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INSIGHTS SERIES 2018

Towards a competitive natural gas market in Brazil

A review of the opening of the natural gas transmission system in Brazil

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Executive summary

This report draws on European gas market reform experiences to develop practical recommendations for the implementation of gas market reform in Brazil in two main respects:

- devising and implementing the institutional and regulatory requirements for the establishment of transmission system operators (TSOs) who operate independently from other activities along the gas value chain (unbundling)
- developing and implementing the operational and technical rules based on regulatory policies (network codes).

In addition, recognising the complex nature of gas market reform, the report also includes other recommendations that the review team considered would also underpin the implementation of a well-functioning gas market.

In Brazil, natural gas has the potential to improve energy security and economic and environmental performance. Natural gas demand[1] in Brazil was around 37 billion cubic meters (bcm) in 2016, representing approximately 10% of Brazil's energy mix. With a consumption of 15 bcm in 2016, the power sector accounted for around 40 % of the total gas demand, while industry consumed around 11 bcm (IEA, 2017a). According to the government's projections, the share of gas in Brazil's primary energy mix will increase by 2% until 2026, when it will account for 12% of the primary energy supply of the country (EPE, 2016).

The Gas to Grow programme

Currently, the market for natural gas in Brazil needs to overcome several barriers to bring the benefits of natural gas to households, gas-fired power plants and industrial consumers. With the Gas to Grow (*Gás para Crescer*) programme, the Brazilian government aims to boost gas production and demand by further improving the current market-oriented regulatory framework established under Law 9.478/1997 (1997 Petroleum Law) and Law 11.909/2009 (2009 Gas Law). This programme seeks to ensure non-discriminatory third party access (TPA) for essential facilities (upstream pipelines, gas processing plants and liquefied natural gas (LNG) terminals), as well as to enforce an independent transmission system and to establish entry-exit zones with liquid virtual trading points (VTP). Market integration will be underpinned by appropriate deployment of efficiently used infrastructure, enabling gas to move freely between market areas to the locations where it is most valued by market participants. To promote a competitive market, a reduction in the dominant position of the state-controlled company Petrobras is foreseen through a partnership and divestment programme (*Programa de Parcerias para Investimentos* - PPI) and by introducing market-oriented measures including new tax rules for natural gas downstream, more flexible licensing procedures for the construction and operation of gas pipelines and integration of the gas and power markets.

Until now, Petrobras has been able to match the supply and demand of natural gas through the vertical integration of its activities along the value chain and long-term contractual arrangements for supply, imports, transportation and trading activities. Besides having a share of approximately 80% of total national gas production and supplying more than 90% of the gas consumed in Brazil, Petrobras controls and operates almost all offshore pipelines and all processing plants. It also books almost all existing transport capacity, holds shares in 19 of the 27 distribution companies

[1] Refers to total final consumption in transport, industry, services/commercial and households, power generation and energy industry own use. Figures produced by the Brazilian government may differ from IEA data.

and consumes around one-third of all gas volumes available in the country. Around 97% of all gas volumes in the wholesale market are currently traded on the basis of long-term contracts with Petrobras. Despite the fact that prices of natural gas in this market can freely be negotiated, the existence of long-term bilateral contracts with all distributors and large industrial consumers is one of the reasons Petrobras has maintained a dominant influence in the price formation of the country.

Currently, other producers do not have access to upstream pipelines or gas processing plants, which prevents them from selling their gas directly to customers via the transmission network. Petrobras is the sole contracting user of firm transmission capacity in the market. Gas producers without processing and transportation capacity sell their gas to Petrobras who then trade the volumes domestically. The counterparts for Petrobras' gas sales agreements include power plants, power plants with the intermediation of local distribution companies (LDCs), and the LDCs themselves. Industry end-users, with exception of Petrobras refineries and fertilizer plants, are supplied by the LDCs.

Brazil is now undertaking further steps towards unbundling, with the divestments carried out by Petrobras, and the establishment of new system operators who have been able to acquire parts of the national natural gas transportation and distribution systems. Further progress in fully separating production and trading from transportation activities is to be welcomed. European experience shows that certification of system operators by the regulatory authority provides a useful tool to ensure this process takes place without placing too much burden on the system operators.

In principle, if the institutional and regulatory proposals presented in the Gas to Grow programme are successfully implemented, the prospects for a competitive wholesale natural gas in Brazil are promising, as the use of gas is set to expand in the country. The potential to increase domestic gas production and gas demand, and the presence of different gas sources (domestic production, pipeline imports from Bolivia and LNG imports) are favourable conditions to develop a competitive wholesale market. With these positive opportunities, Brazil is currently witnessing an increasing number of foreign investments in the sector, including in the transmission infrastructure. The country is also offering new opportunities for oil and gas exploration investments. The bidding rounds in 2017 and 2018 were a significant success, generating together around R$ 21 billion in signature bonuses. The extent to which Brazil will be able to reap the benefits of a competitive gas market will depend on the quality of the regulatory framework which is yet to be put in place and the decisiveness of its subsequent implementation. This report addresses the specific Brazilian challenges for the regulation and implementation phase, drawing upon the lessons learnt from European experience.

The challenges

During the reform process a major challenge for the Brazilian government will be to avoid a situation in which the gas infrastructure divestment programme leads to exclusive rights being given to individual purchasers, especially with respect to access to this infrastructure, thereby undermining the development of a competitive gas market. Such a scenario could slow down the positive transformation of the Brazilian gas market resulting from greater unbundling, an increased use of LNG and planned auctions of transmission capacity. It will be important to avoid the development of a privatised market with semi-monopolistic players, or one where an undue proportion of transmission capacity and capacity contracts remains with the incumbent. Making the grid accessible to third parties (one of the main elements of the reform) should remain a key consideration of future reform.

Currently all transmission capacity in Brazil is contracted under long-term point-to-point contracts. For the development of competition within the new entry-exit zones it is therefore crucial that the existing point-to-point capacity contracts are amended to entry- and exit capacity contracts and that – as far as possible – a considerable proportion of the available capacity falls in the hands of the new TSOs who can then offer this capacity to new entrants on a non-discriminatory basis. At the same time, the government should also make optimal use of new opportunities, such as the 2019 expiration of existing long-term contracts with Bolivia, to increase market access of new entrants and diversify supply to the Brazilian market.

Following the divestment of parts of the transmission system by Petrobras, the current level of system integrity and security of supply as provided for by Petrobras will need to be maintained through explicit regulation. In this context, network codes will need to set clear rules regarding the interoperability of the interconnected systems as well as the information exchange between TSOs, LNG system operators, upstream infrastructure operators and LDCs.

Taking into account that one of the main aims of the reform is to attract investments for the expansion of the transmission system to meet the expected increase in gas peak demand in Brazil, the government will need to introduce a model of economic regulation that ensures a reasonable return for investors based on a fair allocation of risks between the TSOs and other players in the market. Furthermore, an appropriate methodology to determine the entry and exit tariffs that provides locational signals for efficient investment needs to be established.

Within the federal structure of the country, consisting of 26 states and a federal district, the harmonisation of gas trade and operation of the gas infrastructures across the country will be one of the main tests faced by the reform in the longer-term. Taking into account the responsibilities and competencies of the states concerning gas infrastructure, a mechanism to coordinate or harmonize access and operational security terms and conditions for federal and state level infrastructure may eventually be required, but its current absence should not prevent progress from being made in reforming the market in the interim. In this context, the experience in the European Union (EU) seems to be of particular relevance, even if one cannot directly compare the European Commission (EC), a supranational institution, with the Federal government of Brazil. However, in creating or maintaining a competitive gas market, both face a need for coordination and harmonization across different regulatory areas. The EU gas market reforms proceeded in a gradual manner. The trajectory followed by the EU first involved passing legislation that set out the goals that all EU countries had to achieve, but left it up to the individual countries to legislate on how to reach these goals. Subsequently it led to a process of binding regulation, which had to be applied in its entirety and uniformly across the EU.

Lessons from European experience

European experiences of gas market reform provide relevant lessons for Brazil, but effective implementation depends on local policy objectives and on an in-depth understanding of the Brazilian gas market. Some specific policy and regulatory solutions that were effective in Europe may not be directly applicable in Brazil, as the two faced a different set of challenges.

At the start of the reform, natural gas demand in most of continental Western Europe was not expected to increase considerably. Brazilian domestic supply and demand, on the other hand, are expected to grow over the next decades, resulting in increased infrastructure needs. Moreover, domestic supply and demand patterns are also changing, partly due to growing associated gas production and the need to balance increased intermittent renewable generation, respectively.

European experience strongly suggests that the ultimate success of the reforms undertaken in the Gas to Grow programme will depend on the resolve and long-term ambition of government to allow markets to effectively determine natural gas prices without interference, based on short-term or other political considerations. Institutionally, this means a further shift from direct policy intervention and market involvement to an emphasis on regulation and monitoring of the activities of market participants. In order to implement the market reform programme in full, the regulatory authority (*Agência Nacional do Petróleo, Gás Natural e Biocombustíveis* – ANP), will need the necessary tools to play this role as it oversees the unbundling already occurring in the vertically integrated incumbent, Petrobras, and the establishment of new independent system operators.

The separation of transmission from exploration, production and trade is essential for the realisation of an efficient, competitive and well-functioning Brazilian gas market. European and wider experience shows that transmission and distribution are "natural monopoly" activities that need to be regulated. Competition in production and supply is based on non-discriminatory access to infrastructure and a market governed by a stable, non-discriminatory and transparent regulatory environment. These conditions are also essential to attract new market participants and investment.

To ensure competition, unbundling of vertically integrated firms is a necessary condition to guarantee effective TPA to essential infrastructure, gas transmission networks and, where possible, distribution networks. In most EU markets, market reform focused on the transmission sector in the first stage before moving on to the distribution sector.

Experience in Europe shows that several models of unbundling are available to create TSOs who operate independently from other activities along the gas value chain and that different unbundling models can co-exist in the same market. Full ownership unbundling (OU) and the independent transmission operator (ITO) models are the most common implemented models in Europe, but others are also used.

Brazil might eventually apply OU as this is the most effective and transparent model. However, on the road towards the OU model, Brazil could also consider implementing the ITO model as an intermediary step, since the OU model is also the most complex and costly to implement in the case of existing vertically integrated companies. The ITO model might be the best suited for rapid implementation as it avoids the often cumbersome process associated with the unbundling of vertically integrated companies. The downside is that the ITO model requires stronger regulatory oversight in order to ensure that the activities of the overall group of affiliated companies are and remain separated, whereby all contracts between the vertically integrated undertaking and the ITO require approval by the regulator.

On the network codes side there are also challenges of implementation. At the legislative stage it is important to plan carefully to ensure that the law anticipates the use of network codes in gas market regulation. A second challenge arises from the federal nature of Brazil and thus the need to avoid a possible proliferation of incompatible, state-level network codes which may make harmonisation of regulation more difficult over time. In the EU, the network codes greatly enhanced standardisation by effectively overriding existing domestic rules, including national laws and regulatory frameworks. In Brazil, they could potentially not only manage trade between zones, but more broadly help to harmonize broader regulations across federal states and/or trading zones. To achieve this outcome, a thorough legal study, including of constitutional barriers, would be required to explore the potential application of the instrument of network codes in the Brazilian context. Finally, an important lesson from European experience is that development of the codes requires close consultations with TSOs. In the EU, the European Network of Transmission System Operators (ENTSOG) was charged with the drafting of the codes, which helped to ensure their applicability across Europe. This drafting was based on guidelines developed by the European Agency for the Cooperation of Energy Regulators (ACER).

Key recommendations

Based on the experience of European gas market reform and taking into account specific Brazilian circumstances, the government of Brazil should:

General steps

- Recognise the long-term nature of successful gas market reform and continue to build consensus among all the relevant stakeholders in support of a transparent, competitive and liquid gas market.
- Build further on the steps taken under the partnership and divestment programme of Petrobras by proactively fostering the entry of new players into the market whilst ensuring that no exclusive rights are given to individual companies that could undermine the development of a competitive gas market.
- Establish a consistent and stable set of mandatory rules to be applied across all market areas. Where regulatory responsibilities exist at both the federal and state levels, establish mechanisms to allow for nationwide coordination – and harmonization in the medium term.
- Develop a long-term implementation strategy that recognises the important role individual states and highlights the local benefits of market opening, allowing them to liberalise in line with their circumstances and priorities and facilitating interconnection with other states or trading zones over a common time frame.
- Further improve existing law and regulation to ensure non-discriminatory TPA to transmission (and, where possible, distribution systems) and negotiated TPA to upstream pipelines, gas processing plants and LNG terminals, and establish entry-exit zones with liquid virtual trading points.
- Within the new regulatory framework, take into consideration the need for new energy data collection mandates and support systems (e.g. prices, flows, and investment data).
- Provide the independent regulator with the necessary powers to develop and monitor the implementation of the new regulatory framework and to enforce changes as required. The regulator should also be appropriately resourced and independent of the influence of energy policy makers.

Unbundling approach and related steps

- Use available unbundling models to establish TSOs that operate independently from other activities along the gas value chain, in order to ensure transparent TPA to the transmission system. It is not necessary to opt for one specific unbundling model as the case of Europe shows.
- Charge the TSOs with developing long-term investment plans subject to the approval of the independent regulator.
- When certifying the independence of TSOs, establish a regulatory requirement that they are equipped with all the human, technical, physical and financial resources necessary for carrying out the activity of gas transmission.
- Ensure the new regulatory regime includes mechanisms that allow the market to signal where investments are needed and provides TSOs with a predictable framework for generating sufficient revenues to recover the costs of the infrastructure. Auctions and open season procedures should be designed to facilitate trade between different zones, by applying market-based investment procedures for offering incremental and new capacity.

- In order to create liquid market conditions, some degree of regulatory flexibility may be justified in order to attract major investments in new infrastructure. Such flexibility should only be granted in a transparent manner and only during a defined transitional period.
- Maximise the transmission capacity offered to the market and mitigate contractual congestion, by introducing congestion management and capacity allocation measures to make sure, for instance, that capacity that is contracted (booked) but will not be used becomes (again) available to the market.

Introducing Network Codes

- Safeguard the integrity of the system during the process of moving away from a vertically integrated supply system. In this respect, introduce network codes that set clear rules regarding the roles and responsibilities of the individual actors, e.g. in terms of the interoperability of the interconnected systems as well as the information exchange between TSOs , LNG regasification terminals operators, upstream infrastructure operators and LDCs.

Entry / exit systems

- If possible introduce entry-exit systems and the set of corresponding network codes at the same time. Experience in the EU shows that the development of network codes in a transparent and inclusive manner requires time. Taking this and the subsequent implementation period of these network codes, this suggests that entry-exit systems could be introduced over the next few years.
- Analyse the feasibility of setting up an entry-exit zone comprising more than one TSO, i.e. ideally a multi-TSO entry-exit zone comprising all interconnected TSOs. In the first phase, each of the TSOs could implement an entry-exit zone for its own transmission system. A roadmap for merging of single-TSO entry-exit zones towards that multi-TSO entry-exit zone should be established by the regulator ANP at an early stage.

Capacity allocation and congestion management

- To the extent that Petrobras' ongoing and/or expiring transmissions contracts allow, put in place a regulated and transparent mechanism to facilitate the freeing-up of capacity to allow market entry for new players.
- Introduce network codes that apply to all transmission contracts, i.e. existing and new contracts. Rules regarding securities as collateral for payment obligations under capacity contracts should equally apply to all network users.
- Amend existing point-to-point capacity contracts for transportation capacity to the entry-exit model. This is a necessary condition to develop competition within the new entry-exit zones. When amending existing transportation contracts to entry-exit capacity contracts, ensure that there are no material negative economic impacts on the parties involved and that the main elements of those contracts do not substantially deteriorate.

Balancing

- Introduce a system of balancing portfolios (or balance groups) that allow for a grouping of a network user's inputs and off-takes. Commercial balancing should be done on the basis of balancing portfolios, not individual transmission capacity contracts.
- Where possible introduce balancing zone(s) that comprise the transmission as well as the distribution level. If not possible, as an intermediary step, a trading region concept could be introduced which covers only the gas transmission system(s) and thereby establishes a "trading

balancing zone". It is essential for the balancing system to work properly that the principle "allocated as nominated" is applied at all entry and exit points. Petrobras could temporarily act as balancing shipper for the interim phase until operational balancing accounts are implemented at all entry and exit points.

Virtual trading point

- Take measures that ensure the firmness of trading activities at the VTP (e.g. by putting obligations on Petrobras to ensure base liquidity). This is also an important requirement for an organised gas market to develop, i.e. for brokers and exchanges to become active. For independent gas producers, a key criterion for investing in the Brazilian upstream sector might be that the gas produced can be efficiently marketed close to its production. For that purpose, a liquid VTP within the entry-exit zone(s) is a key requirement.

