail in Section 4.

As for the cost analysis, it is based on the equivalence between the Net Present Value of the Total Revenue (NPVTR), and the Net Present Value of the Total Cost (NPVTC), both at the assumed discount rate (i):

$$NPV\mathrm{TR} \equiv NPV\mathrm{TC} \qquad (1)$$

$$\sum_{t=1}^{n} \frac{TRt}{(1+i)^t} = \sum_{t=1}^{n} \frac{TCt}{(1+i)^t} \qquad (2)$$

Assuming the premise of a market with fixed price (ACR), the total electricity revenue is composed of Q_{MW}, the amount of electricity generated in MWh in the year t, that is sold at a stable and constant price $P_{MW,}$ throughout the lifetime of the power plant. In this energy physically backed call option, or capacity PPA (power purchase agreement), the consumer "rents" the power plant at an annual gross revenue from the generator and pays an additional variable operation cost when the power plant is dispatched.

The equality above indicates the break even at a stipulated discount rate. The correspondent calculations were based on the present value of both discounted total revenue and discounted total costs. Since ANEEL (2016) has defined the WACC - Weighted Average Cost of Capital for new auctions of investments in generation as 7.16% p.y., then such discount rate was adopted as basis for the analysis of all cases.

Whenever there is mention to a discount rate in the present study, it is a nominal discount rate that is meant. Concerning this aspect, a commonly used inflation index in Brazil is the IPCA, which for the 2007-2017 period had an average of about 5.92% (IBGE, 2018).

The most relevant costs that constitute the inputs of the power plant are the cost of investment, cost of operations & management, cost of fuel, cost of emissions, and the cost of decommissioning the facility after its lifetime (See Nomenclature Section). In the study, two additional variables were included in the calculations of the LCOE. One of them is the cost of transmission, to assess its impact on the overall cost of generation. As observed by Khatib (2010), it could be very representative sometimes and depends on the country or region.

It is a fact that natural gas can be flared or intentionally ventilated at the production sites. Also, there is the occurrence of unintentional leakage in pipelines, compressors, and other equipment, mainly at the upstream part of the gas production chain. Therefore, this aspect was included as a second additional variable, the cost of leakage, meaning that for a given percentage of leakage in the system, an additional measurable cost was added to the final results.

The cost with decommissioning the facility can be very relevant for some kinds of utilities, especially nuclear power plants, where it can reach up to 15% of the total investment (Garson, 2015). For the thermoelectric generators under evaluation, this cost is much smaller and its final effect after discounted in time is negligible and close to zero. Therefore, it was discarded from the analysis and the final discounted cash flow model can be rewritten as:

$$\sum_{t=1}^{n} \frac{TRt}{(1+i)^t} = \sum_{t=1}^{n} \frac{TCt}{(1+i)^t} \rightarrow (3)$$

$$\sum_{t=1}^{n} \frac{(Q_{MWt} \cdot P_{MW})}{(1+i)^t} = \sum_{t=1}^{n} \frac{Cinv_t + Cop_t + Cfuel_t + C_{eqCO2_t} + C_{deco_t} + C_{trans_t} + C_{leak_t}}{(1+i)^t} \quad (4)$$

As the equation term P_{MW} in equation (4) is the constant of the sum, it can be isolated outside of it, this way, rearranging the terms and considering $C_{deco} \approx 0$ the proposed MLCOE is:

$$MLCOE = P_{MW} = \frac{\sum_{t=1}^{n}(Cinv_t + Cop_t + Cfuel_t + C_{eqCO2_t} + C_{trans_t} + C_{leak_t}) \cdot (1+i)^{-t}}{\sum_{t=1}^{n} Q_{MW_t} \cdot (1+i)^{-t}} \quad (5)$$

The levelized cost of electricity methodology, although comprehensive and efficient, presents some weaknesses while measuring and comparing different technologies. As well observed in the 2016 Annual Energy Outlook – AEO 2016 (EIA, 2016), projected utilization rates, existing resource mix, and capacity values, can vary substantially across regions where new generation capacity may be required. This implies that the direct comparison of LCOE across technologies might be problematic in some cases and can be misleading as the only method to assess the economic competitiveness of various generation alternatives.

However, this is more prone to happen when the comparative analysis involves renewables displacing existing fossil fuel technologies. In this case, there is usually a different economic value based on the specificities of the country or region and the displaced technology. Also, renewables might have incentives such as feed-in tariffs and other subsidies. To resolve this issue, another indicator was proposed at the referred report, the levelized avoided cost of electricity (LACE).

EIA (2013) observed that a better assessment of the economic competitiveness of a given generation project can be gained through combined consideration of its LCOE and its avoided cost, or LACE, as a measure of what it would cost the grid to meet the demand that is otherwise displaced by a new generation project. Avoided cost involves both the variation in daily and seasonal electricity demand in the region where a new project is under consideration, and the characteristics of the current generation assets, to which new capacity will be added, thus comparing the new generation resource against the mix of new and existing generation and capacity that it could displace.

It provides another approach to the assessment of economic competitiveness of the various technologies, as a measure of what it would cost to the grid to generate the electricity that is otherwise displaced by the new generation project. Therefore, in order to provide additional conclusions regarding the economical competiveness of various technologies, levelized avoided cost of electricity data were also used in the comparison.

The difference between the LACE and LCOE values for the project under evaluation provides an indication of whether or not its economic value exceeds its cost, where cost is considered net of the value of any taxes.

For this purpose, the LACE values presented for each of the generating technologies were the ones derived from the AEO 2016 (EIA, 2016 – Table 4), for facilities entering in service in the year of 2022 (Table 4). The specific assumptions for each of the factors that constitute the mentioned indicator are detailed in the Assumptions to the Annual Energy Outlook (EIA, 2016). The main idea behind this additional comparative analysis is when the LACE of a particular technology exceeds its calculated MLCOE, or the difference LACE – MLCOE > 0, the technology would generally be economically attractive to build.

Table 4 – Regional variation in levelised avoided costs of electricity (LACE)

Technology	**LACE (US$/MWh)**		
	Min	Average[10]	Maximum
Natural Gas CCGT	54.7	61.1	66.1
Mineral Coal – Pulv.	54.6	61.0	66.0
Biomass – Bagasse	54.7	61.2	66.3

Source: EIA (2016) for new generation resources in service at 2022

The data obtained from (EIA, 2016) indicate that the LACE between similar generation technologies is very close, because calculations used similar parameters such as the grid cost of electricity displacement. In the present study, consequently, such average

[10] The average is the non-weighted average levelised avoided cost per technology based on additions in 2018 - 2022.

costs were very close, since all technologies are thermoelectric and involve the combustion of fossil fuels. Comparative results between MLCOE and LACE confirmed conclusions regarding the natural gas and the biomass as the most competitive and viable generation alternatives as detailed in Sections 4 and 5, when compared to other fossil fuels.

It must be noticed that the LACE and MLCOE estimates are simplifications of modeled decisions and may not completely include all decision factors or match modeled results. The purpose was to combine results in order to provide a stronger indication of the most suitable generation technology.

3.2 Regulatory framework assessment

A regulatory framework assessment was performed, identifying most relevant changes of the oil & gas industry related laws, as well as the current infrastructure in Brazil and how it is comparable to other more developed regions. One major hypothesis is that the increase in market liberalization and pipeline integration, by means of regulatory framework improvements, would contribute to the promotion of natural gas pipeline infrastructure expansion and to attract further direct investment flows.

Different characteristics of natural gas markets in Brazil and Argentina were analyzed in a comparative manner, focusing on understanding the effects of legal marks and governmental policies on the development of infrastructure and energy integration of NG in Mercosul, as well as its impact on investment. The focus of such case study approach was to better understand the dynamics of each market, through the evidences provided by their main regulatory policies in energy law.

The paradigms for the analysis were Brazil and Argentina most relevant legal marks for the oil and natural gas industry, since both countries are relevant Member States of the Mercosul. The analysis was performed in order to better understand the bottlenecks and other characteristics for the natural gas market in each country.

Theoretical sampling was the basis for the discussion, which demonstrated to be the recommended approach to analytic induction, because it accommodates existing theories better. In collecting and analyzing data for this study, legal frameworks and diplomatic documents were the basis for the analysis. Also, the comparison to other more developed NG markets was also preferred.

4. Discussion

4.1 Comparative economic and policy study of thermoelectric generation.

4.1.1 Investment Costs

In order to calculate the MLCOE, a theoretical electric utility was created for each technology, with an average investment cost (C_{inv}) and an average installed capacity (Q_{MW}), using the data collected from the Sep. 2016 Consolidated Result of the Brazilian Electric Energy Procurement Auctions, for new energy contracts, performed by CCEE (See Table 5). This is the entity in charge of the accounting and financial settlement for the short-term market and the energy contracted in the ACR.

Table 5 – Summary statistics for different generating technologies

Technology	Number of Plants	Capacity (MW)			
		Min	Mean	Median	Max
Natural Gas –CCGT	08	499.20	933.97	910.50	1,515.64
Mineral Coal – Pulv.	04	340.00	473.30	360.05	720.05
Biomass –Bagasse	11	34.05	50.05	40.00	116.00
Fuel Oil (A1)	04	50.00	120.60	129.00	174.30

Source: CCEE (2016)

Table 5 presents size statistics for the different technologies under study and the capacity can refer to a single power station or the combined capacity of multiple units on the same site.

4.1.2 Fuel and operational costs

The study considers the oscillation of the natural gas prices, through the technical analysis of the commodity future prices quotations, negotiated at NYSE with the code NYSE:NGJ6, for contracts with due date at April/2016 (Fig. 9). It provided different scenarios of prices for comparison with other fuels, to assess the eventual drawbacks that might come from the fluctuation of prices, which would ultimately impact the cost of fuel (C_{fuel}) for the natural gas-fired facility.

