# Implementing Gas Market Reform in Brazil

## Insights from European experience

International Energy Agency

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# IEA-BRAZIL GAS MARKET REFORM DIALOGUE AND PEER REVIEW PROCESS

Phase II (2019-2020)

# Abstract

The Novo Mercado de Gás (New Gas Market) reform programme is set to enhance the physical flexibility of the gas system, enable gas to be delivered more quickly, foster competition and facilitate the integration of a higher share of intermittent renewables into the Brazilian energy system. In the longer term, an open, competitive gas market can more easily adapt to a multi-gas system that includes and deploys low-carbon gases. At the request of the Brazilian government, the International Energy Agency (IEA) has been providing technical advice based on international experience to inform and shape the country's gas market reform programme from day one.

This current white paper follows the report "Towards a competitive natural gas market in Brazil: A review of the opening of the natural gas transmission system in Brazil", published in September 2018. It aims to share best practices from Europe in terms of gas market design and reforms, including commercial and practical implications. This white paper includes a section on the role of natural gas and low-carbon gases in Brazilian clean energy transition.

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# Introduction

On 8 April 2021, Brazil's President Jair Bolsonaro sanctioned the New Gas Law (Law nº 14.134/ 2021), setting the basis for a profound reform of the Brazilian Gas Market. Natural gas market reforms can bring substantial benefits to economies and support their recoveries from the current global crisis. The establishment of liquid wholesale gas markets fosters competition among suppliers, supports efficient resource allocation, and ensures transparent price discovery.

Besides fostering competition and improving efficiencies, gas market reforms can support clean energy transitions. An open and transparent access to the gas network improves the physical flexibility and short-term deliverability of gas systems and as such can facilitate the integration of a higher share of variable renewables into the broader energy system. In addition, the open, non-discriminatory grid access rules, enhanced operational transparency, flexible congestion management mechanisms and improved network interoperability made possible by these reforms will support the introduction of decentralised, small-scale and variable production of low-carbon gases (such as biomethane, hydrogen, synthetic methane) into the gas system as well as enabling their cost-and time-efficient trading. The effective deployment of low-carbon gases would further require the introduction of supporting schemes and the development of market rules related to the non-discriminatory application of blending limits, interoperability, enhanced data exchange and quality-neutral gas trading. This longer-term prospect should be further taken into consideration as the current regulatory framework is developed.

Gas market reforms are usually complex and lengthy, with both the European and North American experiences showing that it takes at least a decade to establish well-functioning, competitive wholesale gas markets. Strong political commitment, clear regulation and international experience-sharing can help fast-track gas market reforms.

The relationship between Brazil and the International Energy Agency (IEA) has grown considerably since the country joined the IEA as an association country in October 2017. Since then, collaboration and joint work has expanded to new topics, including energy innovation, system integration of renewables, as well as power and natural gas markets reforms.

Starting in 2018, and thanks to the support of the government of the United Kingdom, the IEA has led the IEA-Brazil natural gas market reform dialogue and peer review process. This collaboration aims at facilitating access to European experiences on gas market reform, providing technical support for the Brazilian government to develop policies and regulations that take stock of international best practices, but are adapted to the particularities of the Brazilian context.

Under this dialogue and peer review process, and in close collaboration with the Brazilian Ministry of Mines and Energy (MME) and other stakeholders, the IEA has organised a number of key activities in Brazil and Europe (as well as remotely), including international workshops, fact-finding missions, technical visits and dissemination activities. In October 2018, this led to the publication of the IEA report "*Towards a competitive natural gas market in Brazil: A review of the opening of the natural gas transmission system in Brazil*" (IEA, 2018), which was translated to Brazilian Portuguese in 2019.

The white paper reflects the discussions and outcomes of the second phase of this collaboration, which focuses on key topics for the implementation of Brazil's New Gas Market (*Novo Mercado de Gás*).

The paper is structured around six key topics. The first chapter provides an introduction to the regulatory framework enabling market liberalisation. The second chapter focuses on the development, the regulation and operational functioning of the transmission system. A special section has been dedicated to how capacity auctioning and booking systems can facilitate an efficient and cost-effective utilisation of the network. The third chapter provides a detailed analysis of the tools and mechanisms for enhancing the midstream flexibility of the gas system. Midstream flexibility is crucial both in terms of security of gas supply and as a prerequisite for short-term trade development. The fourth chapter focuses on hub development and on those factors which make a hub successful, i.e. a liquid, well-developed market place where demand from market participants is matched with supply in a time- and cost-efficient manner. The fifth chapter provides an in-depth overview of the regulation of distribution system operators. The white paper includes a special focus section on the role of natural gas and low-carbon gases in Brazil's clean energy transition and how the deployment of low-carbon gases can be supported by a forward-looking regulatory framework and infrastructure planning.

# Chapter 1. Towards a new gas market in Brazil

## *Novo Mercado de Gás*: The New Gas Market programme

Since the 1990s, Brazil has enacted policies to liberalise its energy sector. The two major policy acts for the natural gas sector are national laws *9.478/1997* (the Petroleum law) and *11.909/2009* (the Natural Gas law). While the former institutionalised the end of the Petrobras monopoly, it did not distinguish between oil and gas, and mandated that Petrobras create a subsidiary to operate pipelines and other infrastructure. The latter Natural Gas law, combined with a series of Decrees and ANP[1] resolutions, has provided the institutional framework for competitive wholesale and retail natural gas markets and has enacted third-party access (TPA) to transmission networks.

While these laws introduced important steps toward creating competitive markets, Petrobras continued to be dominant in the natural gas sector, though not a formal monopolist. Moreover, through constitutional force (*1988 Federal Constitution of Brazil – Article 25, paragraph 2*), states are responsible to regulate local distribution and create a diversity of regulatory choices.

In this context, the beginning of Petrobas' partnership and divestment programme (*Programa de Parcerias para Investimentos)* in 2015 created an important window of opportunity to improve the natural gas sector's institutional frameworks in Brazil. In 2016, the Gas to Grow (*Gás para Crescer*) programme targeted increasing competition in the natural gas sector by guaranteeing TPA to essential infrastructure and the transmission system and establishing market-oriented rules. This programme engaged several stakeholders and produced policy recommendations (*CNPE Resolution No. 10/2016*), some enacted by decree and others incorporated into a bill that was, however, never voted.

In 2019, two other CNPE Resolutions (*No. 04/2019* and *No. 16/2019*) caused the creation of a committee to promote competition in the natural gas market and defined guidelines for this task. This resulted in the New Gas Market programme (*Novo Mercado de Gás)*, which contains four main elements: promotion of

[1] The National Oil, Gas and biofuels regulatory agency.

competition, harmonisation of state level rules, and integration of the natural gas sector with the power and industrial sectors and removal of tax barriers.

In addition to the New Gas Market programme, the CMGN committee (*Comitê de Monitoramento da Abertura do Mercado de Gás Natural*) was established to monitor the natural gas market (Decree *No. 9.934/2019*). A related factor was an agreement between the Brazilian Administrative Council for Economic Defence (CADE) and Petrobras, which targeted the end of Petrobras' de facto monopoly. These initiatives include the involvement of different institutional players: the Ministry of Mines and Energy, the Ministry of Economy, the Energy Research Office (EPE), the Competition Authority (CADE), the federal regulator (ANP), and the Office of the President (Casa Civil) are each actively engaged in this process.

At the time of this writing, the COVID-19 pandemic has created a new set of challenges for policy makers around the world, who have been required to address urgent problems while continuing to work on crucial, long-term reform projects that will remain relevant once crisis measures are lifted. Social distancing measures around the world have led to a drastic reduction in economic activity, resulting in an unprecedented drop in energy demand[2].

This current situation could have major financial consequences for energy utilities, which tend to hold firm supply contracts that largely exceed current demand levels. To avoid long-term structural consequences, which could jeopardise the implementation of current reform efforts, governments should consider short-term support mechanisms to maintain the financial health of the supply chain without negatively impacting affordability for final consumers.

Despite short-term turbulence, reforms such as the Novo Mercado de Gás—which provide a long-term vision for the Brazilian gas market—remain essential for the development of the country's gas sector.

# Co-operation with the International Energy Agency

Brazil joined the International Energy Agency as an association country on 31st October 2017, opening new avenues for co-operation towards a more secure and sustainable energy future with Latin America's largest country.

This agreement naturally led to a closer co-operation between Brazil and the IEA in several fields, including gas market design and reforms.

[2] For more IEA analysis on the impacts of COVID-19 in global energy, please refer to the Global Energy Review 2020, https://www.iea.org/reports/global-energy-review-2020

During the Gas to Grow programme, the IEA led a technical dialogue and peer review process of the Brazilian natural gas market reform, carried out by a team of international experts. This process, which included a fact-finding mission and an in-country workshop, resulted in the publication "*Towards a competitive natural gas market in Brazil: A review of the opening of the natural gas transmission system in Brazil*" (IEA, 2018), which was translated to Brazilian Portuguese in 2019.

In the context of the New Gas Market programme, this collaboration continued with two important events. First, an international workshop on the modernisation of transmission and distribution services in Brazil in October 2019. This workshop was an opportunity to continue exploring international experiences and covered the following topics: market based mechanisms for capacity allocation, inclusive growth of the energy sector, balancing regime and hub price development, gas storage and grid expansion, as well and distribution sector reform and regulatory quality.

Second, this dialogue and peer review process continued with a technical visit organised by the IEA and supported by the UK and Dutch governments to London and The Hague. During this technical visit, a delegation of Brazilian experts participated in discussions on the transmission and distribution in the United Kingdom, key learnings from reform implementation and hub development in the United Kingdom, the decarbonisation of the natural gas sector and the Dutch experiences and lessons from their gas sector. Besides the delegation of Brazilian and IEA experts, other participants were the National Grid UK, Ofgem, Energy Networks Association, PRISMA, Oxford Energy Institute, Sustainable Gas Institute of Imperial College, the Dutch Ministry of Economic Affairs and Climate Policy, the Dutch Authority for Consumers and Markets (ACM) and Gasunie.

# Sharing European experience

This white paper follows the report *"Towards a competitive natural gas market in Brazil: A review of the opening of the natural gas transmission system in Brazil"*, published in English in September 2018, and aims to share best practices from Europe in terms of gas market design and reforms, including commercial and practical implications. This white paper includes a section on the role of natural gas and low-carbon gases in Brazilian clean energy transition.

The paper is structured around five key topics. The first chapter introduces the regulatory framework enabling market liberalisation. The second chapter focuses on development and the regulation and operational functioning of a transmission system. A special section is dedicated to the discussion of how capacity auctioning and booking systems can facilitate efficient and cost-effective network utilisation. The third chapter provides a detailed analysis of the tools and mechanisms required for enhancing gas system midstream flexibility. Midstream flexibility is crucial both in terms of gas supply security and as a prerequisite for short-term trade development. The fourth chapter focuses on hub development and on those factors that make a hub successful, such as a liquid, well-developed marketplace where demand from market participants is matched with supply in a time- and cost-efficient manner. The fifth chapter provides an in-depth overview of the regulation of distribution system operators.