Other important steps

- Include obligations related to network development planning into the future regulatory framework, to allow for planning and coordination of long-term infrastructure developments by the regulator.
- Introduce a system for a fair allocation of volume risk between the TSO and the market. In order to achieve this goal, ANP could take a stepwise approach by applying price cap regulation before moving to non-price cap regulation as the market develops over time.
- Introduce a regulatory framework that allows for a proper sharing of the risk of future revenue under/over recovery between network users. Consideration should be given to whether the tariffs for entry and exit capacity should be fixed for the duration of the contract term (fixed prices) or subject to changes based on future increases or decreases in the allowed revenues of the TSO (i.e. floating prices). We recommend applying floating prices as a default rule and allowing only for the application of fixed prices in the case of incremental capacity. Fixed prices provide greater tariff stability for long-term capacity bookings and as a consequence a more stable system usage, so a TSO's willingness to invest in incremental capacity would probably increase.
- Conduct an inquiry into competition in the Brazilian gas market a few years after the entry into force of the gas market legislation to assess the effects of the reform and whether additional steps are needed to meet its objectives.
- Together with the development of a regulatory framework for the gas sector by ANP (*ex ante* regulation) based on the Gas to Grow bill, competition law measures (*ex post* regulation) should be applied by the *Conselho Administrativo de Defesa Econômica* (CADE), if necessary.
- Consider whether ancillary measures are necessary to support the development of a gas market, such as by reforming the rules applied in the electricity sector.

Duration of reform steps and phasing of reform[2]

- While the specific timing and sequencing of steps is beyond the scope of this report, several streams of the reform can be performed in parallel with different actors in the lead, including:

[2] Timeframes given in this section are based on European experience and assume supportive political and regulatory implementation action.

- 1 - Guaranteeing TPA for essential facilities
    - Ensure that upstream producers can access gas processing units.
    - Access to LNG terminals.
- 2 - Amending existing contracts to entry-exit model
    - Petrobras and the TSOs reviewing the global portfolio of gas transmission agreements (GTAs) and developing proposals on amending the existing point-to-point capacity contracts to the entry-exit model.
    - Petrobras and the LDCs renegotiating all gas sales agreements (GSAs) to split them into capacity contracts and commodity contracts at the city gates. Ideally, the delivery point of the commodity contracts should be the VTP.
    - Enhancing TPA to the gas infrastructure, for instance by introducing (temporary) capacity and commodity release obligations for Petrobras.
    - ANP developing and consulting a methodology for setting entry and exit tariffs. These tariffs will be a relevant element in the renegotiations of the GSAs.
- 3 - TSOs preparing the applications for certification based on one or other of the unbundling models and applying for approval by ANP.
- 4 - ANP, with support from the TSOs, to develop and consult on guidelines for network codes with stakeholders, including:
    - rules for the allocation of available capacity, e.g. on the TBG system from January 2020.
    - implementing effective congestion management procedures (e.g. capacity surrender) that apply under the entry-exit system.

  The network codes themselves could subsequently be developed in close collaboration between ANP and the TSOs.

- Based on experience in Europe, it is reasonable to assume that the TSO certification procedures as well as the network code development will take approximately 2 years.
- Fulfilling the certification requirements by TSOs may require an implementation lead time of approximately 1.5 years. Implementation of the network codes, e.g. establishing the information technology (IT) infrastructure and data exchange interfaces could be done in parallel and may require an equivalent period.
- This suggests that the main elements of the reform could be implemented between 3.5 to 4 years from the passage of the relevant reform legislation.

Introduction

This report is the result of a technical peer review of Brazil's natural gas market carried out by an international team of experts assembled by the International Energy Agency (IEA). The review visit team was composed of senior experts from Austria, the Netherlands, Spain and the UK supported by members of the IEA Secretariat. Through this peer review, the IEA aims to support Brazil's development of a new gas market design under the Gas to Grow programme. The peer review was supported through a voluntary contribution from the UK to the IEA.

The IEA review team held two jointly-organised workshops in Brazil between the 23 -25 January 2018 with representatives of the Brazilian Ministry of Mines and Energy (MME), the national energy planning body (*Empresa de Pesquisa Energética - EPE*) and the Brazilian national regulatory agency of Petroleum, Natural Gas and Biofuels (*Agência Nacional do Petróleo, Gás Natural e Biocombustíveis - ANP*). The IEA team also held two separate meetings with representatives of Brazilian industry and academia. The aim of these workshops and meetings was to reflect on the gas market reform in Brazil by sharing international experience from IEA country experts and Secretariat.

A draft version of the executive summary of this report was discussed at an IEA workshop in Brazil on 23 August 2018, which brought together more than one hundred and twenty local stakeholders from government, academia and the private sector. The report was subsequently finalized for submission to the Brazilian government.

The gas market reform in Brazil, including the legislation currently before the Brazilian Congress, has been strongly influenced by similar recent reforms in the EU. This report sets out the lessons of European experience and best practice, taking into account the specific challenges in Brazil and presents recommendations for the reform implementation phase to achieve a liquid and well-functioning Brazilian gas market.

This report also focuses on specific topics of relevance for the Brazilian government in relation to the reform process and contains practical recommendations on how to:

- Successfully implement the institutional and regulatory requirements for the establishment of TSOs who operate independently from other activities along the gas value chain (unbundling)
- Develop and implement operational and technical rules based on regulatory polices (network codes).

The following sections focus on:

- The government's Gas to Grow programme in the context of the Brazilian gas market
- Possible lessons for reform implementation in Brazil from the experience with gas market opening in the EU, focusing on two main aspects: unbundling of the natural gas system in Brazil and the introduction of network codes.

The Gas to Grow programme and the opening of the gas transmission system in Brazil

The Brazilian market context

Prospect of reform: supply and demand aspects

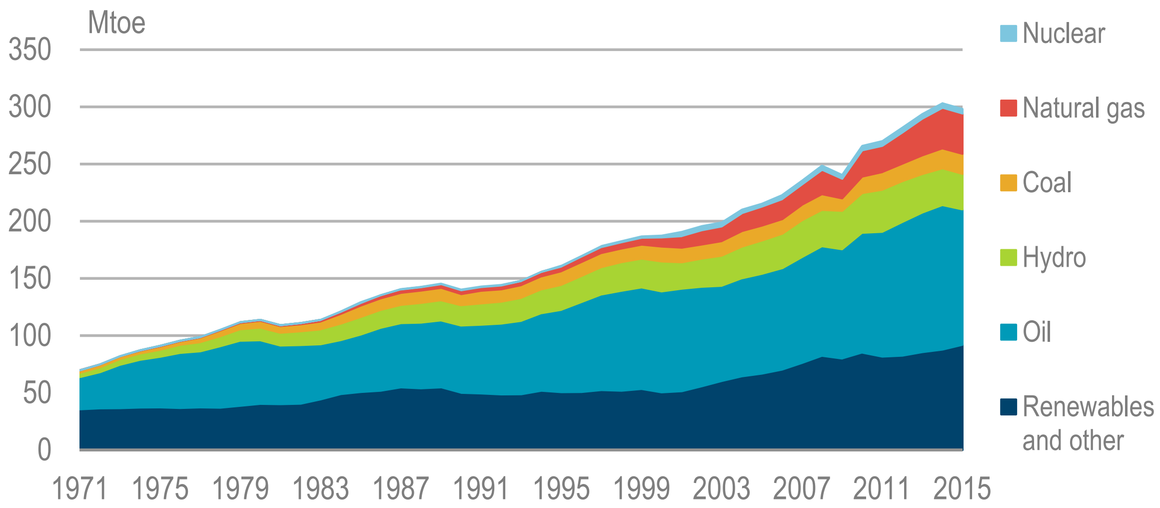
In 2016, the Brazilian government launched the Gas to Grow programme to boost gas production and demand in the country by further improving the current market-oriented regulatory framework. The potential for increased local production and demand, as well as the presence of diversified sources of supply (domestic resources, pipeline imports from Bolivia and LNG imports) are favourable conditions to develop a competitive wholesale market in the country. In principle, the prospects for a competitive wholesale natural gas in Brazil are promising and important elements are present to expand the use of gas in the country.

Natural gas demand[3] in Brazil was around 37 bcm in 2016. The fuel accounts for around 10% of Brazil's energy mix. With a consumption of 15 bcm in 2016, the power sector used around 40 % of the total volume. Until 2011, the industrial sector had traditionally been the main gas consumer in the country. In 2016, industry consumed around 11 bcm, accounting for one third of the total volume (IEA, 2017a). According to the government's projections, the share of gas in the primary energy mix will increase by 2% until 2026, when it will account for 12% of the primary energy supply of the country (EPE, 2016). In the medium-term, the growth will be primarily caused by more use of gas by industry due to the economic recovery and more residential consumption following investments in transmission and distribution networks (IEA, 2018). Currently, only around 8% of the 5.570 municipalities are connected to the gas network, accounting for no more than 3 million of the country's 68 million residences. The transportation sector will see only a slight increase due to the tendency of lesser Compressed Natural Gas (CNG) conversions in the light vehicle fleets. The contribution of natural gas to power generation is expected to decline as less gas-fired power is dispatched due to the normalisation of hydrological conditions and growing renewable capacity (IEA, 2018).

Due the severe drought experienced in the country and the significant decrease in hydro generation (from 81% to 62% of overall production in the period 2011-2015), the increasing role of gas-fired generation in the power generation mix has pushed natural gas demand beyond Brazil's traditional supply sources, i.e. indigenous production and pipeline imports, mainly from Bolivia via the Bolivia-Brazil pipeline (*Gasoduto Bolívia-Brasil* – GASBOL). With more than of 75% all gas volumes produced in association with oil as of 2017, the ramp-up of new oil production facilities in the Santos Basin has been a major driver for gas output. Around 80% of the gas output is extracted offshore. In February 2018, 95% of oil and gas production in the country came from fields operated by state-controlled national oil company Petrobras (ANP 2018a).

[3] Refers to total final consumption in transport, industry, services/commercial and households, power generation and energy industry own use. Figures produced by the Brazilian government may differ from IEA data.

Figure 1 • Total Primary Energy Supply in Brazil (1971-2015)

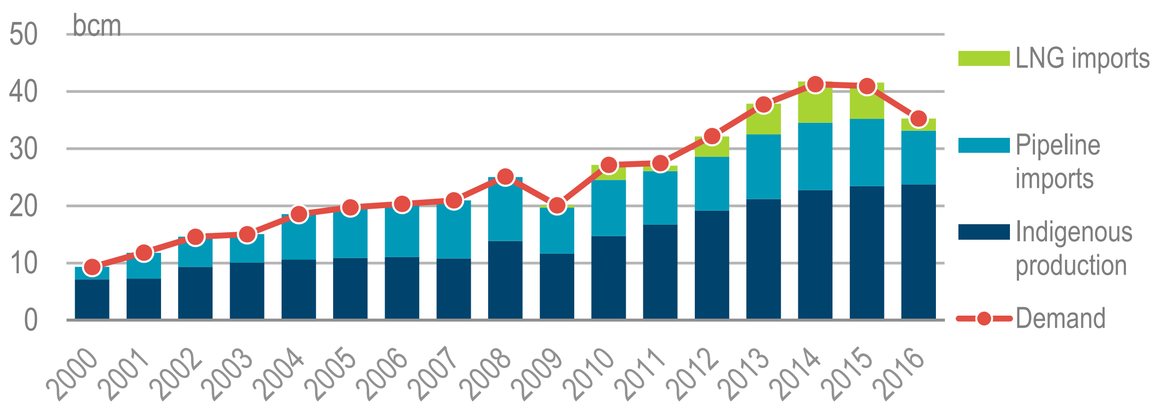


Source: IEA (2017d), World Energy Balances 2017 (database), www.iea.org/statistics/.

With new opportunities, Brazil has also witnessed increasing foreign investment in the sector. Since the 1970s, Brazil's gas production has been growing steadily and in the last nine years gas output accelerated, with an average yearly growth rate of 11%. Until about a decade ago, associated gas was seen as little more than a by-product of oil production and was mainly re-injected to enhance oil recovery. In the context of increasing demand, associated gas now has a crucial place in the energy mix of the country, despite its limited current production. Brazil aims to double its natural gas output by 2030 and to increase the number of producing states (from 8 to 16). To reach this goal, the government presented a schedule for the period 2017-2019 for nine oil and gas bidding rounds. The successful 2017 and 2018 rounds generated around R$ 21 billion in signing bonuses, reflecting the regulatory changes introduced in the country to make the investment climate more attractive for new investors. For the 14th bidding round, several rules in the concession regime were simplified, such as the introduction of a single exploration phase, the relaxation of local content requirements from the bidding criteria and the extension of the tax incentive regime.

In 2016 Brazil produced 25 bcm, covering almost 70% of domestic demand, with pipeline imports from Bolivia making up the large majority of total imports (Figure 2).

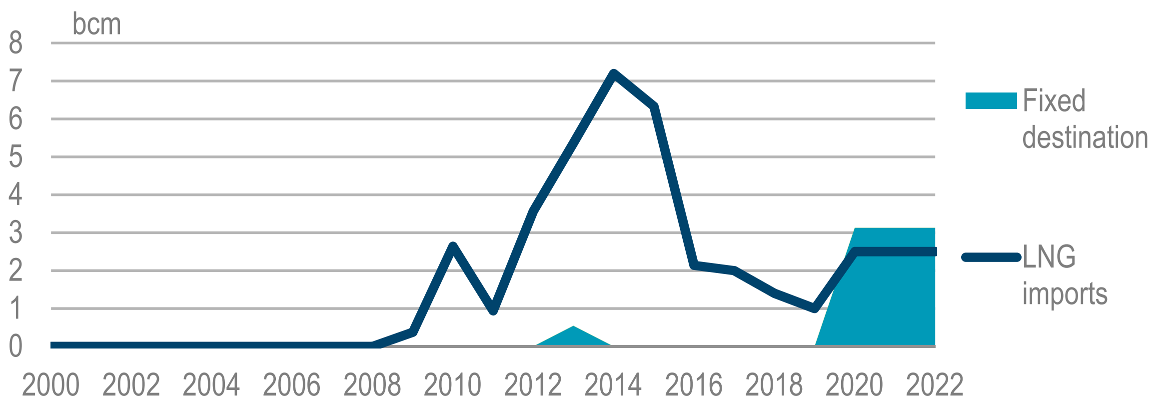
Figure 2 • The gas market in Brazil (2000-2016)



Source: IEA (2017b), Global Gas Security Review 2017, OECD/IEA, Paris, https://www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2017.pdf

LNG demand in Brazil is closely linked to hydro availability, with thermal generation increasing in dry years, such as 2014. The contribution of natural gas to power generation is expected to shrink in favour of growing intermittent renewable generation (IEA, 2018), which will influence the flexibility requirements that must be met by gas-fired generation. A number of projects have been called upon to keep providing this flexibility in the future. These projects, known as LNG-to-wire, have business models based on integrated solutions combining combined-cycle gas turbines (CCGTs) with dedicated floating storage regasification units (FSRUs). The first LNG-to-wire project to take final investment decision was Porto de Sergipe, in country's north-east. This project comprises a FSRU terminal with a 1.5 GW CCGT. It was awarded with a power purchase agreement in the A-5 auction in 2015, is expected to come on line by 2020 and would include long-term LNG supply contracts (of 25 years), as reflected in Figure 3.

Figure 3 • LNG contracted volumes and LNG imports in Brazil (2000-2022)



Source: IEA (2017b), Global Gas Security Review 2017, OECD/IEA, Paris, https://www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2017.pdf.

Beside the Sergipe terminal under construction, there are two other terminals planned – all of them owned/planned by new entrants. These new LNG terminals will provide additional supply, flexibility and market contestability.

Current market organization: legal framework and the role of Petrobras

The Brazilian constitution establishes that the local distribution network business and regulation are under the jurisdiction of the individual states (1988 Federal Constitution of Brazil - Art 25, paragraph 2), while upstream and mid-stream activities are subject to federal regulations.

At the federal level, the legal framework for natural gas in Brazil has been developed gradually since the end of Petrobras' monopoly in the mid-1990s. Due to the prominence of associated natural gas in the country's production, the changes introduced by the 1997 Petroleum Law did not distinguish between oil and natural gas. The 1997 Petroleum Law mandated that Petrobras create a subsidiary to build and operate its pipelines, maritime terminals and vessels to carry hydrocarbons and its products. As such, lawmakers intended to separate the transportation activities from the other segments, but without imposing any cross-ownership limitations. In compliance with the legal requirement, Petrobras set up two wholly-owned subsidiaries: Transportadora Associada de Gás S.A. (TAG), which owned the pipelines, and Transpetro, which operated them.

