Study on the Use of the **Pre-Salt Natural Gas**

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Summary

1. INTRODUCTION

The main motivation for this study is to contribute with information on the use of the Pre-Salt of the Natural Gas (NG), with focus on the increment of its commercial use and the participation in the country's energy matrix, pursuant to the guidelines established by public policies, such as Resolutions of the National Council for Energy Policy – CNPE No. 10/2016[1], 17/2017[2] e 16/2019[3]. The purpose is also to present the different alternatives for the use of natural gas to the market players and the society, as well as to indicate potential actions to be taken for the implementation of any guidelines and instruments to stimulate the commercial use of the Pre-Salt gas.

2. CONTEXT

The commercial production of hydrocarbons in Brazil began in 1941, in the Candeias field, Recôncavo Basin. The production of natural gas began slowly and, a few years later, in the 1950s, the production was absorbed by the industrial sector, with about 170 thousand m³/day. In the 1970s, a slight, continuous growth of the natural gas production began, taking 50 years to reach the current level of gross production (including contaminants)[4] of about 140 million m³/day. About 80% of the Brazilian natural gas production is associated gas, produced with the oil in the offshore fields. Accordingly, most reserves of Brazilian natural gas are associated gas, produced simultaneously with the oil, which characterizes the need for the natural gas to be produced and used regularly, in order to not constrain the oil production.

In 2019, according to data sent by the operators to the National Agency of Petroleum, Natural Gas and Biofuels – ANP, the Brazilian Proven (1P) natural gas reserves reached a volume of 364 billion m³, while the estimated volume for the Total (3P) reserves was 549 billion m³.

The Brazilian offshore production reached about 112 million m³/day of natural gas in 2019, corresponding to 80% of the total national production. The most productive maritime wells reached, during that year, volumes of 1,900 thousand m³/day in the Santos Basin. The onshore

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[1] Defines the strategic guidelines for the design of the new natural gas market; establishes the Technical Committee for the Development of the Natural Gas Industry in Brazil, aiming at proposing measures that ensure gradual and safe transition, preserving the proper operation of the natural gas industry; and assessing the possibility of accelerating the transition, among other provisions.

[2] Defines the Policy for the Exploration and Production of Oil and Natural Gas, defines guidelines and provides guidance for the planning and execution of bidding processes, pursuant to Law No. 9,478 of August 6, 1997, and Law No. 12,351 of December 22, 2010, among other provisions.

[3] Defines the Policy for Exploration and Production of Oil and Natural Gas, defines guidelines and provides guidance for the planning and execution of bidding processes, pursuant to Law No. 9,478 of August 6, 1997, and Law No. 12,351 of December 22, 2010, among other provisions.

[4] In the whole document, except for a contrary provision, the gas flow rates are gross, including contaminants.

production, on its turn, reached about 27 million m³/day of natural gas in the same year (ANP, 2019a), corresponding to 20% of the total national production. Thus, the main sedimentary basins producing associated gas (AG) are Campos and Santos, while Solimões and Parnaíba are the main basins producing non-associated gas (NAG).

It is estimated that the oil and gas productions in the next years will be strongly influenced by the production of the Pre-Salt reservoirs, especially in the Santos Basin. The oil in those reservoirs has a gas/oil ratio (GOR) higher than that which is traditionally found in oil reservoirs of other Brazilian plays. Thus, given a rich associated gas reserve, coupled with the high productivity of the reservoirs, the Pre-Salt gas became the main option, in terms of domestic production, for the supply of the gas market in the next years.

It is worth mentioning that the commercial use of the Pre-Salt natural gas competes, partly, with the reinjection in the reservoir itself, practice which has been increasing considerably over the last few years. The operators choose reinjection mainly due to the CO_2 content found in some Pre-Salt reservoirs, as well as a mechanism for reservoir pressure maintenance. Thus, reinjection aims at preventing the emission of the CO_2 produced with the gas and at increasing the oil ultimate recovery.

Pursuant to the forecasts considered in the Ten-Year Energy Expansion Plan 2029 (Energy Research Company – EPE, 2019), the national gas production, currently at around 139 million m³/day, should follow a growing trend, reaching by 2029 levels of about 253 million m³/day. This continuous increase follows the growing trend of oil production, highly influenced by the start-up of the production systems presented in the business plans of Petrobras, partner companies and other operators. In this case, attention is called to the Búzios field and other fields of the Transfer of Rights (ToR) contract (especially Sépia and Atapu), including the surplus volumes and the Mero field.

In the long term, after the next ten years, the production will be maintained by the promising areas in the Pre-Salt, currently under exploration, already granted at the bidding rounds for concession and production sharing, and by the resources yet to be discovered of the ToR surplus or not bidden yet. The Post-Salt areas that may contribute in the long term are those discovered in ultra-deep waters of the Sergipe-Alagoas Basin and deep waters of the Potiguar Basin, in addition to the onshore Parnaíba and Solimões basins.

Notwithstanding the growth of the gross production of gas, the net production, which corresponds to the gas potentially available to the Natural Gas Processing Units (NGPUs), should maintain a more stable trend in the next decade. The net gas production is obtained by discounting, from the total gas production, the gas reinjection, losses, flaring, and the internal consumption of natural gas (to generate power for the Production Units). Figure 1 presents the history of the national natural gas production, divided into net production, internal consumption, flaring and reinjection up to 2019, and Figure 2 presents the forecast up to 2030. In 2019, the total reduction reached 38% of the gas production, and reinjection was the main factor, reaching 24% of the amount produced. It is important to highlight that the CO_2-rich stream separated in the Stationary Production Units (SPUs) in the Pre-Salt must necessarily be reinjected and, due to

the efficiency of the separation system, a portion of the natural gas remains, being reinjected as a part of the CO_2-rich stream, reducing the gas rate available for marketing.
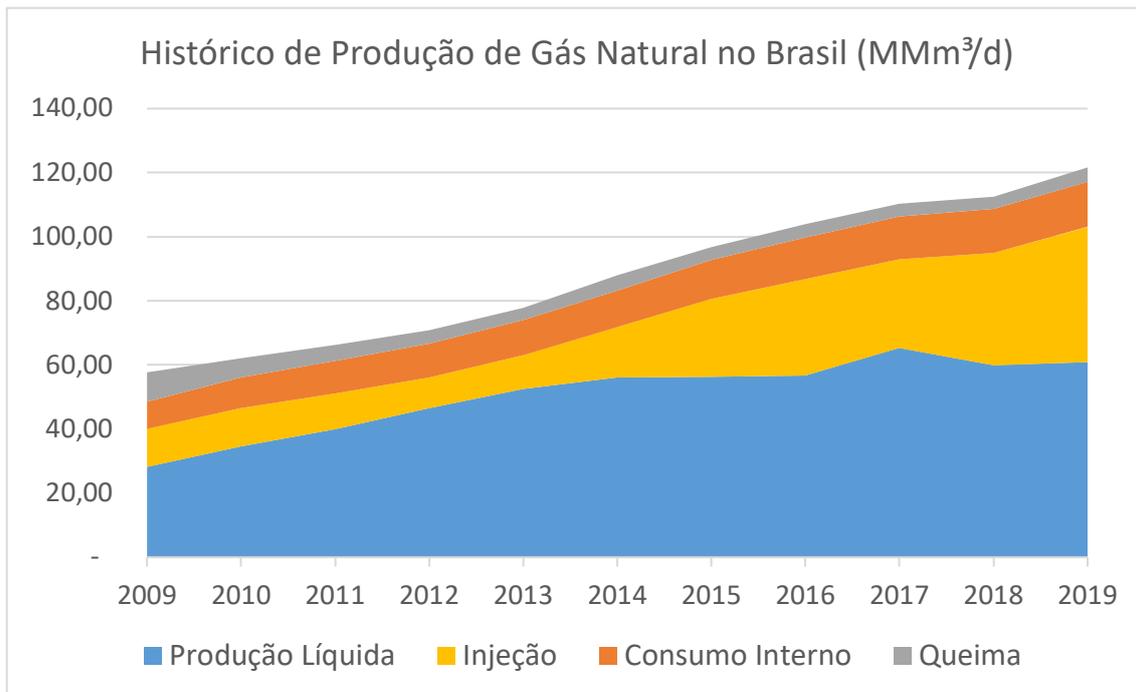
Legend:
History of Natural Gas Production in Brazil (MMm³/day)
Produção Líquida = Net Production
Injeção = Injection
Consumo interno = Internal Consumption
Queima = Flaring

Figure 1 – National Production of Natural Gas (annual consolidation – ANP, 2019c)
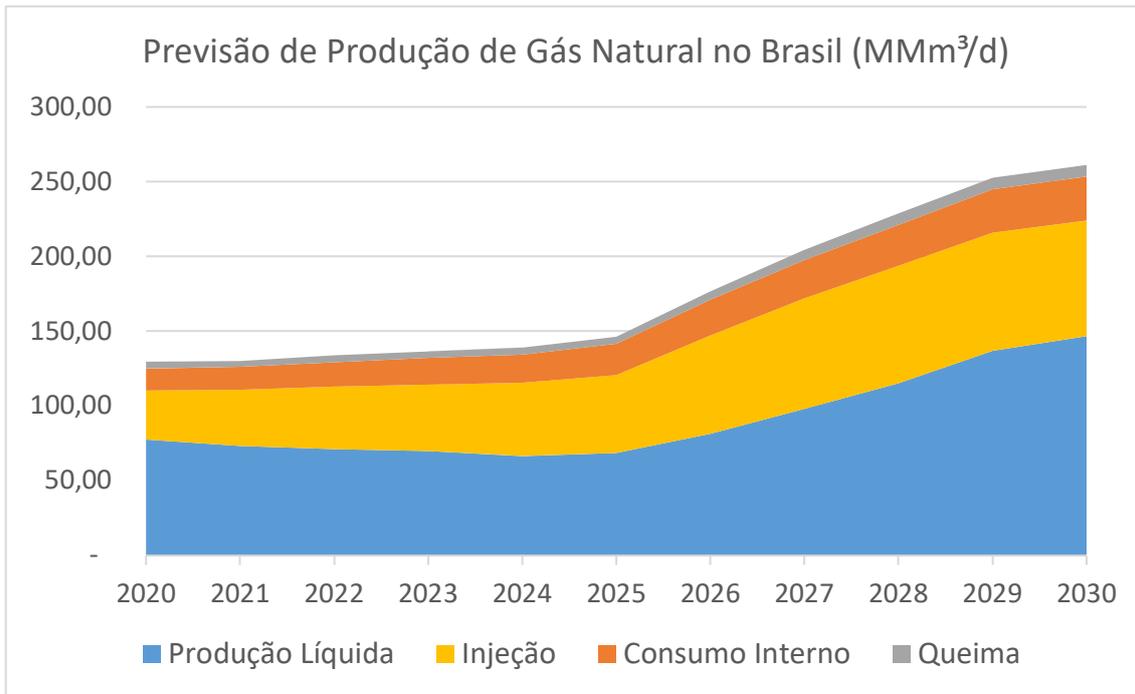
Previsão de Produção de Gás Natural no Brasil (MMm³/d)

Figure 2 – Forecast of National Natural Gas Production (EPE, 2019)

Considering the Pre-Salt environment, in the Campos and Santos basins, the reinjection level reaches higher proportions, about 50% of the gross production, higher than the gas available for commercial use. Figure 3 presents the history of the associated gas production in the Pre-Salt[5] up to 2019, divided into net production, internal consumption, flaring and reinjection, and Figure 4 presents the forecast for up to 2030.