# Chapter 2. Market liberalisation: Regulatory framework

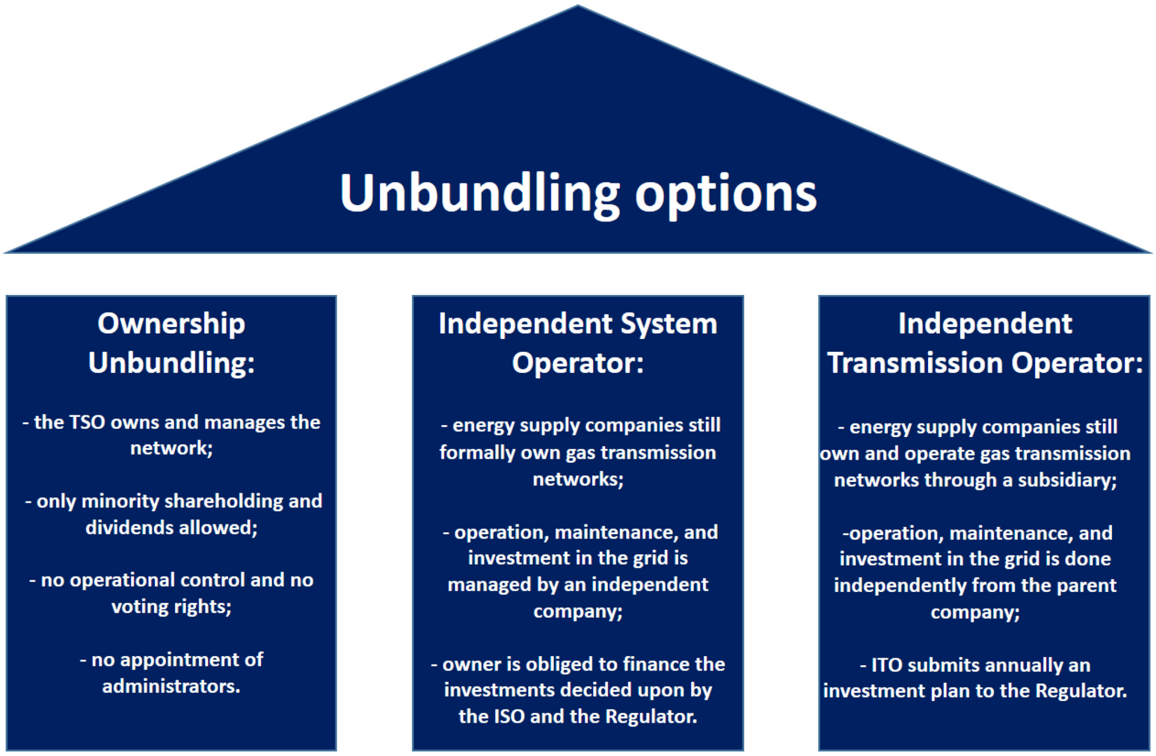
The concept of gas market liberalisation is to promote competition in wholesale and retail markets and to facilitate market entry for new players to compete against the incumbent(s) in supplying gas. A competitive gas wholesale market needs to be efficient, delivering gas where it is most valued while providing network users with the correct incentives to secure supplies to consumers. An efficient market must also provide investment signals in both gas production and gas network infrastructure, including transmission and storage, to meet the demands of gas consumers. Non-discriminatory and fair arrangements for network users to access the gas infrastructure are also necessary to allow competition to develop and the network to be used efficiently while guaranteeing adequate remuneration for investments.

Successful market liberalisation requires that an effective regulatory framework is in place with the following cornerstones, along with consistent oversight to ensure its implementation.

## Unbundling

Gas networks are frequently natural monopolies. Often, owners of these networks are active in other parts of the gas supply chain. Where this is the case, regulatory authorities must ensure that network owners cannot use their position to disadvantage other (competing) market players. This is achieved through a variety of unbundling options that effectively separate network operation from other, competitive market activities such as production and supply. Figure 2.1 provides an overview of the available unbundling models under EU regulation, with ownership unbundling considered to be the most effective option.

**Figure 2.1 Unbundling models in the European Union**






Source: IEA analysis based on European Commission (2020), *Third Energy Package*.

**European experience shows that multiple models of unbundling can co-exist.**

In the agreement signed between Petroleo Brasileiro SA (Petrobras) and the anti-trust authority Conselho Administrativo de Defesa Econômica (CADE) in July 2019, Petrobras committed to sell its remaining shareholdings in the transmission system operators[3] (TSOs) and to cease its indirect participation in gas distribution companies. Provided that no other vertically integrated undertaking holds and/or acquires shares in a transmission system operator that allow it to exercise control over that operator, all transmission system operators could be considered fully ownership unbundled.

# Network codes

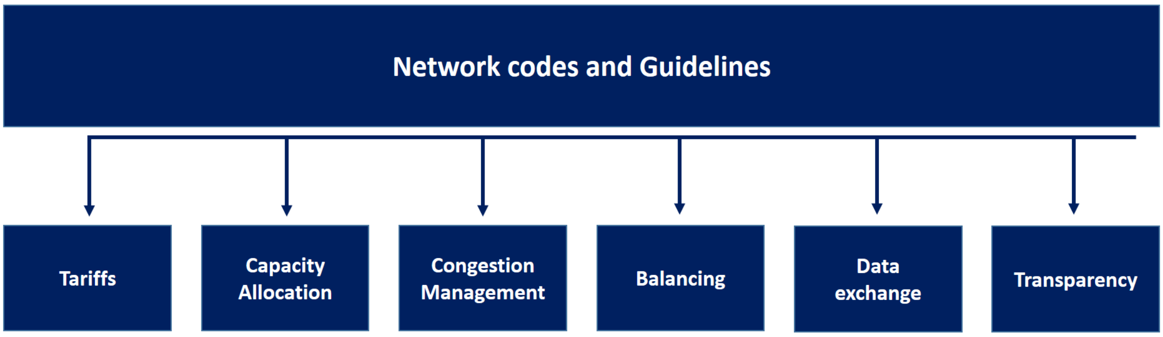
Unbundling is complemented by network codes, rules that regulate third-party access to the gas network. These ensure that market players are not discriminated against by system operators, are treated equally, and face the same conditions

[3] 10% in Nova Transportadora do Sudeste S.A. (NTS), 10% in Transportadora Associada de Gás S.A. (TAG) and 51% in Transportadora Brasileira Gasoduto Bolívia-Brasil S.A (TBG).

when attempting to be successful on the gas market. For eligible (free) consumers, this means that they can freely choose a gas supplier.

To create a well-functioning market, common rules for capacity allocation, tariffs, congestion management, interoperability and data exchange, transparency and several other areas are required (Figure 2.2). Development of these rules should be driven by the regulatory authority and unbundled transmission system operators. Involvement of all stakeholders in the development of network codes is key.

**Figure 2.2 Network codes and guidelines**






Source: IEA analysis based on ENTSOG (2020), *Network Codes and Guidelines*.

**The development and implementation of network codes and guidelines provides the regulatory framework necessary for a well-functioning, liberalised gas market.**

# Ensuring stakeholder involvement in the development of network codes

The process developed by the European Network of Transmission System Operators for Gas (ENTSOG) is considered as best practice regarding stakeholder involvement. ENTSOG set up Stakeholder Joint Working Sessions (SJWS) that are open to all interested parties during the period where ENTSOG is working towards developing a network code. The SJWS serve to gather ideas, reactions, assist in the formulation of, and test, proposals. All stakeholders, TSOs, regulators, and ministries can attend the SJWS. The aspiration is that attendees will share their company or organisation's view on matters of significance to network code development, and actively contribute to the process.

Records are kept for each SJWS to reflect attendance and to capture the essence of the discussion; in particular, items of agreement/disagreement and agreed actions are captured. Minutes are published via the ENTSOG website. After several SJWS, ENTSOG prepares a draft network code that is then subject to one or more public consultation(s).

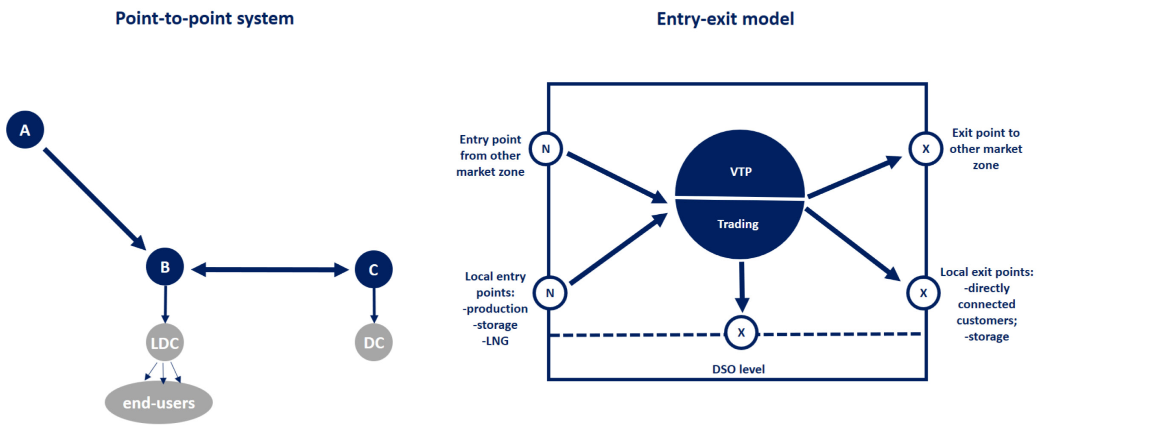
In Brazil, transmission system operators jointly formed the Association of Natural Gas Pipeline Transport Companies (ATGÁS) in December 2017. This is a civil, non-profit association with the objective to promote expanding the gas transmission network and developing a stable regulatory environment. Equipped with sufficient resources, this association could be tasked to assume a similar role as ENTSOG and ensure inclusive stakeholder engagement in the development of network codes. Ultimately, network codes should be subject to the scrutiny of the regulatory authority responsible for issuing network codes as generally applicable resolutions.

# Entry–exit model

In the European Union, the entry–exit model has been adopted for organising access to gas transmission networks. This model is best suited to enhance competition through liquid wholesale markets as it enables gas trade independent of its location in the system.

This contrasts with a point-to-point capacity reservation system, where capacity is defined and reserved at distinct delivery and redelivery point(s) along a clearly identified (and contractually binding) transportation route or connecting path. Figure 2.3 provides a schematic comparison of the two models.

**Figure 2.3 Comparison of a point-to-point system and entry-exit model**






Notes: LDC = local distribution company; DC = direct consumer(s); VTP = virtual trading point; DSO = distribution system operator.
Source: IEA analysis based on various public sources, including DNV KEMA for the European Commission (2013), [Study on Entry-Exit Regimes in Gas, Part A: implementation of Entry-Exit Systems.]

**An entry–exit model breaks down the contractual and path-rigidities of a point-to-point system by allowing market participants to trade on the virtual hub.**

An entry–exit system is a gas network access model that allows network users to book capacity rights independently at entry and exit points, creating gas transport through zones instead of along contractual paths. Network users who have booked entry or exit capacity can sell or buy gas at the virtual trading point (VTP) within the entry-–exit zone. A more detailed discussion of the main settings and functions of a virtual hub is provided in Chapter 5.

In Brazil, the National Council of Fiscal Policy (CONFAZ) published an agreement (*Ajuste SINIEF nº 03/2018*[4]) to adjust the current taxation mechanism at the state level, lifting a key barrier to implementing an entry-exit model. Following this agreement, taxation is no longer based on observed gas physical flows but on contractual entry-exit points. In future, to allow gas trading without specifying its physical destination, it is desirable to base taxation on injection or withdrawals of natural gas, without indicating both (entry-exit) points for each transaction.

# Institutional framework

Confirming regulatory framework compliance is the responsibility of regulatory authorities, who must perform their duties impartially, transparently, and without susceptibility to political influence or pressure from regulated companies. Since the outset of liberalisation, the range of tasks required of regulators to perform has grown steadily in many countries. To carry out this expanding number of responsibilities, regulatory authorities must be provided with sufficient resources.

# Virtual pipelines

EU legislation sets no obligation for customers to connect to the TSO or DSO network. Moreover, besides pipelines, a few alternative technologies and methods have been developed to monetise and transport natural gas, including gas-to-wire and the transportation of compressed natural gas (CNG) containers and small-scale LNG ISO tanks via trucks and rail. These “virtual pipelines” can be crucial for meeting local natural gas demand in emerging market areas with strong consumption growth and a still developing pipeline network.

The development of virtual pipelines enables natural gas delivery to remote areas without developed physical gas networks. However, in regions where physical gas networks exist, gas-to-gas competition, such as competition between gas transported through virtual pipelines and gas transported through physical pipelines, may appear.

[4] AJUSTE SINIEF 03/18, DE 3 DE ABRIL DE 2018 Conselho Nacional de Política Fazendária (CONFAZ), Ministério da Economia, Brasil.

This competition can be established and monitored by competition legislation, both generally and specific to natural gas. The existing gas networks regulation should provide clear rules and not create barriers to competition. For example, parties interested in investing in virtual gas pipelines might be reluctant to do so in regions where physical pipelines do not exist but must be constructed and consumers subsequently connected to the network.

# Chapter 3. The transmission system: From network planning to capacity auctioning

Brazil's gas transmission system is composed of 9409 km of pipes, 14 processing plants, 33 compressor stations and 187 city gates[5]. The country's gas network is expected to develop rapidly in the coming years, in line with growing gas production and demand. In EPE's Indicative Pipeline Development Plan (*Plano Indicativo de Gasodutos de Transporte*) over 2000 km of potential transport pipeline projects are included. It has been estimated that BRL 17 billion (USD 4.5 billion) in investments could be required in the gas transmission infrastructure system.