ARSESP is the agency responsible for the regulation of sanitation and energy in Sao Paulo and fixates through annual deliberations the ceiling prices for pipeline natural gas supply. This is performed for each concessionary, segmented by monthly consumption and final use. The consumption of gas calculated in cubic meters for the theoretical CCGT natural gas-fired power plant is of about 106 MMm^3/month, for an installed capacity of about

934MW. This consumption rate locates the theoretical utility at the highest consumption segment for thermoelectric and cogeneration facilities (more than 20 MMm^3/month) (ARSESP, 2016).

Considering that the remuneration in this case is composed of a fixed term[11] of US$ 21,502.32 plus two variable terms, one of US$ 0.020436 / m^3 for the consumption itself, and the other of US$ 0.271384/m^3 for the transportation and cost of the ducted gas, including federal taxes. This way, the calculated natural gas price for thermoelectric generation in the case (GN São Paulo Sul S.A) is of about R$ 28.34 / MMBTU or approximately US$ 8.10 / MMBTU. Thus, three distinct price scenarios were assumed for the natural gas:

- **Natural Gas A** – the cost of fuel is the mean value of the long-term support (LT SUP – Fig. 5) for the analyzed future contract. It is slightly higher than the strike price of US$ 1.643/ MMBTU, and also the actual approximate Henry Hub NG Spot Price (Table 6) so that P_{fuelA}=US$2.0/MMBTU;
- **Natural Gas B** – the cost of fuel is the first long-term resistance, tested twice, in the period between 2008 and 2016. It is also the natural gas price for distributors, without taxes, as defined by Petrobras (1st. LT RES – Fig. 9 and Table 6), so that P_{fuelB} = US$ 6.0/MMBTU;
- **Natural Gas C** – the cost of fuel is the regulated ceiling price, calculated according to the Annex 2 of Deliberation Arsesp n^0 263 – Segment Cogeneration and Thermoelectric, so that P_{fuelC} = US$ 8.10/MMBTU.

Figure 9 – Historical Natural Gas Prices (NGJ6-NYSE)

[11] An average exchange rate of **US$1.00 = R$3.50** (from May 2016) was used to convert Brazilian Reais (R$) to U.S Dollars (US$) in all calculations.

Souce: Author elaboration with data from NYSE (Stock Market)

Table 6 – Petrobras Natural Gas Prices for Distributor

JAN/2018	Petrobras Price for Distributor[12] (Exempt of taxes)			
Region	**Contracts**	**Price US$/MMBTU**		
Northeast	Domestic Gas	7.4962		
Southeast	Domestic Gas	7.4402		
		Commodity	**Transport**	**Total**
Southeast	Imported Gas	4.6269	1.8414	6.4683
South	Imported Gas	4.3520	1.8219	6.1739
Center-West	Imported Gas	4.6269	1.8414	6.4683
PPT	JAN/18	4.24		
Henry Hub	SET/18	3.00		

Sources: MME (2018); EIA (2018)

The operational aspects concerning energy conversion efficiency for the different technologies under evaluation, capacity factors, as well as the operation and management costs, were explicitly obtained in the reference literature, especially at (e.g. Beer, 2007; Filho, 2009; Garson, 2015; Mendes, 2007; Pinhel, 2000). The considered values for these specific parameters are detailed at Table 7.

Table 7 – Overall parameters and average costs for the different theoretical generators

Parameter	Units	NG fired (CCGT)	Coal fired (Pulv.)	Biomass fired	Fuel Oil fired
Lifetime	years	30	30	30	30
Capacity Factors	[%]	80%	80%	50%	80%
Electrical Conversion Efficiency	[%]	59%	40%	29%	39%
Investment Cost Av.	[US$/kW]	682.47	2017.71	810.53	1973.76
O&M Fixed	[US$/kWe]	29.43	37.64	33.54	35.44
O&M Variable	[US$/MWh]	2.70	3.40	3.05	3.01
Av. Installed Capacity	[MW]	933.97	473.33	50.00	120.60
GHG Emissions	[gCO2eq/ kWh]	500.00	1,200.00	900.00	800.00

Sources: Beer (2007); Filho (2009); Garson (2015); Mendes (2007); Pinhel (2000); CCEE (2016); Author elab.

Most natural gas-fired power plants in Brazil operate with a combined cycle gas turbine (CCGT), in which part of the thermal energy contained in the gases leaving the exhaustion portion of the turbine (Brayton Cycle) are then partially recovered at a secondary steam turbine (Rankine Cycle). In this operating system, conversion efficiencies are usually at about 60%.

The most recent coal-fired generators in Brazil employ pulverized coal combustion, in order to achieve higher efficiencies (ABCM, 2016). It consists of promoting the combustion of pulverized coal, which increases the area of contact between fuel and oxygen, increasing the kinetic parameters of the combustion reaction and the performance of the utility as a whole.

[12] PPT: Brazilian Acronym for Priority Thermoelectric Program. The price of natural gas for the PPT does not include taxes and its calculation is based on Portaria Interministerial n^{0} 234/02

Beer (2007) related the efficiency of coal-fired generators to the pressure and temperature of the produced steam. Most of the facilities in operation employ the subcritical operation cycle, in which efficiencies usually reach up to 40%. Some more advanced systems operate with higher pressure and temperatures, the so-called supercritical operation cycle, and achieve efficiencies of about 45%.

The following types of mineral coal are the most commonly used in facilities throughout the country, so two different scenarios for comparison with other fuels were idealized for such fuel (ABCM, 2016):

- **Mineral Coal A** – the utilized coal is of domestic origin, from the city of Cambuí/MG, with a net calorific value of 4,850 kcal/kg and a P_{fuelA} = US$ 83.40/ton.
- **Mineral Coal B** – the utilized coal is of international origin, imported from South Africa, with a net calorific value of 6,700 kcal/kg and a price, when federal and importation taxes are included, of P_{fuelB}= US$ 82.10/ton.

For the purpose of this study, the biomass is considered to be composed exclusively of sugarcane bagasse. The most employed technology in Brazil is the traditional of topping cogeneration cycle with counter pressure steam, in which electricity is generated before the step of the productive process that utilizes heat. The average net calorific value of the sugarcane bagasse is of 1,650kcal/kg. Since the cost of fuel (C_{fuel}) is very low in this case, two different scenarios for comparison with other fuels were also idealized (FAEG, 2015):

- **Biomass A** – the cost of fuel is composed of the harvest and transportation costs, incurred for mechanized harvest and transportation of the bagasse to the power plant, in a distance not greater than 30km, which is of about P_{fuelA} = US$ 8.14/ton.
- **Biomass B** – the cost of fuel is the market average price to purchase the bagasse directly from the sugar-alcohol project, as happens when the generator does not own the sugarcane plantation, and is of about P_{fuelB} = US$ 20.00 / ton.

Finally, for the fuel oil, there was only one scenario to be compared, as the average price in 2014 for the fuel oil grade A in Sao Paulo, according to (ANP, 2015), was of R$ 1.16/kg or about P_{fuelA} = US$ 333.14/ton.

4.1.3 Direct and indirect environmental costs

The direct and measurable environmental costs were included as the cost of combustion emissions and the cost of leakage. The latter is exclusive for the natural gas-fired utilities. Some other relevant environmental issues were also addressed due to their relevance and impact.

Differently from the European Union, where CO_2 prices or costs are explicit, several countries such as Brazil or the United States do not have an explicit price for carbon. Since a peak of prices in the EU (US$ 30.00/ton of eq.CO_2) was reached in mid 2008's, the carbon quotations have adopted a tendency of secondary and tertiary decline, being negotiated in some periods at merely 10% of that peak value.

In this context, the carbon dioxide price forecast conducted by (Luckow *et. al.,* 2015) has achieved several estimates for the long term prices of carbon, based on several data sources and a reasonable range of expectations regarding future efforts to limit greenhouse gas (GHG) emissions. The most conservative number obtained was of US$ 15.00/ton of eq.CO_2, for a low case price projection, levelized for the 2020-2050 period as US$ 26.24/ton of eq.CO_2.

In this case, the carbon price refers to an indirect cost, which is not directly borne by investors but must be considered when choosing between the most efficient and less polluting alternative. This becomes more relevant especially in a global warming scenario, such as experienced nowadays. Hence, for the calculations of the MLCOE, the adopted price for carbon was of US$ 15.00/ton of eq.CO_2.

4.1.4 Other environmental impacts

The combustion of mineral coal and solid organic residues in general, including sugarcane bagasse, produces particulate material, sulfur dioxides (SO_x), such as SO_2, one of the responsible for acid rains, and nitrous oxides (NO_x), being all of them highly soluble in water. This will cause these elements to deeply penetrate in the ecosystem, combining to create several other hazardous substances, even carcinogenic, such as nitrosamines.

Miranda (2012) concluded that CCGT thermoelectric utilities are those with smaller environmental impact among their alike, producing 80% less GHG or approximately 60% less CO_2, 95% less NO_x, and 100% less SO_x, when compared to mineral coal-fired power plants.

The sugarcane bagasse impacts the environment not only because of its high emissions, such as coal, but it also creates conflict for the use of soil, that would otherwise be employed to cultivate foodstuff. The cultivation of sugarcane in Brazil is one of the major causes of deforestation and elevated consumption of potable water for irrigation.

Moreover, the mining and processing of mineral coal produces a large variety of residues, rich in trace-elements. In addition, oil and grease are found in the mine water, as well as several organic and inorganic compounds, some with high toxicity potential, especially iron, copper, manganese, and nickel. The drainage of the acid workshop effluents degrades and lowers the pH of the surrounding water supply and interconnected rivers, with the prevalence of sulphites, such as 1-5% of Pirite (FeS_2) (Tiwary, 2001).

Such toxic residues and heavy metals can be lethal to aquatic animals and prevent their reproduction, or enter the food chain by accumulating in fish tissue. Thiosulphate and sulphuric minerals may also create environmental problems through their oxidation to acid in receiving waters. They originate from the dissolution of pyritic sulphur in the underground mines and their concentrations are generally found high in mine water. These elements increase the hardness of water resources and consequently reduce their utility for drinking purposes.