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[5] Includes the production, in the Post-Salt, of the fields of Badejo, Baleia Azul, Baleia Franca, Barracuda, Caratinga, Jubarte, Linguado, Marlim, Marlim Leste, Pampo, Pirambu, Trilha and Voador
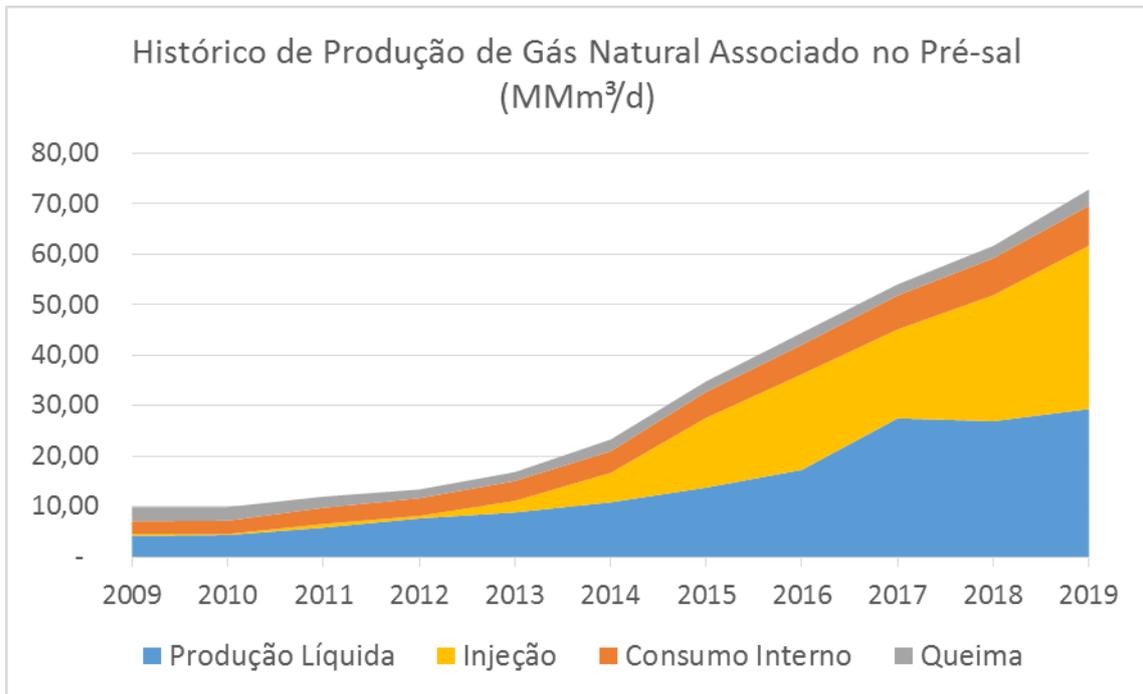
Legend:
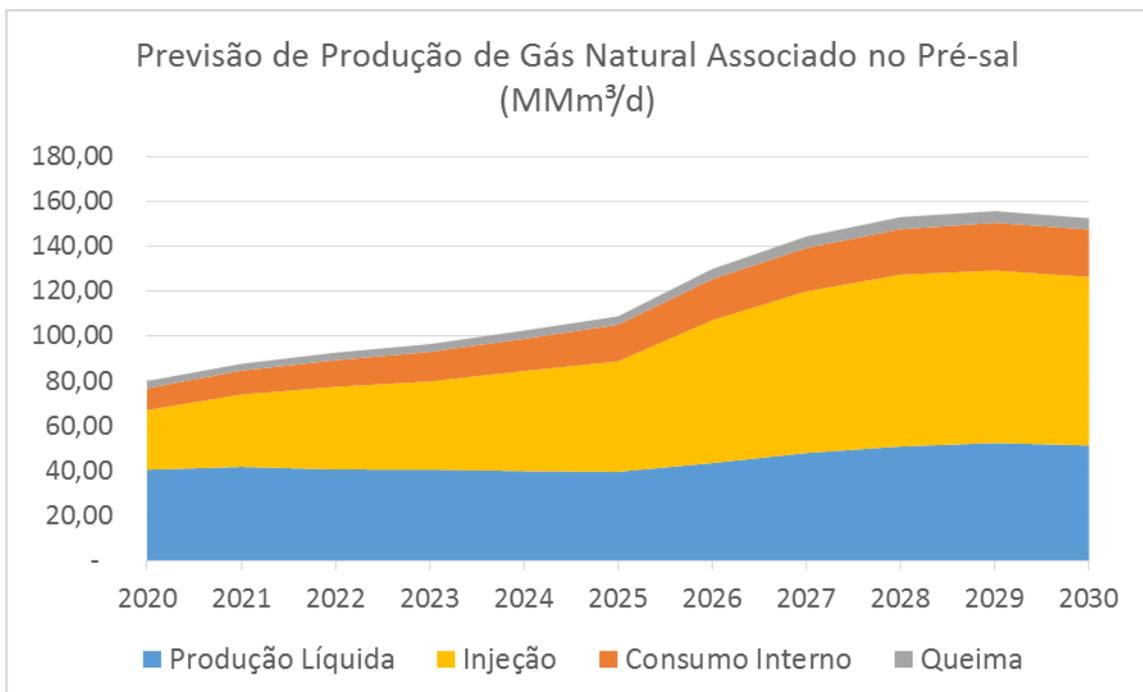History of Associated Natural Gas Production in the Pre-Salt (MMm³/day)
Produção Líquida = Net Production
Injeção = Injection
Consumo interno = Internal Consumption
Queima = Flaring

Figure 3 –Associated Natural Gas Production in the Pre-Salt (annual consolidation – ANP, 2019c)

Figure 4 – Forecast of the Associated Natural Gas Production of in the Pre-Salt (EPE, 2019)

On the other hand, regarding the Brazilian production of offshore Non-Associated Gas, the volumes are smaller than the volumes of Associated Gas; however, both are significant in terms of the size of each project. We emphasize the volumes produced in the fields of Mexilhão (f 6.3 million m³/day in October 2019) and Manati (4.6 million m³/day in October 2019)

In the Campos Basin, Equinor holds the operation of the BM-C-33 block, located in water depths of 2,900 meters, with significant non associated gas production perspectives. The block was granted in the seventh bidding round (in 2005), and Equinor took over the operation in 2016. The Consortium includes Repsol (35%) and Petrobras (30%). In the block, still under assessment, three discoveries were made in the Pre-Salt: Seat (2010), Gávea (2011), and the major discovery of gas and condensate of the Pão de Açúcar prospect, announced in 2012. A total of four assessment wells were drilled in the block, confirming a total recoverable volume of hydrocarbons estimated at about 1 billion barrels of oil equivalent (Equinor, 2020). Among other exploratory areas with discoveries of gas condensate, we also highlight the areas of Gato do Mato, Júpiter and Libra Central in the Santos Basin.

3. DEFINITION OF NATURAL GAS

Pursuant to article 6 of Law No. 9,478 of August 6, 1997, natural gas is all hydrocarbons which remain gaseous under the normal atmospheric conditions, extracted directly from oil or gas reservoirs, including wet, dry and residual gases and rare gases. In terms of composition, its predominant content is paraffinic hydrocarbons, in addition to non-hydrocarbon components. The predominant hydrocarbons in the natural gas are: methane (C_1), ethane (C_2), propane (C_3) and butane (C_4). Usually, the current of hydrocarbon components from pentane (C_5) to dodecane (C_{12}), found in smaller amounts, is called C_{5+}. The main non-hydrocarbon components include nitrogen (N_2), carbon dioxide (CO_2), water (H_2O), hydrogen sulfide (H_2S) and sulfur compounds.[6]

The richness of the natural gas is the set of components heavier than ethane, that is, the C_{3+} fraction (mixture containing propane and heavier hydrocarbons), which may be transformed into products with a high commercial value. The higher the proportion of those components, the higher the heating value of the mixture and, consequently, the richer the natural gas will be considered. The natural gas with heavy hydrocarbon content higher than 8% is considered as a

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[6] Sulfur compounds: carbonyl sulfide - COS, carbon disulfide - CS_2, and mercaptans (organic chains containing sulfur bonded to a hydrogen and to the carbon chain; they are similar to alcohols, with sulfur acting as the oxygen of the alcohols).

rich gas; when that content is lower than 6%, the gas is considered lean, and when that content is from 6% to 8%, the gas is considered medium-rich (Almeida, 2013). For purposes of comparison, Figure 5 shows the average richness of the natural gas from three types of production fields: associated or non-associated gas, onshore, offshore Post-Salt, or offshore Pre-Salt Sea plays.
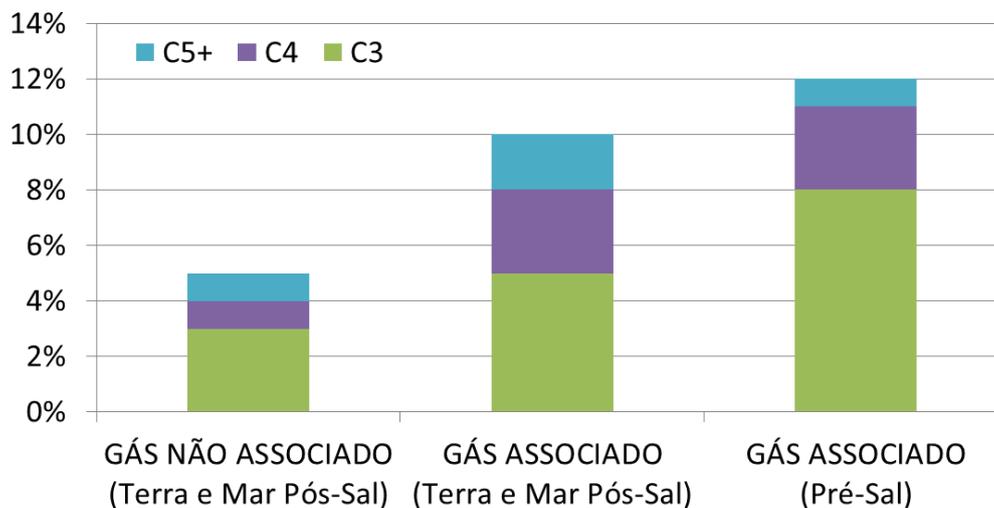
Legend:
GÁS NÃO ASSOCIADO (Terra e Mar Pós-Sal) = NON-ASSOCIATED GAS (Earth and Post-Salt Sea)
GÁS ASSOCIADO (Terra e Mar Pós-Sal) = ASSOCIATED GAS (Earth and Post-Salt Sea)
GÁS ASSOCIADO (Pré-Sal) = ASSOCIATED GAS (Pre-Salt)

Figure 5 - Average richness of three types of natural gas (estimated based on the compositions of fields in Brazil, according to calculation charts of the Natural Gas Reference Price, at the ANP website).

3.1 Associated Gas and Non-Associated Gas

Besides the classification by richness content, the natural gas may be characterized as Associated Gas (AG) or Non-Associated Gas (NAG). The AG is the solution gas found in the reservoir oil. Along the oil production process, with depressurization as the fluid lifts, the solubility reduces, and it is gradually released until it reaches surface conditions. The AG production is, then, a consequence of oil production. The Pre-Salt reservoirs usually present initial solubility ratio (or gas-oil ratio) between 200 and 450 m^3_{std}/m^3_{std}. That is, for each cubic meter of oil at the surface, 200 to 450 m³ of gas are released at standard atmospheric conditions.

The gas in an original or secondary gas cap (created as a result of the reservoir depressurization due to the oil production) is also considered Associated Gas. In this case, it is called Associated Free Gas. Usually, the gas cap remains in the reservoir in order to control the pressure depletion, assuring the oil production, and leaving the oil to be produced near the field abandonment; however, depending on the production strategy and on the completion of the wells, part of the gas cap may be produced along with the oil.

The NAG is the gas present in gas reservoirs, where it will be produced if it can be marketed. In some cases, the NAG reservoir is of Gas Condensate, which, in subsurface conditions, presents rich fractions (heavier hydrocarbons) vaporized in the gas and liquid at surface conditions. Such liquid fractions are called "condensate". Depending on the pressures during production, a part of the vaporized condensate may liquefy and deposit in the reservoir, and the remaining portion is produced with the gas. In very special situations, it may be economically feasible to deploy a gas cycling process, that is: to produce the rich gas, separate and market the condensate and reinject the lean gas in order to maintain the reservoir pressure (maintaining the condensate in the gas).

3.2 Specification of the Natural Gas (NG)

In Brazil, the specification of the natural gas, of national origin or imported, to be marketed in the country, is established by ANP Ordinance No. 16/2008. The ANP specifications for the natural gas control the maximum limit of certain components, to enable the gas marketing. The main contaminants present in the natural gas are total sulfur, hydrogen sulfide (H_2S), inert gases (CO_2 and N_2), oxygen and solid particles. In most cases, the contaminants, alone or with water, become corrosive, affecting transportation, or leading to a decrease in the heating value of the gas. Regarding the contaminants content, the natural gas specified for sale must have:

- CO_2 content lower than 4% in volume;

- H2S content lower than 10 ppmv.

Additionally, the ethane content must be below 12%. It is also important to mention that the 3% CO_2 limit for the gas to be evacuated to shore, considers, with reasonable safety, the limitations imposed by ANP.

When the natural gas has a different composition than the one established in ANP's specifications – which is the case for most volumes of the offshore gas, it needs to be processed in a Natural Gas Processing Unit (NGPUs) to remove the liquids, as well as contaminants that may have remained after the primary treatment at the platform or that may have been introduced by the mixture with other gas streams. The liquid processed at the NGPU may also be specified for sale as LPG ("kitchen gas" sold in cylinders), natural gasoline, petrochemical ethane and propane, among other streams, which can generate revenue, contributing to the economic feasibility of the commercial use of the natural gas.

3.3 CO$_2$ Content in the Pre-Salt

One of the problems faced by the oil industry in E&P activities is the presence, in hydrocarbon reservoirs, of corrosive gases, such as the carbon dioxide (CO_2) and hydrogen sulphide (H_2S). Depending on the concentration, these gases may cause risks to workers' lives, cause damage to equipment, or even make projects unfeasible (Gamboa, *et al.*, 2019; Müller, *et al.*, 2006).

Specifically for the CO_2 found in some Pre-Salt reservoirs, it is known that it may be present in several sedimentary basins around the world (for example, in Southeast Asia, Italy, Eastern Australia) in different geological contexts. Its presence in oil and gas fields is described in cases

such as the giant natural gas field of Natuna-d-Alpha, in Indonesia, the oilfields of Miller, in the North Sea and in the McElmo Dome field in the United States, with variable concentration.

The Pre-Salt gas has a range of CO_2 content, depending on the reservoir and the fluid migration process. Sometimes the CO_2 content within the same reservoir changes, laterally or vertically. In the Lula field, for instance, the CO_2 content in the produced gas varies between 8% and 25%. In the Iracema accumulation, which is a part of the Lula Field, the CO_2 content in the produced gas is below 1%.

The CO_2 is produced with the oil, being released in the production process, with the natural gas. In the Pre-Salt production systems it is usual to separate CO_2-rich stream at the Stationary Production Unit (SPU), followed by reinjection in the reservoir, thus avoiding the emission of greenhouse gases. It is important to note that, with the currently available CO_2 separation systems, the membranes have high selectivity for CO_2; however, a portion of the hydrocarbon molecules of similar size as the CO_2, such as methane and ethane, also permeate the membranes, adding to the CO_2 stream.

In the paper "An Evaluation of Large Capacity Processing Units for Ultra Deep Water and High GOR Oil Fields", registered as OTC-25274, it was simulated , for a typical Pre-Salt processing plant, the gas fraction available for export as a function of the CO_2 content, considering also the gas for power generation at the FPU and the amount converted into condensate. Table 2 of such paper is presented below.