The development of the natural gas market in the country highlighted the need for a specific law for natural gas, which came with the 2009 Gas Law and was followed by a number of decrees and

ANP resolutions in the following years, introducing market-oriented features. The law established regulated TPA to the transmission network but not to other essential facilities (such as upstream pipelines, processing facilities and LNG terminals). This TPA had to be negotiated between producers and transporters, and the ANP would step in and set the price for the service only if the involved parties could not strike their own bargain. This made it virtually impossible for independent producers to access the transport infrastructure, leaving them no choice but to sell their production to Petrobras.

A significant number of states, including Rio de Janeiro, São Paulo and Bahia, have established local regulatory agencies to monitor the operations of the LDCs, but these can be subject to political interference. Other states have not set up such agencies, and local distribution services are regulated by branches of the local executive powers.

Some of the provisions of the federal laws have not been effectively translated into local regulations. An example of this is the ''figure of free consumers[4]'', introduced by the 2009 Gas Law at a federal level, which allows consumers to switch suppliers. This has had limited implementation, and it only applies to customers with very large consumption volumes.

Currently, there is only one gas sales agreement in place in the Brazilian integrated gas system under the free consumer figure, to the UTE Santa Cruz thermal power plant, owned by Furnas, a federal government controlled company.

Federal split of competences: an ongoing legal debate

Whether the state monopoly granted by the Federal Constitution includes the commercialization of the commodity or relates only to the distribution service is currently subject to current debate in Brazil. The current legal understanding is that the Federal government can introduce mandatory rules up to the state city gates only. According to this understanding, the Federal government can neither introduce mandatory rules across the whole country for local distribution network businesses and regulation nor regarding *Imposto sobre Operações relativas à Circulação de Mercadorias e Prestação de Serviços de Transporte Interestadual e Intermunicipal e de Comunicação* (ICMS, a state value added tax), which are both under the jurisdiction of the states. Moreover, the *Imposto Sobre Serviços de Qualquer Natureza* (ISS, a service tax) is under the jurisdiction of the Municipalities, as per the 1988 Federal Constitution.

Petrobras de-facto monopoly

The natural gas market in Brazil has historically been controlled by Petrobras, whichplayed a major role throughout the natural gas value chain. In addition to producing over 80% of the domestic gas output, Petrobras was practically the only natural gas supplier to the market, as it purchased and marketed practically all the remaining production and all of the country's natural gas imports.

Through its subsidiaries TAG and Petrobras Logística de Gás S.A. (Logigás), Petrobras has controlled most of the country's transmission infrastructure. Before its PPI programme, the company had stakes in over 95% of the transport network and all LNG import terminals. Petrobras operated 69% of the country's transport network – as well as all regasification capacity - through Petrobras Transporte S.A. (Transpetro). The remainder is mainly operated by TBG, where Petrobras owns a 51% stake.

[4] Law 11.909/2009 (Gas Law) defines free consumers (*consumidores livres*) as "natural gas consumers who, subject to the applicable state legislation, have the option to acquire natural gas from any producer, importer or trader".

Petrobras also has stakes in over three-quarters of the country's state-level distribution companies either directly or through Petrobras Gás S.A. (Gaspetro), a subsidiary.

Table 1 • The natural gas transmission sector in Brazil

<table>
<tr><th></th><th>Ownership</th><th>Operation</th></tr>
<tr><td>TAG</td><td>100% Petrobras</td><td>Petrobras (through Transpetro*)</td></tr>
<tr><td>TBG</td><td colspan="2">51% Petrobras (through Logigás*)
29% BBPP Holdings Ltda.
12% YPFB Transporte do Brasil Holding Ltda.
8% GTB-TBG Holdings S.A.R.L.</td></tr>
<tr><td>NTS</td><td>10% Petrobras
90% Brookfield Infrastructure Partners</td><td>contracted to Petrobras
(through Transpetro*)</td></tr>
<tr><td>TSB</td><td colspan="2">25% Petrobras (through Logigás)
25% TotalFinaElf
20% Ultrapar
15% Repsol
15% Tecgás</td></tr>
<tr><td>GOM</td><td colspan="2">99% Zetta Lighting**
1% J&F Investimentos</td></tr>
</table>

* Transpetro and Logigás are wholly owned by Petrobras.

** Zetta Lighting is a subsidiary of J&F Investimentos

Source: Adapted from MME (2016), Gas para crescer - Relatório técnico, http://www.mme.gov.br/documents/10584/4033411/0.Gás+para+Crescer_Relatório+Técnico.pdf/91716743-86ae-44e9-a838-c850a1f5d6cb.

Gas pricing

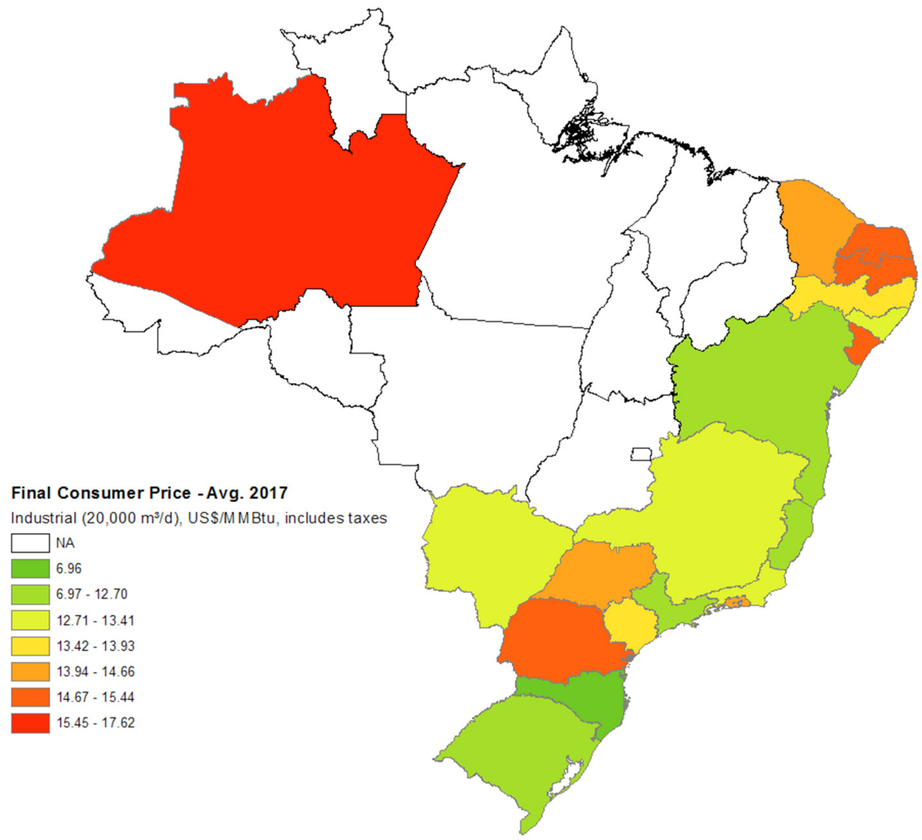
Prices of imported pipeline gas are stipulated in the long-run contract with Bolivia (GASBOL GSA) and, in this contract, the gas price is indexed to oil prices plus a fixed fee, annually revised, to reflect transportation costs. As for LNG, Petrobras makes purchases as and when required on the spot market or based on short-term contracts.

Presently, Petrobras' gas sales to LDCs are based on two types of contracts: the "imported gas contract" *(Gás importado)* and the "New Policy Firm Mode" *(Nova Politica Modalidate Firme).* The latter can be used for both imported gas and domestic production and Petrobras is in the process of phasing its use in as contracts expire and are renegotiated. Gas prices for sales to LDCs are derived from a fixed transmission tariff, based on economic indices, and a floating commodity price, which is determined by fuel oil prices.

State governments regulate natural gas distribution activities and retail prices through regulatory agencies that approve regular price adjustments taking into account inflation, distribution margins and the tariffs of gas distribution companies. Consequently, there is no uniform natural gas distribution tariff in Brazil. Regional price differences arise as a result of there not being a unique (e.g., federal) regulatory procedure for natural gas prices for households and industry across states (Figure 4). State-level regulation permits natural gas distributors to pass on supply prices to end-users and charge a distribution margin. Some agencies provide for a five-year margin review process and may enforce some efficiency criteria.

In January 2018, LDCs in Brazil paid between 7.4 and 8.3 USD/MBtu at the city gate (including commodity and transportation costs) depending on the contractual conditions and geographical location, with the lowest prices being found in the country's South, Southeast and Center West regions.

Figure 4 • Gas prices in Brazil



* NA – Non Available; LDCs without gas consumption or without public data regarding prices for industry.

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: EPE (2018), "Presentation to the IEA on natural gas"

Prices paid by industrial end-users averaged over 13.5 USD/MBtu in 2017, an 18% increase compared to 2016, but considerably below the 15.5 USD/MBtu average seen in 2014, at the height of the drought. Prices showed considerable variations around the country, as distribution tariffs and most taxes are decided by the states. In January 2018, consumers in Santa Catarina (South) paid around 8 USD/MBtu while consumers in the state of Amazonas (North) paid almost 19.6 USD/MBtu (MME, 2018).

Prices paid by electricity generators included in the Thermoelectric Priority Programme (*Programa Prioritário Termelétrico* – PPT) were substantially lower, at between 3.9 and 4.3 USD/MBtu between 2013 and 2017. During the same period, CNG prices in the country have stayed between 16.8 and 21.5 USD/MBtu, while commercial and residential consumers paid the highest prices, around 25.8 and 31.4 USD/MBtu, respectively, in January 2018.

Initial steps towards an opening

The 1997 Petroleum Law and the 2009 Gas Law marked the first steps of natural gas market reform in Brazil but did not effectively open the market to new entrants, with Petrobras retaining its dominant role across the value chain. This continued de facto monopoly is to a large degree explained by the specific design of certain key components of a competitive market, which were in principle included in the 2009 Gas Law, but never fully implemented. For example, the law contained provisions to ensure TPA, but, in practice, alternative market participants did not even reach the point of access due to difficulties in accessing gas processing plants and upstream pipelines. Also, the legal framework established the concept of free consumers, but this was never effectively introduced in most states.

After decades of *de facto* state (i.e. Petrobras) monopoly, signs of an effective opening the gas market are becoming visible. With the Gas to Grow programme, the government is already building confidence among international companies willing to participate and invest in the gas market of Brazil.

As a result of Petrobras's PPI programme, which resulted in more than USD 20 billion in asset sales since 2015, new parties have been able to acquire parts of the natural gas transmission and distribution systems of the country. With this strategy, the government of Brazil aims to increase investments in new pipeline capacity and expand the number of gas consumers.

At the end of 2015, Petrobras finalised the sale of 49% of its natural gas distribution company, Gaspetro, to Mitsui & Co., Ltd. Taking into account that Gaspetro controls Petrobras's stakes in 19 state-run natural gas distributors, this was an important step in the process of opening the market to new players.

On 18 March 2016, the ANP published Resolution No. 11, which regulates (i) the performance of transportation services by authorized agents or concessionaires of natural gas transportation activities; (ii) the assignment of contracted transportation capacity under the firm modality; (iii) natural gas swaps; (iv) the standard, approval and registry of natural gas transportation service agreements; (v) the promotion of public calls for the contracting of natural gas transportation capacity; and (vi) the reclassification of transference pipelines as transportation pipelines; pursuant to the guidelines of the 1997 Petroleum Law, the 2009 Gas Law and Decree No. 7,382/2010 (Gas Law Regulation) (Chequer, A. 2016)).

In April 2017 Petrobras announced the final sale of 90% of its shares in Nova Transportadora do Sudeste S.A. (NTS) to Nova Infraestrutura Fundo de Investimentos em Participações (FIP), managed by Brookfield Brasil Asset Management Investmentos Ltda. This sale encompasses a pipeline network that connects the states of Rio de Janeiro, Minas Gerais and São Paulo with the GASBOL pipeline, an LNG terminal and processing plants, covering around 50% of the total gas consumption of the country. Beside its ongoing 10% participation in NTS, Petrobras will continue to use the network of NTS to meet obligations under current gas transport contracts, and Transpetro (the Petrobras transport company) will remain in charge of the operation and maintenance of NTS's transport facilities through a new service agreement signed with NTS. In June 2018, a federal court suspended discussions between Petrobras and Engie regarding the sale of 90% of Petrobras' shares in TAG, which operates 4,500 kilometres (2,800 miles) of pipelines in the North and North-east of Brazil.

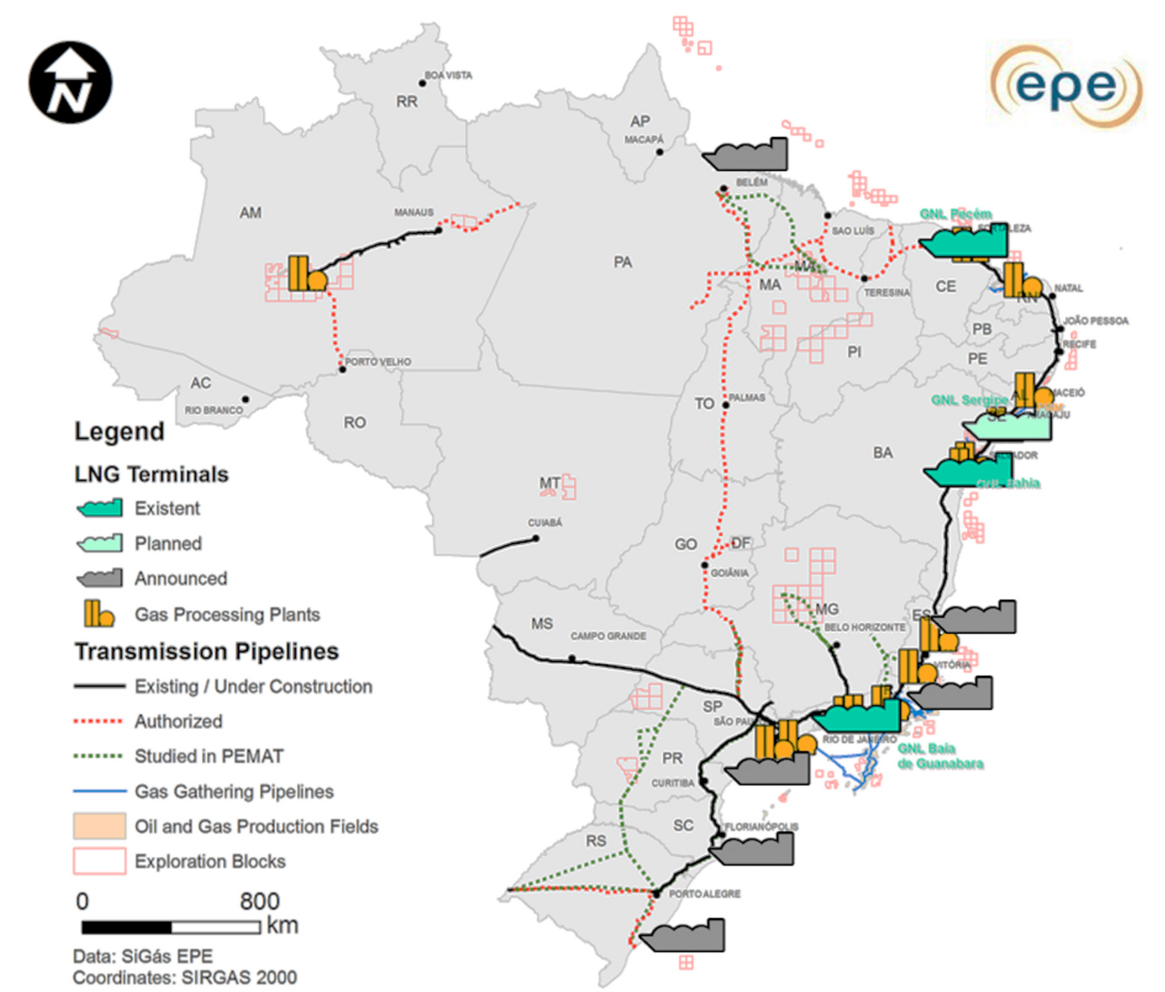
Further steps by Petrobras to reduce its stakes in other LDCs, and the sale of these LDCs by Brazilian states, will accelerate the opening of the gas market in Brazil.

