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Levelized cost analysis of thermoelectric generation in Brazil: A comparative economic and policy study with environmental implications

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ABSTRACT

A comprehensive economic comparison between the most commonly employed thermoelectric technologies in Brazil, such as natural gas, coal, biomass, and fuel oil is of great relevance for an assessment of the electricity mix status and potential. Multiple scenarios were evaluated through the application of a modified levelized cost of electricity (MLCOE), obtaining the overall thermoelectric generation cost in the country, given its specificities, the market, and other relevant issues. Moreover, the analysis of the produced data combined to an additional indicator, the levelized avoided cost of electricity (LACE), provides an extensive view of economic, environmental, and infrastructural aspects. The major modifications in the traditional LCOE methodology were the introduction of the cost of leakage in the natural gas production chain, the transmission costs, and the fuel prices analysis for the different technologies involved. Additionally, the recent discoveries of large gas reservoirs in the Brazilian ultra-deep waters, on the coast of Sao Paulo, the largest electricity market in South America, show a promising scenario, along with strategic investment and adequate policy, for a sustainable transition in the electricity mix of Brazil. This transition should occur through the use of natural gas-fired power stations, as part of strategic planning to avoid the shortage of electricity supply. In this context, results indicated that natural gas-fired generators are very competitive and efficient, in both economic and environmental aspects, when compared to other thermoelectric technologies, even when externalities such as leakage, transmission, and carbon costs were considered. In addition, this study concluded that the natural gas leakage has the same impact as the CO_2 emissions from combustion, when the percentage of leakage goes beyond 4.0% on a mass basis. Above this percentage, the impact of the CH_4 leakage begins to surpass that of CO_2, to a level in which natural gas becomes as greenhouse gas intensive as biomass.

1. Introduction

The electricity sector of Brazil includes a large group of stakeholders who provide services through distinct electricity generation, transmission, and distribution for different classes of final customers (Table 1). It also includes several governmental agencies that regulate the sector. In 2015, there were 4520 electric utilities in operation in Brazil, resulting in a total installed capacity around 143.1 GW or 667.4 TWh of electricity generation, with a 4-year forecast to be increased in another 27.7 GW (ANEEL, 2016).

The predominant power source in this electricity mix is hydraulic, which accounts for about 61.32% of the total. The thermoelectric generators participation is approximately 26.25%, included among that percentage natural gas, coal, biomass, and other fossil fuels (Fig. 1 – EPE, 2015).

In this scenario, natural gas-fired power plants contributed to about 13.0% of the total generation and experienced a 12.7% growth when compared to 2014. The overall thermoelectric participation in the National Interconnected System (SIN) has jumped from 25,210 MW in 2006 to 41,643 MW in 2016, an increase of 65% or an average annual growth rate of 5.1%. Hydroelectric power has increased at a slower pace, from 73,430 MW in 2006 to 92,671 MW, or about 2.3% annual growth for the same period (ANEEL, 2016).

Such data demonstrate that hydroelectric power is gradually reducing its relative participation in the Brazilian electricity mix.

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Nomenclature

Q_{MW}	quantity of electricity generated in MWh in the year *t*
P_{MW}	constant price of electricity sold in the year *t*
TR_t	total revenue in year *t*
TC_t	total costs in year *t*
C_{fuel}	cost of fuel
C_{inv}	cost of investment
C_{eqCO_2}	cost of emissions
C_{trans}	cost of transmission
C_{op}	cost of operations & management
C_{leak}	cost of leakage
P_{fuelX}	price of fuel for a given scenario X
i	discount rate

Table 1
Brazil's national electricity consumption per class (EPE, 2011).

Electricity Consumption in the grid, per class (GWh)					
Year	Residential	Industrial	Commercial	Other	Total
2010	105.538	182.338	69.223	58.766	415.865
2014	105.787	223.456	87.825	68.724	506.791
2019	156.546	274.774	118.416	83.297	**633.033**

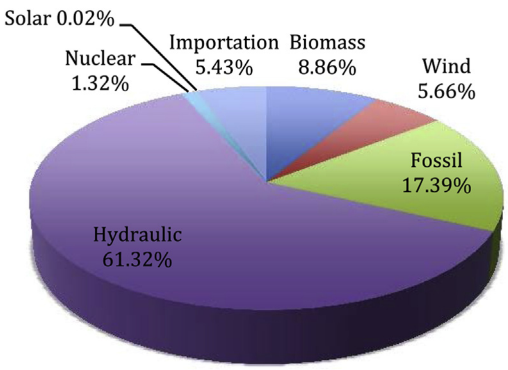

Fig. 1. Electricity mix in Brazil – Generation Percentage (EPE, 2015).