Table 2—Fraction of gas flow rate available to export as a function of CO_2 content in the produced gas, after processing by membranes

CO₂ Content in Feed Stream (% mol/mol)	Treated Gas Flow Rate Percentage (Remain/Feed)
10%	70%
20%	56%
30%	45%
40%	36%
45%	30%
50%	27%

In the paper, the estimates were made for a FPSO with a gas processing capacity of 6 million m³/day. If we consider that the gas flow used for power generation in the platform is about 600 thousand m³/day, it is possible to create the following table:

Teor de CO2 no gás produzido	Fração do gás produzido disponível para escoamento, descontando o gás usado para geração elétrica (artigo OTC)	Fração do gás produzido disponível para escoamento e para geração elétrica na plataforma	Fração do gás produzido permeado nas membranas (corrente rica em CO2)	Fração de CO2 no gás permeado nas membranas
10%	70%	80%	20%	35%
20%	56%	66%	34%	50%
30%	45%	55%	45%	60%
40%	36%	46%	54%	69%
45%	30%	40%	60%	70%
50%	27%	37%	63%	75%

Legend:
Teor de CO_2 no gás produzido = CO_2 content in the produced gas
Fração do gás produzido disponível para escoamento, descontando o gás usado para geração elétrica (artigo OTC) = Fraction of the gas produced available for flow, deducting the gas used for power generation (OTC paper)

Fração do gás produzido disponível para escoamento e para geração elétrica da plataforma = Fraction of the produced gas available for flow and for power generation in the platform
Fração do gás produzido permeado nas membranas (corrente rica em CO_2) = Fraction of the produced gas permeated in the membranes (CO_2-rich stream)
Fração de CO_2 no gás permeado nas membranas = Fraction of CO_2 in the gas permeated in the membranes

In the Pre-Salt, Petrobras and partners have been developing, with the suppliers, new technologies for membranes, in order to increase the selectivity for CO_2 (Touma, et al., 2019). It is worth mentioning the Carbon Molecular Sieves (CMS) technology, which is being tested in the Atalaia Experimental Center (NEAT) in the Petrobras Research Center (CENPES) in Aracaju, Sergipe. Additional tests must be performed, in large-scale prototypes, before the technology is approved for industrial application. These tests are scheduled for 2021. This technology may be deployed in new or existing SPUs, in case of a revamp to allow operations with higher CO_2 concentrations in the produced gas. In addition to the higher selectivity for CO_2, the CMS membranes are expected to be able to separate H_2S and water vapor, which would simplify the processing plants.

The deployment of the systems for separation and reinjection of the CO_2 increases the complexity of gas plant in the SPU, not only in terms of operation, but also in area and weight. As a result, the gas processing capacity, and, consequently, the oil processing capacity, may be limited, affecting the economic indicators of the project.

4. WATER AND GAS INJECTION IN THE PRODUCTION OF HYDROCARBONS

Water injection is the most used secondary recovery method in the world. In offshore fields, seawater is injected, treated to control the solids' content, oxygen and bacteria. Depending on the characterization of the water reservoir rock, it may be necessary to remove the sulfate, to prevent scaling in the production wells and control the biogenic souring, also associated to seawater injection.

Although waterflood is the most used secondary recovery method, gas injection also contributes to pressure maintenance. In addition to pressure maintenance, both water and gas injections increment the sweep efficiency, increasing the oil recovery. Other methods are also effective to increase recovery, particularly the Water Alternatig Gas method (WAG), which can be even more efficient when CO_2 is added to the gas stream.

Gas reinjection has been proved to be quite important for the Pre-Salt fields, especially for those with high CO_2 content. As the gas, to be evacuated to shore, must have a maximum concentration of 3% CO_2, it is mandatory to have a CO_2 separation and reinjection system in the platform.

In the Pre-Salt reservoirs, especially due to its high pressure, the injected gas is miscible with the oil, which enhances the displacement efficiency and the ultimate recovery. The recovery increase with miscible gas injection is related to the following mechanisms: (i) reservoir pressure maintenance; (ii) gas solubility and oil swelling; (iii) oil viscosity reduction; (iv) interfacial tension reducing, favoring the displacement efficiency; (v) reduction of the residual oil saturation. When the oil is displaced by water in a porous media, a significant residual oil is left (usually between

20% and 40%). With miscible gas displacement the residual oil saturation is close to zero, that is, when gas (or mixture of gas and CO_2) sweeps a pore, no residual oil will be left in this pore.

Gas injection is, therefore, a consolidated oil recovery method. The natural gas rate to be added with the CO_2 stream (that must be reinjected) is evaluated for each reservoir, considering its effect on the reservoir management, final recovery and the economic indicators. The limit cases are the full gas reinjection (maximum gas reinjection) and just the CO_2-rich stream reinjection (minimum gas injection), in this case, evacuating the gas specified to be marketed.

The water alternating gas (WAG) method aggregates the efficiency of the water injection method for pressure with the high displacement efficiency of the gas injection. Additionally, due to the differences in the viscosities and densities between gas and water, the sweep efficiency is improved, especially in heterogeneous reservoirs, where preferential channels may be created between injection and production wells. The alternate injection also allows the control of GOR increase due to eventual early gas breakthrough, which would reduce oil rate due to the limitation of the gas processing capacity.

In the largest Pre-Salt fields in operation (Lula, Sapinhoá, Búzios), the gas is injected in the oil zone. The gas is injected alternating with water, thus controlling the gas displacement front and improving the displacement and sweep efficiencies, as well as the ultimate recovery. The more CO_2 in the gas injection stream, the easier it is to develop miscibility between gas and oil, since, in the reservoir conditions, CO_2 is an excellent solvent. Additionally, as rich gas is injected, the heavier fractions (C5+) end up being produced with the oil.

By analyzing several Pre-Salt fields, Pré-Sal Petróleo S.A. – PPSA, based on the studies carried out by the operators, has observed that:

- when the reservoir does not present significant depth variation, the miscible water alternating gas (WAG) leads to the best results;

- in thick reservoirs, with significant depth variation (case of Carcara in block BM-S-8), gas injection in the structural highs, complemented by water injection in the reservoir lows, with oil producers in intermediate depths, allows a higher ultimate recovery when compared to waterflood with gas export.

Schaefer *et al.* (2017) show recovery increase achieved with the WAG method (with full gas reinjection) in a reservoir with similar characteristics as the Pre-Sal reservoirs. In the simulated period, an increase between 25% and 30% in the final recovery has been reported, comparing WAG with the continuous injection of water or gas.

The assessment of the better recovery method, in economic terms, must be performed on a case by case basis, considering numerical reservoir simulation, incorporating data from laboratory tests and the most suitable physical and mathematical models for each reservoir. The performance of each recovery method depends on several factors, such as the characteristics of the reservoir, heterogeneities, type of oil, composition of fluids, production and injection rates, pressure, temperature, etc.

5. GAS INJECTION *versus* COMMERCIAL USE

The evaluation of the best economic option for development of a Pre-Salt reservoir should take into account, among others, the following extreme scenarios:

a) Minimum gas reinjection scenario – water injection, separation and reinjection of the CO_2 stream into the reservoir and gas evacuation to the market. This scenario requires an infrastructure to evacuate and process gas, or other technologies (Floating LNG, Floating GTL), thus marketing the natural gas.

b) Maximum gas injection scenario – reinjection of all produced gas, complementing, if necessary, with water injection.

For both scenarios, the increase in oil and natural gas production and recovery factors should be made clear, as well as any production loss caused by GOR increase in the maximum natural gas injection scenario. For scenario "a", the investments in infrastructure should be considered as well, in addition to the possible necessity to limit the gas and oil processing capacity of the SPU as a result of the CO_2 separation and reinjection infrastructure to be deployed.

On the other hand, the volumes of natural gas reinjected that will not be produced should also be evidenced. In this context, it is important to consider all potential monetization scenarios and the revenues associated to the commercial use of natural gas.

The fact is that part of the excess natural gas could be supplied to the market through investments in infrastructure, especially construction of gas pipelines or liquefaction (liquefied natural gas (LNG)). Other ways to monetize the natural gas would be the Gas to wire (GTW) and Gas-to-liquids (GTL) technologies. The former consists in the conversion of gas into energy, through thermal power plants, while the latter consists in the conversion of gas into high-quality liquids (especially diesel, aviation kerosene and synthetic lubricants) or synthetic petroleum (Wood, 2012).

Floating Liquefied Natural Gas (FLNG) plants are recent, and the first gas export occurred in 2017, through the FLNG Satu facility (Malaysia). This facility has 1.2 million tons per annum (MTPA) capacity, which is equivalent to about 4.5 million m^3/day. The PFLNG1 (Songhurst, B.) was the first to start offshore production in the Kanowit field, in November 2016, but was recently relocated to the Kebabangan field, which shows the flexible nature of the floating LNG facilities. As there are few examples of this type of facility, this first project was adopted as a reference. As for pipelines, in order to analyze the feasibility of a project, we will consider the possibility to incorporate more than one field or consortium.

It is worth mentioning that:

- In the gas export scenario, ideally, the gas evacuation and marketing should occur with the first oil. Otherwise, there is a risk to delay the production start-up, which should be considered in the economic evaluation of the project;

- Depending on the characteristics of the reservoir, miscible gas reinjection has the potential to increase the oil recovery factor, making the project economically more attractive, but the optimal percentage of the produced gas to be reinjected should be pursued and assessed on a case by case basis. Reinjecting an excessive volume of gas may

reduce oil recovery, either for reservoir-related aspects (early gas breakthrough) or facility-related aspects (restriction on oil processing due to high GOR and constraint in the gas processing);

- For a reservoir containing CO_2, the deployment of the separation and reinjection system to deal with the CO_2 results, with the technologies currently available, in a constraint in the maximum gas and oil processing capacity of the SPU, reducing the Net Present Value (NPV) of the project;

- On the other hand, full gas reinjection results that the SPUs, after a while, top in the gas processing capacity, thus reducing the oil production. Any efforts to reduce the gas rate arriving at the platform would allow the increasing of the oil rate, increasing the NPV. The HISEP technology (high-pressure separation of the dense phase), a Petrobras's patent, has a prototype being tested in the CENPES plant at the Asphalt Factory in Fortaleza (ASFOR). The technology allows separation and reinjection of a large fraction of the associated gas (that may contain CO_2) as a dense phase, at the seabed, so that a smaller amount of gas flows to the platform, thus enabling a greater oil processing capacity. The tests have shown good results, supporting the technology (PASSARELLI, et al., 2019);

- As mentioned, the gas export scenario, with previous investments in gas pipeline and NGPU must be compared, in terms of NPV, to the full or partial gas reinjection scenario, either only the gas or alternately with water (WAG). The best economic option must be pursued, since it follows the Best Practices of the Oil Industry and allows the best exploitation of the hydrocarbons;

- The quantification of the net present value of each option (reinjection x commercial use) must be made on a case by case basis, with the production forecasts obtained by numerical reservoir simulation, incorporating the geology and other characteristics, especially the fluid characterization.

Due to the high investments to allow the gas export, it is worth, for the Pre-Salt environment, to work with a master plan vision, by grouping the development projects in each area (even with different consortia) to use the same infrastructure. The projects which would potentially use the infrastructure must have a firm commitment with the investment, as well as a consistent schedule among them. Each project must necessarily follow the investments, which may require prepayment, affecting the economic results. This is a possible solution to stimulate the evacuation and marketing of the Pre-Salt gas.

If gas evacuation has not been considered in the project design, it would probably be necessary to either replace the Production Unit or to deploy a "hub" to treat and export the gas, which adds new investments and costs to the project. In that scenario, it is naturally necessary to estimate the income with gas monetization to support the investments.

Alternatively, even in the scenario of full gas reinjection, the SPU could be designed and built with flexibility for future gas export, as already happens in some Pre-Salt projects.

Be it through a "hub" or gas treatment in the SPU itself, the gas export and marketing shall result in income, which should be considered for in the economic feasibility studies. The project design

should take into account the options to market the natural gas, in order to verify its feasibility and compare it to other options.

As mentioned above, there is a minimum amount of gas to be reinjected in the reservoirs, due to the maximum CO_2 content in the export gas to be exported and the hydrocarbon gas that is necessarily removed with the CO_2. Not to mention the effect of the injected gas to increase the oil recovery and the economic value of the project.

However, the development of new technologies, especially for CO_2 removal, may reduce the minimum gas rate to be reinjected. Moreover, the reservoir management with the analysis of data acquired during production enables a better understanding of the fluid and oil displacement behavior and, consequently, the model calibration and definition, with less uncertainty, of the optimum injection flow rates to increase the oil recovery factor.

5.1 Gas Injection History

Figure 6 shows the evolution of the use of natural gas in Brazil since 2009. There is a significant reduction in the gas flaring throughout the years due to ANP's regulation, which established flaring limits and induced the operators to comply. It is also possible to note that the internal consumption shows an increase compatible with the increase of the number of facilities and the production of natural gas itself.