Existing natural gas supply contracts for electricity generators and LDCs have started to be renegotiated, on a voluntary basis, under Petrobras' *Nova Politica Modalidade Firme Renegociado*, which separates the transportation and commodity costs at the city gate.

Pipeline supply between Bolivia and Brazil is subject to a long-term contract that delivers up to 11 bcm per year. Under the current contract, gas is directly supplied to Petrobras through the GASBOL pipeline, which is operated by Transportadora Brasileira Gasoduto Bolívia-Brasil (TBG), where Petrobras has a 51% stake. Petrobras makes use of the largest part of the capacity. The contract expires in 2019, yet both parties have already signalled their intention to extend it until 2022. However, clauses concerning volumes are likely be revised downward as Petrobras is understood to intend to stop sourcing gas for other players in the Brazilian market and will only uptake volumes to cover its own needs and to export all of its production in Bolivia to Brazil. With the tender planned for the first half of 2019, capacity on the GASBOL pipeline will also become accessible for new entrants (ANP, 2018b).

The 2019 expiry of these long-term contracts will thus create new opportunities to give market access to new entrants and to diversify suppliers in the Brazilian market. Large distribution companies will have to enter into negotiations with the Bolivian supplier Yacimientos Petrolíferos Fiscales Bolivianos (YPFB), or alternatively YPFB may also directly supply the Brazilian market. The expectation is that some distributors in states bordering and/or supplied by the Gasbol pipeline (and which may be privatised) will partially replace Petrobras' contracts with Bolivia when the current contract expires.

Figure 5 • Brazil's gas infrastructure



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: EPE (2018), "Presentation to the IEA on natural gas"

The aim of the government to promote access to essential gas infrastructure could also support an increase of LNG demand in the long term, allowing the country to increase system flexibility in the power sector. The LNG needs of Brazil are heavily affected by changes in hydro availability and climate conditions given the country's strong reliance on hydro in power generation (around 75% on average over the past five years). While industrial and residential baseload demand is met via pipeline gas imported from neighbouring Bolivia (under long-term contracts), large fluctuations in the level of gas used in power generation are predominantly addressed via LNG spot purchases. When the country experienced a severe drought, which started in 2012 and extended over the following three years, Brazil's LNG spot purchases shot up. As hydro conditions started to improve markedly in 2016, Brazil's LNG intakes have been adjusted downward (imports were halved for the first nine months of 2016). In this context, because the strategy of Petrobras was to buy from the spot market and pay a premium for the delivered flexibility, Brazil has purchased LNG at generally higher prices compared to other countries. Petrobras was the only owner and user of the LNG regasification capacity of the country up to the end of 2016. In December 2016 Petrobras reached an agreement to provide access by the French oil major Total to the Bahia regasification terminal, but no access had been effectively granted at the time of writing. In addition, Petrobras agreed to transfer to Total a 50% interest of two cogeneration plants located in the Bahia area that will be connected to the regasification terminal to enable Total to supply gas to these plants.

Implications for the gas market reform in Brazil

The long-term resolve of the government and the level of consensus among stakeholders in support of a transparent, competitive and liquid gas market will determine the level of success of the reforms under the Gas to Grow programme.

The reform programme contains many of the necessary elements to reform the existing commercial and institutional arrangements and establish new ones such as TSOs that operate independently from other activities along the gas value chain, after the transport and commercial activities of Petrobras are separated.

In this more complex scenario with new actors operating the transmission network it is important to guarantee the transparency and continuity of pipeline network operation, as well as to safeguard system integrity and security of supply.

To this end, TSOs should be responsible for:

- Information flow management and transparency
- Balancing the transmission system
- Analysing and proposing network expansion in a co-ordinated way between the transmission companies
- Hub operation, ensuring that commercial transactions in the virtual hubs can be realised during the real-time operation of the system in a reliable, transparent and neutral way

The governance of TSOs must incorporate mechanisms for guaranteeing fair, non-discriminatory and transparent behaviour, in particular with regards to access to the network and pricing. By allowing the market to set the wholesale price level for natural gas, formerly bundled and regulated prices should be separated into a regulated transmission price and a wholesale price that is set by the market and includes commodity and services costs and a profit margin. Large customers will then be able to choose their supplier for the products that suit their needs, at the lowest possible cost. As result of the introduction of non-discriminatory TPA to the grid, the number of market participants is likely to increase, creating a need for additional network capacity, which, in an expanding market, should lead to new grid investments.

New opportunities for suppliers and consumers outside their existing long-term contracts will lead to the introduction of market based pricing mechanisms, allowing shippers to cover their demand and balance their portfolios. Such a development will stimulate the creation of a VTP that can be used as a daily balancing instrument by all market participants, generating prices that will reflect the value of the commodity in the entire relevant trading area without geographic differentials resulting from transportation costs. A competitive market and an open accessible grid will undoubtedly generate to an increasing demand for flexibility instruments among shippers to be able to balance their portfolios. In Brazil, where gas generation is expected to deliver the required flexibility when hydropower is insufficient to cover domestic demand, incentives may also arise for developers and investors to increase LNG regasification capacity and build storage capacity.

In the process of breaking up a vertically integrated supply system and switching to a competitive market, an important challenge will be how to guarantee the integrity and balance of the gas system effectively and to ensure adequate security of supply. In the transition period to a competitive market, as the process of privatisation can lead to fragmentation of the system. Considering the role Petrobras has played in matching supply and demand of natural gas via vertical integration of its activities along the value chain (based on long-term contractual arrangements for supply, transportation and trading activities), the network codes to be developed will be key to maintaining system stability by setting clear rules regarding the roles and responsibilities of the individual actors.

More broadly, it is important to establish a consistent and stable set of rules applying across all market areas, which in the case of Brazil will require mechanisms to ensure the harmonization between state and federal regulations in the longer term.

Co-operation and co-ordination mechanisms will be needed to ensure access to the distribution system operators (DSOs) data to balance the market areas that will be created by the regulator. As the setup of entry-exit zones is a task at federal level, the accompanying balancing rules (definition of roles and responsibilities of the DSOs) will need to take into account the shared competencies of states and the federal government. Additionally, the new market model should contain incentives to increase effective coordination – if not harmonization – between the different markets to support the further development of a more interconnected market.

In the process of making the grid accessible to third parties, many transitional questions arise on how to deal with long-term contracts for the use of the existing network. An acceptable transition time should be agreed to give the opportunity for the parties involved to renegotiate these contracts with the aim of freeing up available capacity to the extent possible, thereby making the grid accessible to third parties. A regulated and transparent mechanism should facilitate this process.

The European experience also shows that there are several mechanisms available to free up capacity booked under long-term capacity contracts (see “Designing and implementing network codes in Brazil” below).

Most of the firm capacity in the transmission network is controlled by Petrobras through long-term contracts. Under these market conditions, independent gas producers without processing and transportation capacity are largely required to sell their gas to Petrobras who will trade the volumes domestically based on long-term contracts with power plants and the industry.

Independent and appropriately resourced regulators are needed to successfully implement ownership unbundling and network codes. Institutionally, that means a shift in the governments role, from market involvement to regulating and monitoring the activities of market participants. From the moment the market reform programme comes into force, ANP will increasingly play such a role by:

- approving, after public consultation, the investment plans submitted by TSOs
- organising auctions to build new pipelines and open seasons for long term capacity booking
- setting the general terms and conditions for TPA to gas infrastructure
- introducing regulatory measures, such as gas release programmes, to reach a well-functioning wholesale market.

European experience shows that the role of the national regulatory authority (NRA) will evolve over time, as the focus of the activities is most likely to shift from policy development and defining regulation to drafting network codes, implementation and subsequent monitoring. The consequence of such as transition, at least in the case of Europe, is that the emphasis of the market reform activities will gradually shift from the policy level to the regulatory level, leading to a greater role for the ANP.

The Gas to Grow programme

With the Gas to Grow programme launched in 2016, the government aims to boost gas production and demand in the country by introducing a market-oriented regulatory framework. Gas demand in Brazil has historically been constrained by factors such as market structure and network access as a result of the de facto monopolistic position of the state-controlled company Petrobras, limited transparency in price formation, slow deployment of new distribution networks, limited development of secondary markets and different regional taxation regimes.

The overall objective of developing an efficient Brazilian gas market is in customers' interests. To promote such a competitive market, a reduction in the dominant position of Petrobras is taking place (through its PPI programme) and market-oriented measures, such anew tax rules, more flexible licensing procedures for the construction and operation of gas pipelines and the integration of the gas and power markets, are being introduced.

This vision of a competitive gas market in Brazil comprises non-discriminatory TPA to the transmission system, negotiated access to essential infrastructure (such as gathering pipelines, processing plants and LNG terminals) and the establishment of entry-exit zones with liquid VTPs. Market integration requires an appropriate level of infrastructure, which is utilised efficiently and enables gas to move freely between market areas to the locations where it is most highly valued by gas market participants.

Figure 6 illustrates the desired end-point of such a liberalisation process, but the implementation of this vision remains to be set in future regulations.

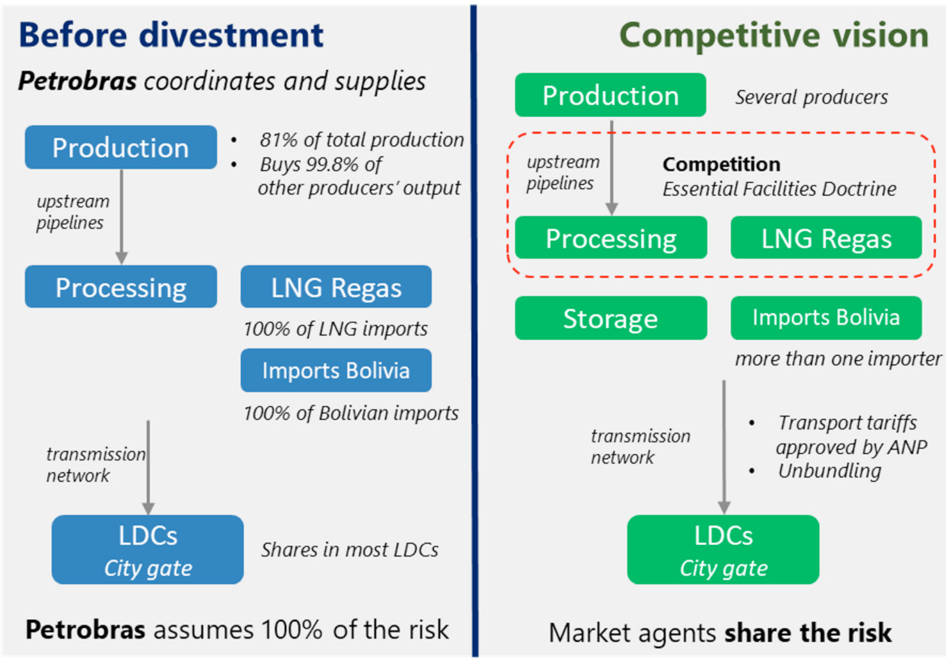
The Gas to Grow programme focuses on the major requirements of the reform, providing a general framework, whilst recognising that many aspects of implementation will need to be taken forward at the state level in due course based on local circumstances and priorities. Market reform is a long process and it may not be possible to assimilate the Brazilian gas market into a single liberalised wholesale market at the outset. It may be more realistic to develop interconnected wholesale markets or trading zones at the TSO level, each liberalised within its own timeframe.

In Europe, the gas market reform started with the opening of the wholesale market by allowing industrial consumers and power plants who were directly connected to the transmission network to choose suppliers and delivery points. Consumers who were connected to the distribution networks where given the same rights only a couple of years later.

In particular, the Brazilian gas market is envisaged in the Gas to Grow programme to consist of interconnected entry-exit zones. Within each entry-exit zone there will be a VTP or hub and shippers should be able to trade gas freely within and between each zone. The size of each zone should be defined in advance depending on the level of internal physical congestion in the existing infrastructure.

To attain a single gas market in a later phase requires sufficient interconnection between zones, so the regulatory regime should include mechanisms that allow the market to signal where investment is needed and provide TSOs with a predictable framework for generating sufficient revenues to cover the costs of infrastructure. Using established principles for running auctions and open season procedures will facilitate cross-border, market-based investment offering incremental and new capacity, and applying common rules will ensure that TSOs operate their businesses and communicate with one another in a manner that does not restrict cross-border gas trading.

Figure 6 • The structure of the gas market before and after the proposed reforms



Source: Adapted from Fidelis, M. A. (2017), "A transição da indústria do gás natural – incentivo ao acesso de novos agentes ao sistema de transporte", http://www2.camara.leg.br/atividade-legislativa/comissoes/comissoes-permanentes/cme/audiencias-publicas/2017/16-08-2017-gas-para-crescer/anp.

Once built, interconnection capacity needs to be easily accessible to shippers on a non-discriminatory basis, and at a transparent and fair price. The capacity offered to the market needs to be maximised and contractual congestion mitigated. Shippers need both long-term and short-term capacity as gas may be traded in both time periods. Sufficient accessible interconnection will promote liquidity in trading zones.

The Gas to Grow programme is focusing on arrangements for non-discriminatory access to gas infrastructure (Table 2). This is an excellent starting point but it is also necessary to link this with the needs of wholesale market development. Technical rules (Network Codes) have to be developed to turn regulatory policies (Framework Guidelines) into operational rules, following the principles and objectives of the Gas to Grow programme. These technical rules will improve access arrangements in specific areas such as transparency, capacity allocation mechanisms, congestion management procedures, interoperability, gas balancing and transmission network tariffs structure. New data collection mandates and data exchange rules will also have to be developed to ensure system operation and monitoring.

Table 2 • Planned changes in the Brazilian gas market included in the Gas to Grow programme

	Current situation	Gas to Grow programme
Transmission pipelines	Capacity hired point-to-point on long-term contracts	Formation of entry-exit systems
	Legal unbundling	OU for new TSOs. Existing ones must apply for an Independent Certification (according to ANP regulation)
	Operation co-ordinated by Petrobras	Operation co-ordinated by Independent Market Area Manager
	Auctions for new pipelines and expansions (concession)	Auctions for new pipelines and expansions (authorization/permit)
	Ten years planning published by MME based on EPE studies	1) Indicative planning by EPE 2) Investment planning submitted by TSO's and approved by ANP after public consultation
		Capacity release
Commercialisation		ANP can start a gas release program after hearing the competition authority
Distribution	Open market ("*free consumer*") regulated by the states	Open market regulated by the Federal government together with the States
Upstream infrastructure and LNG terminals	No TPA	Negotiated non-discriminatory TPA, based on good practices code
Storage	Concession after auction process	Authorisation (permit)

Source: Adapted from de Almeida, E. (2018), "General overview of the 'Gas para Crescer' initiative".

Learning from EU experiences for the implementation phase in Brazil

Within the federal structure of Brazil, a certain level of harmonisation of trade and operation of infrastructures across the state borders will be needed to reach a well-functioning and competitive market. While the federal government determines all policy and regulatory rules for the upstream and midstream levels of the gas market, the distribution level of the natural gas market is the competence of the federal states, which are also in charge of the approving end-user prices, among other things.

Gas market reform in Europe started from an even more challenging situation: independently regulated gas markets, each with a different trajectory, national energy policies and fully separated regulatory frameworks. As was seen in Europe, the first gas directive (EC, 1998) was an important step towards the creation of a liberalised internal market, but was not sufficient to achieve this objective since only general principles were regulated and member states had great discretion to determine their national legal framework. This led to an inconsistent implementation of the directive, which in turn led to distorted competition (as some markets became more open to effective competition than others), therefore failing to achieve the desired harmonisation.

To address these issues, the EC proposed specific regulations to harmonise trade and operation of infrastructures across national borders (the Second Directive (EC, 2003)). With the Third Package enacted in 2009 (EC, 2009), the EC introduced cross-border regulation and initiated the creation of ACER to promote co-operation between national regulators. It also initiated the creation of ENTSOG, to enhance cooperation between TSOs.

Based on European experience, it will be worth exploring new competences for the Brazilian national regulator ANP to:

- Complement and co-ordinate the work of the regulatory authorities of the states
- Where appropriate, take binding decisions on terms and conditions for access and operational security for cross-border infrastructure
- Advise federal and state-level institutions helping to formulate Brazilian network codes
- Monitor wholesale energy markets to detect market abuse, in close collaboration with states regulatory authorities.