The following chapter provides an overview of best practices related to effective planning and transmission system function, including network planning, capacity management, congestion management procedures and balancing. A special focus is provided on capacity auctioning.

## Network planning

The development of a gas transmission system should consider both the commercial necessities of different agents of the liberalised gas market and the security for supply requirements in the broader gas and energy system.

In practice, the aim should be to establish an entry-exit system, relying on a transmission system with sufficient flexibility to allow both short- and long-term commercial operations required for optimal delivery of gas volumes to end-consumers.

First, the type of infrastructure subject to central planning needs to be clearly defined. In Europe, there are countries in which central planning involves not only transmission pipelines, but also other upstream or downstream facilities, such as LNG terminals, underground storages, renewable gas injection points, and so forth.

[5] In addition to transmission pipelines, compressor stations and city gates, processing plants and LNG terminals may also be considered a part of the transmission system and included in the network planning. In Brazil, each of these activities is currently subject to specific regulation and planning.

Efficient network planning requires proper information flow between the stakeholders involved in management of the transmission system:

- The **"Market-to-Policy-Makers"** direction, in which shippers' information (through Open Seasons or Auctions) provide insights to TSOs on required capacity adjustments. This feeds back to the regulatory agency, which adopts or approves the requirement based on a cost-benefit analysis (CBA).
- The **"Policy-Makers-to-Market"** direction, in which first policy makers establish their priorities, upon which TSOs base and design long-term network plans and then offer the capacity to the market.

In Europe, there are several planning procedures relating to national, regional and European levels of gas network development:

**1. National Planning:** each EU member state develops a national network plan based on national regulation. Most of these contain a mandatory grid expansion for a short-term period and an indicative long-term one. There are differing "Market-to-Policy" or "Policy-to-Market" flows.

**2. GRIPs** (Gas Regional Investment Plans): these investment plans, developed every two years, involve more than one member state. They have an indicative nature and focus on solving problems or constraints specific to the region/group of countries involved.

**3. European Planning:** Commonly known as Ten-Year Network Development Plan (TYNDP), this exercise is performed by ENTSOG every two years. It consists of defining a Europe-wide supply and demand scenario for the whole system and considers different types of projects proposed by the national TSOs. Several simulations are performed to test whether the main criteria set up by the European Commission are met or not. Those criteria are based on Security of Supply, Competitiveness, Price Convergence and Environmental Sustainability.

This central role of ENTSOG as technical co-ordinator is important and could be equivalent to the role expected from the Market Area Operator in Brazil in charge of co-ordinating the TSOs when performing the Brazilian Coordinated Network Plan.

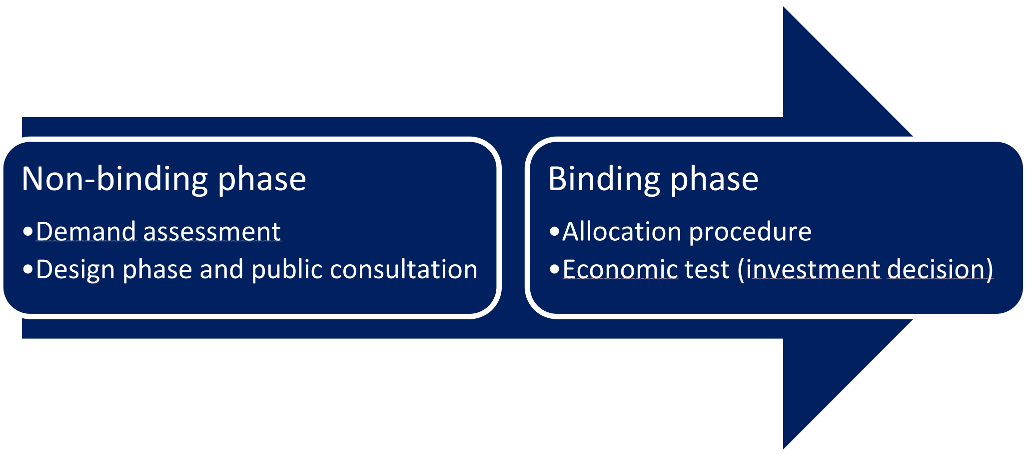
In Brazil, the Ten-Year Energy Expansion Plan (PDE) presents energy demand and supply scenarios every year. However, PDE comprises the whole energy sector and not only natural gas activities. Another national plan is the Transmission Gas Pipeline Indicative Plan (PIG), published in 2019, which presents gas pipeline alternatives based on PDE analyses. This study replaced the Ten-Year Transmission Network Expansion plan (PEMAT), established by a Decree in 2010. Both are indicative plans produced by the Energy Research Office (EPE).

# Incremental capacity

With gas production and gas consumption expected to increase significantly in Brazil over the next few years, a regular process to test market demand for incremental capacity should be introduced.

In the European Union, a process has been established that consists of regular demand assessments followed by a structured phase of design and binding allocation of incremental capacity. Any Brazilian investment decision to further the assessment of market demand for capacity should be subject to an economic test to determine the project's economic viability. This economic test should in turn ensure that network users who demand capacity assume the corresponding risks associated with their demands and avoid exposing captive customers to such investment risks. Figure 3.1 shows the European Union's incremental capacity process.

**Figure 3.1 Incremental capacity process in the European Union**






**The incremental capacity process adopted in the European Union consists of two main phases: a non-binding phase and a binding phase.**

In the non-binding phase, market demand for incremental capacity is analysed by allowing market parties to state their interest in incremental capacity (where, how much, when). When demand indicates, TSOs proceed in the design phase by developing one or more projects that lead to capacity offer levels in line with demand indications. In this phase, close co-operation between adjacent TSOs is required, such as performance of joint technical studies in case a project covers more than one TSO-system. The non-binding phase is concluded by approval of the proposed projects from the regulatory authority. This approval comprises the capacity offer levels, the procedure for allocating the incremental capacity and all relevant parameters of the economic test.

In the binding phase, TSOs run the allocation procedure. If sufficient commitments from market parties are obtained that lead to a positive result in the economic test, an incremental project is initiated. If instead the economic test is negative, the incremental capacity process is terminated.

# Tariff regime

Under the entry–exit model, capacity contracts for input and withdrawal are separated and independent of each another—there is no linked contract path. Service entitlement is to bring gas into the system (entry capacity) or to remove gas from the system (exit capacity), and such services can be obtained by the same or different network users.

In the European Union, *Regulation (EC) No. 715/2009* defines the general principles of tariffs for access to networks. Accordingly, tariffs or the methodologies used to calculate them (i) must be approved by the regulatory authorities; (ii) must be transparent; (iii) should reflect actual costs incurred while including an appropriate return on investments; and (iv) should be applied in a non-discriminatory manner.

Based on those principles, different tariff regimes can be developed alongside the following dimensions[6]:

- **Application of entry and exit charge:** as entry and exit capacities are decoupled in an entry–exit system, it is possible to price either both entry and exit points or only one of them.
- **Application of capacity and commodity charge:** access prices might be set using two different bases: the reserved capacity and the volumes transported. When using the amount of capacity reserved for charging access to the network, it is referred to as a *capacity charge* (alternatively the term *demand charge* is used), whereas when the transported volumes serve as the basis for the tariff setting, it is called a *commodity charge* (or energy charge). Frequently, a combination of both is applied.
- **Locational differentiation:** In an entry-exit system, tariffs can be based on a uniform approach, where tariffs for different network points are set equally, or based on location, where tariffs differ for every entry and exit point or zone.
- **Locational tariffs:** tariffs are set for different network points using various cost allocation schemes such as pipeline length, replacement costs or long-run marginal costs (such as in the United Kingdom).

[6] Categories partly based on DNV KEMA for the European Commission (2013), Study on Entry Exit Regimes in Gas, Part A: implementation of Entry Exit Systems.

- **Postage stamp tariffs**: the same tariff is applied to all entry and to all exit points; however, the tariff applied to entry points might differ from that applied to exit points.
- **Different approaches for entry and exit points**: different tariff setting principles apply to entry and exit points (for instance uniform entry tariffs and location differentiated exit tariffs, or vice versa).
- **Product / customer differentiation:** Tariffs are differentiated related to their network points. For example, different tariffs are applied to capacity products with differing durations (daily, monthly, quarterly, annual). In other cases, tariffs are dependent upon specific properties of the connected party, such as annual consumption, delivery pressure or gas quality.
- **Duration of capacity products:** TSOs might apply different tariffs for short-term capacity products (daily, monthly, and quarterly). These tariffs are usually set based on the reference price of annual capacity using specific adjustment factors.
- **Seasonal factors:** TSOs might apply seasonal multipliers by determining tariffs for short-term capacity products. In this model, capacity products in winter months are priced proportionally higher than in summer months.
- **Consumer groups:** Different tariffs might be applied for different consumer groups, which are differentiated either by maximum capacity of the connection or by annually consumed volumes.
- **Pressure level:** This model differentiates based on the pressure level of the connection (such as in Spain and Belgium).

The choice of the methodology to set tariffs (such as postage stamp vs. methodologies that provide for locational signals) depends primarily on the topology of the network, with a focus on ensuring appropriate cost-reflectivity.

The use of a postage stamp methodology could be appropriate in the following use cases:

- Networks where the difference between the average distance travelled by transit flows and the average distance travelled by domestic flows does not exceed a certain threshold.
- Networks where almost all the capacity is dedicated to the domestic market (for example, no transit flows), and which are not subject to expansion.

The use of methodologies that provide for locational signals might be appropriate in the following use cases:

- A network with a unique geographical node where all flows converge and can be identified (the virtual point-based methodology may be appropriate).
- Networks that are expected to be expanded and where differing tariff levels provide incentives to network users so that network operators can operate the gas system efficiently and plan for expansion.

The EU Tariff Network Code states a clear preference for capacity-based tariffs. This logic is primarily because the largest part of the TSOs' cost is fixed, meaning it is independent of the volume transported. A commodity-based tariff can be set for costs that are driven by the quantity of the gas flow (such as compressor energy). Approximately 90% of TSO costs are fixed and 10% are variable.

In the Brazilian context, where an expansion of the gas system is expected, methodologies that provide for locational signals should be considered. To level the playing field for certain entry or exit points, an equalisation of tariffs at those points could be introduced as a secondary adjustment.

It is important to highlight that *EU Regulation No. 2017/459*, establishing network code on capacity allocation mechanisms, allows for capacity auctions where market participants can directly bid for offered capacity. As such, the value of capacity is directly determined by market participants. A detailed description of capacity auctioning and booking is provided in the section below.

# Capacity auctioning

## Regulatory framework

At the beginning of the 2000s, the European gas market was characterised by significant market fragmentation triggered by different rules and processes for marketing and allocating gas transmission capacity. Furthermore, there was a high level of market integration by large national gas incumbents. This created a situation where access and operations were extremely complicated and only a few shippers had the capability, expertise and knowledge to acquire gas transmission capacity between European countries to deliver natural gas to their customers.

To standardise European gas market functions and to increase competition in all European national gas markets, European institutions approved *Regulation No. 715/2009* establishing the conditions for access to natural gas transmission networks (Congestion Management Procedures (CMP) guidelines), *Regulation No. 984/2013* establishing the Network Code on Capacity Allocation Mechanism (NC CAM) and *Regulation (EU) No. 459/2017* amending the NC CAM.

These regulations profoundly changed the European gas market by:

- providing a high level of transparency, synchronisation, and capacity maximisation
- introducing specific rules to avoid market dominance and capacity hoarding
- introducing regulations and processes for marketing and allocating gas transmission capacity.