On the other hand, the behavior related to gas injection shows a big change after 2013 (related to the production increase in Lula and Sapinhoá fields). The gas availability also shows a significant increase, although with a smaller slope than the one related to the total gas production.
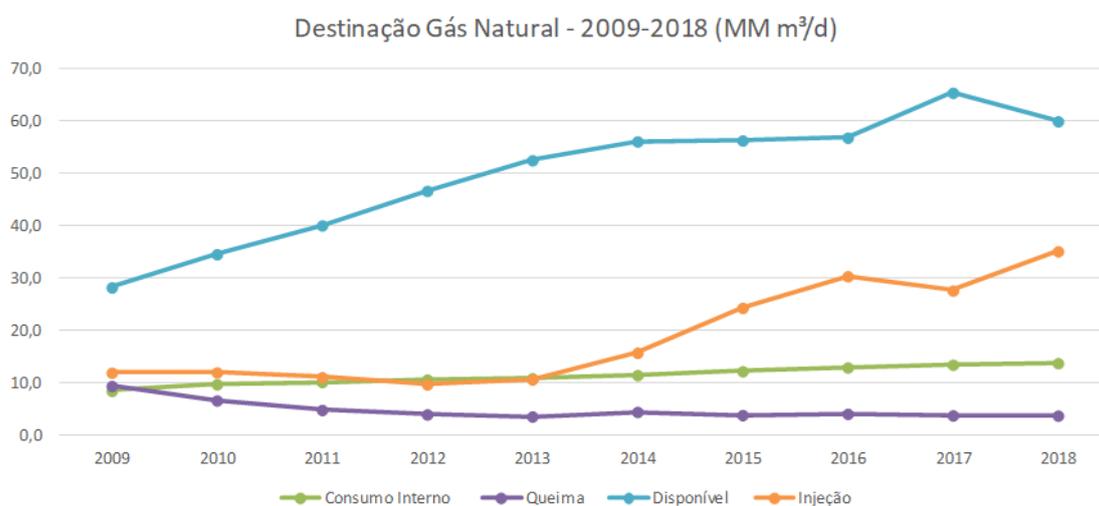
Legend:
Consumo interno = Internal Consumption
Queima = Flaring
Disponível = Available
Injeção = Injection

Figure 6 – Destination of the natural gas (ANP, 2019)

Figure 7 shows the gas production and injection history in Lula and Sapinhoá Fields. Figure 8 presents the percentage of the produced gas that was reinjected. These are the only fields in the Pre-Salt of the Santos Basin that export gas nowadays. It is possible to note that, in both fields, the injected gas is currently around 45% of the produced gas. The CO_2-rich fraction in these fields, considering the efficiency of membrane separation, is, on average, between 25% and 35%, i.e., the injected gas is approximately between 10 and 20 percentual points above the minimum amount (CO_2-rich stream). Since a typical Pre-Salt platform has a gas processing capacity of 6 MMm^3/day, it means that each platform has recently injected between 600 and 1,200 MMm^3/day of gas above the minimum required rate (CO2-rich stream). It is worth mentioning that, as evidenced hereafter in this study, there is nowadays an infrastructure constraint that prevents the increase of gas evacuation through pipelines.
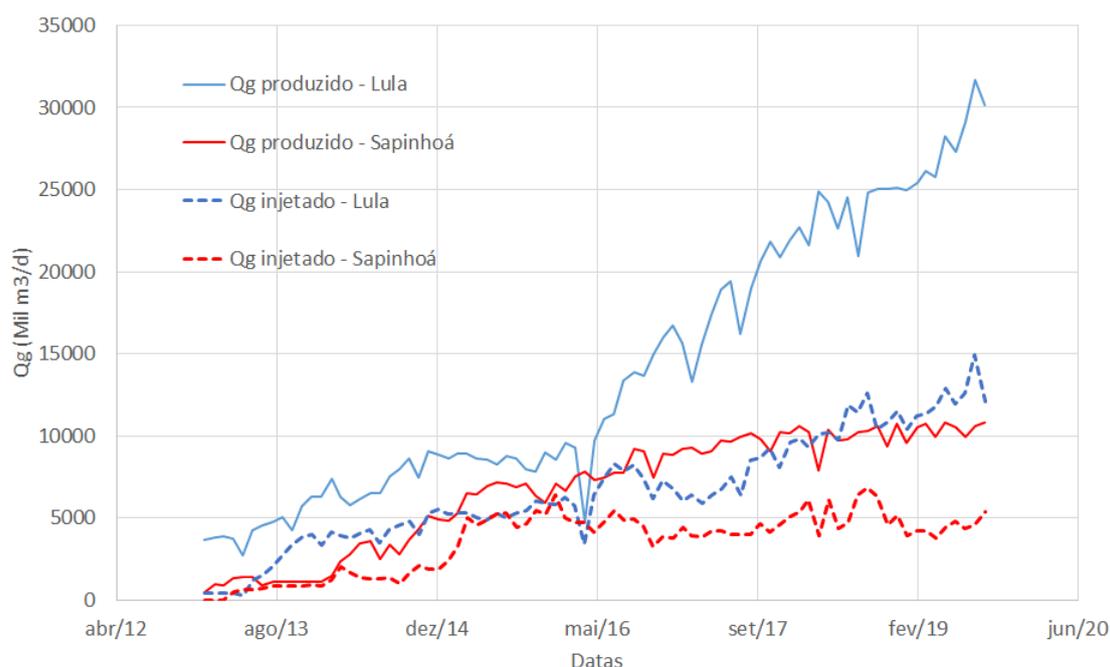
Legend:
Qg produzido – Lula = amount of gas produced in the Lula field
Qg produzido – Sapinhoá = amount of gas produced in the Sapinhoá field
Qg injetado – Lula = amount of gas injected in the Lula field
Qg injetado – Sapinhoá = amount of gas injected in the Sapinhoá field
abr/12 = apr/12
ago/13 = aug/13
dez/14 = dec/14
mai/16 = may/16
set/17 = sep/17
fev/19 = feb/19
jun/20 = jun/20
Datas = Dates

Figure 7 – Total produced and reinjected gas in Lula and Sapinhoá fields
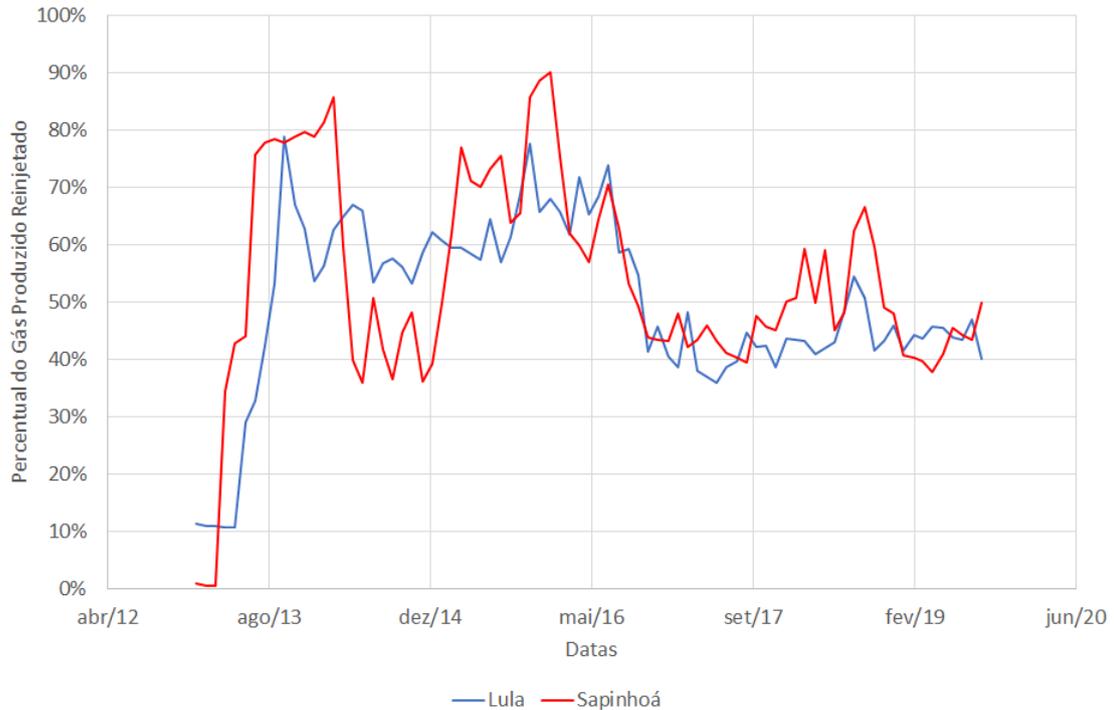
Legend:
Percentual do Gás Produzido Reinjetado = Percentage of Produced Gas Reinjected
abr/12 = apr/12
ago/13 = aug/13
dez/14 = dec/14
mai/16 = may/16
set/17 = sep/17
fev/19 = feb/19
jun/20 = jun/20
Datas = Dates
Lula = Lula field
Sapinhoá = Sapinhoá field

Figure 8 – Percentage of produced gas reinjected in Lula and Sapinhoá fields

Based on data provided by the operators to ANP through the Annual Production Programs (PAP), including additional data for gas injection forecasts with the corresponding CO_2 fraction, it is possible to predict the production and injection gas rates for the next years in the Pre-Salt field in Santos Basin, which has the biggest potential, in terms of volume, to increase commercial use of natural gas in Brazil. Figure 9 shows the forecasts until 2023, with the reinjection fraction.
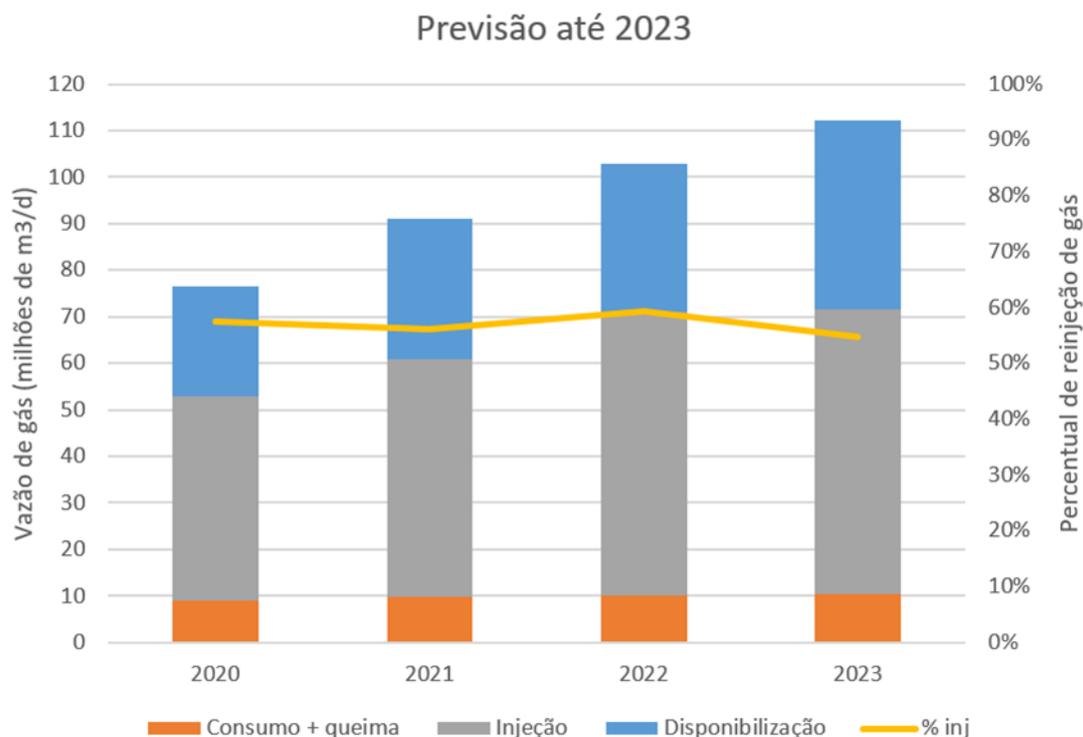
Previsão até 2023 = Forecast until 2023
Vazão de gás (milhões de m3/d) = Gas flow (million m³/day)
Consumo + queima = Consumption + flaring
Injeção = Injection
Disponibilização = Availability
% inj = % of injection
Percentual de reinjeção de gás = Percentage of gas reinjection

Figure 9: Forecasts for gas production and reinjection until 2023 – Pre-Salt fields in the Santos Basin (Source: PAP supplied by operators to ANP)

It can be noted that the gas reinjection fraction is higher than data shown in Figure 8, since the forecast for up to 2023 considers other fields that currently don´t export gas, such as Búzios, that has a significant production and the gas export, through UEP P-74, shall start along 2020. In other words, during some time, a major percentage of gas will continue to be reinjected.

Additionally, between 2020 and 2023, other fields will start production (for example, Sépia and Atapu), with no gas export for some period. Not to mention the Mero field, with high CO_2 content (between 40% and 45%), for which no gas export is expected in the base project for its entire productive life, and, even if it occurs, the reinjected volumes will always represent a significant fraction of the production, due to the high CO_2 content.

Figure 10 shows the expected gas reinjection rates, separated by CO_2 and other components that, due to the current efficiencies of the separation process, need to be reinjected, as well as the excess injection.