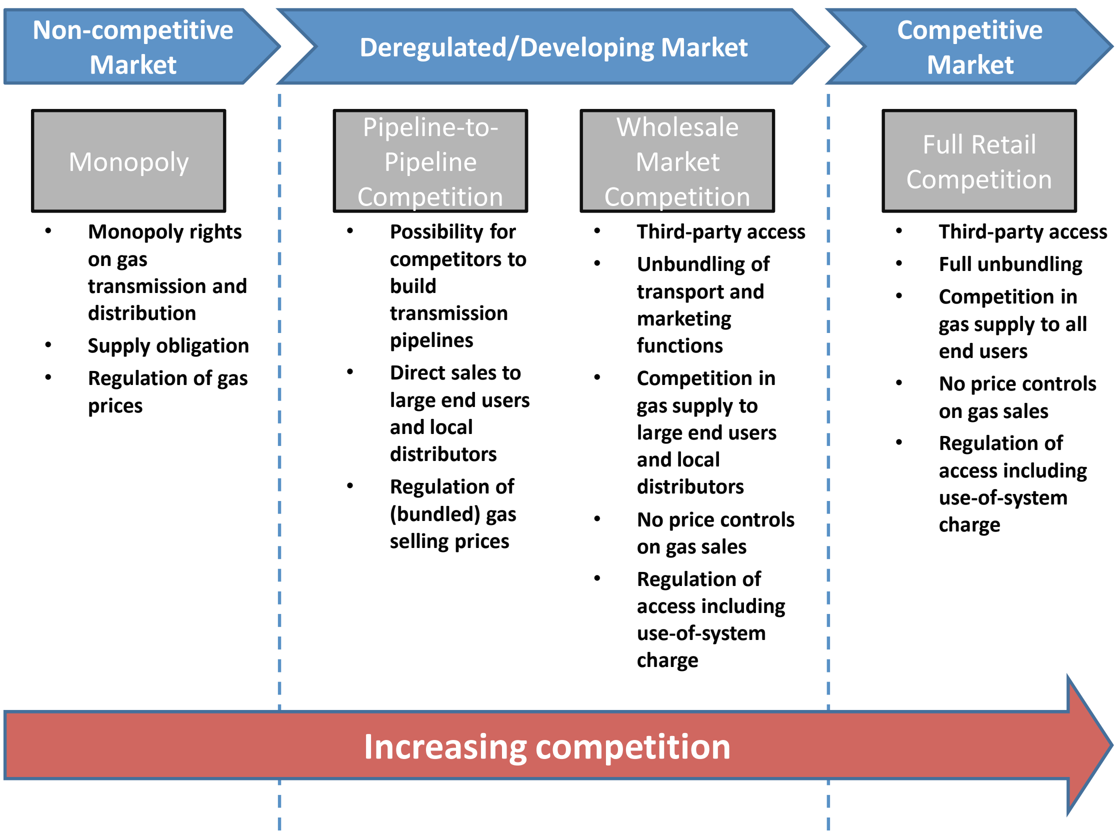
It will also be important to encourage collaboration between ANP and the state regulatory authorities in order to enhance harmonisation and joint working in the development of guidelines that provide the basis for network codes. States that have not established regulatory authorities yet should be encouraged to do so.

European experience suggests that the role of ANP is likely to evolve over time as the focus of its activities shifts from developing policies and defining regulations to drafting network codes. In Europe, the first gas directive gave a lot of implementation freedom to member states, which led to inconsistencies. With the second and, in particular, the third energy packages, the discretionary powers of member states were limited, while more and more uniformity was promoted through the establishment of ACER and the tasks assigned to it, in particular with regards to network codes. In Brazil, the role and position of ANP could evolve over time following a similar trajectory (Annex I).

Unbundling of transmission systems and certification of transmission system operators

Transitioning from a vertically integrated supply chain to a competitive natural gas market is a complex process. The process essentially runs through various stages, from a developing market, towards the desired final state of a competitive market, each stage taking potentially up to several years to mature. From the monopoly situation, the process could involve allowing pipeline-to-pipeline competition, under which competitors are allowed to build transmission pipelines and sell directly to large end users and local distributors. A deepening liberalisation moves to a stage of wholesale market competition, where there is TPA (in theory contained in the 1997 Petroleum Law) and an unbundling of transport (and marketing) functions (Figure 7). European experiences can provide key lessons that can be applied to the specificities of the Brazilian market to support a successful transition.

Figure 7 • Transition steps towards a competitive market



Source: IEA (1998), *Natural gas pricing in competitive markets*.

The available unbundling models used in the EU (Box 1) provide a point of departure for discussing options for the establishment of TSOs in Brazil that operate independently from other activities along the gas value chain. While a single unbundling model may not be sufficient to take into account the variation within the Brazilian gas market, the use of the existing models for establishing such TSOs will guarantee non-discriminatory TPA to the network, as well as the establishment of a body responsible for proposing long-term investment plans.

Box 1 • EU unbundling models

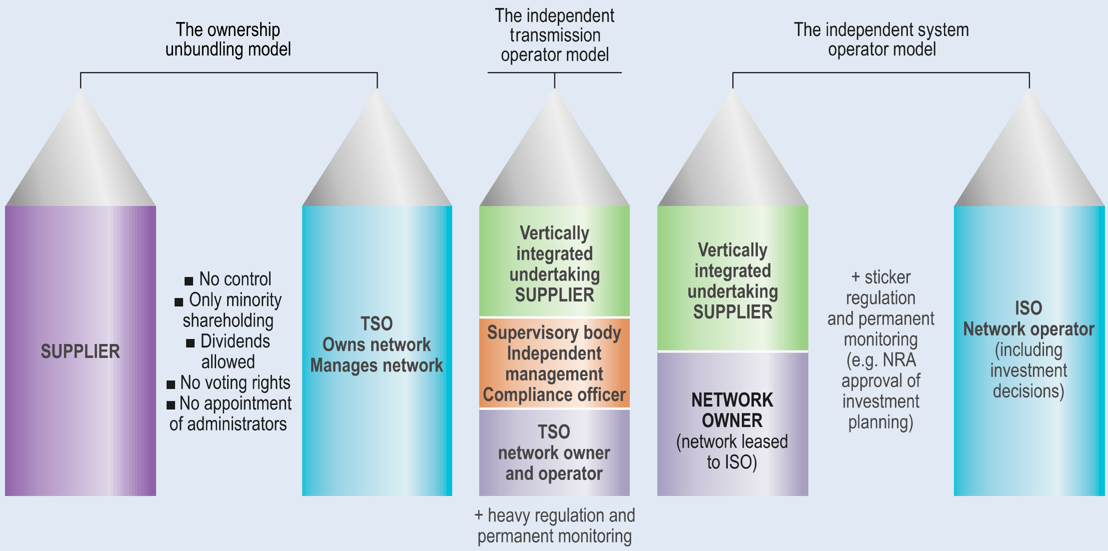
A key and hotly debated element of the third gas directive was the EC's proposal with regard to the unbundling of the vertically integrated national champions.

The preferred option of the EC was the ownership unbundling (OU) model: a complete separation between transportation activities on the one hand and exploration and trade on the other. The EC however allowed in its proposal also another option: the independent system operator (ISO) model. In this option the vertically integrated company could still own the network and receive a regulated return, but the network had to be operated by a company entirely separate and independent from the owner.

The unbundling proposals of the Commission were challenged by vertically integrated national champions and some member states who emphasised the need for national control over the gas system because of the strategic, economic and political importance of the sector.

Following extensive discussions, a compromise was reached by introducing a third unbundling model: the ITO model. In this model the owner and the operator of the network are separate legal entities, but they both may belong to the same group of affiliated companies (some of which could be involved in competitive energy activities).

Figure 8 • The three unbundling models



Member states could opt for the implementation of an alternative model as long as they believed they could guarantee a more effective independence of the TSO than under the ITO model.

Experience in Europe shows that the chosen unbundling models can co-exist. In most of the cases, a pragmatic choice of one of the TSO models can be made, building on existing arrangements in Brazil.

Which unbundling model for Brazil?

There is no specific need to implement all three models in Brazil. Two models (OU and ITO) might well be sufficient, but also a choice of just one model could be enough. Although the OU model is the "purest" and probably also the most effective unbundling model, it can also be the most complex and costly to implement in the case of vertically integrated companies. Major steps would have to be taken to ensure a very strict separation of transport activities from production and trade activities. The determination of the value of the activities and the underlying asset base (pipelines, platforms) can be very complicated, as well as the subsequent transfer of part of the asset base to a newly created company.

There may be reasons to initially choose an alternative model. The ITO model strikes a balance whereby the unbundling actions are more limited, which, combined with a good compliance programme and strongly implemented oversight by the regulator, can provide a guarantee that there are no detrimental interactions between the different activities of the TSO[5]. It would then still be possible to go for the OU model at a subsequent phase, if deemed necessary.

The ITO model is also compatible with the establishment of privately owned TSOs which is likely to happen as a result of Petrobras' PPI programme and the sale of publicly-owned LDCs. In Europe, there has been an increase in the level of private ownership and/or mixed public-private ownership of TSOs. In the Czech Republic, Great Britain, Latvia and Portugal, TSOs are completely privately owned, while the Dutch TSO (Box 2) and those in five other countries out of 26 are fully under state ownership.

Regardless of which model or models are chosen, the implementation phase in Brazil will probably need to allow for some regulatory flexibility in specific cases for a defined period in order to attract new investment in infrastructure. In Europe, investors in new infrastructures (pipelines, LNG terminals, storage) where exempted from TPA provisions for a defined period of time, which led to investment by new entrants to the market. Such flexibility can be justified in view of the overall goal of creating liquid market conditions, which require the mobilization of large investments in a short timeframe. A key issue in this context will be to ensure any flexibility is granted in a transparent and time-limited way.

Independently of the choice for one or more of the models, or whether to adopt a transition period, it will be important to ensure that Petrobras has no control over the newly established TSOs. This will be particularly relevant for Transpetro, a Petrobras subsidiary that still provides operation and maintenance services for the recently-divested NTS network, and to TAG, where Petrobras still has a 100% stake. One approach would be for Petrobras to sell its shares in Transpetro and possibly for the TSOs to acquire Transpetro's gas unit. In this way, the TSOs could fulfil the requirement that they dispose of all necessary resources in order to be certified under one of the unbundling models. A similar approach was followed in Austria for the case of Trans Austria Gasleitung GmbH (Annex II).

Box 2 • The state-owned TSO: the case of the Netherlands

Until 1998, the gas market in the Netherlands was dominated by Gasunie, a 50:50 joint-venture between the Dutch State, and Shell and ExxonMobil. The Dutch government made the choice for the OU model and decided that the transmission system was to be owned by the government. Later, it was decided that the same unbundling rules should apply to the vertically-integrated distribution network companies that were owned by local and regional governments.

This decision led to resistance by some of the vertically integrated companies, but their objections were rejected in subsequent court cases. Consequently, the local and regional governments retained ownership of the distribution networks and sold the other trading activities of the vertically integrated companies. The rationale for retaining the networks in the hands of the government was to ensure that they served the general interest and to protect the users of the networks against abuse by a monopolist. The reason for choosing the OU model was that the government wanted system operators to fully concentrate on their core activities and to prevent financial revenues from system operation to be used for production, supply and trade activities.

[5] According to initial discussions at the MME in October 2016, the ITO model was also singled out as the potentially best solution, stressing the neutrality needed for system operation and a lesser need for governmental and regulatory intervention with existing companies (MME, 2016).

Certification procedures

An important component of an unbundling framework are the certification procedures, which verify that the TSO complies with the unbundling provisions. For example, such procedures will be needed to make sure that the newly established TSOs are equipped with all human, technical, physical and financial resources necessary for carrying out natural gas transportation activities independently.

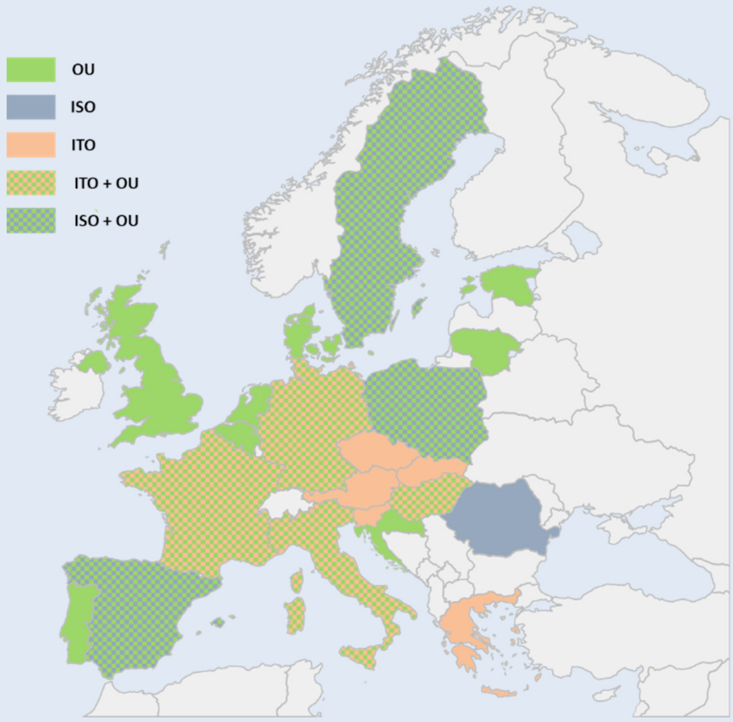
Box 3 • The certification process and implemented models in the EU

Article 10 of the Gas Directive (EC, 2009a) and Article 3 of Regulation 715/2009 (EC, 2009b) set the certification procedure for a company to be designated as a TSO. Once the EC has received a notification of the certification from the NRA, the EC shall take a decision and the NRA shall comply with the EC's decision.

In order to provide a minimum degree of harmonisation required to achieve the aims of this Regulation, there are some public documents which provide guidance:

- In order to assist the member states in the transposition and implementation of the Gas Directives, the EC issued a Staff Working Paper explaining the Commission's interpretation of the unbundling provisions (EC, 2010).
- The European Regulators' Group for Electricity and Gas carried out preparatory work to advise the TSOs on the certification procedure.
- In order to clarify the certification procedure to the NRAs the EC issued a document to explain the information which is required by the EC in the process (EC, 2011).

Figure 9 • The European landscape of unbundling models



This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: Adapted from CEER (2016), *Status Review on the Implementation of Transmission System Operators' Unbundling Provisions of the 3rd Energy Package*, https://www.ceer.eu/documents/104400/-/-/a6a22f89-3202-4f8b-f9ed-adf705185c33.

The EC publishes on its website the notifications that it receives from the national regulators about TSO certification decisions. Likewise, the EC publishes its opinions on the certification decisions of each TSO. When the TSO is certified and designated, the member state notifies the EC. Such notification is published in the Official Journal of the EU.

Overall the majority of gas TSOs, have been certified either under the ITO-model (44%) or under the OU model (40%). Seven member states have used two different models for the TSO certification. The Council of European Energy Regulators (CEER) published a Status Review on the Implementation of TSO Unbundling Provisions of the Third Energy Package in April 2016. Some of the major obstacles identified in the certification process are concerned to the ownership structure, the unclear exercise of control and rights in OU cases, the unclear definition of the ITO tasks and the lack of independence of the management, the board members and the Supervisory Body (CEER, 2016).

Entry-exit systems and competitive gas markets

The Brazilian market currently operates based on a system of point-to-point transmission capacity contracts for single pipelines or group of pipelines. Point-to-point capacity contracts do not allow their holders (network users) to trade gas at a VTP. **The Gas to Grow bill foresees that new contracts for transportation capacity will be based on an entry-exit model, and that existing contracts will be amended to the same model.**

Box 4 • The EU entry-exit system

An entry-exit system is a gas network access model which allows network users to book capacity rights independently at entry and exit points, thereby creating gas transport through zones instead of along contractual paths. The independence of entry and exit capacities is further supported by a VTP where network users who have booked entry or exit capacity can sell or buy gas, respectively. In this set-up natural gas can easily change ownership, facilitating the gas market. Compared to point-to-point relations, this model represents a general improvement providing more flexibility for network users and non-discriminatory access, fostering competition and creating an EU internal gas market for natural gas. The main reason why entry-exit systems have been introduced in the EU is to facilitate the development of competition by concentrating transfers of title to gas at VTPs within the entry-exit systems.

An entry-exit system is characterised by the following features[6]:

- Entry and exit capacities – Independent booking and use of entry and exit capacities. In an entry-exit system, network users should be able to book and use entry and exit capacity independently from each other. By moving away from predefined transportation routes, gas that enters the market area can be delivered at any exit point.

- Free allocability of capacities – Entry and exit capacities are generally freely allocable. This means that gas brought into the system at any entry point can be made available for off-take at any exit point within the system on a fully independent basis. Each exit point can be supplied from any entry point without any restrictions.