The main reason behind this fact is that hydropower is reaching its operational limit, mainly due to geological, hydrological, and environmental factors, such as the limitation of concessions and low site availability. The environmental restrictions for new hydraulic energy projects demand that their reservoirs have small volumes in relation to the river flow. Hence, these power plants are of the “run of the river” types. The most recent and relevant of such power plants are Belo Monte, in the Xingu river basin; Jirau and Santo Antônio, both in the Madeira river basin.

These new facilities are located in the Brazilian Amazon, region with large forested or flooded plains and low height terrains. Run of the river hydroelectric utilities are also known for their high seasonality in supply, given the fact that very few modern concession projects in Brazil allow large accumulation reservoirs (ANEEL, 2016). It is also required to build long transmission lines, given the distance of the Amazon from the major consuming markets in the Southeast. Aside from being costly, this has evident negative impacts on the local inhabitants and the ecosystem of the region.

The major participation of hydropower in the Brazilian electricity mix implies that in regular years the water reservoirs are able to supply the seasonal variations in demand. Consequently, thermoelectric dispatch remains only for exceptional circumstances. However, when climate conditions are adverse, such as prolonged droughts, as the one that occurred in 2014–2015, the risk of supply shortage increases, which makes it necessary to plan in advance how supply has to be designed and which energy source to develop, in order to avoid rationing and attend demand increase (Moreira et al., 2015).

For the third year in a row, due to unfavorable hydrological conditions, there has been a major decrease in the hydroelectricity offer. In 2014, the decrease was of about −5.6% when compared to the previous year, resulting in an overall decrease in the renewable energy participation from 81.9% in 2011 to 61.3%, as observed in the beginning of 2016 (EPE, 2015).

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 2024 (EPE, 2016) presents a forecast where the aggregate demand annual growth rate for the period of 2019–2024 is of 5.2% per year (Table 1). 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 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.

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.

Vahl and Filho (2015) state that emerging economies will account for more than 90% of net energy demand growth to 2035. Furthermore, the authors conclude via the analysis of CO_2 emissions data, that the natural gas-fired generation is a more environmentally friendly alternative, when compared to coal or fuel oil for example. 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 the natural gas and up to 52% for the mineral coal.

The wide dispersion of that index, along with the fact that no single technology can be said to be the cheapest under all circumstances, indicate that the market structure and the policy for the environment also play a strong role in determining the final cost for any investment.

De Jong et al. (2015) concluded utilizing the levelized cost of electricity (LCOE) methodology that wind power, along with hydroelectric, would be the cheapest generation technologies in Brazil. However, it must be noticed that some biases from the IEA study (Garson, 2015) have been transmitted to their results regarding the natural gas, for example. Khatib (2010) observed this fact in the review of the IEA study, where he addressed that the adopted prices of natural gas were almost twice of the prices prevailing at the time of that review (April 2010), which cast concerns on the results of the study in case of costing output of CCGT plants.

Natural gas prices have decreased even more substantially since 2010, being ever since in open tendency of secondary and tertiary decline. Indeed, future option contracts with due date at April, 2016 were negotiated with about −85% lower prices in the New York Stock Exchange (NYSE), when compared to the prices assumed by (De Jong et al., 2015) (Fig. 5 - NGJ6).

In the same direction, 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 in the Sao Paulo State (Fig. 2).

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 3150 km in length and transports about $33MMm^3$/day. As depicted in Fig. 3, 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).

The fact is that in the Northeast of Brazil there are already several large wind power facilities that 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 successful 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.

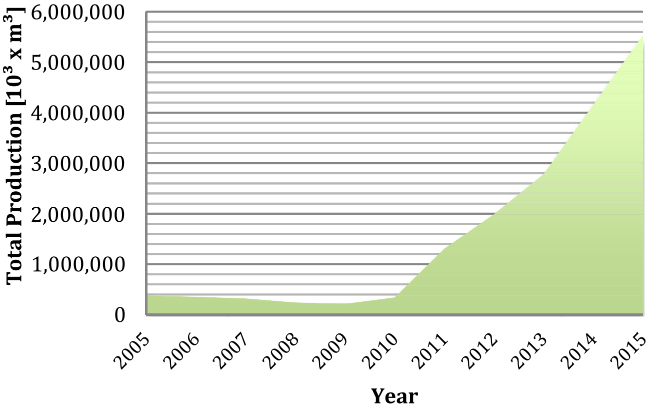

Fig. 2. Total production of NG in the state of Sao Paulo (ANP, 2016).