Previsão de injeção de gás
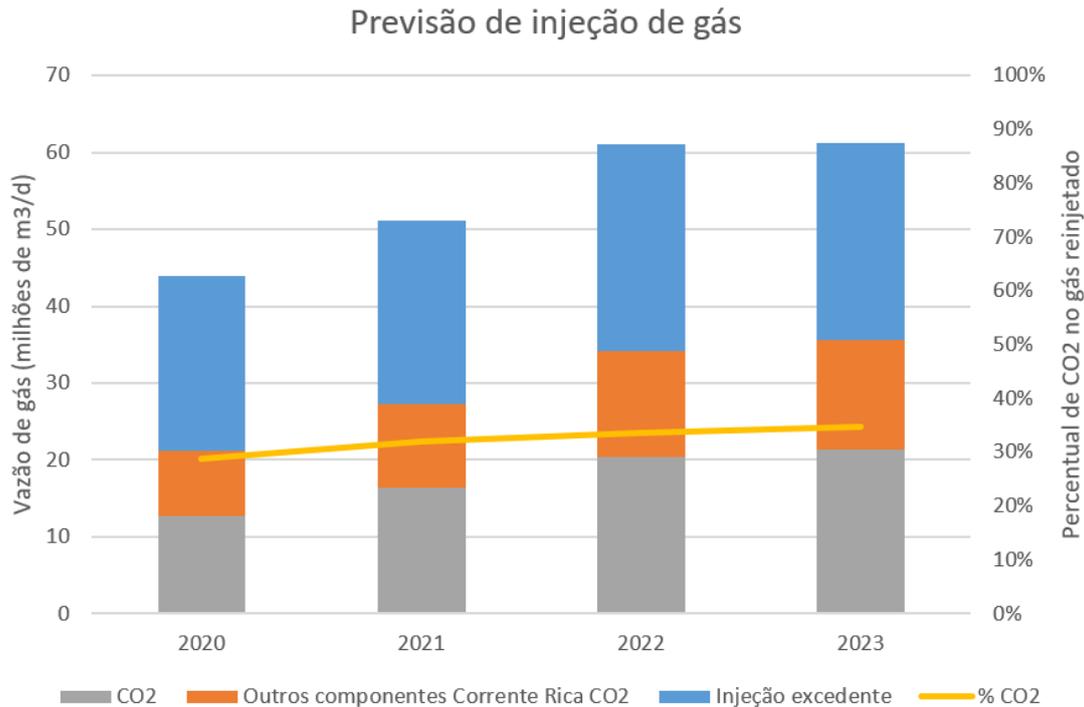
Legend:
Previsão de injeção de gás = Gas reinjection forecast
Vazão de gás (milhões de m3/d) = Gas rate (million m³/day)
CO2 = CO_2
Outros componentes Corrente Rica CO2 = Other components, CO_2-Rich Stream
Injeção excedente = Excess injection
% CO2 = % of CO_2
Percentual de CO2 no gás reinjetado = Percentage of CO_2 in the reinjected gas

Figure 10 –CO_2 in the gas reinjection and potential excess up to 2023 – Pre-Salt fields in the Santos Basin (Source: PAP supplied by operators)

Considering the aforementioned assumptions about the minimum gas rate to be reinjected due to issues of CO_2 removal technology and materials used in wells and lines (adopting, to simplify, an amount of 60% for the CO_2 content in the injected stream) and the CO_2 contents produced by each field, it is possible to estimate about 25 million m³/day of additional natural gas reinjection for the following years (excess injection in the plot), which could be available to the market, if it was feasible to export. This figure does not take into account the reservoir aspects, which could increase the necessity for gas injection. On the other hand, technological advances may reduce the hydrocarbon fraction currently injected with the CO_2.

5.2 About Natural Gas Availability

When comparing gas reinjection with commercial use and marketing, it is important to consider the potential of development and feasibility of new investments in the industrial, vehicle, residential and thermal sectors, in addition to the use of natural gas as raw material for several other industrial processes.

The increase in the natural gas supply in Brazil can leverage the use of a cleaner fuel when compared to other fossil fuels, as well as stimulate new businesses. In this context, it is important to highlight that the availability of the Pre-Salt natural gas is considered in the policies defined in the government program New Gas Market, whose expected results are:

> *"– To increase the use of gas in the Pre-Salt fields, in the SE/AL basin and other discoveries*
>
> *– To increase investments in infrastructure for gas evacuation, processing, transportation and distribution*
>
> *– To increase the competition in the thermal power generation*
>
> *– To resume the industry competitiveness in its several segments, such as cellulose, fertilizers, petrochemical, steel, glass, ceramic and others."*

Therefore, the availability of natural gas to the market must consider structuring projects that enable the expansion of the logistics infrastructure coordinated with the supply, with the fundamental principle of access to gas pipelines and NGPUs to third parties.

As we will mention hereafter, the expansion of the infrastructure may not necessarily be restricted to the construction of gas pipelines to export the Pre-Salt gas to shore. Existing technology already enables study of the implementation, for example, of Floating LNG, or the application of "gas to liquid" (GTL) processing. For sure, one should not overlook the economic feasibility of such projects, as well as the competitiveness of the gas to be marketed, in terms of prices.

Given the need for expansion of the natural gas market and its influence on the several sectors, one should consider the cost of the gas including the investments vis-à-vis the cost of the imported gas, by pipeline or LNG.

In this context, it is important to highlight that, currently, there are three terminals for regassing LNG authorized to operate by ANP, one in the pre-start-up stage and one under construction. Additionally, several other projects have been included as possibilities in thermal power bidding rounds evaluated by ANP and EPE over the last few years.
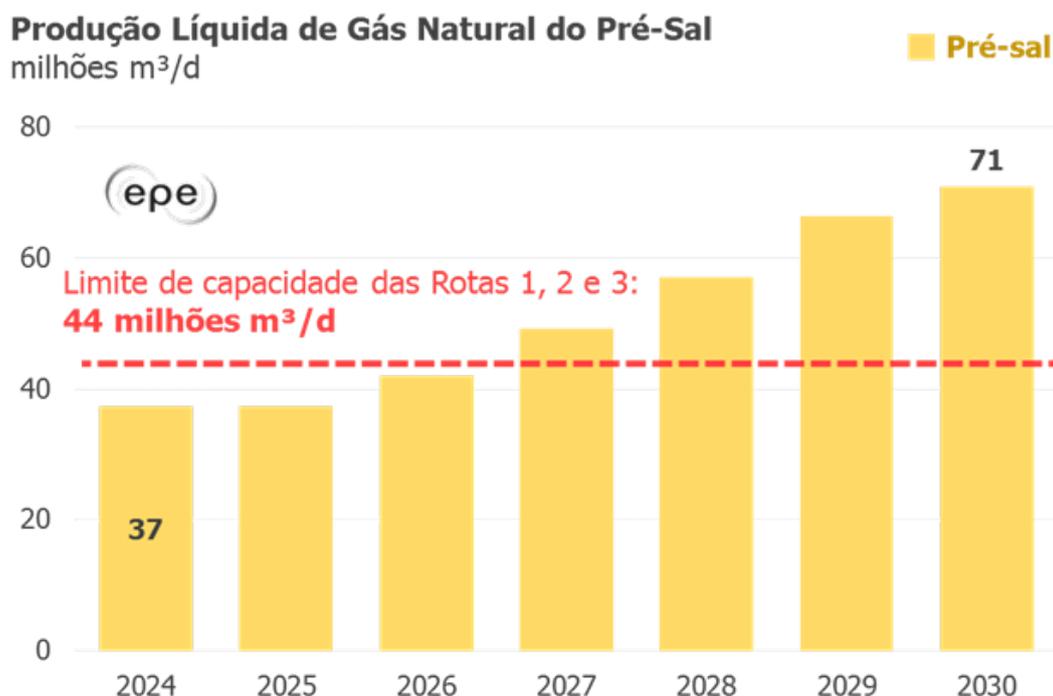
6. Costs of the Pre-Salt Natural Gas

EPE (2019) presents the economic evaluation and the range of the breakeven prices for the lean gas (processed in the NGPU) of typical Pre-Salt fields, with different CO_2 contents and distances to shore. The economic evaluation of the development schemes must be performed for each project, based on the production forecasts.

Additionally, it is important to include in the analysis the issues related to: (i) access to the gas market; (ii) estimates for the gas sales price; (iii) marketing of C5+ and LPG processed in the NGPU; (iv) environmental license, including the gas pipeline shore approach, and path to the NGPU, among others. All those issues must be well-defined in order to support the investment decision for gas evacuation and processing.

Thus, the monetization of Pre-Salt natural gas must take into account the technical, economic and socioenvironmental aspects specific to each project, and they must be defined during the project design phase by each operator, aligned with partners.

First, the players may prefer to access the natural gas transport infrastructure which is already operating, especially in the Campos and Santos Basins. The access of third parties, in case of the gas pipelines, must occur through non-discriminatory discussions, based on international practices, with the composition and flow limits supported by the existing systems.

In this case, the existing infrastructure may receive gas from several players until it reaches its capacity. As shown in Figure 11, it is estimated that gas evacuation full capacity for the Santos Basin Pre-Salt, considering the infrastructure which currently exists (Routes 1 and 2) and is under construction (Route 3), will be reached in 2026, for the reference scenario of the Ten-Year Energy Expansion Plan (PDE) 2029.
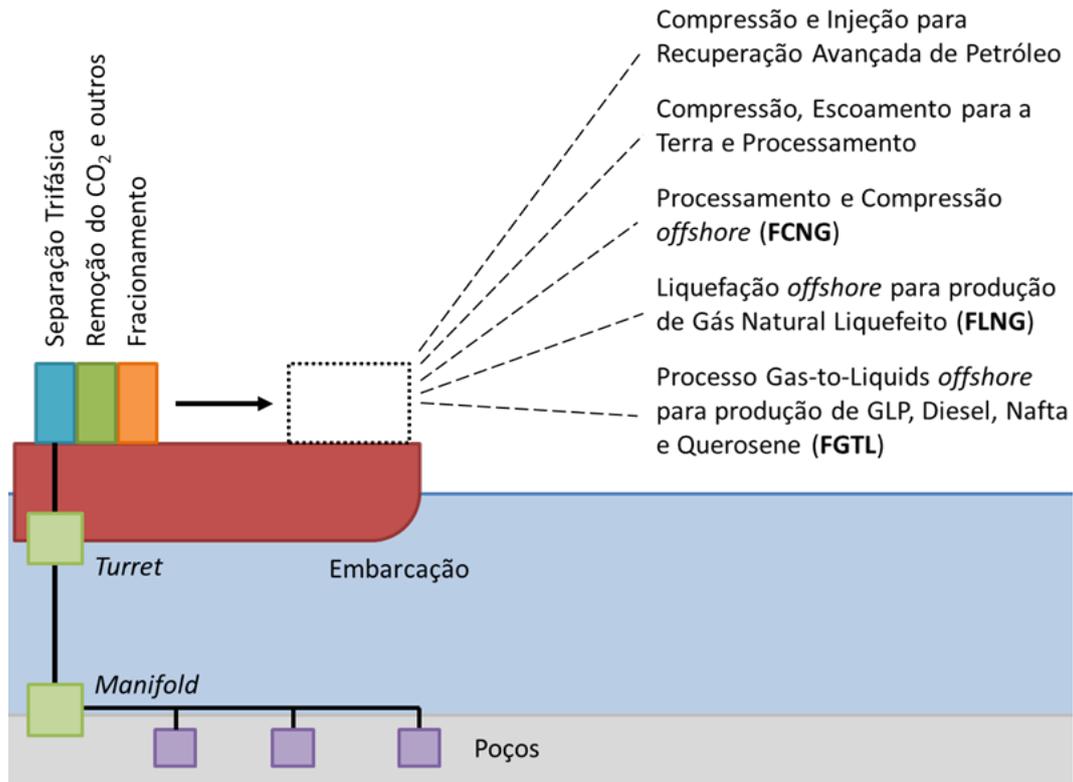

Legend:
Produção Líquida de Gás Natural do Pré-Sal = Net Natural Gas Production in the Pre-Salt
milhões m³/d = million m³/day
Pré-sal = Pre-Salt
Limite de capacidade das Rotas 1, 2 e 3: 44 milhões m³/d = Total capacity of Routes 1, 2 and 3: 44 million m³/day

Figure 11 – Net Natural Gas Production in the Pre-Salt

Additional gas volumes to the present and under construction export capacity require investment decisions by the agents, so that it can be evacuated to shore and monetized. As aforementioned, gas pipelines are just one of the options. Other possible alternatives are Compressed Natural Gas (CNG), Liquefied Natural Gas (LNG), or in the form of liquid fuel (GTL), as shown in Figure 12. These alternatives depend on technical-economic, social and environmental analyses so that they can be applied to each project.

Legend:
Separação Trifásica = Three-Phase Separation
Remoção do CO_2 e outros = CO_2 removal and others
Fracionamento = Fractionation
Compressão e Injeção para Recuperação Avançada de Petróleo = Compression and Injection for Enhanced Oil Recovery
Compressão, Escoamento para a Terra e Processamento = Compression, Evacuation to shore and Processing
Processamento e Compressão *offshore* (**FCNG**) = Offshore Processing and Compression (**FCNG**)
Liquefação *offshore* para produção de Gás Natural Liquefeito (**FLNG**)= Offshore Liquefied Natural Gas (**FLNG**)
Processo Gas-to-Liquids *offshore* para produção de GLP, Diesel, Nafta e Querosene (**FGTL**) = Offshore Gas-to-Liquids process to generate LPG, Diesel, Naphtha and Kerosene (**FGTL**)
Turret = Turret
Manifold =Manifold
Embarcação = Vessel
Poços = Wells