- Existence of a VTP with unrestricted access – One of the key characteristics of an entry-exit system is the existence of a VTP where network users can freely exchange gas. Access to the virtual trading point should be available for all network users and from all entry and exit points, in order to enable network users to optimise and balance their portfolios and to facilitate trading in the wholesale market.

[6] See "Study on Entry-Exit Regimes in Gas" prepared by DNV KEMA for the European Commission – DG ENERGY, https://ec.europa.eu/energy/sites/ener/files/documents/201307-entry-exit-regimes-in-gas-parta.pdf

- Distribution level included – In a "full" entry-exit system, the distribution level is included in the sense that transmission and distribution network operators take care of capacity and connection related issues at their interconnection points (city gates). Network users only book exit capacity on the network level where the final exit takes place. Imbalances between injections and withdrawals (taking into account the transactions at the VTP) are aggregated across all entry and exit points in a network user's portfolio, regardless of the network level.

For the development of competition within the new entry-exit zones it is therefore crucial that the existing point-to-point capacity contracts are amended to entry- and exit capacity contracts, while ensuring that the other main elements of existing transportation contracts do not substantially deteriorate.

This is even more important as currently all transmission capacity in Brazil is contracted under long-term point-to-point contracts. The European experience regarding the change from point-to-point systems to entry-exit systems is quite diverse. In some countries, the change was more disruptive than in others. In Great Britain, for example, with the majority of gas produced domestically, a complete reset of legacy GTAs was done when introducing the entry-exit system. In other EU member states, especially those with a high share of transit flows, focus was put on limiting the risk of termination of existing GTAs upon their amendment to the entry-exit system. In Austria, a provision in the Gas Law specified the principles for amending the existing contracts as follows:

- Booked transport capacity is replaced by separate entry and exit capacity bookings to the same amount at the relevant entry and exit points
- The new entry and exit tariffs shall be paid by the network user

The TSO gives the network user the possibility to trade at the VTP, on a firm basis if possible but if this is technically impossible, on an interruptible basis. If the aim is to limit the risk of termination of existing GTAs upon their amendment, the contract amendments should ensure that the main contractual elements (revenue, contracted capacity quantity and quality) do not substantially deteriorate.

These amendments should enter into effect at a defined point in time, i.e. the start of the entry-exit system. Furthermore, it should be specified that the related changes to existing contracts regulating the access to the transmission network do not constitute a right to fully or partially terminate these contracts.

For liquidity and competition to develop at the VTP, the place of execution of any existing title transfer services offered by TSOs or other operators at other points (e.g. flanges, city gates, LNG terminals) should be transferred to the VTP in the relevant market area, and the corresponding nominations shall be made with the VTP operator.

Box 5 • The European gas market model

The vision of an efficient internal gas market in Europe was articulated in the ACER Gas Target Model (GTM), which sets out a model of a competitive European gas market, comprising entry-exit zones with liquid VTPs, where market integration is served by appropriate levels of infrastructure, which is utilised efficiently and enables gas to move freely between markets areas to the locations where it is most highly valued by market participants. The GTM interprets the Gas Regulation requirement of "facilitating the emergence of a well-functioning and transparent wholesale market" as implying a liquid spot market and, crucially, a liquid wholesale forward and/or futures market, so that cost-effective wholesale market risk management is possible. For example, this means that a new entrant can sell a fixed-price contract to a consumer for delivery of gas in a year's time, and in turn purchase the required gas at a fixed price in the wholesale gas market.

Interconnections have a key role to play in achieving a functioning EU gas market. The Capacity Allocation (CAM) Network Code and the Congestion Management Procedures (CMP) Guidelines represent a fundamental step forward, but are not sufficient in many cases. The GTM therefore includes an assessment of the functioning of wholesale markets at national level, developing a revised series of metrics to assess whether a wholesale market is "well-functioning". These metrics can be grouped into two key characteristics of markets:

- They meet market participants' needs: products and liquidity are available that enable effective management of wholesale market risk
- They have "market health": the wholesale market is demonstrably competitive, resilient and has a high degree of Security of Supply.

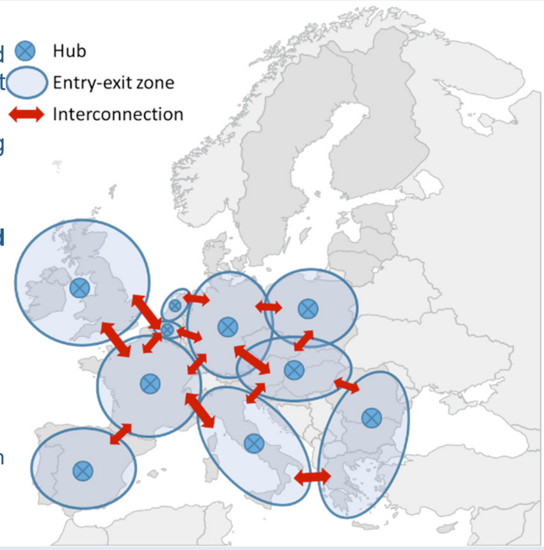
The GTM proposes that all EU member states assess whether they are likely to meet, or continue to meet, these GTM metrics in order to determine whether their market will be well functioning. If it will not, the GTM suggests considering structural market reforms. At least three market integration tools have been identified:

- Full market merger: full merger of two or more adjacent markets by merging their VTPs and balancing zones
- Trading region: partial merger of two or more adjacent markets at the wholesale level by merging their VTPs and establishing a cross-border trading balancing zone
- Satellite market: substantial linking (via pipeline capacity) of a non-functioning gas market to a directly neighbouring, well-functioning wholesale gas market.

Additional tools, including market coupling, can have a beneficial effect by facilitating co-ordinated, simultaneous access to capacity and spot gas markets.

Figure 10 • The European Gas Market Model

- **Entry-exit zones with VTPs:**
  - Shipper can flexibly book and use capacity at entry and exit points.
  - Concentration of trading activities at one VTP.
- **Liquid hubs with sufficient and efficiently used infrastructure.**
- **Functioning markets in all of Europe.**



*Zones drawn for illustration. Size of zones will depend on cost-benefit analysis.

This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.
Source: Adapted from Backes, M. (2011), "Recap of the draft CEER consultation document", https://www.ceer.eu/documents/104400/-/-/1b4f16bd-fe05-a1ce-5f64-ccea2be98d18.

Transportation tariffs in entry-exit systems

For gas networks that are expected to require future expansions due to the increase in peak gas demand, entry-exit tariffs should provide locational signals. The Brazilian gas system is expected to require investments in order to accommodate the projected increase in peak demand. This is a crucial aspect to be considered when regulating the TSOs' revenues as well as when choosing a methodology to determine the entry and exit tariffs. In a situation of increasing peak demand, several countries in Europe have used long run marginal costs (LRMC) or long run average incremental costs (LRAIC) to set entry and exit tariffs in a way so that they provide locational signals that reflect the costs of reinforcing the network (Box 6).

Box 6 • The case of Great Britain

Great Britain's TSO, National Grid, calculates the LRMC of reinforcing the network to accommodate additional supply/demand at entry/exit points. However, capacity tariffs set at the LRMCs are unlikely to recover the allowed revenues of the TSO, at least in the Great Britain (GB) system. For this reason, National Grid scales up the tariffs calculated based on the LRMC calculations.

In performing this type of scaling, National Grid uses two objectives: 50% of the allowed revenue for capacity charges are recovered through the exit capacity tariffs (this is done by LRMCs for all exit points being uplifted by a common additive factor to recover 50% of allowed revenue) and the other 50% of the allowed revenue is recovered from entry charges (the LRMC is used as the auction reserve price at entry points and any shortfall on recovering 50% of allowed revenues is done by applying a charge on actual flows – the commodity charge).

As the two mechanisms of exit additive factor and entry commodity charge are set *ex-ante*, two regulatory accounts are also needed (one for entry revenues and one for exit revenues) which are reconciled every year.

In the EU, different approaches to economic regulation of TSOs are used. The European network code on harmonised transmission tariff structures for gas (TAR NC) (EU 2017) distinguished between "price cap" and "non-price cap" regimes. Generally, non-price cap regimes require a more stringent approach by regulatory authorities for setting the methodologies and parameters used to determine the allowed (or target revenue) of TSOs.

Price cap regimes set a cap on the price that the TSO can charge. The TAR NC defines a price cap regime as a regulatory regime under which a maximum transmission tariff based on the target revenue is set by the NRA. Under a price cap regulation, the TSO bears the volume risk as revenue varies with the volume of capacity sales. This regime is used in the EU mainly by member states with significant transit flows in order to protect customers in these member states from the transit volume risk. In practice, the price cap regime creates incentives to under-forecast volume at time of their determination and to rebalance tariffs within a tariff or regulatory period to manage profit risk.

Non-price cap regimes seek to limit the amount of total revenue received by a TSO. The TAR NC defines non-price cap regimes as regulatory regimes, such as the revenue cap, rate of return and cost plus regimes, under which the allowed revenue for the TSO is set by the NRA. In these regimes, the market (i.e. network users and gas customers usually bear the volume risk as the TSO is allowed to adjust tariffs to recover allowed revenues irrespective of changing demand. This results in greater price volatility and is usually used by member states with minor transit volume risk, i.e. where the majority of the volume risk is related to fluctuations in demand of customers within that member state. Revenue cap regimes are well suited to introducing economic incentives for the TSO, e.g. by allowing the TSO to earn more if he sets actions that improve the functioning of the market.

Due to the fact that a number of TSOs in Europe held long-term capacity contracts that ensured the main share of their allowed (or target revenue), **a stepwise approach was adopted by some NRAs by applying price cap regulation before moving to non-price cap regulation as markets developed. A similar approach could also be considered for Brazil.**

A proper sharing of the risk of future revenue under/over recovery between network users needs to be found. It should be considered whether the tariffs for entry and exit capacity should be fixed for the duration of the contract term (fixed prices) or subject to changes based on future increases or decreases in the allowed revenues of the TSO (i.e. floating prices). The most significant difference between the two variants relates to the different way in which each shares exposure to the risk of future increases in allowed revenues and/or the risk of future revenue under/over recovery, between network users. Under the floating price, this risk is shared evenly between all network users: the price is determined by the underlying cost allocation methodology, and the reference price of the capacity sold in following years is adjusted to meet allowed revenues or to ensure reconciliation of the regulatory account. Under the fixed price approach, network users who book capacity in advance are protected from changes to the reference price between the time of booking and the time of use, and therefore do not have their charges scaled to meet changes in allowed revenues of the reconciliation of the regulatory account. In networks where allowed revenues grew significantly over time, the uneven protection of network users could undermine competition if higher charges are concentrated on future users or those booking shorter term. For the EU it was therefore decided to apply floating prices as a default rule. However, it also needs to be acknowledged that fixed prices provide greater tariff stability for long-term (existing and new) capacity holders and as a consequence of a more stable system usage, the TSO's willingness to invest in e.g. incremental capacity would probably increase. The EU regulatory framework therefore explicitly provides for the possibility to apply fixed prices in the case of incremental capacity.

Designing entry-exit zones

For competition to develop, entry-exit zones should be as large as possible. The EU gas market underwent a process of gradually reducing the number of entry-exit zones by creating larger zones through mergers. Mergers of entry-exit zones led to a 50% reduction of the number of market areas between 2006 (around 54 markets) and 2017 (around 28 markets), especially in Germany and France. German TSOs formed joint companies which acted as market area managers for the multi-TSO entry-exit zones. They co-ordinate certain activities for the involved TSOs which can only be done at the level of the entry-exit zone, e.g. the operation of the VTP and balancing.

Co-ordination and co-operation between TSOs is key in multi-TSO entry-exit zones. For example, TSOs need to co-operate regarding the capacity model for the entry-exit zone so that all TSOs can calculate their capacity offer. The main aim of such capacity models is to maximise the calculation of firm freely allocable capacity for the entry exit zone. The model allows the TSOs to calculate the capacity based on a common calculation logic and agreed assumptions and based on a common approach to considering the internal connections between the TSO-systems and to the connected DSO-systems. For example, in the case of Austria, the capacity model is established by the market area manager, based upon which each TSOs calculates its capacities. Focus is put on the calculation of long-term capacity based on the hydraulic characteristics of each system, i.e. shorter term effects based on e.g. seasonal effects are not covered in the capacity model. The capacity model also considered the existing transmission capacity contracts that have been concluded before the introduction of the entry-exit system.

We recommend that Brazil should analyse the feasibility of setting up a multi-TSO entry exit zone comprising all three existing TSOs from the beginning. The advantage of setting up such a larger entry-exit zone right from the start would be that a competitive gas market could develop more quickly. However, if a gradual approached is chosen, each of the TSOs could initially establish an entry-exit zone for its transmission system. Future mergers of the entry-exit zones should be defined as a goal and a respective roadmap could be developed by ANP.

Designing and implementing network codes in Brazil

Network codes are essential to safeguard the integrity of the transmission system during the opening of the market. They should clearly define roles and responsibilities of each of the market actors, in terms of the interoperability of the interconnected systems as well as the data and information exchange between TSOs, LNG terminal operators, LDCs and upstream system operators.

Developing network codes in a transparent and inclusive manner requires time. Sufficient time should be given to the development of network codes in order to enable all stakeholders to actively participate in the discussions and consultations. Experience shows that the development of network codes in the EU took at least two years. Fulfilling the certification requirements by TSOs may require a year and half, while the implementation of the network codes, IT infrastructure and data exchange interfaces (a part of which could be done in parallel) may require a lead time of up to one and a half years. Ideally, the introduction of entry-exit systems and the set of corresponding network codes should enter into force at the same time. Realistically, the start of the entry-exit system could thus be envisaged in about four years from the passage of the necessary reform legislation.

As the existing transmission pipelines are fully booked under existing long-term contracts, proper congestion management rules are of utmost importance to make some capacity available for new entrants. That capacity should then be allocated in a transparent and non-discriminatory way. For the establishment of a VTP the design of the balancing rules is key. Transparency rules as well as data exchange and settlement rules should be developed to facilitate market entry and the operation for new entrants. Interoperability rules should be developed in order to ensure a seamless operation of the overall gas infrastructure.

Box 7 • The European Network Codes

The European Network Codes (ENCs) specify common rules for the Internal Energy Market to deliver the implementation of an efficient, liberalised Europe-wide gas market. The Gas Regulation anticipated the development of Network Codes for cross-border and market integration issues. The ENCs are technical rules that follow the principles and objectives of the Gas Regulation, aimed at improving access arrangements in the internal market. ENCs are EU Regulations (Laws). Once adopted by member states, they are directly applicable and do not need to be transposed. They effectively 'trump' existing rules, including national laws and regulatory frameworks. For Gas, there are five main network codes that cover both transportation capacity and commodity related issues:

Congestion management procedures (CMP) :

- The frequent occurrence of contractual congestion, where users cannot get access to capacity in spite of its physical availability, hinders the efficient connection of adjacent entry-exit systems.
- CMPs are applied at interconnection points to facilitate the efficient use and maximisation of capacities in the networks.

Capacity allocation mechanisms (CAM) :

- The lack of equal and transparent access to gas infrastructure for all network users hamper market integration.
- CAMs ensure that pipeline capacities offered at both sides of a border become a bundled product, allowing gas shippers to use it between two neighbouring systems.

Tariffs (TAR) :

- Network users are facing a large variety and often inconsistent tariff structures in the EU, in some cases tariff structures lack objectivity or do not reflect system costs.
- The code provides for cost-reflective, non-discriminatory access arrangements, facilitate competition and promote the efficient use and development of investments in the networks.

Interoperability and data exchange (INT):

- The lack of harmonisation of basic interoperability and data exchange rules poses barriers to cross-border gas transport and hinders gas market integration.
- Operational, technical, communication and business rules are a prerequisite for a proper interoperability of transmission systems.

Balancing (BAL):

- Highly fragmented gas markets and inefficient balancing regimes do not support network users to exploit arbitrage opportunities and develop wholesale gas markets;
- Market-based balancing rules and daily balancing regimes aim at financially incentivising network users to balance their own positions via cost-reflective imbalance charges. These rules are designed to also promote the creation and development of short-term wholesale markets.

The process for the development of ENCs was set out in the Third Package. The process begins with a request from the EC to ACER to submit a Framework Guideline. ENTSOG then develops the related network code in line with the ACER Framework Guideline, conducting extensive public (stakeholder) consultations throughout the development process. After going through a comitology procedure during which the EU member states are consulted and asked to endorse the code. The network codes becomes legally binding upon approval by the EC.

Network codes, once applicable, should apply to all transmission contracts, i.e. existing and new contracts. Existing regulation (ANP Resolution 11/2016) already provides for a legal basis to develop network codes for the gas market in Brazil. In order to ensure that all network users are treated equally and are subject to the same rules, the network codes, once applicable, should apply to all transmission contracts, i.e. existing and new contracts.