Therefore, it seems to be strategically more appropriate if the projected gas pipelines were deviated to the West, passing through the States that border Bolivia and Peru. This would better connect the large cities and capitals in the Amazon to the natural gas distribution network, in order to benefit from the generation of natural gas-fired electricity, instead of developing more dams for hydropower plants in the Amazon rivers.

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 and 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$ 1260.00/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. Methods

A model for the financial assessment of thermoelectric generation in Brazil was designed in order to adequately analyze the different generating technologies. The model is supposed to measure comparatively the costs and other relevant aspects between the major competitors or substitutes for the natural gas in the thermoelectricity generation chain (Fig. 4). In this context, a long-term levelized cost of electricity analysis was used 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.

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. As well noted by (Garson, 2015), this method it 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). 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):

$$NPV\mathrm{TR} \equiv NPV\mathrm{TC}$$

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

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

Fig. 3. Operating and projected gas ducts in Brazil (ABEGAS, 2016).

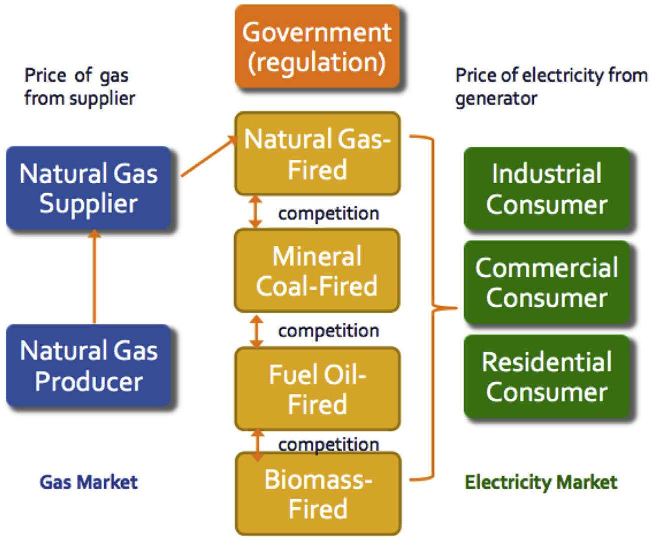

Fig. 4. Natural gas for electricity generation integrated chain (Adapted from (Tian et al., 2015).

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 transmission as 7.6%, then a discount rate of $i = 7.0\%$ was adopted for the analysis of all cases.

The methodology of the study opted to choose a nominal discount rate, which does not include the effects of inflation. The most relevant inflation index in Brazil is the IPCA, which for the 2005–2014 period had an average of about 5.41% (IBGE, 2016). When reference is made to the discount rate, then it is the nominal discount rate that is meant.

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 (Larson, 2013). 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:

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

$$\sum_{t=1}^{n} \frac{(Q_{MWt} \cdot P_{MW})}{(1+i)^t} =$$

$$= \sum_{t=1}^{n} \frac{Cinv_t + Cop_t + Cfuel_t + C_{eqCO2_t} + C_{deco_t} + C_{trans_t} + C_{leak_t}}{(1+i)^t}$$

As the equation term P_{MW} 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:

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

2.1. Additional indicator

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).[1] 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 a new generation project. Thus, in order to provide additional conclusions regarding the economical competitiveness of various technologies, levelized avoided cost of electricity data were also used in the comparison.

For this purpose, the LACE values presented for each of the generating technologies were the ones derived from the AEO 2016 (EIA, 2016 – Table 2), for facilities entering in service in the year of 2022 (Table 2). 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.

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 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.

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. Market and costs assessment

3.1. 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 most recent data collected from the last Consolidated Result of Electric Energy Auctions, for new energy contracts, performed by CCEE (Table 3). 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 3 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.

3.2. 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. 5). 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 934 MW. 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

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[1] Further details of the levelized avoided cost indicator and its use in assessing economic competitiveness can be found in this article: http://www.eia.gov/renewable/workshop/gencosts/.

Fig. 5. Historical natural gas prices (NGJ6-NYSE) [US$/MMBtu].