Figure 12 – Option to monetize the Pre-Salt gas

The CO_2 content in the produced gas and the distance to shore represent other challenges and higher costs to separate and reinject the CO_2 stream and evacuate the natural gas. As shown in Figures 13 and 14, it is expected that, in the coming years, gas production tend to be located at slightly shorter distances to shore than those currently produced, but it may have a higher CO2 content.
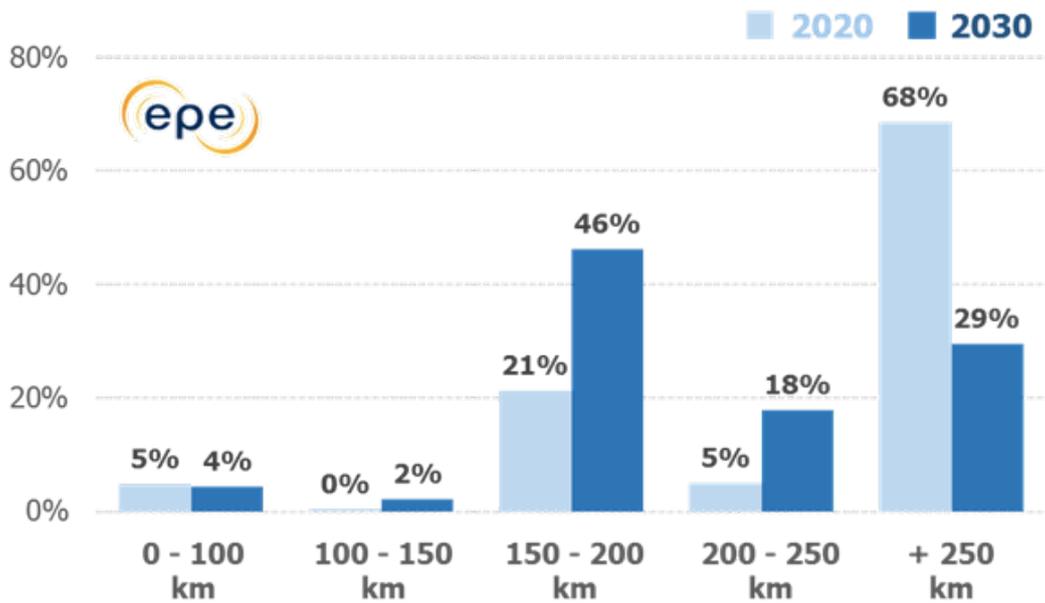
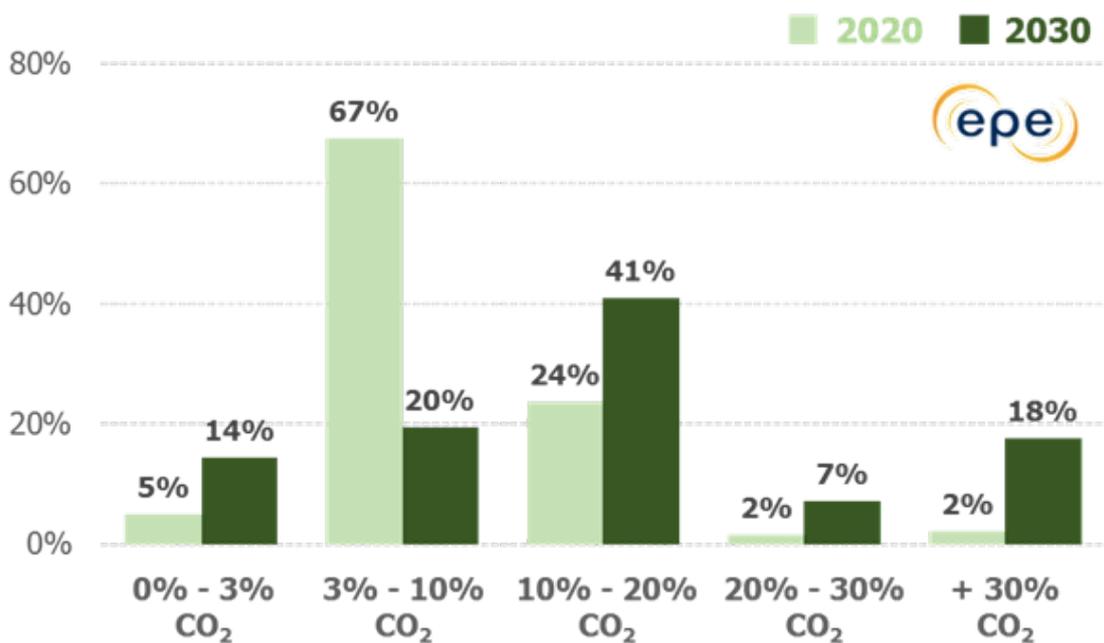Figure 13 – Total Pre-Salt gas production and distance to shore

Figure 14 – Total Pre-Salt gas production and CO_2 content

To analyze the economic feasibility of offshore natural gas in Brazil, EPE prepared a report containing an estimated break-even costs, considering the distance to shore and CO_2 content of each field (EPE, 2019a). The study estimates CAPEX and OPEX for a generic E&P project in the Pre-Salt, then adds the costs for CO_2 separation, when needed. After estimating the value of wet natural gas out of the platform, the costs for gas evacuation and processing were estimated separately considering the sale of LPG and C5+ in the NGPU (EPE, 2019b). Estimated break-even costs for the natural gas were obtained, considering conditions and premises for several CO_2 contents and distances from shore.

It was observed that the break-even values could vary considerably, from 2 USD to USD10/MMBtu for CO_2 contents up to 20%, and maybe even higher for higher CO_2 contents. Such study was based on theoretical production forecasts and average cost estimates. The orders of magnitude of the costs are intrinsically related to the premises used in the study, such as the number of wells, cost of equipment and other economic parameters that can be consulted in the mentioned studies (EPE, 2019a; EPE, 2019b).

Within the general context, it is possible to note that monetization of the natural gas in the Pre-Salt is a topic that must be analyzed in details for each project, and such analysis must be made prior to the sanction of the field development project. This is because the infrastructure necessary for processing, compression and evacuation, in addition to the marketing itself, has a long maturation period, from three to five years in advance. Ideally, neighboring areas with potential for gas export could be gathered in a hub, so that the infrastructure to monetize the gas is analyzed in an integrated way.

7. INFRASTRUCTURE FOR GAS EVACUATION

The best use of the Pre-Salt gas, as well as the increase in supply to the market, depends, mainly, on the infrastructure to enable the access to the end consumers.

The natural gas infrastructure comprises, basically, of flow gas pipelines, transport gas pipelines, Processing Units, LNG terminals, city gates,[7] and distribution branches.[8] It is capital intensive, especially gas pipelines, which require years to be deployed, requiring billions of Reais and strict environmental requirements, among other complexities.

According to Law No. 11,909/2009, the "Gas Act [*Lei do Gás*]", the access to transport gas pipelines is mandatory, and should be granted on a non-discriminatory basis, considering the period related to the exclusive right of the players which contributed for the investment. This access is regulated, and ANP is responsible to define or approve the transportation fees.

Regarding flow gas pipelines and NGPUs, as well as liquefaction and regassing terminals and storage installations, Law No. 11,909/2009 made it clear that the access thereto to third parties is not mandatory.

However, after Decree No. 9,616/2018, that amended Decree No. 7,382/2010 ("Decree for Regulation of the Gas Act"), operators of flow gas pipelines, NGPUs, LNG terminals and liquefaction and regassing units whose denial of access is considered anticompetitive conduct, shall be subject to applicable sanctions, pursuant to Law No. 12,529 of November 30, 2011. Accordingly, it is correct to state that this provision established that the denial of access is not only subject to the operator's will.

The infrastructure for natural gas transportation and processing is illustrated by Figure 15. At the end of 2018, Brazil had 11,732 km of gas pipelines for transportation or transfer and treatment capacity of 95.65 million m³ per day. From this processing capacity, about 24%, or 23.22 million

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[7] City Gates, pursuant to Law No. 11,909/2009 (art. 2, XII) are the spots in the transportation gas pipelines where natural gas is delivered by the carrier to the distributor, or to whoever it appoints. The city gates interconnect transportation networks and distribution networks.
[8] Distribution extensions constitute a network which transports natural gas from the City Gate to the end consumer in the urban centers.

m³/day, are in the states of São Paulo and Rio de Janeiro. Comperj's NGPU, with expected capacity of 21 million m³/day, will practically double the capacity of processing of the states closer to the Pre-Salt fields, making Rio de Janeiro and São Paulo responsible for almost 38% of the national processing capacity.

FONTE: ANP/SIM.
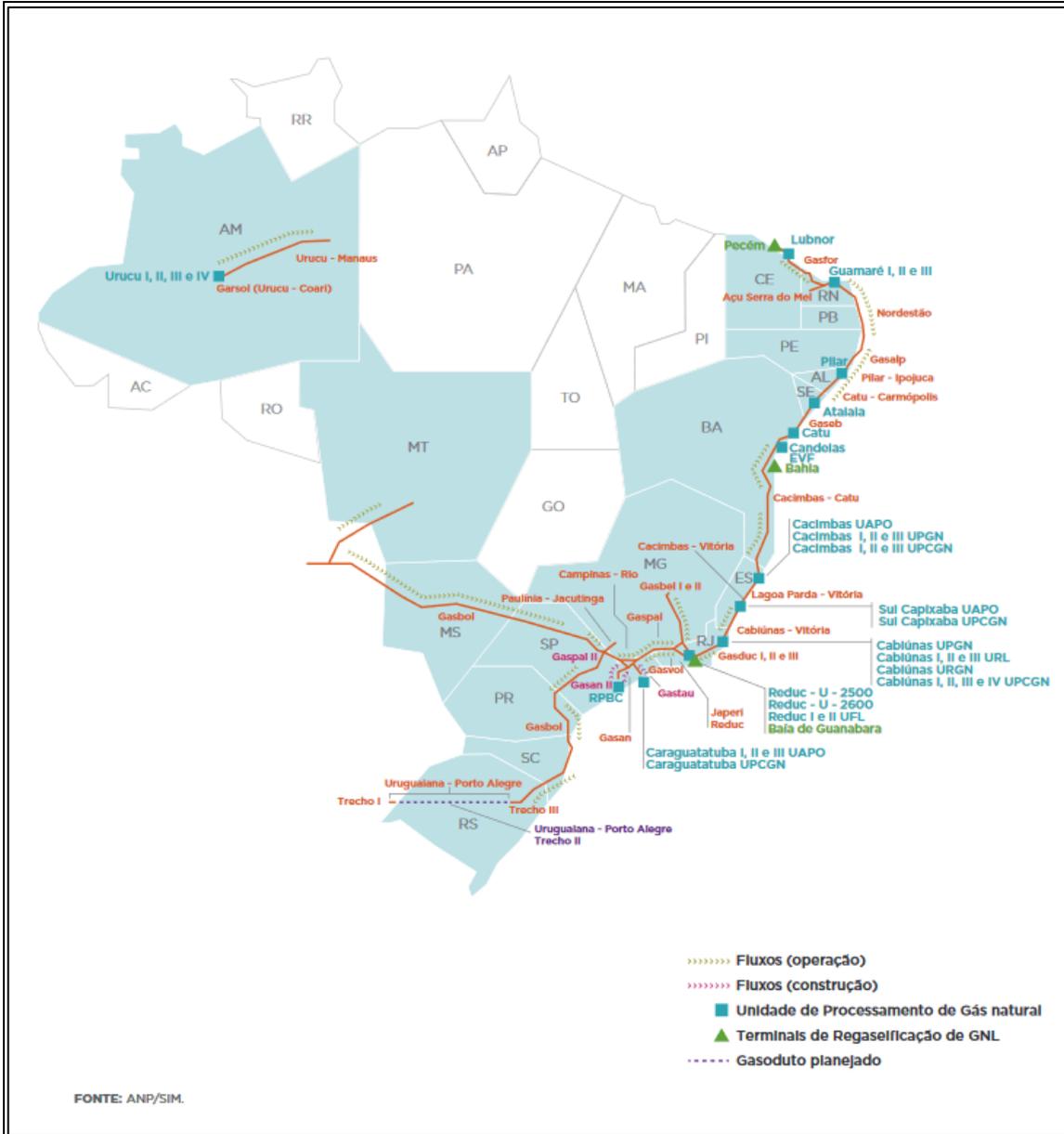
Legend:
Trecho I = Branch I
Trecho II = Branch II
Fluxo (operação) = Flow (operation)
Fluxos (construção) = Flows (construction)
Unidade de Processamento de Gás natural = Natural Gas Processing Unit
Terminais de Regaseificação de GNL = LNG Re-gasification Terminals
Gasoduto planejado = Planned gas pipeline
FONTE: ANP/SIM. = Source: ANP/Superintendence for Infrastructure and Operation (SIM)