Marketing and allocating gas transmission capacity represent the most important processes defined in the NC CAM, which regulates:

- the standard gas capacity products to be marketed by gas Transmission System Operators (TSOs)
- their obligation to offer firm bundled[7] capacity and the processes for interruptible capacity
- the calendar accordingly to which the capacity shall be offered to the market
- the algorithms for allocating the gas transmission capacity
- the joint use of a web-based booking platform for marketing gas transmission capacity
- the process for marketing "incremental capacity".[8]

## Standard capacity products

NC CAM defines the products that TSOs shall offer to the market for allocating their transmission capacity:

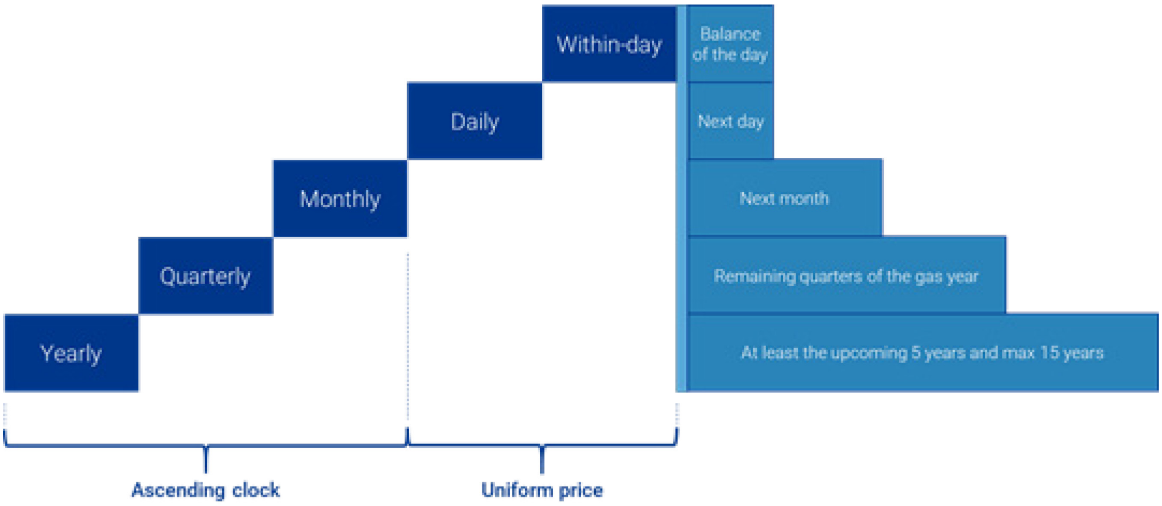
- yearly products – from October to September of the following year
- quarterly products – four quarters of the gas year
- monthly products – every single month
- daily products – every single day
- within-day products – from a starting hour till the end of the gas day.

Figure 3.2 illustrates the sequence of standard capacity products as defined by the NC CAM; it is important to highlight that gas transmission capacity should be offered to the market from products with the longest duration before the ones with the shortest duration. This implies that gas transmission capacity shall be initially offered via yearly auctions and, if not sold before, via quarterly auctions. If still available, gas transmission capacity will be also offered via within day auctions.

[7] The NC CAM introduces the following definition of 'bundled capacity': a standard capacity product offered on a firm basis which consists of corresponding entry and exit capacity at both sides of every interconnection point and the implementation of a joint nomination process.

[8] The amended version of the NC CAM defines 'incremental capacity' as a possible future increase via market-based procedures in technical capacity or possible new capacity created where none currently exists that may be offered based on investment in physical infrastructure or long-term capacity optimisation and subsequently allocated subject to the positive outcome of an economic test, in the following cases:
at existing interconnection points
by establishing a new interconnection point or points
as physical reverse flow capacity at an interconnection point or points, which has not been offered before.

**Figure 3.2 The sequence of standard capacity products as defined by the NC CAM**




Source: Reproduced from ENTSOG (2010), ENTSOG Current Work on Auctions.

**The rationale behind this product hierarchy is to prevent products with longer duration from not being available to market participants because a shorter product was fully allocated.**

These standard capacity products should be offered to market participants as “firm” capacity and may be offered as “interruptible” capacity only if the corresponding monthly, quarterly or yearly standard firm capacity product was sold at an auction premium, was sold out or was not offered. If firm daily capacity product was sold out or not offered, TSOs have the obligation to offer interruptible daily capacity products in both directions.

Firm capacity products should be offered as bundled capacity by neighbouring and connected TSOs only when gas transmission capacity at one side of the Interconnection Point was allocated before entry into force of the NC CAM. The connected TSOs can market unbundled capacity for an amount and duration that does not exceed the existing transport contract at the other side.

*Article 19 (5)* of the Tariff Network Code[9] provides guidelines to national regulators regarding how auction premia should be used. Accordingly, the auction premia can be used to either reduce physical congestion (such as to increase technical interconnection capacity) or to decrease tariffs in the next tariff period. TSOs may

[9] “Subject to a decision in accordance with Article 41(6) (a) of Directive 2009/73/EC, the earned auction premium, if any, may be attributed to a specific account separate from the regulatory account referred to in paragraph 4. The national regulatory authority may decide to use this auction premium for reducing physical congestion or, where the transmission system operator functions only under a non-price cap regime, to decrease the transmission tariffs for the next tariff period(s) as set out in Article 20.”

not keep these revenues, as this creates an incentive to deliberately cause congestion at borders by underinvestment.

## Auction calendar

One fundamental feature of the European gas market is the calendar according to which gas transmission capacity is made available to market participants via auction. This calendar not only defines the days and hours when different capacity products are offered, but also specifies the days and hours when information regarding the different standard capacity products must be published by TSOs. This obligation is extremely important, as it provides a high level of transparency; European market participants know when TSOs will publish the amount, price and characteristics of standard capacity products. Publication is performed ahead of the start of capacity auctions (i.e., for yearly auctions, the relevant information is published one month before the start of the auction) to provide enough time for market participants to evaluate and prepare their participation in the auction(s).

The auction calendar is illustrated in Table 3.1.

### Table 3.1 The auction calendar

| Product | Frequency of auctions | Number of products per auction | Publication of available capacity | Start of the auction | Bidding rounds | Notification of allocation results to participants | Auction type |
|---|---|---|---|---|---|---|---|
| Auction calendar for film capacity types | | | | | | | |
| Year | Annual | 5-15 years | 1 month before the start of the auction* | 1st Monday of July | First round 09:00-12:00<br><br>Following rounds 13:00-14:00 15:00-16:00 17:00-18:00 | No later than the next business day *** | Ascending clock auction |
| Quarter | Quarterly | Q1-Q4<br>Q2-Q4<br>Q3-Q4<br>Q4 | 2 weeks before the start of the auction* | 1st Monday of August<br>1st Monday of November<br>1st Monday of February<br>1st Monday of May | | | |
| Month | Monthly | M1 | 1 week before the start of the auction* | 3rd Monday of the month | | | |
| Day | Daily | D1 | With the start of the auction | 16:30 | 30 minutes | No later than 30 minutes*** | Uniform price auction |

| Product | Frequency of auctions | Number of products per auction | Publication of available capacity | Start of the auction | Bidding rounds | Notification of allocation results to participants | Auction type |
|---|---|---|---|---|---|---|---|
| Within day | Hourly | H+4 | With the start of the auction | Every hour | 30 minutes | No later than 30 minutes*** | |
| Auction calendar for interruptible capacity types | | | | | | | |
| Year | Annual | 5-15 years | One week before the auction starts** | 1st Monday of August (TBC) | First round 09:00-12:00<br>Following rounds 13:00-14:00 15:00-16:00 17:00-18:00 | No later than the next business day *** | Ascending clock auction |
| Quarter | quarterly | Q1-Q4 Q2-Q4 Q3-Q4 Q4 | | 1st Monday of September 1st Monday of December 1st Monday of March 1st Monday of June | | | |
| Month | Monthly | M1 | | 4th Monday of the month | | | |
| Day | Daily | D1 | With the start of the auction | 17:30 | 30 minutes | No later than 30 minutes *** | Uniform price auction |

Notes: * 9:00, ** 7:00, *** after the end of the bidding round. Time Zone in Central European (summer) Time. In some cases, different auction cases may apply.
Source: Reproduced courtesy of ENTSOG/ACER.

## Algorithms for allocating gas transmission capacity

Another fundamental element of European regulation is the definition of specific algorithms that must be utilised when identifying successful and binding requests for gas transmission capacity. Currently the NC CAM allows for two different algorithms:

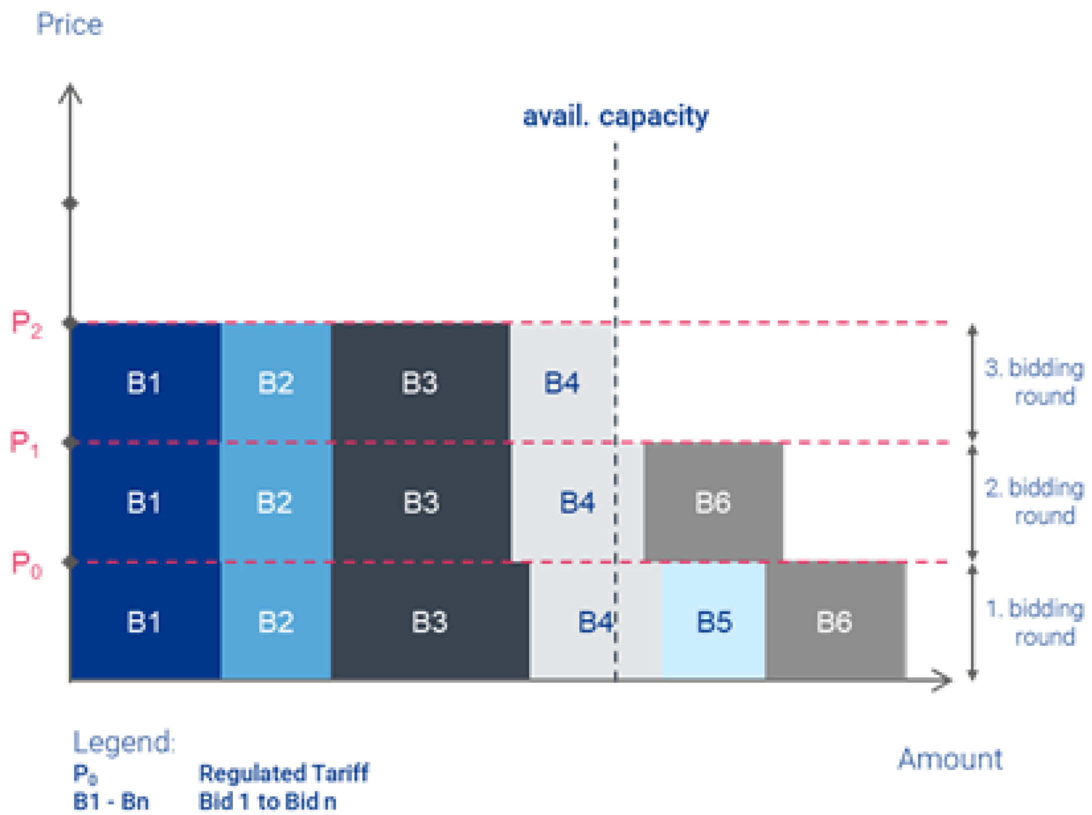
- **ascending clock algorithm** - for allocating gas transmission capacity via yearly, quarterly and monthly auctions; and
- **uniform price algorithm -** for allocating gas transmission capacity via daily and within day auctions.

### Ascending clock algorithm

This algorithm is based on the principle that market players place volume bids only against escalating price values; the starting price at auction is the sum of regulated tariffs of the bundling TSOs, and it increases incrementally if the total demand for gas transmission capacity is higher than the available capacity.

Figure 3.3 shows a case in which several market participants were interested in buying gas transmission capacity at the starting price of $P_0$ (equal to the regulated tariffs of the TSOs); the total demand, expressed by the market participants, was higher than the available capacity and for this reason the auction continued to the next price step. In the second bidding round, the total requested capacity was higher than the available capacity and the auction had to continue to the next price step ($P_2$). In the third bidding round, the total requested capacity was equal to the available capacity and the auction successfully terminated at the final price $P_2$. The gas transmission capacity was allocated to market participants who placed a bid in the third bidding round (in the picture above $B_1$, $B_2$, $B_3$ and $B_4$).

**Figure 3.3 Auction with several market participants interested in buying gas transmission capacity at the starting price point**




Source: Reproduced from PRISMA European Capacity Platform GmbH (2019), Presentation "Network Code on Capacity Allocation Mechanisms", 20.01.2020, London.

The advantage of this algorithm is that it does not require market participants to place one unique bid, composed by needed quantity and willingness to pay for gas transmission capacity, but allows them to discover how willing the market is to pay via introducing different price steps. A potential drawback to this algorithm is the risk that the auction could continue over several days due to high demand or low increase in subsequent price steps of the gas transmission capacity. The appropriate value definition of the price step is extremely important and must be rigorously evaluated before it is applied.