4.1.5 Transmission Costs

The transmission costs are a consequence of the natural monopoly of electricity transmission, which in Brazil is regulated by the federal agency in charge of the electric sector, the ANEEL. The users are charged with tariffs for the transmission system use called Transmission System Use Tariff (TUST). Such tariffs are calculated according to locational signals based on a periodical ten-year electricity expansion plan.

The referred agency uses both short and long-term planning data to calculate tariffs, which are then annually corrected, all based on data informed periodically by the National Electric System Operator (ONS), entity responsible for the coordination and control of the Brazilian Interconnected System.

For new generators that win the energy auctions, the initial homologated tariff will remain valid for a ten-year period, after which it is annually revised. The TUST value is divided among the users, in order to guarantee that the total revenue from the basic grid user is equal to the revenue necessary to pay the transmission companies the remuneration for their assets.

In order to calculate the cost of transmission (C_{trans}), the considered value was the average of Thermoelectric Facilities Tariffs, located in the Center-South axis of Brazil, as defined in Annex I of the Technical Note nº 162/2015-SGT (ANEEL, 2015), and it is considered to be a fixed value of R$ 3.96/kW.month, or about US$ 1.13/kW.month (See Footnote 11).

4.2 Natural gas and the electricity market

In Brazil, there are two types of electricity markets; one of them is called Regulated Contract Environment (ACR), where the contracts are formalized directly between generators and the distributors, through the Chamber of Electric Energy Commerce (CCEE). The contracted energy in this case is sold to the captive consumers of various segments, who receive it at a fixed and regulated price by ANEEL. Therefore, the ACR might be considered as a pool of buyers, that aggregates demand from several distributors in periodical electricity procurement auctions.

The other market is called Free Contract Environment (ACL) and operates much like a wholesale market, where generators, retailers, and other financial intermediaries, sign bilateral contracts both for short-term delivery of electricity (Spot Price) and for future delivery periods. The contracts signed under ACL rules are being employed commonly as a hedge mechanism for price uncertainty, since prices are subjected to fluctuation.

In 2017, around 70% of the electricity consumption was located in the regulated contract environment (ABRACEEL, 2018), that is a captive market with monopolistic regulation. Therefore, the hypothesis adopted for the purpose of this study is of electricity supply contracted at a fixed and regulated price, as occurs in the ACR. This implies that the MLCOE methodology is sufficient to compare similar generating technologies for current market conditions.

Several costs and other related data were applied to the model for each of the scenarios, where the MLCOE was calculated using the average discount rate of i=7% p.y. for all technologies. Considering that thermoelectric facilities have similar useful lifetimes of up to 30 years and that Decree n. 5.163/04 stipulates a maximum contract term of 30 years, counted from the beginning of supply, although thermoelectric utilities usually contract for 20-25 years, the different generating assets were assumed to have the same lifetime of 30 years. Figure 10 shows each of the results obtained for the suggested scenarios and conditions, with distinct combinations of pricing and emissions, in order to evaluate their relevance and the extension of their impact on the overall cost of generation.

Based on the results shown in Table 8 and Figure 10, it can be inferred that when the considered price is the mean value of the long-term support, as in the Natural Gas A scenario, then it would be the cheapest alternative among the technologies analyzed, with a MLCOE of US$ 40.50/MWh.

Table 8 – MLCOE and gross profit margins for competitive theoretical generators at a 7% discount rate

Parameter	Gas A	Gas B	Gas C	Coal A	Coal B	Biomass A	Biomass B
Investment Cost	8.63	8.63	8.63	23.20	23.20	16.40	16.40
Fuel Cost	13.77	41.31	55.08	22.10	26.31	14.14	34.74
O&M Cost	6.06	6.06	6.06	7.70	7.70	6.88	6.88
Emissions Cost	7.49	7.49	7.49	18.00	18.00	13.50	13.50
Leakage Cost	2.73	2.73	2.73	–	–	–	–
Transmission Cost	1.81	1.81	1.81	1.80	1.80	1.81	1.81
Total Cost (MLCOE)	**40.50**	**68.04**	**81.81**	**72.81**	**77.02**	**52.73**	**73.33**
Av. Winning Bid[13] (Auction Apr/2016)	**71.23**	**71.23**	**71.23**	**64.52**	**64.52**	**58.02**	**58.02**
Std. Deviation (Auction Apr/2016)	10.17	10.17	10.17	1.87	1.87	10.40	10.40
Av. Winning Bid (Auction Set/2018)	73.18	73.18	73.18	70.76	70.76	64.25	64.25
Std. Deviation (Auction Set/2018)	12.76	12.76	12.76	2.05	2.05	12.77	12.77
Total Gross Profit Margin (2016 Basis)	**30.73**	**3.20**	**-10.58**	**-8.29**	**-12.50**	**5.29**	**-15.31**
Gross Profit Margin[14]	**40.96**	**13.42**	**-0.36**	**9.71**	**5.50**	**18.79**	**-1.81**
Gross Profit Margin Percentage	**135.32%**	**23.21%**	**-0.50%**	**17.72%**	**9.32%**	**47.89%**	**-3.02%**

Source: Author elaboration (Units in US$/MWh)

The natural gas remains as the most attractive alternative until its prices breach the current market price and also first long term resistance, getting closer to the ceiling price as calculated for the Natural Gas C scenario, or about US$ 81.80/MWh. In this case, the MLCOE gradually increases until it approximates to the coal-fired power plants. It was observed that the cost of fuel for the natural gas has a major impact on the final cost. However, there is relative room for prices to move within the studied intervals, so that it still remains less costly than other fuels.

The mineral coal, either domestic or imported, has a MLCOE ranging from US$ 70.00 – 80.00/MWh, with a pronounced impact of emissions and investment costs in the final results, being the most polluting alternative studied, where the observed cost of emissions alone ($C_{eq.CO2}$) was of about US$ 18,00/MWh.

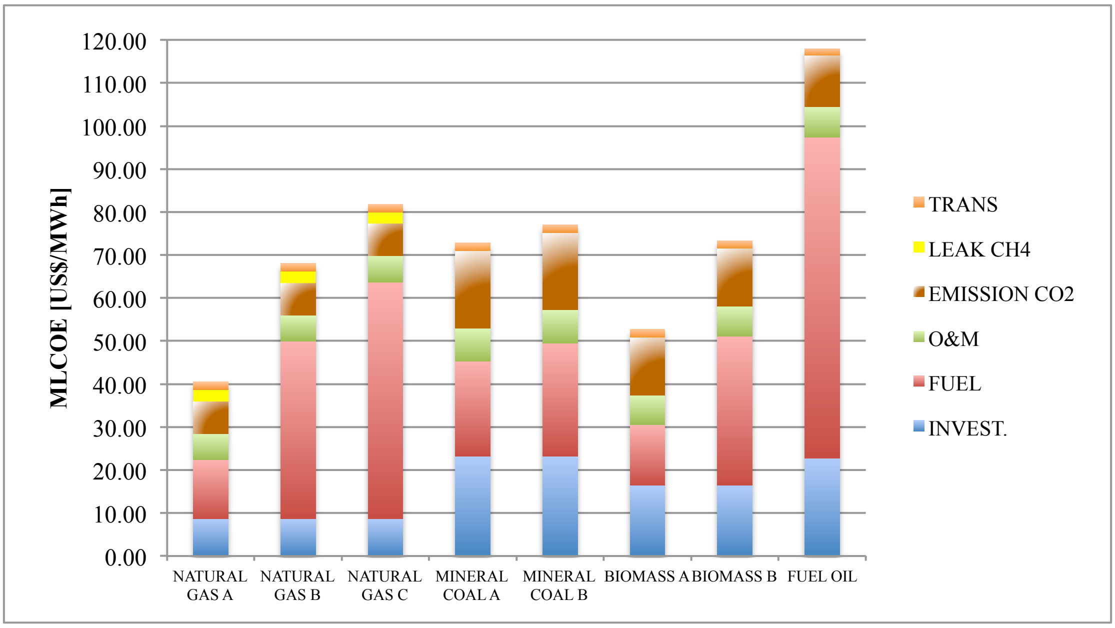
Another economically attractive technology is the biomass, with a MLCOE of US$ 52.73/MWh, when the cost of fuel was considered to be composed only of the mechanized harvest and transportation costs. This changes when the sugarcane bagasse has to be purchased, as detailed in Section 4.1.2, since the biomass overall cost reaches US$ 73.33/MWh. Such conclusions for the biomass are valid for small scale (QMW ≤ 50MW) and local generation projects, as were the majority of studied plants (See Table 7).

Most projects were commonly below this limit due to the discount offered in the electricity system use tariffs. Larger biomass projects would have to cope with higher

[13] Average for winning bids per generating technology, as provided by CCEE converted to U.S Dollars.
[14] Excludes the emissions and leakage costs, which are not directly borne by investors, from the calculation. Without federal and state taxes. Calculated for the 2016 data.

investment and O&M costs, low efficiency issues, limited capacity factor due to the harvesting season, as well as high emission levels, which all impact the final cost adversely. However, since the above mentioned discount limit was elevated in 2017 by ANEEL to 300MW, it is very likely that new biomass power plants will be larger than the current ones.

Figure 10 – Comparative analysis of the MLCOE for each generating technology divided per each cost



Source: Author elaboration

Also, the relevance of the LACE analysis is the conclusion it provided, that the only technologies able to successfully demonstrate to be economically attractive in both terms were the natural gas and the biomass, since they presented for some market conditions a positive difference between the both indicators (See Table 9). This implies that for the studied price intervals and market conditions, these technologies are the only able to replace their counterparts with economic and environmental advantages.