In the case of the Pre-Salt fields, as shown in Figure 16, the connection with Processing Units has become a reality upon the start-up of the gas pipelines referred to as Route 1 (between the Santos Basin and Caraguatatuba/SP) and Route 2 (between the Santos Basin and Cabiúnas/RJ), which capacities are, respectively, 10 and 16 million m³/day. In addition to this capacity, there is also 18 million m³/day in Route 3, which is the gas pipeline under construction, planned to start operation in 2021, will connecting the Santos Basin to Comperj, in Itaboraí (RJ).
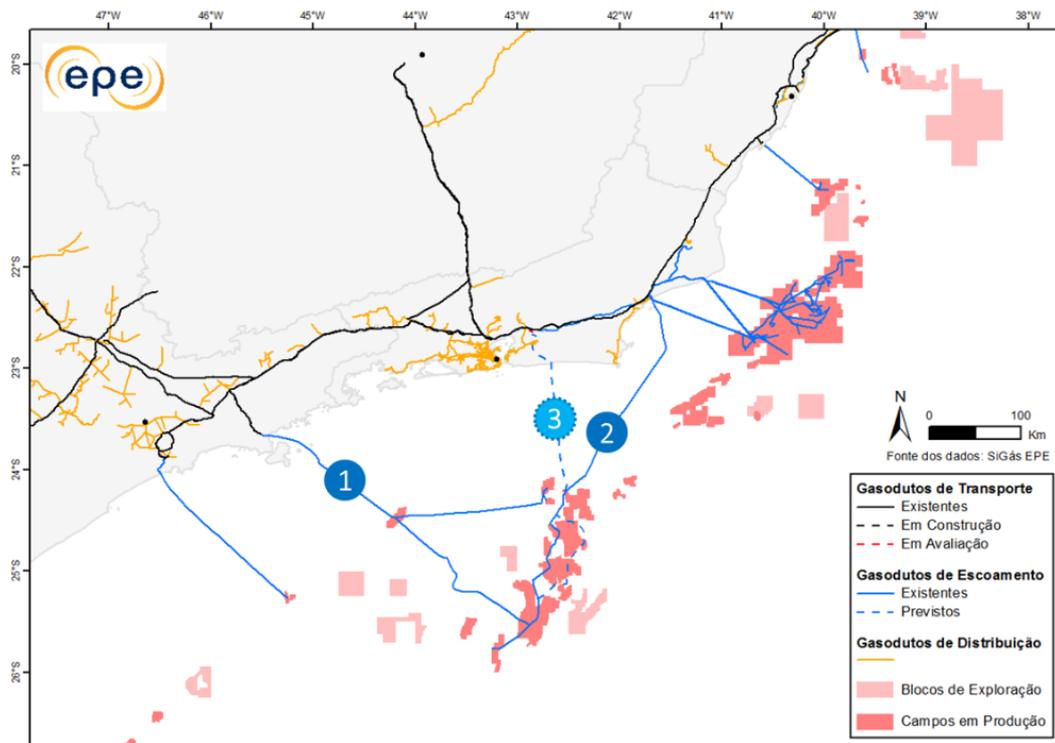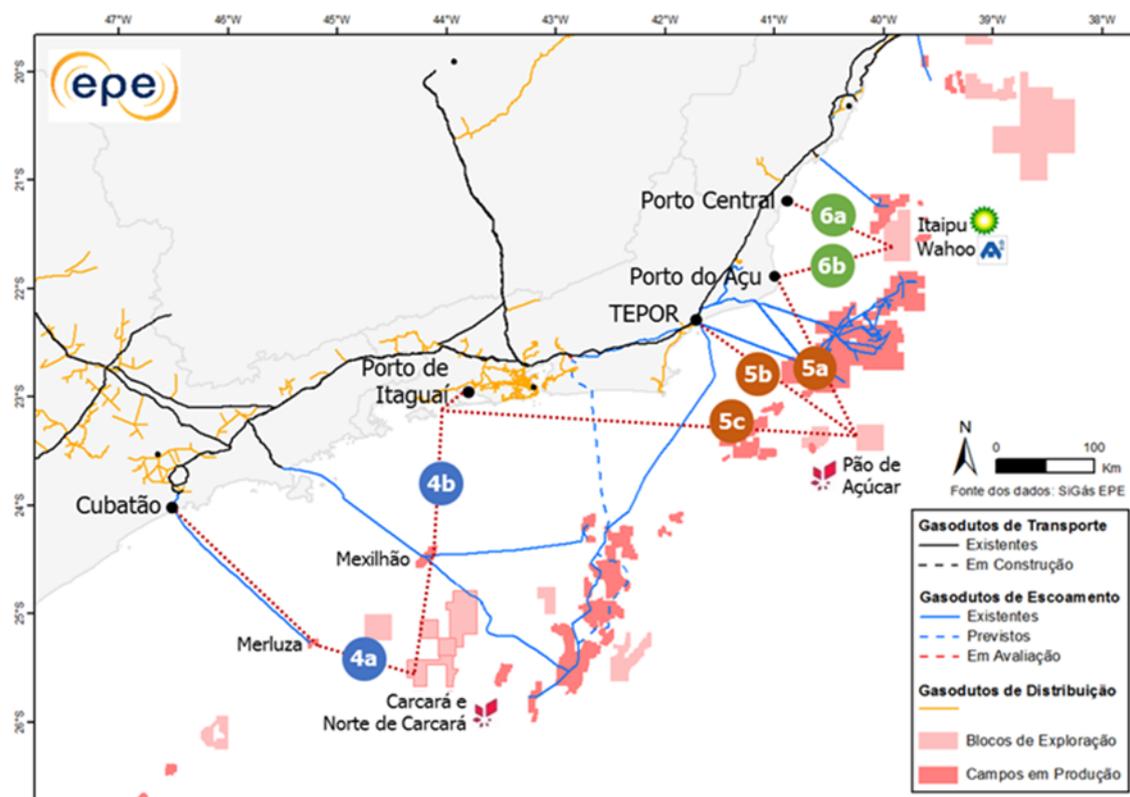

Legend:
Fonte de dados: SiGás EPE = Data source: SiGás EPE
Gasodutos de transporte = Transport gas pipelines
Existentes = Current
Em Construção = Under Construction
Em avaliação = Under assessment
Gasodutos de Escoamento = Flow gas Pipelines
Existentes = Current
Previstos = Expected
Gasodutos de distribuição = Distribution gas pipelines
Blocos de Exploração = Exploratory Blocks
Campos em Produção = Production Fields

Figure 16 – Indication of gas pipelines Routes 1, 2 and 3 – EPE (PIPE 2019)

Some scenarios indicate that the full capacity of the three gas pipelines routes will be achieved by 2025. From this year on, to increase Pre Salt natural gas export to shore, it would be necessary to deploy new gas pipelines in the Santos and Campos basins.

EPE carried out studies seeking to assess options for the outflow of the natural gas from several fields, mostly for the Pre-Salt environment. In the Indicative Plan for Processing and Flow of

Natural Gas (PIPE), 11 indicative projects of gas pipelines connected to NGPUs were mapped, 7 of them based on Pre-salt volumes, and other 4 based on Post-Salt volumes. The gas pipelines are about 2,100 km long, and some of these projects present different options for the evacuation of the gas from the same sedimentary basins (Santos, Campos, Espírito Santo-Mucuri and Sergipe-Alagoas). Considering the construction of only one alternative for each basin, these projects may add more than 77 MMm³/day of export capacity in the Brazilian offshore, in addition to NGPUs with total processing capacity of over 70 million m³/day. Figure 17 presents the projects studied (EPE, 2019c) with respect to the Pre-Salt environment in the Campos and Santos basins.

Legend:
Fonte de dados: SiGás EPE = Data source: SiGás EPE
Gasodutos de transporte = Transport gas pipelines
Existentes = Current
Em Construção = Under Construction
Gasodutos de Escoamento = Flow gas Pipelines
Existentes = Current
Previstos = Expected
Em avaliação = Under assessment
Gasodutos de distribuição = Distribution gas pipelines
Blocos de Exploração = Exploratory Blocks
Campos em Produção = Production Fields

Figure 17 - Gas pipelines studies in the Santos and Campos Basins (Pre-Salt)

The need for infrastructure for the Pre-Salt gas creates opportunities to analyze the feasibility of billionaire projects in offshore gas pipelines into the continent in medium and long term. These are necessary investments to enhance the gas supply by several producers in a competitive environment and to increase consumption by several users with the current and potential demand.

The projects for offshore gas pipelines are complex, demand a long implementation period, after a long economic and financial maturation. They also demand long-term financing, which limits the range of potential funders. Accordingly, in order to avoid bottlenecks in the Pre-Salt natural gas outflow infrastructure as of 2025, there is a need to begin funding and structuring for these projects as soon as possible.

Given the complexity of structuring and funding of such projects, the study group invited the Brazilian National Bank for Economic and Social Development – BNDES to one of its in-person meetings to explain about the report "Gas for Development", which is in the final stage of preparation. At the time, the Bank emphasized the importance of developing a new business model to operate gas pipelines in Brazil, seeking implementation of a gas pipeline infrastructure shared between several oil and gas traders. In this model, the traders and concessionaires, as well as institutional investors, would form a consortium to build the gas pipelines that could be operated by oil and gas producers or, alternatively, by a gas pipeline operator.

In BNDES' vision, the materialization of such business model in Brazil can be supported through a company with a specific purpose (SPC) responsible for the operation of the shared gas flow infrastructure. The concept would be the oil and gas operators and traders to connect the gas production fields to an offshore hub that, from this point on, would provide a gas pipeline with capacity to transfer the natural gas production from several fields to a NGPU onshore.

The SPC would optimize the outflow of natural gas by avoiding investments from a single part. It is important to note that this kind of business model is able to contribute to the development of a competitive natural gas market in Brazil. The model considers the use of the gas pipeline by several producers or traders, enabling to increase gas offer in the Brazilian market, higher competition and lower price to the end consumer.

8. DEMAND FOR NATURAL GAS

Figure 18 presents the forecasts of the Ten-Year Energy Expansion Plan (PDE) for the balance between supply and demand of natural gas until 2029. It is important to highlight that two parameters are taken into account in the presentation of supply and demand data: one that considers the New Market Program and one that does not. Assuming that the investments necessary for the increased supply of natural gas to the market are considerably higher than the investments necessary for heating the demand, there is a likely scenario that, if there are no investments in infrastructure, the demand will be higher than the supply capacity that effectively reaches the market starting in 2025.
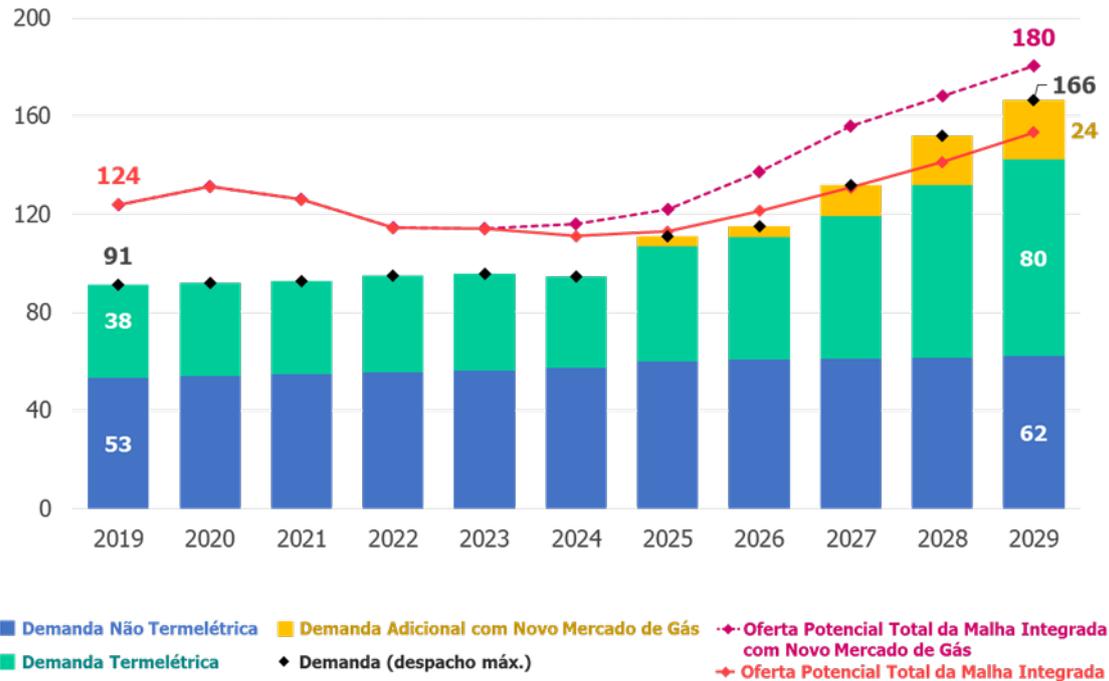
Demanda Não Termelétrica = Non-Thermal Power Demand
Demanda Termelétrica = Thermal Power Demand
Demanda Adicional com Novo Mercado de Gás = Additional Demand with New Gas Market
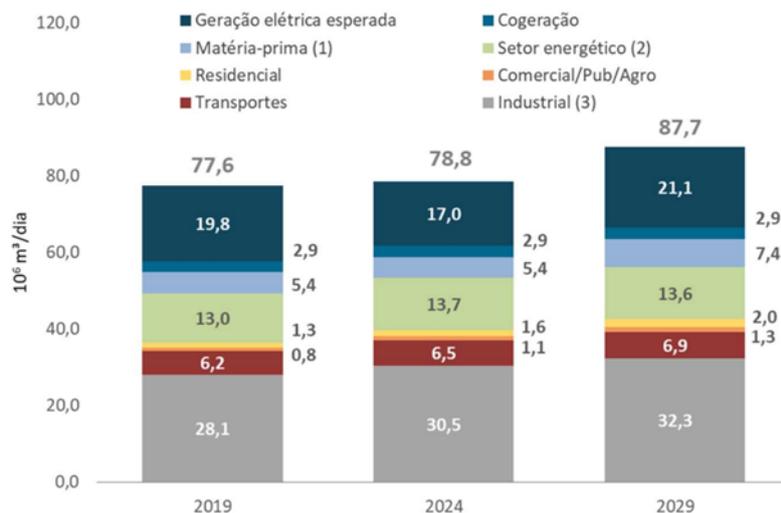Demanda (despacho máx.) = Demand (maximum dispatch)
Oferta Potencial Total da Malha Integrada com Novo Mercado de Gás = Potential Total Offer of the Integrated Network with a New Gas Market
Oferta Potencial Total da Malha Integrada = Potential Total Offer of the Integrated Network

Figure 18 – Expected Balance of Supply and Demand of Natural Gas in Brazil (EPE, 2020)

The Ten-Year Energy Expansion Plan (PDE) forecasts, for 2029, a total consumption of 87.6 million m³/day of natural gas, which represents an additional 10 million m³/day when compared to the 2019 consumption. For the non-thermal power demand, in the next 10 years, it is expected an average annual growth rate of about 1.4% p.a. On the other hand, the forecasted demand of natural gas for electricity generation indicates an increment of 1.3 million m³/day up to 2029, which represents an additional 6.5% when compared to 2019. The estimated consumption per sector can be found in Figure 19.

Figure 19 - Estimated Consumption of Natural Gas in Brazil by Sector (EPE, 2020)

Below there are some considerations on the gas demand, segregated by sector, registered in the study "Gas for Development":

a) Natural Gas for the Industry

The industrial sector is the main firm consumer of natural gas, with high and continuous levels of daily consumption. According to data of the National Energy Balance (BEN), base year 2018, the industry accounted for an average of 35% of the annual demand of natural gas from 2006 to

2018. In 2018, the total consumption of the industry was 34 MM m³/day. With respect to the final consumption of natural gas, which does not include the volume used for power generation and production of petroleum by-products, the industry accounted for more than 50%, approximately 31 MM m³/day.