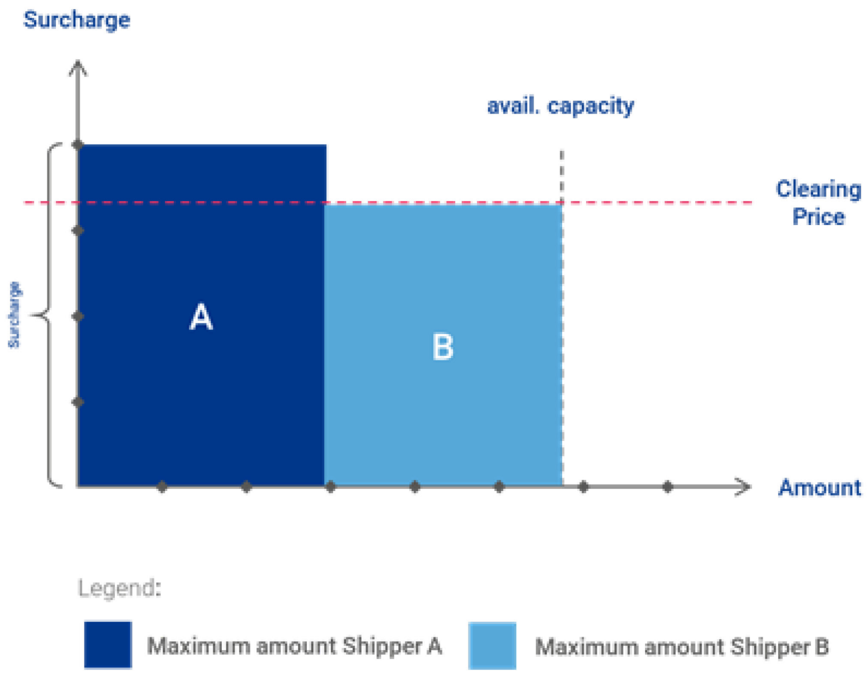
## Uniform price algorithm

The "uniform price" algorithm is based on the principle that all successful market participants pay the same price for gas transmission capacity, and that price is identified in one unique round.

In uniform price auctions, market participants must submit for each bid the quantity of gas transmission capacity they would like to acquire and the price they are willing to pay; the identification of the clearing price is made by ordering first the bids from those with the highest willingness to pay down to the lowest. The clearing price represents the willingness to pay for the last accepted bid.

Figure 3.4 illustrates a simple situation in which two market participants participate in an auction; Shipper A is willing to pay the highest amount for gas transmission capacity and for this reason is ranked first. Shipper B placed the clearing price of the auction and, in this case, this is also the price that Shipper A pays for gas transmission capacity.

**Figure 3.4 Auction with two market participants**




Source: Reproduced from PRISMA European Capacity Platform GmbH (2019), Presentation "Network Code on Capacity Allocation Mechanisms", 20.01.2020, London.

**The Uniform price algorithm is today used in European member states for marketing daily and within day capacity products.**

## Capacity booking platform

NC CAM introduces the obligation for TSOs to market gas transmission capacity via "*one or limited numbers of joint web-based booking platforms*". This provision has been implemented in different ways in Europe. Some TSOs upgraded their IT-system, implementing new features to comply with European requirements; other TSOs created a new company tasked with developing a new web-based platform to fulfil the obligations of NC CAM.

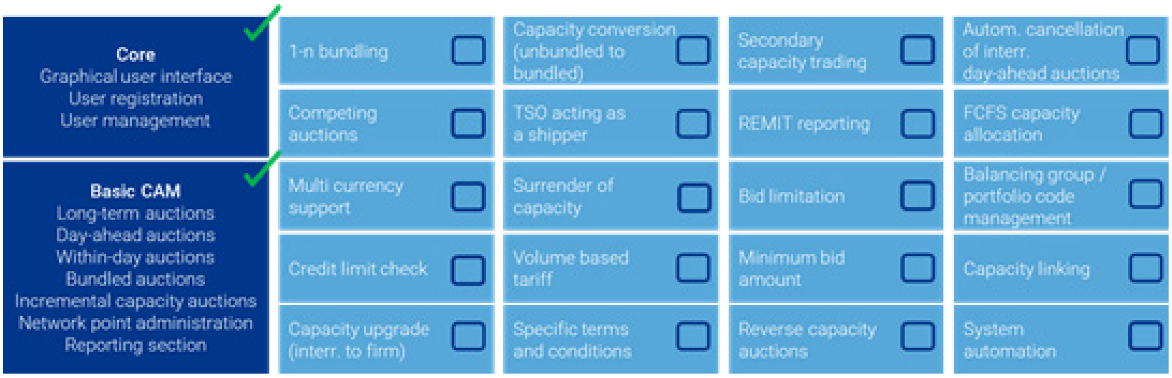
These different approaches have created the situation that currently exists in Europe, where three booking platforms market gas transmission capacity on behalf of TSOs:

- **Regional Booking Platform**—owned by FGSZ (the Hungarian TSOs) and used in South-East Europe.
- **Gaz-System Platform**—owned by Gaz-System and used at some border points of Poland.
- **PRISMA European Capacity Platform—**owned by several European TSOs and used by the majority of the European TSOs and by one Tunisian TSO.

These three booking platforms have developed in different trajectories: PRISMA European Capacity Platform also offers services for storage system operators; moreover, all booking platforms have developed additional services that support TSOs marketing their transmission capacity.

For example, PRISMA developed the following services to fulfil the obligations of NC CAM and other TSOs' requirements (Figure 3.5):

**Figure 3.5 Services to fulfil the obligations of NC CAM and other TSOs' requirements**




Source: Reproduced from PRISMA European Capacity Platform GmbH (2019), Presentation "Network Code on Capacity Allocation Mechanisms", 20.01.2020, London.

**In this case, identifying the services that TSOs can use from a booking platform must be assessed and jointly evaluated with stakeholders.**

# Congestion management procedures

When there is a high interest from the market in certain products or services, there is a risk of reaching contractual congestion. To mitigate this, there are several Congestion Management Procedures (CMPs) in place. The core Congestion Management Procedures commonly used in Europe, applicable to other gas markets, are the following:

- **Oversubscription and buy-back** is a basic instrument to prevent contractual congestion based on the idea that the TSO offers more firm capacity to the market than is technically available. This cannot be done in the case of physical congestion, which is why the TSO makes use of statistical scenario planning to determine a probable amount of capacity that that will remain unused by capacity contract holders. This oversubscription and buy-back scheme is a preventative measure meant to be applied continuously to ensure that contractual congestion does not occur, but inevitably is accompanied by a certain degree of risk, where the TSO could be forced to apply a market based buy-back procedure in which network users can offer capacity.
- **Firm day-ahead use-it-or-lose-it** consists of removing capacity previously booked from agents who are not using it (nominating it), and offering this capacity back to the market. This can be a highly effective tool, although it places some extra restrictions on the way in which capacity rights can be used.
- **Capacity surrender** allows network users to offer capacity they do not intend to use back to the TSO and which the TSO can then reallocate. Capacity surrender is entirely voluntary for network users and it an alternative to their rights to offer capacity on the secondary market. Those platforms should offer a secondary market service, with the scope of trading capacity products to allow changing capacity ownership based on market requirements.

# Balancing

From an operational point of view, natural gas flows in the transmission system from one point to another on the network due to pressure differential existing between those two points. The gas transport network must be in balance so that gas can be transported safely and effectively. 'In balance' means that the transport network remains at the correct pressure and that the overall volume of gas removed from the network matches the volume entering it. However, pressure fluctuations stemming from market parties' injections and off-takes—if the tolerance levels of the transport system are not considered properly—can lead to imbalances and undermine the network's safe operation.

Using the traditional model of vertical integration, an incumbent monopolist is typically the only shipper on a transmission network responsible for most injections and withdrawals. In a liberalised gas market, a variety of network users (including shippers and traders) are present, each providing a fraction of the total gas trade.

Consequently, in a liberalised gas market, each network user is responsible for the quantity of gas it removes or feeds in, which means that network users also share responsibility for maintaining the transport network balance. It is therefore crucial to design a balancing scheme that motivates each market participant to maintain system balance, while the TSO retains the ultimate responsibility to ensure safe operation of the grid daily.

A balancing model usually consists of two sides:

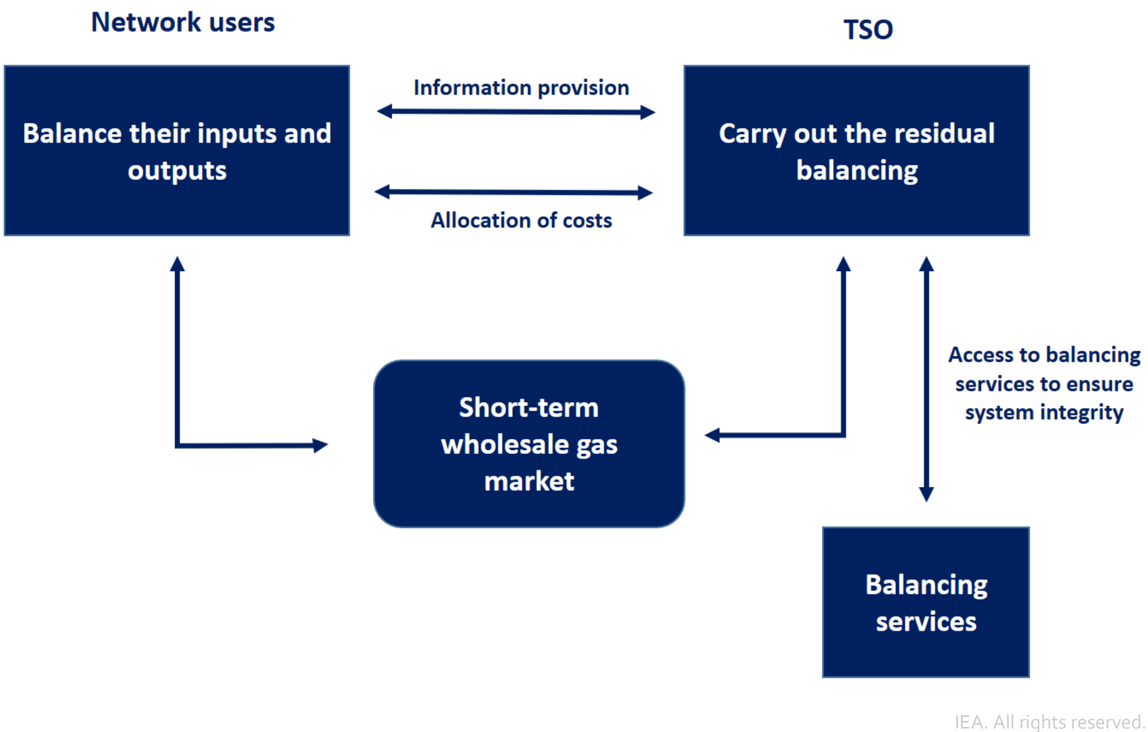
- **System balancing**—maintenance of the physical system's stability during network operation.
- **Imbalance settlement**—the ex-post commercial process when individual deviations between injection and off take are cleared.

In the European Union, Regulation (EC) *No. 715/2009* emphasises that "The network users shall be responsible to balance their balancing portfolios in order to minimise the need for transmission system operators to undertake balancing actions". More specifically, the regulation requires that:

- Balancing rules are market based
- TSOs provide proper information on shippers' balancing status.
- Imbalance fees are cost reflective
- TSOs try to harmonise balancing arrangements to facilitate gas trade.

Figure 3.6 provides a simplified scheme of the European balancing model.

**Figure 3.6 EU balancing target model**




Source: IEA analysis based on ENTSOG (2017), *BAL NC monitoring report 2017 presentation*.

**In a liberalised gas market, network users are responsible to balance their short-term positions on the wholesale gas market while the TSO carries out residual balancing.**

The balancing scheme defined by the network code for gas balancing shall include cost-reflective imbalance charges to the extent possible, established based upon the marginal price, to motivate network users to balance their portfolio efficiently. Network users shall receive up-to-date information on their own balancing position as well as the system's balancing status during the balancing period to facilitate this. This process minimises the TSO's role in balancing and increases that of market participants, provided that flexible gas is released and wholesale markets, which allow for flexible gas trade between network users either bilaterally or via an exchange, are developed in parallel.