Table 9 – Difference between averages for levelized avoided costs of electricity (LACE) and modified levelized costs of electricity (MLCOE)

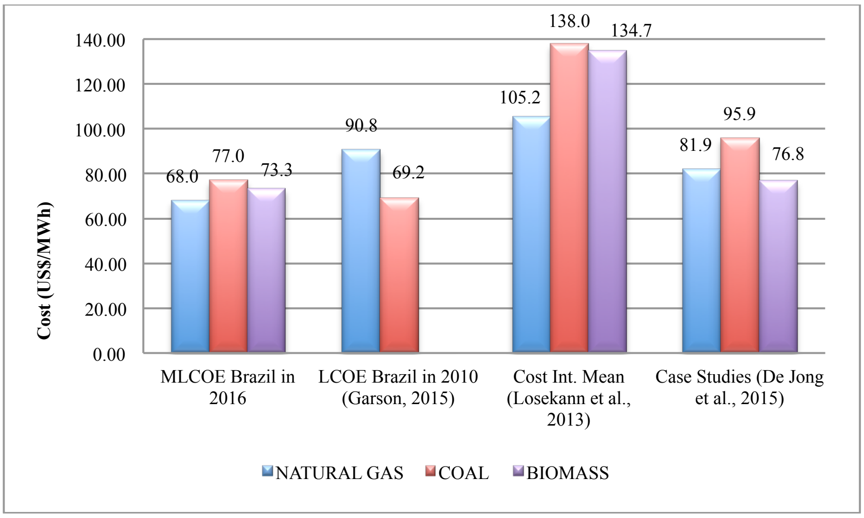
Technology	Comparison of MLCOE and LACE (US$/MWh)		
	Average MLCOE	Average LACE	Net Difference
Natural Gas (A)	40.50	61.1	20.60
Natural Gas (B)	68.04	61.1	-6.94
Natural Gas (C)	81.81	61.1	-20.71
Coal (A)	72.81	61.0	-11.71
Coal (B)	77.02	61.0	-16.02
Biomass (A)	52.73	61.2	8.47
Biomass (B)	73.33	61.2	-12.13

Source: Author elaboration

The most expensive technology for all the simulated scenarios was considered to be the fuel oil, with a MLCOE of about US$ 118.00/MWh. This elevated cost is due to the combination of higher fuel, investment and emission costs and lesser efficiency when compared to a CCGT or a mineral coal power plant. In some occasions, fuel oil-fired utilities might also run on diesel oil, an inadvisable situation since the average price for this fuel in Sao Paulo (ANP, 2016) was of about US$ 2.82/gal. Such high price impacted the final cost drastically, leading it up to more than US$ 180.00/MWh. Hence, this fuel was discarded from the comparative, with the recommendation to be employed only in emergency situations.

It is important to notice that the obtained results for the natural gas scenarios are located mostly in the first 5% percentile for the different carbon prices scenarios simulated by (Losekann *et al.,* 2013). Their calculations were based on a weighed sum of all individual average costs and the risk associated with each technology, through a Monte Carlo statistical experiment for the entire portfolio. The biomass costs at their study varied between US$ 120-135/MWh, a significant difference of about 67% when compared to the Biomass B scenario for example (See Fig. 11).

Figure 11 – Comparison between total costs per technology



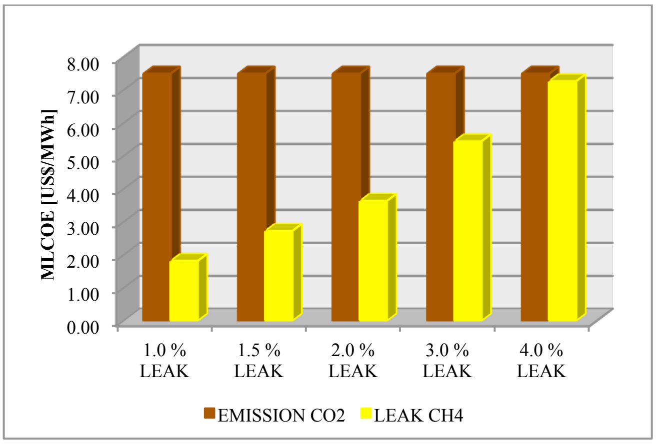
Source: Author elaboration

As well noted, measuring risk is a difficult task, since many factors might not be adequately considered or weighed. Another aspect is that the adopted lifetime for facilities was shorter than usual (e.g. Garson, 2015; De Jong *et al.,* 2015) of about 20 years, and carbon prices were considered to vary between US$ 0.00-60.00/ton.

The costs of O&M in the present study are very close to the average for the same technologies as observed at the IEA Report. When compared to the results of the individual case studies performed by (De Jong et al., 2015), there was major influence of the cost of fuel and O&M. This implied a MLCOE -17% smaller for the natural gas and -20% smaller for the mineral coal. As for the biomass case study, results differ in less than 5% from each other (See Fig.11).

Regarding the cost of leakage, the concerns arisen by (Busch and Gimon, 2014) are legitimate and deserve attention. As can be seen in Figure 12, the cost of leakage is of about 26% of total emissions in eq.CO_2 or about US$ 2.73/MWh, when the assumed gas system leakage is at 1.5% on a mass basis.

Figure 12 – Leakage x CO_2eq. emissions for different scenarios.



Source: Author elaboration

This fact changes as the percentage of leakage increases. It has the same impact as the CO_2 emissions from combustion when the percentage of leakage goes beyond 4.0% on a mass basis. From the analysis of the data, it can be deducted that there is a linear relation between the parameters as follows:

$$\frac{MLCOE_{CH4}}{MLCOE_{CO2}} = 0.24267.LEAK_{\%} \qquad (6)$$

This relation demonstrates that the environmental impact of the CH_4 equals that of CO_2 combustion at about 4.2% on a mass basis, when methane leakage rises to a level in which natural gas becomes as greenhouse gas intensive as biomass, with a total cost of emissions ($C_{eq.CO2}$+C_{leak}) of approximately US$ 15.00/MWh.

Such leakage levels are abnormal and would be difficult to reach with the modern control equipment and systems for detection and early warning. Since the oil fields in the Brazilian pre-salt layer are producing as much oil as natural gas (See Fig. 3), if the natural gas surplus is not adequately used, such as in thermoelectric generators, heating, etc., it will be eventually burned in flares or intentionally ventilated to decrease the well pressure, which poses as a serious environmental issue.

4.3 Regulatory analysis of NG market towards infrastructure and energy integration

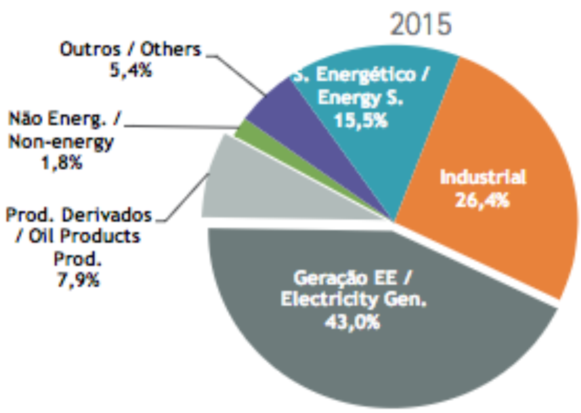
4.3.1 Regulatory Framework of the natural gas industry in Brazil

Brazil is the largest country and economy in Latin America, therefore an interesting case study of successive attempts to integrate its gas distribution network. Despite Brazil's substantial natural gas reserves and the great expectations surrounding the large oil and gas resources located in the pre-salt layer, the natural gas sector in the country is relatively underdeveloped.

Since demand for heating is almost nonexistent, due to mostly tropical and under-tropical predominant climate, most of demand is primarily located in industrial facilities and thermoelectric generators. There is also demand for transportation, commercial, and residential consumers (Figure 13).

According to MME (2018) the average national daily production in 2017 was of 109.86 million m³/day, and the average volume of imported natural gas, including the regasification of LNG, was of 29.37 million m³/day. The Brazilian transportation network is about 11,700km in length, if considered both transport and transfer pipelines, while the distribution network, still primarily concentrated in the States of the Southeast area, has about 27,320 km in length (ANP, 2016; MME 2016).

Figure 13 – Natural gas consumption per sector in 2015



Source: EPE (2016)

The first legal mark of natural gas legislation in Brazil was Law n. 9,478 of 1997, which has shown to be unable to foster the natural gas industry development, especially due to limitations intrinsic to the lack of power in coordinating the market agents and somehow failing to attract investment, especially from private companies. Under this regulatory mark, occurred the construction of the 3,200km Bolivia–Brazil pipeline in 2000, the longest gas pipeline in South America, to serve both the industrial sector and the planned natural gas-fired thermoelectric demand.

Changes in the federal government that occurred in 2003, modified the reform process and instead of pursuing a more open market, focused instead on reinforcing the planning role of the Ministry of Mines and Energy (MME) in the energy sector. Also, the Energy Research Company (EPE) was created in the period, with the main objective of technically assisting the MME in strategically oriented decisions and mid-term expansion strategies.

Historically, the Brazilian natural gas industry's growth was not based on consumption to generate electricity, as occurred in several other countries, but on commercial and specially industrial use. Since the industrial demand is relatively stable and the volumes are enormous, this segment is the main drive for projects to build network infrastructure, for both transportation and distribution (Mathias and Szklo, 2007).

The thermoelectric power plants in Brazil were originally intended for emergency response, in case of occasional severe droughts that would impact adversely the electricity supply, such as the ones occurred in 2001 and more recently in 2014-2015, which culminated in unwanted electricity rationing.

Later, the second regulatory mark established under Law n. 11,909 of 2009 (Gas Act), under intense political debate between the different participants of the gas industry, contributed to the development of regulatory coordination under the National Agency of Petroleum, Natural Gas and Biofuels (ANP). However, the extensive influence of state giant Petrobras throughout the entire gas chain still made it difficult to other agents to enter the market (Colomer Ferraro and Hallack, 2012).