The natural gas is used in the industry both as a power-generation input and as raw material, especially for the production of methanol and nitrogenous fertilizers (urea, ammonium sulphate and ammonium nitrate). It is also used as a reducing agent for iron oxide in the production of pig iron in steelmaking.

In Brazil, the consumption not related to energy is currently constituted by the chemical industry, which uses the natural gas to produce nitrogenous fertilizers. The final consumption of natural gas as a raw material was of 1.8 MM m³/day in 2018. Still regarding the use of natural gas as raw material, it is worth mentioning the estimated value of 0.7 MM m³/day accounted for energy-related use as well as the use of fractions of natural gas liquids in the production of petrochemicals, 1.5 MM m³/day in 2018. The energy consumption in the industry is mostly directed to generation of thermal energy and driving force, accounting for 28.8 MM m³/day in 2018, while electrical energy self-production in the industries consumed an additional volume of 1.48 MM m³/dia.

The industries of chemicals, ceramics, pig iron and steel, cellulose and paper stand out as the biggest consumers of natural gas, accounting for about 66% of the industrial consumption in 2018, considering the final energy consumption, use as raw material and cogeneration. In the USA, the country with the best conditions of supply and distribution of natural gas, the same group of industries (chemicals, pig iron and steel, food, non-metallic goods, cellulose and paper) accounts for about 87% of the consumption.

b) Natural Gas for Thermal Power Plants

One of the main sources of investment capable of enabling the expansion of the infrastructure for flow and transportation of natural gas comes from the thermal power industry, which, when combined with the potential industrial demand, is able to anchor the expansion in regions not yet serviced. However, most thermal power plants installed in the country operates flexibly, not demanding natural gas continuously and operating only as a backup for the hydro power generation system.

In order for thermal power plants to be able to anchor investments in the natural gas chain, it would be important for new contracts in the electric industry to take into account inflexible or partially inflexible thermal power plants. Additionally, some plants could be implemented in regions that do not have a gas pipeline network and that present a potential industrial demand for gas.

A thermal power plant is characterized as a major consumer, so it is considered the main anchor for the expansion of the natural gas infrastructure. The inflexible thermal power plant helps enabling new gas pipelines for transportation and expansion of the distribution network, since only the operation is sufficient to ensure a reasonable portion of the use of the installed capacity of the new gas pipeline. After implementation of a thermal power plant and a new gas pipeline

to supply it, in a typical process of positive externality, it is natural that the distribution network around this new gas pipeline develops over time, starting to also service new clients in industry, commerce, real property and vehicle industries, until it fully occupies the capacity of the gas pipeline.

c) Natural Gas for Vehicles

In Brazil, the total amount of gas-fueled vehicles reaches approximately 1.9 million, consuming about 5.4 million m³/day of natural gas; light vehicles account for virtually the entire amount. The expectation of expansion of the supply and reduction in the price of natural gas may intensify the consumption by the transport sector. It is possible that, with the international regulation for the reduction in sulfur in the bunker, already effective as of this year, the sea transportation may also become a potential significant market.

Today, the automotive industry anchors its structure to large automaking companies and their suppliers. The industry produces both light vehicles (such as passenger automobiles and light commercial automobiles) and heavy vehicles (buses and trucks). Virtually all globally relevant manufacturers are present in Brazil, and the main ones are manufacturers of heavy vehicles. In Brazil, the heavy vehicles are fueled by diesel, but trucks and buses fueled by natural gas virtually do not exist in the country.

On a commercial scale, there are two different technological routes for the adoption of natural gas as a fuel for heavy vehicles: (i) the Otto cycle engine, developed with a dedicated technology, which uses exclusively natural gas; and (ii) the Diesel cycle engine adapted to operate with a gas-diesel mixture, in different proportions.

From the perspective of storage of natural gas in vehicles, there are two alternatives. The compressed natural gas (CNG), stored by means of compression in cylinders, and the liquefied natural gas (LNG), stored in liquid form. It is worth mentioning that the infrastructure installed in Brazil is not prepared for storing LNG in heavy vehicles. The infrastructure installed is directed to storing CNG in light vehicles, and application in heavy vehicles still requires a long fueling time.

The mastery of the technologies by the automaking companies means that the production and supply capacity for heavy vehicles fueled by gas may be improved in the short to medium term. On the other hand, several factors contribute to the total cost of the ownership of the vehicle fueled by natural gas not being attractive when compared to the option of a similar product fueled by diesel, such as: inefficient infrastructure, fuel cost, low demand for the vehicles, cost of acquisition, and autonomy and resale capacity.

Out of such elements, the lack of a proper infrastructure in the country is the most emphasized aspect. The need for prior investments related to the expansion of the distribution capacity, with an expansion of gas pipelines and inclusion of the rest of the country in the supply, is considered as essential for the market of vehicles fueled by gas.

The infrastructure development effort for vehicle natural gas (GNV) to be used in heavy vehicles in Brazil may take advantage of the European experience, where the so-called blue corridors were implemented – infrastructures for LNG supply for trucks implemented in the main European roads, which connect several countries in the continent. This expansion of the infrastructure of LNG supply in Europe arose from a partnership between companies in the several links of the value chain (oil and gas companies, gas distributors, automaking companies, fueling stations)

together with the government, and aimed at demonstrating the feasibility of LNG as a real alternative for medium to long distance transportation, as a supplement to diesel, at first, and, in the future, as its substitute.

Brazil can organize structuring consortia in order to carry out projects for natural gas supply infrastructure for heavy vehicles. In fact, there are already projects like those in progress, with investments in terminals to receive imported LNG, to import the first vehicles powered by the fuel and to discuss the experimental use of such vehicles with large carriers.

9. FINAL CONSIDERATIONS AND RECOMMENDATIONS

The main objective of the Public Policies defined by the Federal Government for the oil and gas industry as of 2017 was the revitalization of the industry by creating a tax and regulatory environment that enables a better attractiveness for new investors and a more intense competition between the players of all segments of the industry. Among the measures, the definition of an annual schedule for the bidding rounds and the authorizations of the National Council for Energy Policy (CNPE) in order to carry out the public offerings for areas in the concession and production sharing regimes, including the Transfer of Rights Surplus, brought predictability and a new dynamic into the market.

Aligned with the same objectives, attention is called to the joint initiative of the Administrative Council for Economic Defense – CADE – with Petrobras, signing, in July 2019, a Commitment Agreement for Cessation of Practice (TCC) disclosing to the market Petrobras's intention to reduce and optimize its participation in the natural gas sector.

This agreement established the bases for boosting the natural gas market, focusing the increase in the competition, diversification of players, in addition to more dynamism and access to information, foundations that contribute to the construction of a favorable environment to attract new investments. In general, according to item 2.5 of such instrument, Petrobras undertook to refrain from purchasing new volumes of natural gas from partners or from third parties, except if such purchase may enable the production of gas in production fields, in which case it must be reported to CADE and comply with the flow limits established in the abovementioned TCC.

In this context, the production of oil and gas in Brazil has been, in recent months, reaching volume records, exceeding 4 million boe/day (barrels of oil equivalent per day) in January 2020. From this amount, the oil production corresponds to 3.1 million barrels/day, and the natural gas production corresponds to 139 million m³/day, which respectively represent a 20% and 22% increase when compared to the volumes produced in January 2019.

The projections point to the maintenance of the growth pace. According to data from the 2029 PDE, in ten years, Brazil will produce 5.5 million barrels/day of oil (volume that can position the country in the five biggest producers in the world) and 253 million m³/day of natural gas, with investments that can reach 1.8 trillion Reais between 2020 and 2029.

In this scenario, attention is called to the Pre-Salt participation in the production of oil and gas. Currently responsible for 66.4% of the total production in Brazil, in 2029, the Pre-Salt will contribute with 77% of the oil production and approximately 80% of the natural gas production.

In a similar pace, the natural gas reinjection levels increase in the Pre-Salt reservoirs. Figure 9 in this study shows the expected levels of reinjection for the Pre-Salt fields in the Santos Basin, which should increase from about 42 million m³/day in 2020 to about 60 million m³/day in 2023. In this context, it is possible to highlight the motivation to create this study group, which, as recorded in the Introduction, aims at contributing with information on the use of the Pre-Salt Natural Gas, with focus on the increase in commercial use and participation in the country's energy matrix. In order to fulfill its objective, the group focused the work on the "competitive" relationship

between the real increase in the gas reinjection levels in the Pre-Salt over the last few years and the potential volume of gas that may be marketed in the future.

The current choice for reinjection by operators is duly registered and justified in the work. In summary, they are related to: i) reservoir pressure maintenance to increase oil recovery of economics of the projects; ii) high CO_2 content found in a good portion of the Pre-Salt reservoirs; and iii) absence of proper infrastructure for gas evacuation and processing, whose investments may not represent the best economic option for the projects.

Considering the expected increase in the production levels and the factors that justify the operators´ choice to reinject the gas instead of marketing, the State's point of view is that there is an opportunity to assess the need for adjustments in the public policies currently established for the industry.

The CNPE's resolutions mentioned in the Study's Introduction and the discussions brought by the "New Gas Market" Program point to guidelines focused on the increased commercial use of the gas. Actions are planned to promote competition, harmonize state and federal regulations, integrate the gas industry with the electric and industrial sectors and remove tariff barriers that preclude the opening of the market. This set of measures intend to attract investments to the industry in the following years, which will depend on governmental actions of incentive and of regulatory nature. It is important to record the importance that such actions are structured so that the economic attractiveness of the projects is respected, especially for the projects being developed, but still with a long term for execution ahead.

The main factors identified in the Study as obstacles to the increase in the commercial use of Pre-Salt gas are:

1. **<u>Infrastructure</u>**: the infrastructure currently available for the evacuation of the Pre-Salt natural gas should not be enough after 2025, when new investments will be necessary in flow gas pipelines. As those are complex investments, it takes years from the initial conception until deployment and operation, that is, for a new gas pipeline to start operation as of 2025, the feasibility studies should start as soon as possible. Its organization, possibly with several players, will require additional efforts. In order to prevent bottlenecks in the infrastructure as of 2025, it would be necessary to start promoting the organization of such joint projects as soon as possible.

2. **<u>Supply-demand relationship</u>**: the supply of the Pre-Salt gas is linked to oil production, i.e., a firm gas supply. This condition requires the consumption to also be firm, represented especially by the industrial, thermal power, commercial, residential and transport sectors. Without an increase and consolidation of the firm demand, the investors in the oil and gas production fields may continue to choose to reinject the gas in the reservoirs instead of making investments in gas processing and flow infrastructures.

Aspects related to the price and specification (especially the ethane content) of the natural gas also may influence the commercial use of the Pre-Salt gas, but they were not explored in-depth in this Study.

In order to overcome the obstacles, the group suggests further analysis of the impact of the following actions:

- Due to the high investments for gas evacuation and processing, it is recommended, for the Pre-Salt, rather than analyzing each project on its own, to work with a master plan vision, by grouping the development projects in areas next to each other (even if the consortia are different) for using the same infrastructure. It is worth noting that the projects which would potentially use the infrastructure must have coordinated pace and firm commitment with the investment. Each project must necessarily follow the investment schedule, a condition that may imply prepayments and impacts on the economic results. However, this is one possible solution to enhance the commercial use of the Pre-Salt gas;

- The development projects of the Pre-Salt fields should take into account the Net Present Value (NPV) and the investment required for the infrastructure, but also the best use of the natural resource, through a sensitivity analysis for the economic parameters for the several scenarios;

- Considering section 2.5 of the Commitment Agreement for Cessation of Practice between CADE and Petrobras on July 8, 2019, in which the state-owned company undertakes, as of the date of execution of such Term, not to contract new volumes of gas from partners/third parties, we recommend PPSA to perform studies to assess alternatives to sell the Federal Government natural gas in the Production Sharing Contracts to operators or even supply to the market;

- To set guidelines to enable the quantification, in an integrated manner, of the gains associated with gas export by the Pre-Salt projects. Among them, there is the chain effect caused by the gas marketing, including the cost reduction in the industry, increasing the economic activity in Brazil, job generation, tax collection, etc.;

- Investments in Research, Development and Innovation (PD&I) aimed at the progress of technologies, to enhance the gas availability after CO_2 removal and cost reduction for infrastructure deployment, will stimulate investment in alternative projects for commercial use of the Pre-Salt gas;

- As in the regulatory review process that resulted in expressive reductions in natural gas flaring, the review of ANP resolution for the Fields´ Development Plans may establish provisions so that, for fields with a significant natural gas reinjection, the operator must submit a detailed study aiming at determining the minimum reinjection rates over the production period;

- Coordination with the main industries that demand natural gas, aiming at the identification of forms to stimulate projects and investments to ensure a firm demand for the Pre-Salt gas; and

- Consider the BNDES report "Gas for Development", which emphasizes the importance of developing a new business model to operate gas pipelines in Brazil, seeking implementation of a gas pipeline infrastructure shared between several oil and gas

operators. In such model, several oil companies, as well as institutional investors, would form a consortium to build new gas pipelines that could be operated by the producers or, alternatively, by a gas pipeline operator. The implementation of such business model in Brazil could be supported through a company with a specific purpose (SPC) responsible for the operation of the shared infrastructure. The SPC would avoid individualized investments from each offshore field operator, reducing risks and optimizing the whole process. At the end of the abovementioned report, BNDES indicates the possibility of supporting these investments.

Finally, we recommend, in coordination with the Committee for Monitoring the Opening of the Natural Gas Market (CMGN), to assess the convenience and the opportunity to send this Study to CNPE for acknowledgement of the work and evaluation of the proposals contained therein.

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