In Brazil, in the case of GASBOL, balancing rules are specified in service contracts, but it is the shipper who pays directly or indirectly. When reforming these rules, decision-makers should aim to encourage each market participant to keep system balance, giving them the responsibility to ensure network's operational safety. Certain mechanisms seen in the European Union, such as penalties that reflect system costs, could prove useful for the Brazilian context.

The decision whether to pursue a market merger or market coupling (implicit allocation) depends upon the capacity relationship between the two (or more) market areas. Indicators such as "Theoretical Interconnection Deficit" and

"Capacity Restriction Rate" can be used for assessment. The Theoretical Interconnection Deficit (TID) estimates the average annual impact of the market merger on existing freely allocable capacity in worst case nomination scenarios. This is then put in relation to total freely allocable capacity to calculate the Theoretical Capacity Restriction Rate (TCRR). In case of a low TCRR, a market merger can make more sense than market coupling (implicit allocation), as it will result in a single market with a single price for all traded products (from spot, to prompt and forward).

Market coupling (implicit allocation) could be beneficial in case of a high TCRR, because it allows the markets to decouple in case of congestion. In consequence, a single price is only achieved in times of sufficient cross-border capacity and usually only for the spot market. For the Brazilian context, an analysis of the capacity situation between the TSOs (market areas) is a first step when assessing the most promising route forward.

# Chapter 4. Midstream flexibility

Midstream flexibility is crucial to ensure effective functioning of liberalised gas markets through facilitating the development of trade and enhancing security for physical gas deliveries.

In contrast with the vertically integrated market model—where all supply flexibility is concentrated and managed by the incumbent—in liberalised gas markets, the different sources of midstream flexibility can be accessed by market participants through transparent and non-discriminatory market based mechanisms.

## Flexibility requirements in Brazil

Each energy and gas system has a different set of midstream flexibility requirements depending upon the profile of both the supply and demand side.

In Brazil, where 90% of gas is consumed by the industrial and power sectors, gas demand swings are primarily driven by the availability of hydropower, with gas-fired power generation ramping-up during periods of drought. The gas demand from the power sector follows an unpredictable pattern, jumping from 3.8 bcm in 2011 to 17 bcm in 2014 and then falling to 10.6 bcm in 2019. This demand has relatively low flexibility, given the limited fuel-diversity of Brazil's thermal generation (with gas-fired assets accounting for two-thirds of the thermal generation capacity). Moreover, Brazil's growing share of intermittent renewables could increase the short-term variability of gas demand and require further midstream flexibility.

In some markets, need for flexibility from the demand side are partly met through modulation of upstream production capacities. In Brazil, approximately 80% of natural gas is produced in association to oil and, as such, does not necessarily respond to gas market dynamics but rather to oil prices and oil market fundamentals.

The combination of Brazil's highly variable and inflexible gas demand with a relatively flat gas production necessitates enhanced midstream flexibility to ensure both a well-functioning market and a secure supply.

## Midstream flexibility: Tools and mechanisms

Several tools and mechanisms can provide both long- and short-term midstream flexibility to the gas system.

## LNG imports

LNG imports can be ramped-up either through exercising contractual flexibility or spot purchases. The global LNG market is increasingly liquid and has become a key source of supply flexibility for the Brazilian market since Brazil's first LNG regasification terminal was commissioned in 2008.

However, the timeliness of unplanned LNG sourcing makes it a less suitable option to respond to short-term supply and demand shocks. Practical examples demonstrate that it can take up to several weeks to purchase additional cargo and bring it to the market where it is needed. Moreover, LNG spot prices show a high degree of variability and can result in high procurement costs in times of market tightness.

LNG regasification terminals can store LNG in storage tanks - which can be used for peak shaving purposes, such as meeting short-term demand surges. However, Brazil's regasification terminals have only limited storage capabilities, equal to less than 1% of the country's annual gas consumption in 2019.

Ensuring effective third-party access to LNG terminals and to the entry/exit points of the pipeline that links the regasification terminal to the market is key to improving market competition and enhancing midstream flexibility and security of the supply. In the European Union, third-party access can be provided either under a regulated or negotiated regime.

It is also possible to receive third-party exemptions under certain conditions (described in Chapter 1). However, it is important to highlight that exempted LNG terminals must have effective use-it-or-lose It (UIOLI) rules in place to ensure a competitive market and avoid capacity hoarding.

Petrobras was the only owner and user of the LNG regasification capacity in the country and had a de facto monopoly on LNG imports. Following the agreement reached with anti-trust regulator CADE in July 2019 when facilitating third-party access to its infrastructure, Petrobras must start leasing capacity at its Bahia LNG regasification terminal and the pipeline associated with the terminal. In a statement issued in December 2019, the company said that it had initiated pre-bid procedures for parties interested in taking part in auctions for regasification and pipeline capacity.

## Pipeline imports

Pipeline import volumes can be ramped-up, either via exercising contractual flexibilities and/or via short-term spot sales, if a) spare pipeline capacity is available; and b) upstream supplier capabilities allow increased export volumes.

Brazil imports piped gas from Bolivia through the GASBOL pipeline. The 11 bcm/y contract between Petrobras and YPFB expired at the end 2019 and a new contract is currently under negotiation, with annual volumes expected to be lower by approximately one-third. In addition, YPFB began marketing gas directly to Brazilian end-users at the beginning of 2020. However, Bolivian piped imports have historically shown limited upside flexibility, which is expected to further decrease given declining gas production in Bolivia (rate of decrease = 4.5% between 2015 and 2018).

In the medium-term, there is growing interest in integrating the Argentinian and Brazilian gas networks. The construction of Uruguaiana-Triunfo (section 2) pipeline would allow the ramp-up of Argentine gas exports to Brazil from the Vaca Muerta shale play, which could provide additional seasonal flexibility supply to southern regions of Brazil. The 5.5 bcm/y pipeline project has been included in Brazil's Indicative Pipeline Development Plan.

**Box 4.1 Contractual restrictions**

The European experience suggests that the exclusion/removal of contractual restrictions, which might limit the free flow of imported natural gas within the internal market, is crucial for the development of internal gas trading and the improvement of market competition. Moreover, it contributes to a greater degree of midstream flexibility and security of supply.

Two main categories of restrictions might apply:

- **Territorial restrictions** (or destination clauses), that prohibit the buyer from reselling the gas to countries or areas other than those for which it is intended.
- **Use restrictions** that prevent the buyer from using the gas for any purposes other than those agreed upon.

The European Commission has played a crucial role in removing such contractual restrictions from both long-term piped GSAs and LNG SPAs through the early 2000s. The Commission argued that both types of clauses are incompatible with European competition law as they prevent the creation of a single gas market and where the buyer is "free to re-sell gas wherever it wishes".

## Linepack flexibility services

Natural gas transport pipelines can provide additional short-term flexibility to the gas system by using gas volumes "stored" within the linepack.[10] Storage in pipelines can be built up within the tolerance range of the linepack by controlling

[10] Linepack refers to the total amount of gas present in a pipeline section at a given time of commercial operations.

operation-pressure levels between a minimum and a maximum level but remaining within the limit of safe pipeline operation.

In the European Union, linepack flexibility services (LFS) are regulated by the Network Code on Gas Balancing of Transmission Networks (*No. 312/2014*) and can be offered by the TSO following the approval of related terms and conditions by the national regulatory authority.

To provide LFS, the following criteria must be met:

- The transmission system operator should not need to enter into any contracts with any other infrastructure provider, such as storage system operator or LNG system operator, for the purpose of provisioning a linepack flexibility service.
- The revenues generated by the transmission system operator from provisioning a linepack flexibility service should be at least equal to the cost incurred or to be incurred from providing this service.
- The linepack flexibility service should be offered on a transparent and non-discriminatory basis and can be offered using competitive mechanisms.
- The transmission system operator should not charge, either directly or indirectly, a network user for any costs incurred by the provision of a linepack flexibility service, should this network user not contract for it.
- Provision of a linepack flexibility service should not have a detrimental impact on cross-border trade.

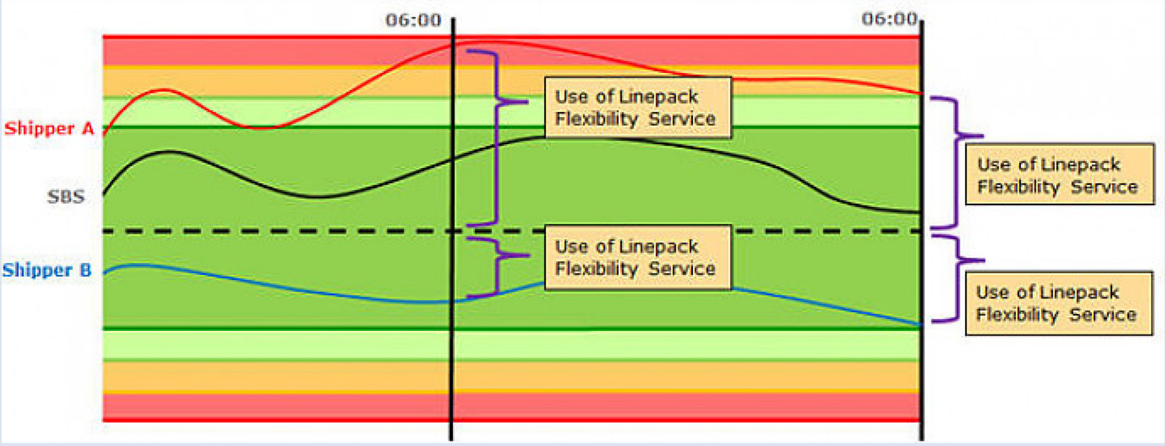
Box 4.2 below describes the LFS provided by Gasunie Transport Services (GTS), the Dutch TSO.

### Box 4.2 A market based approach to LFS

Shippers who have an imbalance—either a shortage or a surplus of gas—at the end of the gas day will use the network buffer (illustrated as the dark green zone) provided by the TSO as linepack flexibility service and subject to a tariff. Hence, shippers pay for the use of the network buffer at the end of the gas day.

The cost of the LFS is equal to the imbalance volume*% of neutral gas price*.

**Linepack flexibility service of GTS**




Source: Reproduced from GTS (2020), *Linepack Flexibility Service*.

It is important to highlight that this service can be provided only when the System Balance Signal (SBS is the aggregation of the Portfolio Imbalance Signals of all shippers active in the network) is within the buffer zone. If the SBS is outside the dark green zone, a within day balancing action has already been taken by GTS. Therefore, the end-of-day position of every shipper is always fully supplied by the linepack flexibility.

* The neutral gas price per day is defined as the weighted average of the TTF price for the volume at a designated gas exchange for all transactions executed during the day, the day before and two days before the day of delivery.

## Underground gas storage

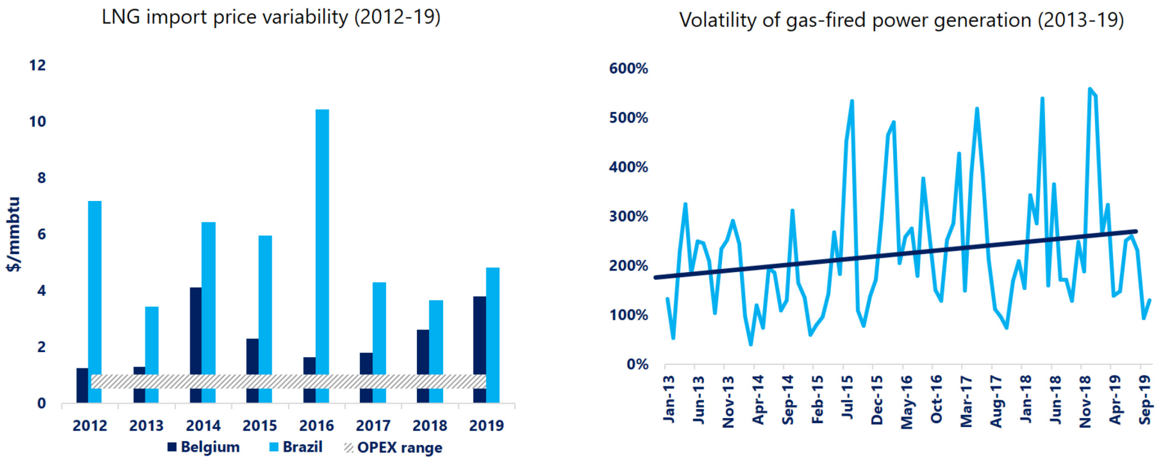
Underground gas storage (UGS) located near demand centres is used to adjust supply in response to both short- and longer-term demand swings. Two main types of storage facilities can be distinguished:

- **Depleted field/aquifers** are usually used to store larger volumes to meet seasonal/annual demand variations; and
- **Salt caverns** typically offer higher injection and withdrawal rates and hence are more suitable for meeting short-term demand variations.