Under the establishment of Law n. 11,909 of 2009, some issues that were not addressed appropriately in the first regulation mark where then more adequately approached by this legal text. First, the role of the government in the gas sector was substantially changed, allowing further liberalization of the natural gas transportation network, and creating a mechanism of co-ordination to reduce the perception of risk from private investors.

Campos *et al.* (2016) stated that along with this new configuration brought by the Gas Act, is the draft of a new commercial model arrangement, allowing the entry of new actors (self-producers, self-importers, and free consumers) and therefore new possibilities of contractual relations. However, they observed that the actual expansion of the grid remains much smaller than expected under the Gas Act.

Such inability is credited to some particular factors concerning regulatory uncertainties and inadequate resolutions among which: the uncertainty concerning the classification of pipelines (transfer, transportation, production flow, and distribution pipeline), the controversy surrounding the definition of what would be considered a “free consumer”, third-party access to existing pipeline infrastructure, period of contract exclusivity, and PEMAT (Expansion Plan of the Natural Gas Transportation) network expansion planning.

In this case, the associated risks with pipeline deployment can be many, going from leakage control, operation and maintenance issues, to costs with pressure loss along the pipelines. Concessions of natural gas transportation under this legal mark were in charge of ANP and were supposed to last for a thirty-year period, with permitted prorogation.

Table 10 below presents the overall panorama of the latest most relevant regulatory instruments in Brazil, divided by aspects such as granting system for gas transport pipelines or production regimens, degree of market liberalization, state presence, etc. It includes a brief analysis of the intrinsic contingencies contained in each legal text. Since electricity generation is one of the primary destinations for natural gas in Brazil, it is important to analyze recent changes in regulatory legislation and its impacts.

As can be seen in Table 10, there is still the need to better deal with the gas transportation deregulation issue, since it was not adequately addressed in previous legislation. In this matter a brief digression is of importance, especially concerning a much more developed market, the North American.

Busby (1999) observed that the greatest impact of federal regulation in the natural gas industry came as result of Federal Energy Regulatory Commission (FERC) orders implementing the Natural Gas Policy Act, FERC's Orders n. 436 in 1985, n. 500 in 1987 and n. 636 in 1993. Such orders allowed local gas distributors and large customers to "by-pass" the pipeline and purchase gas directly from producers, marketers, and brokers.

This implied that pipeline companies had to transport any purchased gas, resulting in a drastic change in the supplier-costumer relationship. By 1993, FERC orders had covered several relevant issues, among which fully comparable transportation services for gas, whether sold by the pipeline company or by other third party, and separation of purchase and transportation services by interstate pipelines ("unbundling").

Table 10 – Brazil's comparative regulatory framework in the O&G industry

Comparative Regulatory Instrument Analysis

Law/Aspect	Law 9,478 of 1997 (Petroleum Act)	Law 11,909 of 2009 (Gas Act)	Law 12,351 of 2010 (Pre-Salt Act)	Law 13,365 of 2016 (Alters the Pre-Salt Act)
Granting system for production regimes	Authorization granted by ANP	Concession granted by ANP and agreement signed with MME **or** Authorization granted by ANP for international agreements.	MME proposes to the CNPE (National Council of Energy Policy), with ANP's previous hearing, the blocks under shared production regime.	MME proposes to the CNPE, with ANP's previous hearing, the blocks under shared production regime.
Granting system for natural gas transport pipelines	Authorization granted by ANP	MME coordinates studies and proposes decennial expansion plan (PEMAT); Concession granted by ANP; Tariffs for use fixated by ANP	NA	NA
Grant Duration	Variable, Art. 68-A, § 4o limited to further regulation the duration of authorizations	30 (thirty) years, extendable up to additional 30 (thirty) years	35 (thirty five) years	35 (thirty five) years
State presence	Strong	Strong	Medium	Medium-Low
Degree of liberalization	Low	Medium	Medium	Medium-High
Contingency	No regulation	Contingency committee coordinated by the MME, ANP supervises the oil & gas sector	MME proposes to the CNPE the blocks for concession. ANP opines.	Petrobras must opine about right of preference in 30 days, after CNPE communication if it chooses to participate
Import and Export	Authorized by ANP	Authorized by MME	NA	NA
Oil & Gas Trading	Authorized by ANP	Authorized by ANP	Authorized by ANP	Authorized by ANP
Oil & Gas Quality	Established by ANP	Established by ANP	Established by ANP	Established by ANP
Oil & Gas Exploration	Approved by ANP	Approved by ANP	Approved by MME, elaborated by ANP, mandatory Petrobras participation	If Petrobras participates in the consortium (operator or not) minimum of 30%, CNPE proposes blocks for participation.

Source: Adapted and expanded from Cordeiro *et al. (*2012)

Campos *et al.* (2016) presented a subdivision regarding the the major ongoing strategies for the expansion of the natural gas industry in Brazil as: to expand the natural gas supply (production in pre-salt layers and of unconventional gas resources) and importation (projects of international pipelines and of regasification infrastructure (LNG). This aspect is fostered in Laws 12,351 of 2010 and 13,365 of 2016.

Also, to expand the network of transport pipelines, based on a stable regulatory framework, which plans PEMAT in compliance with other planning instruments of the national energy sector, such as the PDE, PNE (National Plan of Energy), and National Zoning of Oil and Gas Resources.

Finally, to encourage the use of natural gas in thermoelectric generation to complement hydroelectric generation and mitigate intermittence related to renewable sources (wind and photovoltaic). In this particular aspect, natural gas-fired utilities present several advantages linked to the quality of the electricity generated such as: reliability, dispatchability, time of answer, and predictability of generation.

The total thermoelectric generation participation in the National Interconnected System (SIN) has increased from 25,210MW in 2006 to 42,861 MW in 2017 and NG power plants contributed to about 30% of thermal generation (ONS, 2018).

In this context, ANEEL Resolution n. 583 of 2013 introduced a major asymmetry concerning the penalties for contracted distributors cutting off NG supply to thermoelectric utilities. It employs a linear equation to calculate the penalty amount:

$$V_{sm} = \left[PMED_m + j\left(\frac{PLD_{max} - PMED_m}{4}\right)\right] ENP_m \qquad (7)$$

Where V_{sm} corresponds to the sanction value, in month m, in which the NG supply cut off occurred, expressed in US$; $PMED_m$ is the average monthly liquidation price of the differences (PLD[15] – spot market price), as publicized by the Chamber of Electric Energy Commerce (CCEE) and expressed in US$/MWh.

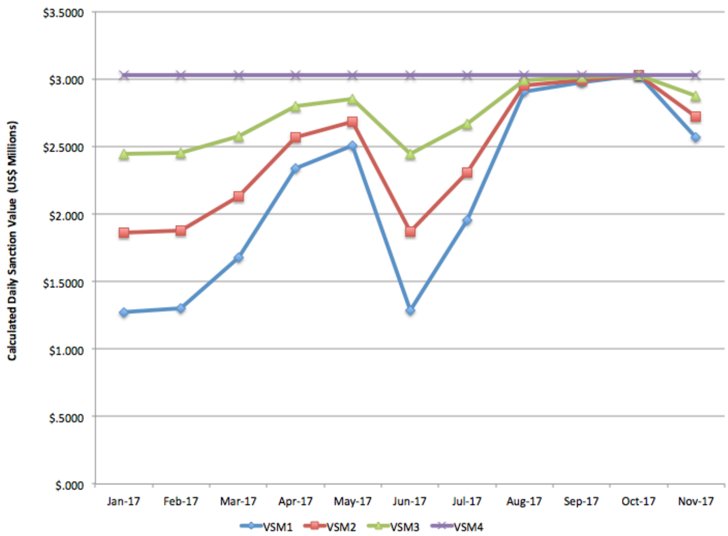
The variable j refers to the number of months in which the natural gas supply cut off has occurred, varying from 1 to a maximum of 4, after which it remains constant. PLD_{max} is the maximum current regulated liquidation price of the differences in US$/MWh, annually

[15] Positive or negative differences between the electricity that was produced or consumed and the electricity that was contracted are liquidated on the spot market and valued at the liquidation price of the differences (PLD), which is determined weekly by each load level and for each submarket based on the marginal cost of operation of the subsystem. The PLD is limited by minimum and maximum prices. In this market, the price does not conform to the economic relationship between supply and demand of the agents. Rather, it is determined by a set of computational models operated by the ONS and the CCEE.

homologated by ANEEL. Finally, ENP_m which corresponds to the amount of electricity that was not generated due to the lack of fuel for the facility, in MWh.

The daily fine imposed on the natural gas supplier, in each month, considering market data for 2017, is demonstrated both in Figure 14 and Table 11. It is important to notice that the V_{sm} depends on values and indicators derived from the electricity market.

Figure 14 – Calculated daily sanction value for NG suppliers.



Source: Author elaboration

This implies that the penalty clause not only transfers risks from the electricity market to the NG industry, but also links them to parameters intrinsic to the Free Contract Environment (ACL, Brazilian Acronym), which is subjected to price fluctuation.

In order to soften these effects, the study proposes a change in the way the sanction value is calculated (V^*_{sm}), using more precise parameters, as the current formula, with an analogous linear format:

$$V^*_{sm} = \sum_{w=1}^{n} \left[PLD_w + j \left| \frac{PLD_w - PMED_m}{4} \right| \right] ENP_w \quad (8)$$

Where, V^*_{sm} corresponds to the mitigated sanction value, in month *m*, expressed in US$; PLD_w is the weekly liquidation price of the differences (PLD)[16].

The coefficient *w* for week varies from 1 to a maximum of 5. ENP_w corresponds to the amount of electricity that was not generated due to the lack of fuel for the utility, in MWh, in the corresponding week. The difference between the weekly and the monthly averages are the new proposed parameters, within a module, since its value might occasionally be negative, which would diminish its penalizing effect unintentionally.