Table 2
Regional variation in levelised avoided costs of electricity (LACE) for new generation resources, 2022 (EIA, 2016).

Technology	LACE (US$/MWh)		
	Min	Average[a]	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

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

Table 3
Summary statistics for different generating technologies (Source: CCEE, 2016).

Technology	Number of Plants	Capacity (MW)			
		Min	Mean	Median	Max
Natural Gas – CCGT	08	499.20	933.97	910.50	1515.64
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

fixed term[2] 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 4) 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

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[2] 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.

Table 4
Petrobras natural gas prices for distributor (source: MME, 2015; ANP, 2010).

NOV/2015	Petrobras price for distributor[a] (Exempt of taxes)			
Region	Contracts	Price US$/MMBTU		
Northeast	Domestic Gas	6.0548		
Southeast	Domestic Gas	6.0548		
		Commodity	**Transport**	**Total**
Southeast	Imported Gas	4.4414	1.8104	6.2518
South	Imported Gas	4.1245	1.7995	5.9240
Center-West	Imported Gas	4.4135	1.8104	6.2239
PPT	NOV/15	3.79		
Henry Hub	NOV/15	2.08		

[a] The price of natural gas for the PPT does not include taxes and its calculation is based on Portaria Interministerial n^0 234/02.

Petrobras (1st. LT RES – Fig. 5 and Table 4), 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

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 5.

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.

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 4850 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 6700 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 1,650 kcal/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 30 km, 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.

3.3. 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

Table 5
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	[gCO_2eq/kWh]	500.00	1200.00	900.00	800.00

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.

3.4. Other environmental issues

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.

3.5. 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. It must be emphasized that consumers support half of this tariff.

4. Discussion

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, with the intermediation of 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 2016, almost 76% of the electricity consumption was located in the regulated contract environment (ABRACEEL, 2016), 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 $i = 7\%$ for all technologies. For simplifying reasons, they were assumed to have the same lifetime of 30 years. Fig. 6 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 6 and Fig. 6, 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.

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

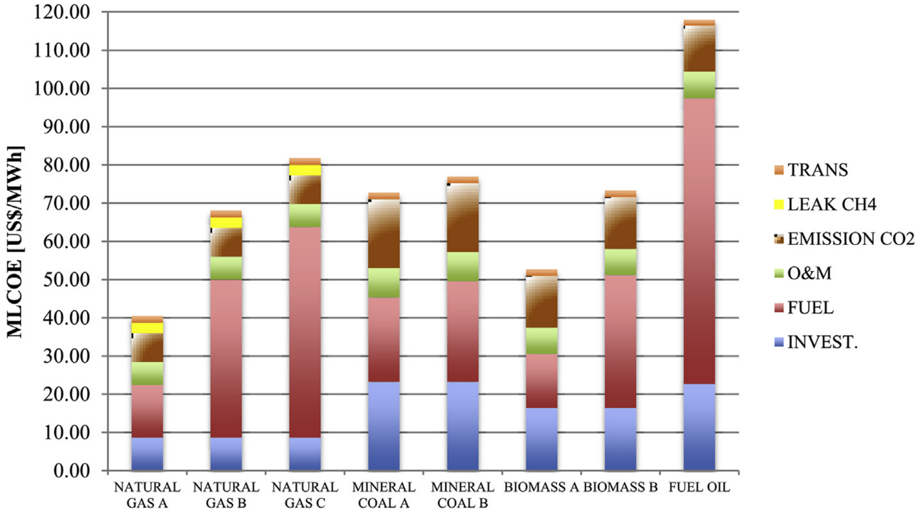

Fig. 6. Comparative analysis of the MLCOE for each generating technology divided per each cost.

Table 6
MLCOE and gross profit margins for competitive theoretical generators at a 7% discount rate [Units in US$/MWh].

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[a] (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
Total Gross Profit Margin	**30.73**	**3.20**	**−10.58**	**−8.29**	**−12.50**	**5.29**	**−15.31**
Gross Profit Margin[b]	**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%**

[a] Average for winning bids per generating technology, as provided by (CCEE, 2016) converted to U.S Dollars.

[b] Excludes the emissions and leakage costs, which are not directly borne by investors, from the calculation. Without federal and state taxes.

alone (C_{eqCO_2}) 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 3.2, since the biomass overall cost reaches US$ 73.33/MWh. Such conclusions for the biomass are only valid for small scale ($QMW \leq 50$ MW) and local generation projects, as were the majority of studied plants (Table 2). Larger biomass projects would have to cope with higher 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.