At the time of this writing, Brazil does not have any major underground gas storage facilities. While Brazilian gas demand does not show a strong seasonality, there are a few benefits UGS could bring to the country's gas market (Figure 4.1):

- **Optimisation of LNG/piped imports:** as Figure 4.1 illustrates, Brazil's LNG import price has a much higher variability when compared to Europe. This is due to several factors, including that Brazil's LNG demand shows a relatively low price-elasticity, as these volumes are usually used in the power sector to support the electricity system. Additionally, Brazil is situated on the outskirts of the main LNG trading routes, resulting in higher shipping costs. Availability of UGS could optimise LNG imports in response to price variations on the global gas market.
- **Integration of intermittent renewables**: the volatility of gas-fired power generation in Brazil has doubled between 2014 and 2018 from a yearly average of 150% to almost 300% last year. This trend could continue with the growing share of intermittent renewables in the Brazilian power mix and further increase short-term flexibility requirements of the gas system. Fast-cycling salt caverns could also enhance short-term reactivity of the gas system.

**Figure 4.1 Potential market based value of natural gas storage for Brazil**






Sources: IEA analysis based on Eurostat (2020), *International Trade in Goods*, MME (2020), *Boletim Mensal de Acompanhamento da Indústria de Gás Natural*, ONS (2020), *Geração de energia*.

**Storage could allow optimisation of LNG imports in a context of high price variability and could support the integration of intermittent renewables by providing additional midstream flexibility.**

- **Network value** allows for more optimal development and functioning of the gas grid. This is primarily the result of lower peak load capacity requirements on the transmission system. For instance, the European gas system requires ~15% additional import capacity without storage to meet seasonal demand swing. Storage reduces transmission system operating and maintenance costs thanks to optimised gas compression and also reduces the risk of potential bottlenecks in the gas system.

- **Facilitation of gas trade development** can serve as the physical basis for both short-term position optimisations and longer-term hedging strategies.

**In Brazil, flexibility in gas supply is also a key issue in the context of gas/power market integration** discussions within the Novo Mercado de Gás. Gas storage could become an attractive segment, reducing price volatility, especially volatility due to variations on power generation demand, which accounts for up to half of the total demand during dry periods.

In the European Union, storage sites operate in a liberalised gas market, under the following regulatory principles:

- **Unbundling**: storage system operators are legally and commercially independent from other entities not related to gas storage.
- **Third-party access** to natural gas storage products and capacity allocation is guaranteed in a non-discriminatory, objective and transparent manner.
- **Tariffs and the methodologies underlying their calculation** are applicable in a transparent and non-discriminatory manner.
- **UIOLI principle**: unused storage capacity is offered on the secondary market to avoid contractual congestion.
- **Exemptions** can be granted to new storage facilities under the conditions that it is necessary to make the investment economically viable and does not distort market competition.

Storage products (injection rate / storage space / withdrawal rate) are typically commercialised as a bundled product. Historically, midstream suppliers concluded multi-year storage contracts to meet their long-term supply commitments. With the liberalisation of the market, traditional long-term storage contracts are gradually disappearing and being replaced by alternative capacity allocation mechanisms, such as auctions. While storage tariffs are regulated, the effective price paid by storage customers to the storage operator depend on the result of the bidding process during the auction. Usually, customer willingness is dependent upon the evolution of seasonal price spreads along the forward curve.

**Box 4.3 Regulatory support mechanisms for gas storage**

In addition to the market based revenue derived from long-term storage contracts and auctions, many EU member states' national regulatory frameworks allow support mechanisms, recognising the value of underground gas storage to gas systems in terms of network development and supply security.

Three main regulatory mechanisms can be distinguished:

**1. Storage obligations** imposed on midstream suppliers, if combined with a regulated price cap, can guarantee a steadier revenue for storage operators, while recognising the security value of storage. This mechanism is reflected in Spain's regulatory framework, where shippers are required to maintain strategic stocks, equivalent to 20 days of their firm sales in the previous natural year, located in underground storage facilities.

**2. Revenue reconciliation** was introduced in a 2017 French regulation. Under this mechanism, storage operators are entitled to additional revenues (from tax recovered by natural gas transmission network operators) if the auction revenue and regulated income of gas storage operators are negative. If their auction revenue surpasses their regulated income, storage operators are obliged to return the surplus to grid users via the grid tariff. This allows storage operators to recover their operating expenses.

**3. Strategic storage** requires that storage operators dedicate a certain share of their storage space to strategic storage, which is not commercially available and the costs are socialised among market participants. This mechanism is used in Hungary and Italy primarily to enhance gas supply security.

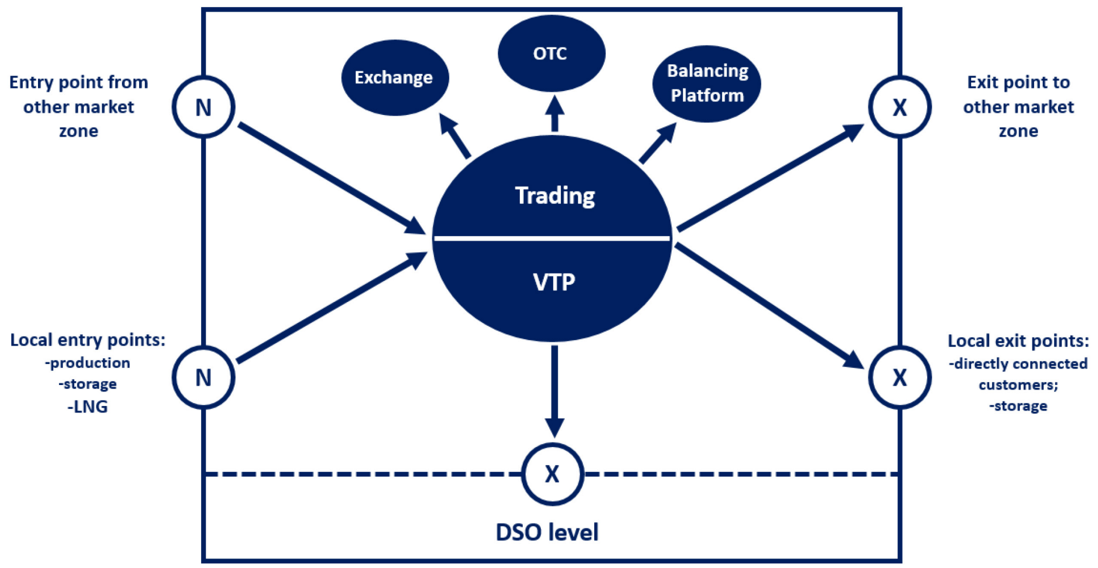
# Chapter 5. Setting up a liquid hub

A hub refers to a marketplace where natural gas is freely exchanged between market participants. There are two main types of hubs:

- **Physical (or locational) hub** is a well-defined geographical point located at the intersection of at least two gas infrastructures that enables an exchange of physical gas volumes and where title transfer service is offered by a dedicated entity (the hub operator). Examples of physical hubs include AECO in Canada, Henry Hub in the United States and Zeebrugge in Belgium.
- **Virtual hub** refers to a notional point within a well-defined entry-exit market zone that offers network users the possibility to bilaterally transfer title of gas and/or swap imbalances, disregarding where the actual physical volumes are located within the gas system. Gas volumes that enter an entry-exit zone are available for trade on the virtual hub. Examples of virtual hubs include TTF in the Netherlands, NBP in the United Kingdom and CEGH in Austria.

In the European Union, *Regulation (EC) No. 715/2009* requires that gas be traded independently of its location in the system. Figure 5.1 provides a simplified scheme of an entry-exit market zone with a virtual trading point.

**Figure 5.1. Entry-exit zone with a virtual trading point**




Sources: IEA analysis based on various public sources, including DNV KEMA for the European Commission (2013), *Study on Entry-Exit Regimes in Gas, Part A: implementation of Entry-Exit Systems.*

**A virtual trading point allows natural gas to be traded independently of its location in the entry-exit market zone.**

With the entry-exit market zone providing the physical basis for exchanging natural gas, actual trading can take place through the following channels:

**1. Over the counter (OTC):** enables trading directly between counterparties, potentially supported by brokering agencies. OTC transactions have inherent credit risks, as one of the counterparties could default at any time.

**2. Exchanges:** offer anonymous trading, clearing, and financial margining services. The exchange operator is the central counterparty to all transactions and ensures clearing and settlement (physical or financial). Intermediaries guarantee performance of the counterparties for each individual transaction. Only standardised products can be traded on an exchange.

**3. Balancing platform:** a facility that allows gas trading where the TSO is the counterparty to every trade. This effectively provides the TSO with a market based tool to manage system imbalances.

Traded products can be tied to either physical deliveries and/or to financial settlements without an obligation to deliver physical volumes ("paper gas"). The time horizon of traded products can range from spot market (intraday, day-ahead) to forward contracts with a delivery/financial settlement date up to several years ahead (up to five on TTF and up to 12 years on Henry Hub). Typically, future contracts are rarely tied to physical delivery, while spot and prompt contracts are used for short-term balancing and therefore more often include an obligation to take or deliver physical volumes of natural gas.

A well-developed, liquid hub has a few benefits. In practice, it allows market participants to:

- Balance their short-term positions on the spot market by trading physical volumes of natural gas and/or by arranging an imbalance swap.
- Optimise supply-demand balance in their mid-range portfolio.
- Manage both volume and price risk by hedging on the forward curve using a variety of trading instruments (including forwards/futures contracts, swaps and options).

Moreover, a hub provides market participants the possibility of price discovery, meaning the actual and expected market value of natural gas. Most importantly, a liquid hub leads to greater market efficiency, which improves the security of supply for the given gas and in the energy market more broadly.

# Hub metrics: How to recognise a liquid hub?

There is not one, universally accepted definition or metric for "liquidity". In essence, a liquid hub guarantees that demand from market participants is matched with offers from other market participants in a time- and cost-efficient manner without causing significant change to the market price.

A number of metrics can be considered to measure the liquidity and maturity of a hub:

- **Number of registered users**: a higher number of active participants (i.e., those who have conducted at least one trade in 12 months) typically increases competition among market participants and therefore benefits the liquidity of the hub.
- **Type of participants**: a more diverse set of active users is indicative of a more developed hub able to satisfy different market needs. The appearance of non-physical, purely financial market players usually is a sign that the hub has matured into a liquid hedging venue that can be used for risk management purposes.
- **Market concentration**: it is crucial to understand whether a small number of traders are responsible for most trades or whether the market is highly diversified. Market concentration can be measured by the Herfindahl-Hirschman Index (HHI). HHI is calculated by squaring the market share of each participant competing in the market and then summing the resulting numbers. It can range from zero to 10 000. A lower measure of market concentration indicates a higher level of competition and hence more liquidity.
- **Traded volumes** and number of trades: a trend showing a growth in traded volumes suggests that the hub is becoming more liquid and more mature.
- **Products actively traded**: a mature hub usually offers a diversified product range both in terms of time horizon (spot, prompt and forwards) and in terms of trading instruments (including swaps and options). Generally, in less-developed hubs most trading takes place on the spot market (balancing hub), while in mature hubs most trading activity takes place further down on the forward curve (traded hubs).
- **Churn rate**[11] is usually considered the most important indicator of hub liquidity. It represents the ratio between the total volume of trades and the physical volume of gas consumed in the area served by the hub. A churn rate of above ten is indicative of a liquid hub (both TTF and Henry Hub have a churn rate of above 100).
- **Bid-offer spreads** are calculated by subtracting the bid price from the offer price, dividing by the offer price, and then multiplying by 100 to give a percentage. The lower the bid/offer spread, the easier it is to arrive at a transaction. As such, tighter bid-offer spreads suggest a more liquid hub.
- **Historical volatility** is a statistical measure of realised price variations for a specified gas contract (e.g., month-ahead) over a specified period. The monthly

[11] The churn rate is a frequently used indicator of liquidity, reflecting the number of times the gas volumes consumed in the market are traded. The churn rate can be calculated as the ratio between the volume of all trades and the corresponding total demand.

calculation takes the logarithmical differences of daily average prices (for the day-ahead contract) across two consecutive trading days. These are used to calculate the relative standard deviation monthly. Historic volatility is "annualised" by multiplying the standard deviation by the square root of the number of observations across a full year. The greater the volatility, the greater the uncertainty surrounding the price. As such, a positive evolution in the early phases of hub development is considered a decline in volatility.