Freeing-up capacity is key to allow market entry for new players. A direct way to allow the TSOs to offer capacity is by allowing Petrobras to surrender some of its contracted capacity, always within the limitations of ongoing contracts.

The EC's Guidelines on CMPs describes the criteria to identify instances of contractual congestion at interconnection points between entry-exit zones, as well as the short and long-term mechanisms that can be applied to address them. Short-term capacity release mechanisms, including FDA UOLI (*Firm Day-Ahead Use-It-Or-Lose-It*) procedure, are the widely used to address increasingly frequent instances of contractual congestion.

An additional option is to develop a secondary market plus UIOLI (*Use it or lose it*) provisions to avoid contractual congestion by the incumbent. This would include regular monitoring of certain shippers' actual utilisation rates of their contracted capacity, with users losing some or all of their booked capacity if any deliberate and systematic under-utilization is detected by the TSO. While long-term UIOLI has not been applied in the EU yet, this mechanism is thought to serve as an incentive for shippers to proactively offer any unused capacity on the secondary market, or via short-term surrender mechanisms.

To avoid a revenue shortfall for the TSOs, Petrobras should retain its rights and obligations under the capacity contract until the capacity is successfully reallocated by the TSO and to the extent the capacity is not reallocated by the TSO.

Moreover, a system should be introduced to monitor (i) the behaviour of TSOs in assigning capacity to market participants and (ii) the actual usage of the available capacity, with the objective of freeing up contracted capacity that is not used and to prevent capacity hoarding. In order to create confidence in the independence of the TSOs, market participants (newcomers in particular) have to be certain that capacity is available and assigned to them on an equal basis and in an open and transparent way. In addition to monitoring, it is necessary to avoid unnecessary investments and to create the right investment signals by ensuring that all the available capacity is available to the market.

Rules regarding securities as collateral for payment obligations under capacity contracts should apply to all network users, i.e. including Petrobras. Thus, if the credit rating of a new network user was lower than the current corporate debt rating of Petrobras, the TSO would be entitled to require the network user to provide a security as collateral for the network user's payment obligations under the capacity contract. The amount of the security would depend on the duration of the capacity contract. For example, in a case where the capacity contract has a duration of more than one year, the security could be equal to 15% of the charge payable for the entire duration of the capacity contract. Such security may, at the discretion of the network user, take the form of a bank guarantee or a prepayment.

Balancing rules that facilitate the development of a liquid spot market

A fundamental requirement of a balancing system is to allow for a grouping of a network user's inputs and off-takes through the introduction of balancing portfolios (or balance groups). Commercial balancing should be done based on a network user's balancing portfolio instead of individual transmission capacity contracts.

Ideally, the balancing zone should comprise the transmission as well as the distribution level. This setup would require co-operation from the DSOs in terms of providing consumption data of the customers connected to their network to the balancing entity. This information provision is key for shippers to be able to live up to their responsibility to balance their balancing portfolios and to minimise the need for the TSO(s) to undertake balancing actions.

In the current system, local distribution network business and regulation are under jurisdiction of the states. Therefore, a joint balancing (DSO/TSO) could only be done if the local state regulation allows such activity, and currently it does not. One important distinction between the transmission (federal level) and the distribution (state level) is that the distribution service is a "public service" (activity attributed by law to the state government to fulfill citizen's demand of services), while transportation is an "economic activity" that requires federal authorization. That implies state control of LDC's assets and economic returns, and presents difficulties for integration with transmission activities and TSOs, as the federal transmission assets and tariffs fall under a completely different regulatory framework. The current data provision obligations by ANP applies to transmission companies, which have to publish gas flows by city gate.

In an intermediary step, a trading region concept could be introduced which covers only the gas transmission system(s) and thereby establishes a "trading balancing zone". Specifically, such a trading balancing zone includes all entries of gas into and all exits of gas out of the included gas transmission systems as well as a (single) joint VTP. The balancing of end user loads in the distribution systems (areas covered by the respective LDCs) is kept separate in LDC balancing zones. By this route, the potential lack of a legal framework that allows DSOs/LDCs to participate in the balancing could be resolved.

For the balancing system to work properly, it is essential that the "allocated as nominated" principle is applied at all entry and exit points. Under this principle, all volumes allocated to shippers must have been properly nominated by said shippers to the network operator, in accordance with the balancing time unit (day, hour), in order to guarantee volume consistency and allocation. **In order to ensure the application of this principle, Petrobras could temporarily act as balancing shipper until operational balancing accounts are implemented.** Ideally, operational balancing accounts (OBAs) are agreed between the TSO and its adjacent system operators (e.g. upstream pipeline network operators or producers, LNG system operators, LDCs). The OBA shall serve to track any imbalance created by the difference between the metered quantities at an entry or exit point and the sum of the confirmed nominations at that point.

As an intermediary step, the "allocated as nominated" principle can also be respected through having a balancing shipper. For that purpose, a shipper balancing account (SBA) is agreed between the TSO and the main shipper, i.e. Petrobras. Any imbalance created by the difference between the metered quantities at an entry or exit point and the sum of the confirmed nominations at that point is charged to the SBA and is borne by the balancing shipper. The "allocated as nominated" principle thus applies to all shippers except for the balancing shipper.

A potential way to balance the competitive advantage of Petrobras due to its large portfolio effect could be to give smaller balancing portfolios higher flexibility/tolerances in the balancing regime. Shippers with large and well diversified balancing portfolios can forecast the overall demand of the customers in their portfolio more accurately and thus incur less risk and costs of being unbalanced.

Virtual trading point

An entry-exit system is the basis for a VTP, where network users and financial market parties can trade. Network users should have the possibility to enter into a legally binding agreement with the operator responsible for balancing (balancing entity), which enables them to submit trade notifications irrespective of whether they have contracted transport capacity or not. This means that it should also be possible for financial market parties, e.g. banks, to engage in gas trading at the VTP, such as for balancing. Experience in Europe has shown that financial market parties have contributed a large part to the liquidity at the VTPs, which can in turn attract new investors in upstream capacity, as marketing production is no longer limited by the distance between producer and consumer.

Ensuring the firmness of trading activities at the VTP is key for an organised gas market to develop, i.e. for brokers and exchanges to become active. Once gas exchanges are established, it will initially be necessary for Petrobras to play a transitional role in ensuring base liquidity. This can be achieved by various measures, including requiring Petrobras to place a certain minimum volume of both gas sale and purchase offers per day, potentially combined with regulation to ensure a reasonable bid/ask price spread.

The gas release programmes could provide the legal basis for these additional obligations on the incumbent. This requires physical balancing that ensures the firmness. Ideally, the balancing entity should also be responsible for operating the VTP. Gas transfers between two balancing portfolios within one balancing zone should be made through disposing and acquiring trade notifications submitted to the balancing entity in respect of the gas day. The balancing entity then carries out a matching of corresponding trade notifications. Should mismatches occur when matching corresponding trade notifications, the balancing entity shall apply the lesser-of rule (i.e. if nominations for a same trade differ according to trade parties, the balancing operator will opt for the lesser of both nomination values to allocate volume). The operation of the VTP should be IT-based and should be operated as a 24/7 automatic process.

Competition law measures

Together with the development of a regulatory framework for the gas sector by ANP (*ex ante* regulation) based on the Gas to Grow bill, competition law measures (*ex post* regulation) should be applied by the CADE, if necessary. This can contribute to further development of CADE's antitrust case law and to providing useful guidance on its interpretation of competition rules.

The EC launched an inquiry into competition in gas and electricity markets in 2005. The final report, published in January 2007 (EC, 2007), identified the following serious shortcomings in European gas markets:

- too much market concentration in most national markets
- a lack of liquidity, preventing successful new entry
- too little integration between Member States' markets
- an absence of transparently available market information, leading to distrust in the pricing mechanisms
- an inadequate current level of unbundling between network and supply interests which has negative repercussions on market functioning and investment incentives
- customers being tied to suppliers through long-term downstream contracts.

The finding that there was too much market concentration in most national markets was due to a lack of transport capacity in Europe, mainly caused by the incumbents' own bookings, preventing competitors from gaining the access to pipelines needed to reach their gas customers. To address this issue, the EC opened a number of *ex-officio* antitrust investigations. The E.ON Ruhrgas and GDF Suez cases tackled the problem that almost the entire capacity on their gas networks was booked, on a long-term basis, by E.ON Ruhrgas' and GDF Suez' own supply businesses, leaving virtually no room for third party transport.

The remedies proposed by GDF Suez and E.ON Ruhrgas in 2009 to allay the Commission's competition concerns were commitments to release capacity bookings. The remedies that were considered adequate by the Commission to solve the issue of long-term capacity bookings consisted in a significant reduction of the capacity bookings of GDF Suez and E.ON Ruhrgas in their respective networks. In both cases, it was agreed to reduce the booking share of GDF Suez and E.ON Ruhrgas to a maximum of 50 % on their gas networks. Since such large reductions of long-term bookings require extensive preparation and time, e.g. for contractual rearrangements or capacity increasing measures, the remedy consisted of two steps: in a first step ("Immediate Release"), GDF Suez and E.ON Ruhrgas released significant capacities (around 10-15 % of the total capacity) at the most important entry points already at short notice (at the latest with effect as of October 2010/2011); and in a second step ("Final Reduction"), GDF Suez and E.ON Ruhrgas further reduced their overall share in the bookings of long-term entry capacity in the relevant networks to a maximum of 50% by 2014 and 2015 respectively. GDF Suez and E.ON Ruhrgas also committed not to exceed these thresholds for ten years thereafter.

A few years after the entry into force of the Gas to Grow bill, an inquiry into competition in the Brazilian gas market could be conducted. At EU member state level, the German Federal Cartel Office decided in 2006 that E.ON Ruhrgas' gas supply contracts with distributors, which include long-term purchase obligations and require distributors to purchase a high percentage of their total gas requirements from E.ON Ruhrgas, violate EU and German competition law (Bundeskartellamt 2006). The German Federal Cartel Office justified its decisions by stating that binding distributors by long-term supply contracts has a foreclosure and thus price-raising effect because it prevents the market entry of newcomers and deprives third providers of supply possibilities for years. Based on this decision, E.ON Ruhrgas terminated its long-term supply contracts with distributors.

Ancillary measures to support the development of a gas market

We recommend that the requirements for power generators to participate in auctions of power purchase agreements should be further reviewed. We understand that operators of gas-fired power plants were required to provide 25-years gas supply contracts and needed to demonstrate that the gas supplier possessed reserves for that would meet the 25-year supply obligation in order to participate in auctions of power purchase agreements. This requirement has already been reduced to 10 and five years. The introduction of an electricity balancing market based on a merit order should be considered.

The introduction of a capacity remuneration mechanism for (low-carbon) electricity generation capacity which is necessary as back-up for volatile hydro (and increased wind and solar) generation should be explored. After the expiry of the emergency power programme (PPT) which offered lower gas prices for 20 years to power plants commissioned by 31 December 2004, a capacity remuneration mechanism may be necessary in order to attract sufficient investment into additional gas-fired power plants.

In order to strengthen its competitive position in the residential and SME sector, natural gas should be price-competitive against alternative fuels, particularly LPG. At the same time, the continuation of subsidised gas prices for vulnerable customers should be considered where necessary.

Annexes

Annex I

The liberalisation of the gas market in the EU

Liberalisation of the energy markets and, in particular, of the gas market, has been high on the agenda of the EU since the last decades of the XXth century. At that time, most of the gas markets in the EU where organised nationally and dominated by vertically integrated national champions (incumbents) who were active along the whole value chain from upstream to downstream, including transportation. There was hardly any competition and there was no free flow of gas across borders and between member states, as trade was dominated by long-term contracts for both gas (the molecules) and transportation, with destination clauses and strict conditions with regard to pricing. This situation led, among other things, to (relatively) high prices for consumers and market foreclosure. By the end of the XXth century, the EC started to take steps to change this situation and to develop an EU energy policy with the goal of providing sustainable, secure and affordable energy for all Europeans.

This policy was driven by three objectives:

- Secure energy supplies to ensure the reliable provision of energy whenever and wherever it is needed
- Sustainable energy consumption through lowering greenhouse gas emissions, pollution, and fossil fuel dependence
- Energy providers should operate in a competitive environment that ensures affordable prices for homes, businesses, and industries.

In order to achieve these objectives the Commission identified the following high-level steps:

- The rules on the free movement of goods should apply to natural gas.
- End monopolies, as they constitute a breach to the free movement of goods: all consumers should be free to choose their supplier.
- Promote competition between suppliers to improve the overall quality of the services and keep prices as competitive as possible.
- Create National Regulatory Authorities to police the system and represent the interests of the public.

Subsequently, the following measures were identified:

- Create open entry-exit systems with VTPs (“hubs”).
- Ensure TPA to gas infrastructures (networks, storage, LNG facilities).
- Stimulate investments in strategic gas infrastructure.
- Abolish destination clauses from gas supply contracts. Buyers of gas should be able to resell the gas if they don’t need it.
- Move away from oil-indexed gas prices towards hub-based gas prices (gas-to-gas prices).
- Phase out regulated gas prices for consumers as they distort market signals and obscure the real costs of the gas to consumers.

The first gas directive

In 1996 a first step was set with the adoption of Directive 96/92/EC (EC, 1996) concerning common rules for the internal market in electricity. In 1998 this was followed by the adoption of Directive 98/30/EC (EC, 1998) concerning common rules for the internal market in natural gas. This directive did set out the following:

- common rules for transmission and storage of natural gas
- common rules for distribution and supply
- rules relating to the functioning of gas markets and access to the market: TPA to transmission networks and free choice of shipper for eligible customers
- accounting unbundling: separate accounts for production, transportation and distribution
- management unbundling: introducing separate management structures for production, transportation and distribution
- member states to designate a competent authority to settle disputes with regard to access to the system.

The first gas directive was an important step towards the creation of a liberalised internal market, but did not suffice to achieve this objective since only general principles where regulated and member states had great discretion to determine their national legal framework. This led to an inconsistent implementation of the directive, which in turn led to distorted competition since some member state markets became more open to effective competition than others. Also the desired harmonisation was not achieved. The Commission therefore proposed a new gas directive: the second directive.

The second gas directive

The second directive was adopted in 2003 (Directive 200355/EC concerning common rules for the internal market in natural gas (EC, 2003). This directive was followed in 2005 by Regulation (EC) 1775/05 on conditions for access to the natural gas transmission network (EC, 2005)[7]. Both the directive and the regulation had the following objectives:

- Further liberalisation of the gas sector: legal unbundling of vertically integrated activities of gas conglomerates and a reduction of their horizontal concentration.
- Introduction of competition in the wholesale market and retail supply: large customers got the possibility to freely choose their supplier in 2004, households to follow in 2007.
- TPA to gas infrastructure: regulated access to networks and regulated or negotiated access to storages and LNG facilities.
- Tariff methodologies for transportation became subject to the approval by NRAs which member states where obliged to set up.

Following the implementation of the measures set out in the second directive, the Commission decided in 2005 to launch an inquiry into the functioning of the European single market for gas (and electricity). This in response to concerns raised by consumers and new entrants to the gas sector regarding the development of markets across the EU and the limited availability of consumer choice.

[7] A key difference between a directive and a regulation is that a directive is a legislative act that sets out a goal that all EU countries must achieve; it is however up to the individual countries to devise their own laws on how to reach these goals. A regulation is a binding legislative act which must be applied in its entirety across the EU with little or no room for specific national implementation features.

In 2007 the final report of the inquiry (EC, 2007) was published and this emphasised the following main problems:

- continued high levels of market concentration: incumbents maintain market power
- vertical foreclosure: old monopolists continue to own the gas infrastructure
- low levels of cross-border trade: insufficient interconnector capacity and to contractual congestion
- lack of transparency: difficult for new entrants to understand how the market works
- lack of confidence that the wholesale gas price(s) are the result of meaningful competition.

Based on this the Commission concluded that the existing legislation – in particular rules on legal unbundling – was not adequate to address these issues as the existing legislation was not able to solve the following problems:

Discrimination in access to infrastructure

- TSOs granting affiliated supply companies rebates not available to others
- TSOs offering transport capacity to affiliated companies while refusing firm capacity on almost an identical route to other suppliers.

Information leakage

- Management of the supply branch having access to strategic business information of the transport company, either directly or as a result of presence on the Board
- Central functions, such as legal advice, provided by the group holding company to all members of the group. This reduces the scope for objective treatment of all market participants by the TSO.