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 (Table 7). 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.

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

Table 7
Difference between averages for levelized avoided costs of electricity (LACE) and modified levelized costs of electricity (MLCOE).

Technology	Comparison of MLCOE and LACE (2016 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

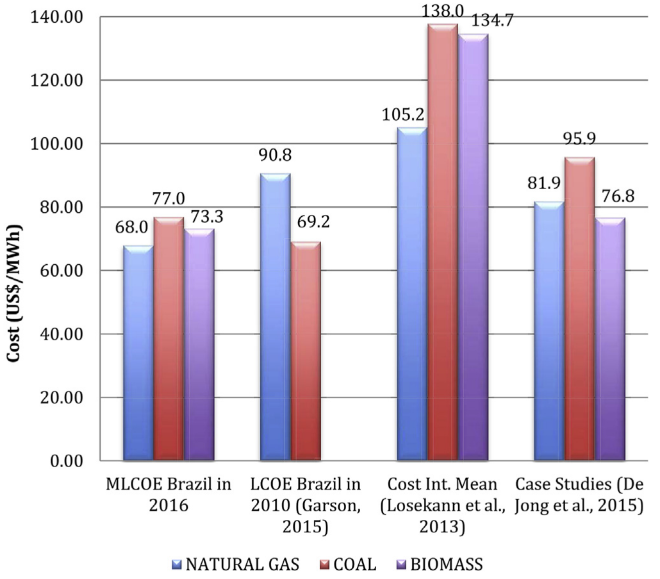

Fig. 7. Comparison between costs per technology.

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 (Fig. 7).

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. 7).

Regarding the cost of leakage, the concerns arisen by (Busch and Gimon, 2014) are legitimate and deserve attention. As can be seen in Fig. 8, 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.

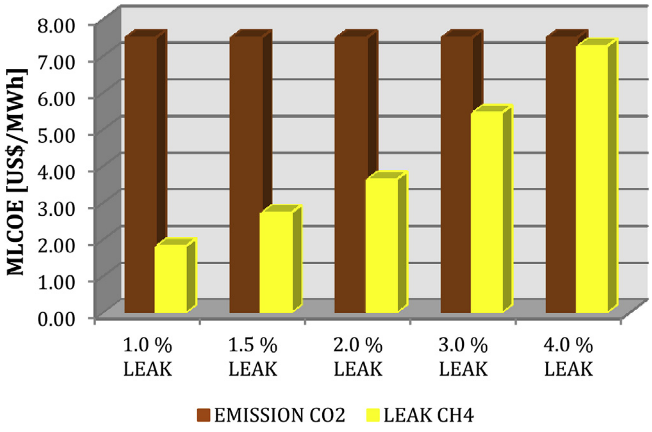

Fig. 8. Leakage x CO2eq. emissions for different scenarios.

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:

$$\frac{MLCOE_{CH4}}{MLCOE_{CO2}} = 0.24267 \cdot LEAK_{\%}$$

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 (Fig. 2), 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.

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 reliable and non-intermittent alternatives, since other renewable sources like wind power or biomass are limited by size, capacity, and require large extensions of land, at specific favorable regions to establish wind farms or plantations. This peculiarity certainly diminishes their versatility to suitably resolve the issue of long term supply planning.

Different factors were analyzed in order to determine which technology would be the most efficient in terms of levelized costs. In this context, 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, with gross margins of up to 135%. The LACE and MLCOE combined analysis demonstrated that only the natural gas and the 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 6 and 7. The obtained results demonstrate that for a wide range of variation in prices, the natural gas is one of the most appealing alternatives with high gross profit margins.

It remains economically attractive until prices reach the level at scenario C, approximately the break-even point for the selected discount rate. Therefore, its competitiveness relies mostly on an adequate supply and moderate natural gas 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 (Table 7) 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.

The biomass has demonstrated to be an interesting alternative for local and small-sized generation, especially for places where gas pipelines do not reach. In the 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%.

The relevant results for natural gas-fired utilities indicate that further strategic investment and adequate policy is required from the market agents, in order to foster the development of pipeline infrastructure and the establishment of more natural gas power plants. This effort would have to engage the private sector, the governmental agencies in charge of the involved sectors (ANP and ANEEL), as well as mixed capital companies, particularly Petrobras, that according to (ANP, 2017) is responsible for about 98% of total natural gas production in Brazil.

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