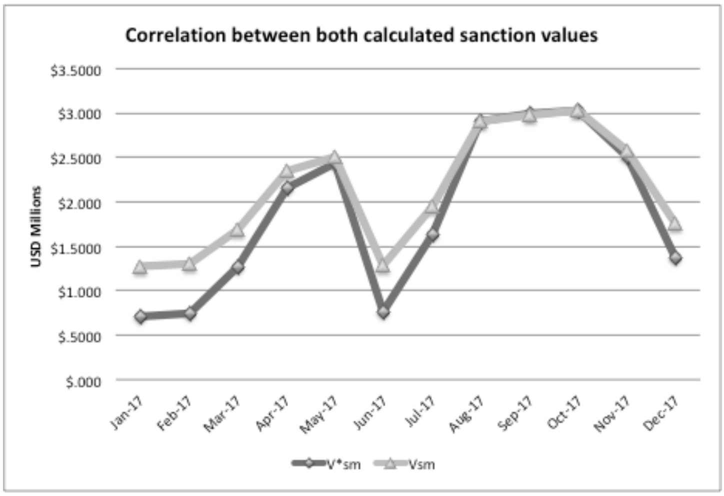
[16] Weekly PLD prices data are available at: www.ccee.org.br/portal/faces/pages_publico/o-que-fazemos/como_ccee_atua/precos

The proposed sanction value calculation does not penalize the electricity generator, since it considers more precise parameters, instead of the monthly averages and the $PLD_{max.}$ Moreover, it considers the same increasing penalty, through the variable *j,* for recurrent supply cutoff. Therefore, the contract neutrality of the proposed calculation is ensured.

It also mitigates the influence of averages and the $PLD_{max,}$ use, therefore decreasing the sanction value for the NG supplier, when compared to the current formula (See Fig. 15). The annual decrease of sanctions value would be of -12.13%, when compared to the current ANEEL Resolution n. 583 of 2013 formula, for non-recurrent suppliers.

Thus, the supplier still has to account for the generator's income losses due to lack of fuel. However, the indemnity is now slightly smaller (Table 11), and more adhered to the actual prices of differences liquidation of the ACL. Figure 15 demonstrates the difference between the two calculated daily fines during 2017, for non-recurrent supplier.

Figure 15 – Comparative calculated daily sanction values (V_{sm} V^*_{sm})



Source: Author elaboration

Table 11 – Calculated daily sanction values per month in 2017 (for the average natural gas-fired power plant).

Month (2017)	PMLD/SE $/MWh	PLD_{max} $/MWh	V^*_{sm} [$]	V_{sm} [$]
January	121.44	533.82	709,499.24	1,274,376.46
February	128.43	533.82	748,231.83	1,304,130.92
March	216.24	533.82	1,259,171.46	1,677,913.40
April	371.47	533.82	2,152,197.00	2,338,683.85
May	411.49	533.82	2,427,546.40	2,509,037.73
June	124.70	533.82	766,427.89	1,288,253.36
July	280.81	533.82	1,625,864.37	1,952,769.73
August	505.95	533.82	2,896,725.49	2,911,127.39
September	521.83	533.82	2,997,865.13	2,978,724.08
October	533.82	533.82	3,029,762.14	3,029,762.14
November	425.17	533.82	2,507,445.01	2,567,269.65
December	235.07	533.82	1,365,521.32	1,758,067.41

Source: Author elaboration

4.3.2 Legal Aspects of the O&G Production Chain

Specifically, when referring to the pre-salt regulation, Law n. 12,351 of 2010 demanded that Petrobras had a mandatory participation in every contracted block of exploration with a minimum share of 30%. It also stated that the company had to be the operator of all operational activities related to the production of oil and gas in the blocks contracted under the shared production regime.

This mandatory participation and more restrictive operational rules, made it difficult for the expansion of production sites, especially given the scenario of financial difficulties that Petrobras has been experiencing in the last five years, making it unable to endorse new prospection and production projects in the pre-salt layer.

The fact is that Petrobras controlled 51% of the shares of its subsidiary Gaspetro, the other 49% belonged to Mitsui, the large Japanese conglomerate. This subsidiary detained over 7,000 km, or almost 97% of gas pipelines in Brazil, through the Transportadora Associada de Gás (TAG) which incorporated all regional natural gas transport subsidiaries in a process of management centralization that began in 2006.

It was later divided into two companies, Nova Transportadora do Sudeste S.A. (NTS) and Nova Transportadora do Nordeste S.A. (NTN), macro segments of distribution in the South and Northeast of the country.

In the second semester of 2016, as part of Petrobras recovery program and its business strategy plan PNG 2017-21, the company announced the sale of 90% of the shares of NTS for the amount of US$ 5.19 billion, the equivalent to 35% of the target of US$ 15.1 billion aimed at the sale plan between 2015 and 2016. This operation was closed in April, 2017 with the Canadian Brookfield Asset Management for the amount of US$ 4.23 billion. These facts are indication that the monopolistic structure of the natural gas industry is beginning to change its core, admitting more players, in pursuit of a more competitive environment, favorable to the entry of additional investment in the market, and to the sharing of infrastructure costs.

In the same direction, the Special Commission for Petrobras and the Pre-salt Exploration of the Chamber of Deputies made the first step to flexibilize these rules. The approved text of Law n. 13,365 of 2016 changes Law n. 12,351 of 2010 configuration, where the presence of Petrobras is no longer mandatory. However, it still has preference to be the operator of blocks to be auctioned under the production share regime. If for any given reason the company chooses to not participate in an eventual auction, the same rules under the Pre-Salt Act will apply to the other block operator awarded.

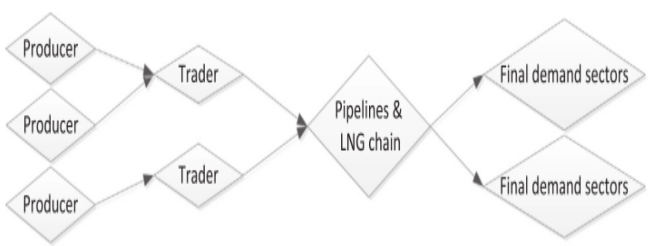
Another innovation is that all choices made by the state company regarding the participation in exploration projects will be submitted to the National Council of Energy Policy (CNPE), which will forward it to the Presidency of the Republic, who pronounces ultimately about which blocks Petrobras participates. This is intended to give room for more investment in the Pre-salt layer development and production, and it is likely to enable the expansion of related infrastructure, such as natural gas transportation pipelines and interconnections for energy integration. The question to be answered is if this is the best course of action.

Such changes imply that Petrobras may no longer be the operator of all blocks contracted under shared production regime. It modifies the article 30^{th} of current Law n. 12,351 of 2010, in a way that the name Petrobras is replaced by the definition "operator of the shared regime contract". Another important issue is that the auction winner, that is awarded the block of exploration in the Round of Bidding, is no longer obligated to constitute a consortium with Petrobras, without such, the awarded operator would find barriers to explore the block, if the state company chose not to participate in the production shared regime.

This legal maneuver was intended to release the state company from a burden it could no longer carry, since under Law n. 12,351 of 2010 and previous legal marks, it was obliged to participate in every block under the production shared regime with the minimum percentage of 30%. Another important aspect is that Petrobras is able to manifest interest to participate in the consortium of a given block.

Specifically referring to the natural gas supply and distribution, the panorama changes a little from the prospected situation in the oil and gas production (See Fig. 16). Cordeiro *et al.* (2012) stated that although many advances were achieved with the new natural gas regulatory framework, mainly after the so-called *Gas Act,* some aspects of the industry organization which demanded regulatory action where left untouched by the most recent law, while others were treated without the proper regard for isonomy principles.

Figure 16 - Supply chain illustration in the Global Gas Model.



Source: Egging and Holz (2016)

The first aspect is that no additional limits on vertical relationships of the natural gas chain were established so far. Also, Petrobras corresponds to practically all of the natural gas injected into the transport network in the current market structure. Moreover, until recently, it had relevant shares on other links of the chain, so this vertical integration yields considerable market power to the mixed capital state company.

Consequently, when compared to the most usual global gas model, the Brazilian market is strongly monopolistic. Producers and traders in Figure 16 generalization could be resumed to the presence of a major company throughout the entire chain, up to the city gates in the States. There local companies are in charge of distribution to the end-consumer.

In this context, the recent disinvestment program that includes the sales of many assets and downsizing of activities began an inevitable process of change in this market structure. This is due to the fact that the Brazilian government can no longer afford to be the primary driver of infrastructure expenditure.

Is was clear that such strong presence of a monopolistic position in the transport link leads to significant barriers to the entry of new shippers, willing to compete in the supply market. The concession granting system reforms were intended to diminish access barriers, but it is going to be a long time until a new set of pipelines is developed without Petrobras' former subsidiaries taking relevant part into the process.

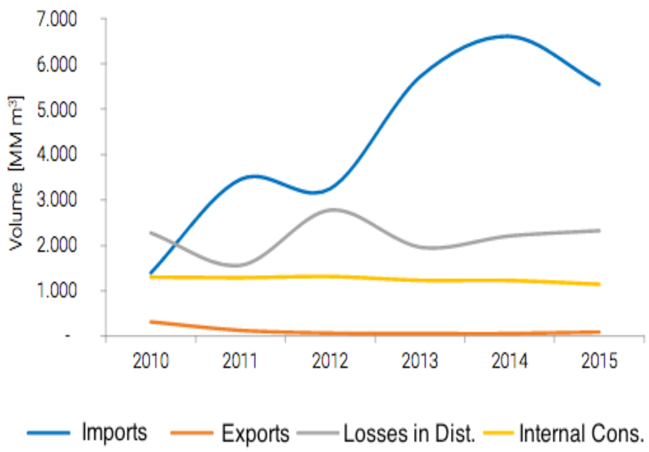
This is more prominent since the company actually does not possess the necessary available capital to successfully develop the remaining of national pipeline infrastructure, required to satisfactorily deliver the natural gas produced from the pre-salt basins to their final destinations. The purchase of NTS's shares by another international conglomerate, as happened with Gaspetro, indicates that major investment groups are aware of the occurring through the natural gas supply chain in Brazil.