Distorted investment incentives

- TSO's investment decisions often taken by the group as a whole, which as a consequence meant that investment which would increase competition for the group was blocked
- Low appetite for third parties to invest if they feared unfair treatment by the network operator.

According to the EC, these problems undermined competition and therefore decided to propose a third gas package (a new directive and a new regulation).

The third gas directive

The third gas package (Directive 2009/73/EC concerning common rules for the internal market in natural gas (EC, 2009) and Regulation (EC) No.7152009 on conditions for access to the natural gas transmission networks (EC, 2009a)) was part of greater package of energy legislation which introduced, among other things, the following elements:

- The establishment of ACER, replacing the existing informal co-operation between NRAs by an agency with powers, resources and a mandate
- The establishment of ENTSOG, a more formal industry grouping of TSOs with the mandate and the responsibility to:
    - propose a 10-year investment plan for the gas grid of the EU
    - prepare and propose technical codes necessary to integrate markets
    - the certification of TSOs under one of the unbundling models.

Annex II

Unbundling in four EU member states

Austria

Before liberalisation of the Austrian gas market in 2002, Österreichische Mineralölverwaltung (OMV), an integrated international oil and gas company based in Vienna, held the monopoly for importing gas to Austria together with a joint venture of vertically integrated LDCs. These LDCs also held the monopoly for supplying customers within their territory, i.e. a given state ("Bundesland") or municipality. Each LDC was and still is majority-owned by its respective state or municipal government.

With the liberalisation in 2002, vertically integrated undertakings with more than 50 000 connected customers were obliged to apply legal unbundling for their transmission and distribution activities. Vertically integrated companies with less than 50 000 connected customers were obliged to keep separate accounts, within separate accounting systems, for the distribution activities within the scope of their internal book-keeping.

All unbundling models provided for by the Third Package have been transposed into the Austrian Natural Gas Act in 2011. At that time, three companies carried out transmission activities, however, one company – Gas Connect Austria (GCA) a 100% subsidiary of OMV – owned all the transmission assets, whereas the other two companies (one was a joint venture between OMV and the German company E.ON Ruhrgas as well as the French company Gaz de France, and the other was a joint venture between OMV and the Italian company ENI) only marketed the transmission capacity, i.e. they were responsible for the commercialisation of the transmission pipeline capacity.

The certification of the TSOs took place between 2012 and 2014. Two companies applied to be certified as ITOs, whereas one company (Trans Austria Gasleitung GmbH -TAG) applied to be certified as ISO. In the end, all TSOs were certified as ITOs.

The main reason why the regulatory authority (E-Control) rejected the ISO application submitted by TAG was that its independence from the vertically integrated undertaking (OMV) was deemed insufficient.

Just like with OU, a vertically integrated undertaking may not exercise control in an ISO. Although OMV, through its 100% subsidiary GCA, only held 11% of the shares of TAG, the articles of association granted GCA control in TAG, i.e. GCA could appoint a managing director and GCA's agreement was needed for decisions in shareholder meetings. Although GCA was already certified as ITO at that time, it remained part of the vertically integrated undertaking OMV. In order for TAG to be certified as ITO, the transmission assets owned by GCA had to be transferred to TAG. GCA also carried out operation and maintenance (O&M) activities for TAG. Consequently, TAG had to be equipped with all human, technical, physical and financial resources necessary for carrying out the activity of gas transmission, e.g. the personnel formerly employed by GCA to carry out the O&M activities had to be transferred to TAG.

As it was not possible for TAG to carry out all the activities as from the date of certification, E-Control granted TAG e.g. a transitory period of one and half years to build up their own commercial dispatching.

Great Britain

Privatisation of the gas industry began in the 1980s as part of a wider political programme of privatisation of national industries. Before privatisation, the British Gas Corporation (BGC) bought virtually all gas produced in and around Britain and had a statutory monopoly to transport and supply gas to end users. The 1986 Gas Act led to the privatisation of the BGC, required TPA to the transportation network and started to dismantle its monopoly retail supply position. This was an incremental process that started with the opening up of competition for larger industrial consumers. The 1995 Gas Act completed this process, with full retail market competition for all consumers, including domestic households and small businesses, by 1998.

The 1995 Gas Act also required the separation of production, transportation (both transmission and distribution) and supply activities into independent companies. This was achieved through a number of sales and demergers. The market arrangements for full TPA to the pipeline network were codified in the Uniform Network Code in 1996.

There have been numerous changes to these market arrangements since and the nature and extent of trading has also changed considerably. Even so, the basic building blocks of the wholesale gas market arrangements have remained largely unchanged to this day. Following the introduction of the Third Package, a certification regime was established to assess compliance with unbundling rules. Transportation licensees are required to be certified as fully ownership unbundled.

The Netherlands

Until 1998, the Dutch gas market was dominated by the company Gasunie, a 50/50 joint venture between the Dutch state on the one hand and Shell and ExxonMobil on the other. All the gas produced in the Netherlands could only be sold by Gasunie and Gasunie was the only company that was allowed to import gas. Next to that Gasunie was the owner and operator of the Dutch transmission system.

Following European developments, in 1998 a start was made with the liberalisation of the Dutch gas market. Gas producers were no longer obliged to sell their gas to Gasunie, they could now sell it directly on the market and also other companies were allowed to import and sell gas on the Dutch market. A Gas Act setting out the rules that governed the gas market was introduced in 2000. Later, in 2005, it was decided to split up Gasunie in two companies:

- A transport and infrastructure company which continued under the name Gasunie and which is today the mother company of Gasunie Transport Services (GTS), the Dutch TSO for gas. Gasunie is 100% owned by the Dutch State and the shares are under the control of the Ministry of Finance. GTS is the owner of the Dutch transmission network.
- A trade company called GasTerra which is the continuation of the original joint venture whereby 50% of the shares are in the hands of the Dutch State and more in particular in the hands of the Ministry of Economic Affairs and Climate Policy. GasTerra sells, imports and trades gas on the wholesale market.

Spain

The history of natural gas in Spain started in 1969 when the first LNG regasification plant in Barcelona (owned by the private company Gas Natural) came into operation. In 1970 the Empresa Nacional del Gas (ENAGAS) was founded as a 100% state-owned holding. In 1975, ENAGAS acquired the LNG plant of Gas Natural, together with its contracts with Algeria and Libya, culminating thus the nationalisation process of the imports and supply of natural gas in Spain. By the late 1970s, supply, regasification and transportation were controlled by ENAGAS.

Spain entered the EEC in 1986, stimulating the government to initiate a first liberalisation of the energy market and facilitating TPA to gas networks. The 1990s were characterised by the application of European policies towards the single energy market and the liberalisation of activities in gas and electricity. In 1993, ENAGAS was privatised, with Gas Natural SDG acquiring 91% of its capital.

The 1998 Hydrocarbons Law initiated the liberalisation of the gas sector, decreeing the separation of transport, distribution and commercialisation activities. The new law suppressed the consideration of the gas sector as a public service and the regime of administrative concessions. It also created the Gestor Técnico del Sistema (System Technical Manager) to ensure the operation of the basic network and the secondary transport networks. The start of liberalisation from 1998 forced Gas Natural SDG to gradually divest of its entire shareholding in ENAGAS, between 2002 and 2009. The 1998 Hydrocarbons Law included restrictions on the shareholding of the company (i.e. no entity could participate directly or indirectly in the shareholding of the parent company in a proportion greater than 5% of the share capital; the sum of direct or indirect participations of entities that carry out activities in the natural gas sector could not exceed 40%). Currently, 95% of ENAGAS capital is free floating on the stock exchange and 5% is held by SEPI (state-owned holding).

The 1998 Hydrocarbons Law establishes two possible models for gas TSO unbundling: OU and ISO. The OU model, adopted for the main TSO (Enagas Transporte S.A.U.), with more than 90% of national transport pipelines ownership unbundled. Small gas TSOs in Spain can opt between the OU model and the ISO model. Enagas Transporte S.A.U. has also been certified as ISO for the primary gas transmission networks owned by SAGGAS and by Enagas Transporte del Norte. Reganosa was certified by the the *Comisión Nacional de los Mercados y la Competencia* (CNMC), the Spanish NRA, in February 2014, under the OU model. The CNMC resolution limits the voting rights and the appointment of members in the supervisory board of Reganosa to the two shareholders from the vertically integrated undertakings (Gasifica and Sonatrach).

Annex III

The implementation of the network codes in four EU member states

Austria

At the start of liberalisation process in October 2002, the legal basis did not provide for the development of legally binding network codes at national level in Austria. Rather, the technical and organisational rules for the gas market had to be defined in the general terms and conditions (GTCs) of the system operators, i.e. in the contractual relationship between the system operators and the network users. System operators were obliged to seek approval of their GTCs from the regulatory authority before applying them.

The regulatory authority decided to ensure a certain level of harmonisation of the GTCs for which the individual system operators sought approval. The regulatory authority therefore proposed drafts and organised consultations and large workshops in order to discuss the content of the GTCs with all relevant stakeholders. At the end of that process the regulatory authority published a template of the GTCs and recommended its use when operators sought approval.

Subsequently, the Natural Gas Act of 2011 provided a legal basis for the regulatory authority to issue ordinances, i.e. binding secondary legislation with rules to achieve efficient network access as well as harmonised rules for all market participants. Such ordinances may only be issued after a public consultation and shall respect the European network codes and guidelines adopted in accordance with the Third Package.

The ordinance based on the Natural Gas Act of 2011 was crucial for defining the rules for the entry-exit system that was introduced in January 2013. The regulatory authority organised a broad discussion process which officially started in November 2011, immediately after the adoption of the Natural Gas Act of 2011, in order to develop the rules to be included in that ordinance. That process was concluded by the end of May 2012. This gave market participants seven months to prepare for the start of the new system on 1 January 2013.

The first European network code (on capacity allocation) entered into force in November 2013. However, the main principles and elements of the network codes on capacity allocation and balancing, as well as the guidelines on congestion management, were already known in 2012 and could be taken into account before issuing the ordinance in May 2012. The ordinance was amended when the network codes became applicable.

Great Britain

The regulatory framework in GB operates through a system of legislation, licences and industry codes with an independent regulator (Ofgem) responsible for regulation of the sector and enforcement of any breaches.

The main legislative framework is set out in the 1986 Gas Act, which establishes a licensing and industry code regime, and sets out the statutory duties of the regulator and the Secretary of State.

Unless an exemption applies, a licence is required for the following specified activities:

- gas transportation (transmission and distribution)
- gas interconnection
- gas shipping
- gas supply.

The Uniform Network Code (UNC) is the industry code that underpins the gas market. It sets out a legal and contractual framework to supply and transport gas, a level playing field for competition. Licensees are required to maintain and comply with the UNC in accordance with the conditions of their licence.

Once passed into EU law, the European Network Codes (ENCs) supersede GB law and therefore the UNC. In order to ensure compliance with the ENCs in GB, a number of steps were taken including:

- licence changes
- industry-led modifications to the UNC
- industry led amendments to the interconnection agreements between TSOs
- industry led changes to interconnector access rules and charging methodologies
- lessons learned.

A key point to note is the role of industry in proposing amendments to industry codes to ensure compliance with the ENCs. Ofgem approves or rejects these changes following an assessment of their compliance with EU law. Ofgem also has powers to lead the modification process.

The Netherlands

In the Netherlands, the implementation of network codes is the responsibility of the Authority for Consumers and Markets (ACM), the Dutch NRA. In undertaking this, the ACM has to co-operate closely with GTS, the Dutch TSO for gas.

The ACM also has to involve stakeholders like shippers in the implementation process, while there is no involvement of the Dutch Energy Ministry. At the time of writing (September 2018) the focus is on the implementation of the Network Codes on harmonised transmission tariff structures for gas (NC TAR; Commission Regulation (EU) 2017/460). This process started immediately after the entry into force of the NC TAR on 6 April 2017, with a first workshop for stakeholders organised by the ACM and GTS. Since then, six more workshops have been held in order to come to a robust implementation proposal and to reach consensus (if possible) on the many 'open ends' of the code, such as:

- what qualifies or not as a transmission service
- what price methodology will be applied
- what discount percentage will be applicable for transport to and from storage.

During the workshops, stakeholders explained their preferences and concerns. This led to a proposal by GTS to the ACM in January 2018 on the implementation of the NC TAR in the Netherlands.

In this proposal, the stakeholder input was taken into account and influenced the choices that were identified. Based on the proposal, the ACM is formulating the final consultation document, which may still deviate from the GTS proposal if elements of this proposal are either non-compliant with the NC TAR, lead to undesired effects or are insufficiently justified.

Public consultation took place until April 2018, with the first decisions based on the NCTAR in May 2018. This decision was subsequently notified to ACER for a check on conformity with the provisions in the network code.

Lessons learned

The implementation of network codes takes time and requires realistic planning. Furthermore, stakeholder consultation is very important to discuss various options and differences of opinion, to create overall support for the way the codes are implemented. In the Netherlands, the implementation process has led to discussions between the ACM and the Energy Ministry on whether the Dutch Gas Act gives the necessary competences to the ACM to assess how network codes may differ from some of the provisions of the EU network codes. This discussion is ongoing and may lead to proposals to amend the Gas Act.

Spain

The implementation of ENCs is considered to be a crucial step towards the completion of the internal gas market. The CNMC, in co-operation with other regulators, is working on a number of topics according to the priorities defined in the Work Plan for the South Gas Regional Initiative.

The NRA has already approved the CMP and CAM mechanisms. The NRA approved the balancing rules in the transmission network of the Spanish Gas System in July 2015. Balancing actions are seen as a positive measure to increase liquidity in the organised market. The organised exchange in Spain, differently from other member states, was not in place until recently and was fostered by the government. It was created for the entire Iberian Peninsula (Spain and Portugal) and is therefore subject to the same legislative framework in both countries, providing a more dynamic and flexible market by increasing transparency in pricing and competition, increasing liquidity in the system, strengthening network interconnections with other states and facilitating access to new suppliers.

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Acronyms, abbreviations and units of measure

Acronyms and abbreviations

ACER	European Agency for the Cooperation of Energy Regulators
ACM	Authority for Consumers and Markets
ANP	Agência Nacional do Petróleo, Gás Natural e Biocombustíveis
BGC	British Gas Corporation
CADE	Conselho Administrativo de Defesa Econômica
CAM	Capacity allocation mechanisms
CCGT	Combined-Cycle Gas Turbines
CEER	Council of European Energy Regulators
CMP	Congestion management procedures
CNG	Compressed Natural Gas
CNMC	Comisión Nacional de los Mercados y la Competencia
DSO	Distribution System Operator
EC	European Commission
ENAGAS	Empresa Nacional del Gas
ENC	European Network Codes
ENTSOG	European Network of Transmission System Operators
EPE	Empresa de Pesquica Energética
EU	European Union
FIP	Nova Infraestrutura Fundo de Investimentos em Participações
FSRU	Floating Storage Regasification Units
GASBOL	Bolivia-Brazil pipeline
Gaspetro	Petrobras Gás S.A.
GB	Great Britain
GCA	Gas Connect Austria
GSA	Gas Sales Agreement
GTA	Gas Transmission Agreement
GTC	General Terms and Conditions
GTS	Gasunie Transport Services
ICMS	Imposto sobre Operações relativas à Circulação de Mercadorias e Prestação de Serviços de Transporte Interestadual e Intermunicipal e de Comunicação
IEA	International Energy Agency
INT	Interoperability and data exchange
ISO	Independent System Operator
ISS	Imposto Sobre Serviços De Qualquer Natureza
ITO	Independent Transmission Operator
LDC	Local Distribution Company
LNG	Liquified Natural Gas
Logigás	Petrobras Logística de Gás S.A.
LRAIC	Long run average incremental costs
LRMC	Long run marginal costs
MME	Ministry of Mines and Energy
NC	Network Codes
NRA	National Regulatory Authority
NTS	Nova Transportadora do Sudeste S.A.
Ofgem	Office of Gas and Electricity Markets
OMV	Österreichische Mineralölverwaltung

OU	Ownership Unbundling
PPI	Programa de Parcerias para Investimentos
PPT	Programa Prioritário Termelétrico
TAG	Transportadora Associada de Gás S.A.
TBG	Transportadora Brasileira Gasoduto Bolívia-Brasil S.A.
TPA	Third-Party Access
Transpetro	Petrobras Transporte S.A.
TSO	Transmission System Operator
UIOLI	Use It Or Loose It
UNC	Uniform Network Codes
UK	United Kingdom
USD	United States dollar
VTP	Virtual Trading Point
YPFB	Yacimientos Petroliferos Fiscales Bolivianos

Units of measure

bcm	billion cubic meter
GW	gigawatt
MBtu	million British thermal units

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