4.3.3 Regulatory Framework of the natural gas industry in Argentina

In 2014, Argentina was the largest dry gas producer and the fourth largest petroleum and other liquids producer in South America, also an interesting case study of successful and failed attempts to integrate the gas network, including from a transnational point of view with Chile. The natural gas consumption in Argentina for the past five years is depicted in Figure 17, also approximately eight million consumers are connected to the gas distribution grids (MEM, 2016).

Natural gas consumption is broadly disseminated in Argentina, which has the most comprehensive network of transportation and distribution pipelines in Latin America. It constitutes of around 15,984km in pipeline for transportation and of 146,506km destined to distribution (ENARGAS, 2016). It is also expected that NG will gradually increase its market share and replace substantial amounts of liquid fuels, such as fuel oil, resulting in better overall performance of thermoelectric utilities (MEM, 2016).

Figure 17 – Natural gas market in Argentina



Source: MEM (2016)

The gas sector in Argentina is more mature than the one in Brazil and has undergone profound changes as a result of regulatory and structural reforms launched by the end of the 1980s. Recent regulatory changes are related to giving absolute priority to domestic supply of gas at stable prices in order to sustain economic recovery.

Such reforms, according to (IEA, 1999) were part of an overall program of economic restructuring, were aimed at improving economic efficiency and increasing investment, through the liberalization of the market and the involvement of more private capital, as has been occurring in the last five years in Brazil.

The design of the legal reforms in the 1980s and the 1990s was inspired heavily on experiences and lessons learnt from other countries, notably Canada, the United States, and the United Kingdom. At the core of these reforms, were the privatization of the downstream gas company, Gas del Estado (GdE), and the upstream oil and gas company, Yacimientos Petroliferos Fiscales (YPF), with the division of GdE into two transmission companies and eight distribution companies.

Moreover, the removal of wellhead and wholesale price controls and the establishment of an open-access regime to the distribution, along with the creation of an independent regulatory authority, called ENARGAS, were some of the major changes in the natural gas market to achieve better efficiency. These measures have demonstrated to be reasonably successful to foster competition throughout the gas supply chain. This was one of the main objectives of Law n. 24,076 of 1992, the Natural Gas Act. However, despite the removal of exclusive rights prior to privatization, YPF still remained as the dominant producer and supplier of gas to the Argentinian market, as happens to Petrobras in Brazil.

After the economic crisis that struck Argentina in 2001, legislation and regulations, including the Economic Emergency Act n. 25,561, were enacted, limiting the 1990s regime and imposing additional government controls over prices and use of natural gas production.

Under the establishment of Law n. 26,197 of 2007, differently from what occurs in Brazil where concession is centralized by the federal government, the Argentinian provinces assumed the ownership and administration of the hydrocarbon deposits within their boundaries. Hence, receiving the power to grant concessions on inland exploration blocks. Regarding offshore reserves, they were divided between provinces and the federal government.

The reduced infrastructure limiting the natural gas market development outside of Argentina is derived largely from past policies in the region, as in Brazil, which strongly encouraged energy self-sufficiency and the development of state-owned oil and natural gas monopolies. As well observed by (IEA, 1999), with the advent of more open, market-oriented policies, in particular the encouragement of private sector investment and reduction of governmental price controls, interest in expanding the use of natural gas in Argentina's neighbors has increased accordingly.

This has been more evident in the last decade, with the construction of new transnational pipelines, especially involving Brazil, Argentina, Bolivia, and Chile.

Renou-maissant (2012) discussed the recent regulatory changes undergone in European energy policies and how they targeted a single European gas market. The objective of deregulating energy markets was to offer real choice to all consumers in the EU, by creating new business opportunities and enlarging cross-border trade, in order to increase the efficiency and competitiveness of the EU energy sector. Moreover, there is indication of strong integration of natural gas markets in continental Europe, except for Belgium, being the process more successful between Italy and France.

Bondorevsky and Petrecolla (2001) observed that the article 33th of the Natural Gas Act in Argentina established a separation between gas transportation and sales. That was meant to avoid that carriers would distort competition in the trade segment, as stated *"carriers may not purchase nor sell gas, except for acquisitions that may be carried out for their own consumption.* This unbundling helped to eliminate the incentive to discriminate in providing transportation services between producers and final users.

Another important issue was the one contained in article 26th, which stated that carriers and distributors were obligated to permit indiscriminate access of third parties to any transportation and distribution utility of their respective transportation systems.

Such legal commandment implies the freedom of consumers to choose a trader of their willing, something that does not occur analogously in the Brazilian market, where consumers are obligated to purchase from the company that detains the concession in each State, in each specific macro region the consumer is situated.

In the 2000s, these market friendly reforms, introduced by President Menem's Administration in the 1990s, were somehow put aside and strong government controls began. In 2001, Argentina went through one of the most turbulent economic crises in its history, when the fixed exchange rate convertibility system that had supported the Argentinian Peso to the U.S. Dollar since 1991 ended abruptly. This caused major depreciation of about 70% of its relative value, forcing the government to adopt extensive austerity measures.

The two governments that followed, known as the Kirchner's Administration (2003-2015) deepened the restrictive policies that had been adopted temporarily in response to the economic collapse. Some of the adopted measures were price controls and tabulations (Vásquez, 2016). These measures alienated investors and impacted the natural gas sector deeply. Due to the deteriorating fiscal and energy situation, the Argentinian government was forced to loosen some of the restrictions to make the hydrocarbons sector once more attractive to private investors. It happened through two Decrees aiming at investment promotion and capital goods, since export controls were relaxed and attractive wellhead gas price incentives were adopted.

Vázquez (2016) emphasized that during the twelve years of the Kirchner-Fernández administrations, the ENARGAS was relegated to a secondary role, while a new government department was created in 2012. The Commission for Strategic Planning and Coordination of the National Hydrocarbons Investment Plan, the enforcement authority of the so-called *"Régimen de Promoción de Inversión",* was created to regulate hydrocarbons investments, with functions that overlapped and sometimes exceeded those of other agencies that the two administrations sought to supplant.

The government of President Macri, whose office started in 2016, has begun with the goal to correct some of the economic and political problems inherited from the previous governments and one of its first measures was the prompt dismantling of the controversial Commission mentioned above (La Nación, 2016). It is evident that Argentina is also struggling with regulatory issues to pursue regional energy integration and natural gas market expansion.

4.4 Infrastructure assessment and energy integration

The most important debates of the new millennium are focused on globalization and sustainable development for nations. Therefore, transnational energy integration in Latin America has been receiving increasingly attention from researchers and policy makers (BID, 2001). This is particularly relevant to the natural gas sector, because in this kind of market the costs associated to contractual reestablishments or changes are substantially high, especially in infrastructure.

The South American countries constitute an enormous potential pool of consumers with considerable room for expansion of natural gas use (see Tables 2 and 3). With the exception of Brazil and Argentina, natural gas use is still limited in the region, except maybe for the Chilean demand for thermoelectricity and mainly heating.

Nowadays, most of the gas pipeline infrastructure in the Mercosul region is distributed along the South; from Bolivia departs four major pipelines that target exportation, two to Argentina (Ramos – Bermejo and Campo Duran – Madrejones) and two to Brazil (Bolívia – Brasil, or GASBOL and Lateral Cuiabá). There are just a few modern projects in actual construction.

The idea of building a high capacity pipeline that would connect Venezuela's production fields to Brazil and Argentina, that arose in midst of the 29th Mercosul Summit in 2005, has not gone much further than the Memorandum of Understanding signed at the occasion. It seems even less likely to occur in the mid-term with the recent suspension of Venezuela from the Mercosul, officially announced in the beginning of December, 2016 and the deepening of its economical and political crisis in 2017.

In this particular matter, the only instrument signed by the Member States of Mercosul was MERCOSUL/CMC/DEC N° 10/99, a Memorandum of Understanding concerning gas exchange and gas integration between its members. As part of such agreement, the countries agreed to "*develop a competitive gas supply market in the short and long term, by offering to the agents of supply and demand of the sector in each state party, conditions of nondiscriminatory treatment and the possibility of access to the market of the region*."

Moreover, the memorandum specified that open access to remaining capacity of transportation and distribution facilities must be respected, including access to international interconnections and that companies would not discriminate on the basis of nationality or destination of natural gas supply, respecting regulated usage rates and contracts, and ensuring that prices and fees would include all the associated costs, particularly environmental and social.

It moved to establish protection against monopolistic practices and abuse of a dominant position for all users of natural gas, to ensure that the same mistakes made during the experience between Bolivia, Argentina and Brazil were not committed again. In the mentioned experience, two companies, YPF and Petrobras, either prevented or obstructed the participation of rival companies in forming a competitive natural gas market. Despite the intended reforms, the memorandum remains as a theoretical guideline not being observed.

It is widely recognized that the costs associated to the development of pipeline infrastructure are several and relatively high. This relies on the fact that natural gas pipelines consist of a series of ducts, valves and stationary compression stations that cannot be redeployed for other purposes easily, at least not without elevated costs with decommissioning the network. However, the gradual expansion of the Mercosul Member States network, with the increase of hubs and interconnections, would make the access to other sites far easier, enabling more potential consumers to connect to the network, as happens analogously to electricity grids.

The adequate development of this potential would bring more efficiency and better economical allocation of the resources in the region. Hence, the energy integration, along with the comparative advantages of each country would ultimately result in better market conditions, such as natural gas price and availability.

In the end of 2005, following the diplomatic rounds of negotiation in the Mercosul, the

Protocol of Montevideo on Trade in Services, providing a regulatory framework for trade in services in the economic block, entered into force, demonstrating that the traditional focus on the trade of goods has been shifting towards creating a more competitive environment.

The Protocol compelled Member States to participate in a program of liberalization based on rounds of negotiations of specific commitments on market access. Also, the Mercosul Trade Commission must be updated on Member State's regulatory changes that may affect significantly trade in services.

Colomer Ferraro and Hallack (2015) observed that in less developed NG markets, such as the Brazilian case, the reduced level of competition in the production and trading of the commodity creates obstacles to the entry of new players in the industry. In the natural gas industry, infrastructure investment analysis is crucial due to the large costs associated to construction, compression, and other infrastructure elements.

According to Schoots *et al.* (2011), "*The ability to value flexibility and identify bottlenecks in the system is also of importance due to the large value created by the production of natural gas*". In Brazil, this problem has received special attention due to low hydro availability in recent years and the recurrent severe droughts.

The fact is that recent changes in the most relevant legal marks in Brazil and in Mercosul as well, signalize that the regulatory framework is moving towards a higher degree of liberalization, especially due to the recent facts regarding Petrobras' lack of capital for major investments in gas infrastructure expansion.

5. Conclusions

The demand for electricity in Brazil is gradually increasing at an average rate of 3.0 – 5.0% per year, as shown in Section 1. Furthermore, hydraulic power that accounts for more than 60.0% of the Brazilian electricity mix nowadays, has experienced a much slower growth, gradually decreasing its market share in the last decade due to several operational, geographical, and environmental limitations.

Thermoelectric utilities are known to be reliable and non-intermittent alternatives, possessing advantages linked to the quality of the electricity generated such as: reliability, dispatchability, time of answer, and predictability of generation. In this context, natural gas-fired generators present themselves as cleaner and cheaper alternatives, under certain market conditions, than their thermo counterparts.

This is more relevant considering that some renewable sources, like wind, solar, or biomass, are limited by size, capacity, and require large extensions of land, at specific favorable regions to establish wind and solar farms or plantations. These characteristics, combined to the intermittent nature of their generation pattern, certainly diminish their versatility to suitably resolve the issue of long term electricity supply planning.

Different factors were analyzed in order to determine which technology would be the most efficient in terms of levelized and avoided costs of electricity. In this context, results indicated that natural gas-fired generators are indeed very competitive and efficient, when compared to other thermoelectric sources, in both economic and environmental aspects, even when some externalities were included, with gross margins of up to 135%. The LACE and MLCOE combined analysis demonstrated that only natural gas and biomass are economically attractive in terms of both indicators.

Scenarios with different levels of prices for each technology were idealized and the data produced are sufficient for some conclusions regarding the economic performance of different technologies, as can be seen in detail in Tables 7 and 8. The obtained results demonstrate that for a wide range of variation in prices, natural gas is one of the most appealing alternatives with better gross profit margins and lesser emissions.

It remains economically attractive until prices reach the level at scenario C, where the cost of gas is the regulated ceiling price of US$ 8.10/MMBTU, approximately the break-even point for the selected discount rate. Therefore, its competitiveness relies mostly on an adequate supply and moderate prices, since other costs are substantially smaller than the other studied technologies.

The leakage throughout the gas production chain was included in the calculations and revealed an interesting fact. When the percentage of leakage goes beyond 4.0% on a mass basis, the calculated MLCOE impact of the CH_4 leakage begins to surpass that of CO_2 emissions from combustion, to a level in which natural gas becomes as greenhouse gas intensive as biomass. If such levels continue to rise, the methane leakage poses as a serious issue regarding its impact as a greenhouse gas. Therefore, strict controls must be used to guarantee that leakage remains as minimal as possible.

The mineral coal was much like an intermediate solution, with a MLCOE varying from US$ 70.0 to 80.0/MWh and a pronounced impact of emissions and investment costs on the final results. It was also considered to be the most polluting alternative studied, where the cost of emissions ($C_{eq.CO2}$) was of US$ 18.0/MWh. The comparison of LACE and MLCOE results for the coal indicated that for current market conditions it is not economically attractive to develop new coal power plants, since results in this comparative (See Table 9) were all below zero. Thus, when such results and other previously discussed environmental aspects are taken into consideration, the coal does not seem to be a viable alternative to address a long-term electricity supply issue.

Biomass has demonstrated to be an interesting alternative for local and small-sized generation, especially for places where gas pipelines do not reach. In Biomass A scenario, where the sugarcane bagasse belongs to the same company or individual that will burn it for electricity generation, the cost of fuel is very low and turns it into an interesting alternative with a gross margin of 47.89%.

On the regulatory side of this big picture, despite the recent achievements and further development of the Brazilian legal marks, designed to promote a better integration of the gas distribution network in Latin America, the actual system integration has been minor so far. Further changes in the regulatory framework and adequate policy are required from the government to attract investment and expand the natural gas pipeline infrastructure in Brazil.

It seems that recent changes in both Brazilian and Argentinian regulations have been thought to further liberalize the oil and gas industry, in order to promote a more competitive environment, especially given the fact that the existing monopolistic structure does not contribute to expansion of the pipeline distribution network and natural gas production. So far, they have not succeeded in changing the core of the market structure.

The analysis of regulatory framework changes and reforms occurred in Argentina permit some recommendations for the Brazilian case, as to further increase the liberalization of the Brazilian market, since the lack of power of investment by Petrobras will make it difficult to the company, which faces a deep and thorough recovery program, to develop natural gas transportation infrastructure alone.

Separation of trading from other activities such as production, transportation, and distribution, is very likely to have a positive impact on the development of market competition, in every segment of the industry, since it would prevent the creation of market barriers, to the access of new producers and traders.

The study proposed an alternative calculation method for sanctions imposed on suppliers due to the lack of NG supply for thermoelectric utilities. Such formula was thought to mitigate the influence of averages and the PLD_{max}, coefficient, therefore decreasing the sanction value for the NG supplier, without compromising contract neutrality, when compared to the current calculation prescribed by ANEEL Resolution n. 583 of 2013. The comparative calculated annual decrease of daily sanctions value was of -12.13%, for non-recurrent suppliers.

Additionally, in order to fully develop competition along the natural gas transport segment, there is the need to encourage the entry of new carriers. Thus, it is also necessary to create or modify regulatory structures that would ultimately reduce the overall risk of deploying natural gas transportation infrastructure, since it is not easily redeployed. Some potential carriers are those other producers, importers, and local distribution companies, which nowadays do not have many incentives to manifest their willingness to distributing natural gas.

Also, reduced capillarity of transportation and distribution networks continues to be one of the major drawbacks for the expansion of the natural gas market in South America, among with other significant weaknesses related to short-term supply conditions. This is more important since the status quo of energy integration in South America faces uncertainty because of the recurrent concerns about security of supply from Bolivia.

Multiple suppliers could be achieved by eliminating the producer entry barriers. This could also occur through incentives for producers to negotiate sales independently, and encouraging new supply sources and alternative supply points. Additionally, the introduction of indiscriminate access of third parties to any transportation and distribution network in Brazil, allowing other market agents to sell their natural gas supply to final customers, would substantially decrease the intrinsic risks for new carriers.

Considering the fact that in recent years Brazil has discovered several new natural gas production sites, the most prominent challenge is how to attract upstream investment, besides of those made by Petrobras and its subsidiaries, necessarily including the impact of the natural gas supply scenarios on the Brazilian economy, both in terms of revenue and investment. Market indicators will show if changes introduced by Law 13,365 of 2016 tend to attract more private investment for the pre-salt layer prospection, through the admission of consortiums that no longer need the participation of public investment to explore the blocks. Therefore, promoting the further expansion of the upstream part of the oil and gas industry.

The comparative regulatory analysis indicated that further strategic planning and investment, as well as adequate policy changes are required from the market and governmental agents, in order to foster the development of the natural gas industry as a whole in Brazil, aiming to use the potential of energy integration in the Mercosul. Such efforts would have to engage the private sector, governmental agencies in charge of the involved sectors (ANP and ANEEL), diplomatic negotiations, as well as the national mixed capital companies, particularly Petrobras, that according to (ANP, 2017) is responsible for about 98% of total natural gas production in Brazil.

Thereby, gas network integration in Latin America, especially in Mercosul, is not only necessary but also mandatory, if such nations want to fully develop their energy and commercial potential in the next decades. From that perspective, Brazil has a major role in acting as a policy driver and epicenter of regional and transnational cooperation in energy infrastructure integration.

Lately, the Brazilian international agenda in Mercosul included indeed some multilateral discussions concerning energy integration. However, there is the need to establish more defined roles for each Member State. Also, following the example of the electricity sector, there is the prominent need to expand infrastructure, financed most likely through use tariffs, and to pursue open market rules for accessing the transportation and distribution pipelines. This is a challenge so far, since legal framework still lacks some instruments to improve market competition.

It is evident that Brazil has to deal with these regulatory and structural problems pragmatically. By observing the experience of other economies, one can encounter points of conversion between them, making this sampling process a fertile ground for alternatives, bearing in mind that each economy has its own particular dynamic.

5.1 Limitations of the present study and suggestions for future research

The research evaluated several aspects of the thermoelectric generation within the Brazilian market conditions, focusing on the most relevant costs that make up the MLCOE. However, the proposed formula could be enhanced through the incorporation of prices volatility to the calculations, this would improve the method and also introduce an important aspect to the produced results.

Current MLCOE calculations involve the need to establish price levels for the different fuels; with the incorporation of price variation in time as a variable, this would automatically update results and also provide a price in time dependent cost function, making possible further analysis and discussion.

One of the aims was to study about regulatory and diplomatic approaches towards the oil and gas industry in Brazil, and to compare it with the other more mature markets context. Evidently, such regulatory environment is highly complex and involves a variety of other actors. Therefore, it is suggested future research to be conducted considering the other actors involved, such as outside Mercosul Member States (Bolivia, Chile, etc) participation on such issue, as well as other economic blocks.

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