The monitoring of hub liquidity and tradability—either by the national regulatory agency or by a specifically appointed authority—is crucial particularly during early phases of hub development. Such monitoring should be done in a transparent manner, on a regular basis and in consultation with market participants. Besides providing a quantitative overview of the evolution of the liquidity metrics, the monitoring report should also survey market participants on the "tradability" of the hub, i.e., their subjective perception of hub development in terms of access, hub services and liquidity.

In the Netherlands, the Competition Authority and, later, the Authority for Markets and Consumers, issued on a regular basis a "*Liquidity Report wholesale markets for natural gas and electricity*". In 2009, the authority signalled in its monitoring report a "slow development" in market competition, noting that:

- "The wholesale gas market still has some major shortcomings. Shippers perceive the limited access to flexibility as a hindrance."
- "The commitment of all market participants is required. GasTerra, the exclusive marketer of Groningen gas, has a key responsibility here."

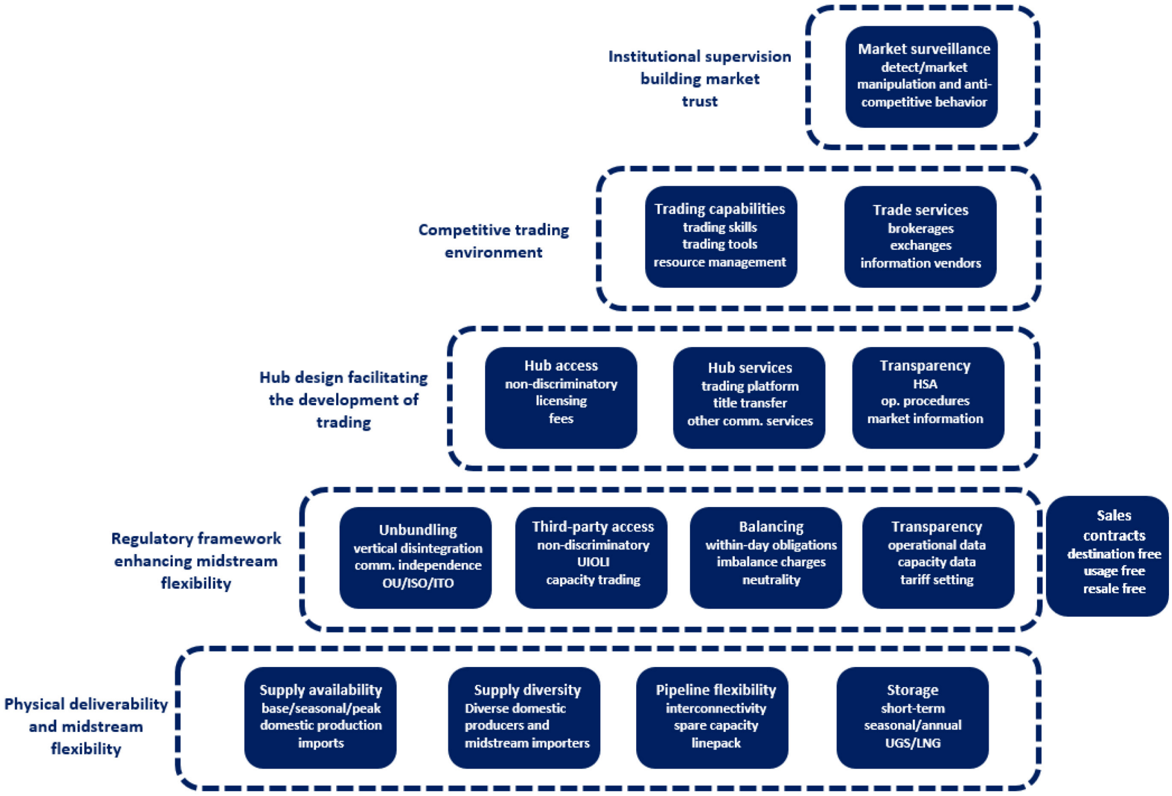
Consequently, the Competition Authority engaged in discussions with GasTerra following which the company played an important role in providing additional flexibility to shippers and traders active on TTF, the Dutch hub. Among other factors, this has been a key factor in the improvement of TTF's liquidity.

# What makes a hub successful?

The European experience shows that it takes at least 10 years to establish a well-developed, mature hub, which allows market participants not only to balance their short-term positions but also to trade along the forward curve for risk management purposes.

Figure 5.2 illustrates the most important factors facilitating development of a gas hub. However, it is important to highlight that each gas and energy market is different by definition and consequently will take its own distinct development path toward establishing a liquid hub.

**Figure 5.2. Building bricks of a successful gas hub**






**A successful gas hub should be based on a transmission system that provides firm physical deliverability, a regulatory framework enhancing midstream flexibility and a hub design facilitating trade.**

The building blocks of a successful hub can be constructed on five, interlinked layers:

## 1. Physical deliverability and midstream flexibility

A hub should be based on a gas supply system and infrastructure able to meet consumers' average, seasonal and peak demand requirements. As such, it is crucial that network development plans and investment decisions reflect evolving supply-demand patterns of the given gas market. A diversity of supply sources and, most importantly, a diversity of upstream suppliers, can be beneficial for development of competition and usually improves liquidity on the hub. The availability of midstream flexibility (through a range of instruments, including pipeline flexibility, storage and LNG) allows not only for a greater degree of supply security, but also provides the physical space necessary for short-term trading and balancing actions.

## 2. Regulatory framework to enhance midstream flexibility

The regulatory framework should enable market participants to access the gas infrastructure and midstream flexibility products (such as entry-exit capacity at pipeline interconnections, storage, LNG regasification, LNG storage, linepack flexibility) in a non-discriminatory, objective and transparent way. This includes the non-discriminatory application of capacity allocation rules, congestion management procedures, and use-it-or-lose-it (UIOLI) principles for both short- and long-term capacity. As described in Chapter 3, capacity booking and trading platforms could further enhance market players' access to midstream flexibility products and services. The balancing system should be market based and provide further incentives for market participants to balance their short-term positions on the hub.

The TSO should provide market participants with operational transparency, in terms of firm and interruptible capacity, tariffs, nominations, re-nominations and physical flows on an at least daily basis on an open and transparent information platform. This is crucial to reduce information asymmetries among market participants.

Another important aspect of midstream flexibility is the elimination of any clauses in gas sales contracts that might hinder the re-sale and free flow of gas (such as destination clauses, usage restrictions or mechanisms impeding re-sale or the commercial benefits of re-sale). Chapter 4 provides a detailed description of such restrictive clauses within the context of import contracts.

## 3. Hub design to facilitate the development of trading

The entity responsible for management of the hub is usually referred to as the *hub operator*. The functions of the hub operator can be undertaken either by:

- the Transmission System Operator (such as in the Netherlands and Italy)
- the Market Area Manager (typically when there are several TSOs in one market area, such as in Germany)
- a separate entity (such as in Austria and Belgium).

In all cases, the hub operator should be legally and commercially independent from active market participants on the hub to ensure non-discriminatory treatment.

Hub access to market participants should be provided on a non-discriminatory basis, the licensing procedure should be transparent and participation fees (if any) should not create or increase entry barriers.

The licensing procedure should set conditions for market participants, including:

- **Creditworthiness:** each market participant should have a credit rating that is adequate for its intended obligations and be able to meet financial security requirements appropriate for its exposure.
- **Electronic communication:** market participants need to meet the requirements for electronic communication for nominations, entry and exit programmes, the portfolio imbalance signal and balancing actions. A communication check must be performed with the entity providing hub operator services.
- **Prudence:** market participants are required to have the expertise and technical, administrative and organisational facilities required to be able to transport gas in the national grid and act in accordance with the balancing regime.

Hub fees (if any) should be set in a transparent and non-discriminatory manner and at a level that does not create an additional entry barrier to potential market participants.

The hub operator provides certain commercial services to market participants, usually detailed in a Hub Services Agreement (HSA). The HSA (including Operating Procedure) should be standardised, transparent, publicly available and applicable in a non-discriminatory manner to all customers of the hub operator, meaning all market participants active on the hub.

Most importantly, the hub operator provides title transfer services by recording the changes in ownership of a specific gas contract and enabling market participants to trade gas. The hub operator should provide a trading platform—either directly or via a trading platform operator—where market participants can post, amend and accept bids and offers, which in essence allows for OTC trades. The trading platform must make available the necessary information for traders to confirm the trade, publish the evolution of the marginal buy price and marginal sell price. In some markets, a designated exchange provides the platform for bilateral trading.

Besides title transfer, a hub operator may provide additional commercial services. These can play a particularly important role in the early phases of hub development as they provide market participants with additional flexibility instruments and enhance physical deliverability (or firmness) of the hub. Box 5.1 provides a non-comprehensive list of commercial services that may be provided by a hub operator.

**Box 5.1 Hub services**

Wheeling: Gas can be transported from an entry point to a nearby exit point at a tariff that is lower than the sum of regular transport tariffs for the separate points, provided that the points have the same gas quality. This is possible because no physical demand is placed on the transport network.

Parking: A short-term transaction in which the hub operator holds the shipper's gas for redelivery at a later date. Frequently uses storage facilities but may also use displacement or variations in linepack.

Peaking: Short-term duration (usually less than a day and perhaps hourly) sales of gas to meet unanticipated increases in demand or shortages of gas experienced by the buyer.

Loaning: A short-term advance of gas to a shipper by a market centre that is repaid in kind by the shipper within a short time.

Risk management services: Reduces the risk of price changes to gas buyers and sellers through risk management practices, for example, by exchanging futures for physicals.

Administration assistance: Helps shippers with the organisational aspects of gas transfers, such as nominations and confirmations.

## 4. Competitive trading environment

Market participants need to embrace the challenges and opportunities offered by a liberalised gas market. In the traditional model of vertical integration, wholesale companies act as ‘intermediaries’ between producers and end-users, providing gas to customers on a cost-plus basis due to their monopolistic or oligopolistic market position. In contrast in a liberalised gas market, midstream utilities compete both for customers and for supply sources.

In practical terms, this requires that midstream utilities continuously optimise their mid-term supply-demand portfolio, balance their short-term positions and financially hedge their exposures. They must further develop in-house trading capabilities by investing in skill development and acquiring trading tools.

In parallel, a service industry must develop that is devoted to trading and traders’ needs. This must include services that facilitate trading (such as brokerages and exchanges) and market intelligence vendors that sell data and information services to market participants. Price Reporting Agencies are also important, as they enhance market transparency by assessing and publishing the price level of distinct gas contracts on a regular basis.

## 5. Institutional supervision to build market trust

Trading activity in wholesale energy products must be monitored either by the national regulatory authority or by a designated institution to detect and prevent insider dealing and market manipulation (market surveillance).

This is of particular importance, especially in the early phases of hub development, when liquidity is still relatively low and the risk for market manipulation by a dominant player is high. Moreover, market supervision and detection of anti-competitive behaviours by an independent institution is important for building trust among participants.

To involve market participants in the detection of suspicious trade transactions, a notification platform can be established by the supervising agency, where market participants and other stakeholders from the wholesale energy markets can report suspected market abuse.

**Box 5.2 From oil-indexation to hub-based pricing**

Natural gas pricing in Brazil is dominated by oil-indexation. For instance, gas prices for sales to local distribution companies are typically derived from a fixed transmission tariff, based on economic indices and a floating commodity price, which is determined by fuel oil prices.

Oil-indexation was “invented” in the Netherlands in the early 1960s, when the country decided to export natural gas to neighbouring markets. As there was no market for natural gas at the time (and in fact, limited gas consumption), the price of gas was linked to the price of alternative fuels likely to be substituted by different types of end-users—for instance, gas oil for small-scale users and fuel oil for large-scale users.

A well-developed, liquid hub guarantees not only a marketplace where demand is matched with offers in a time- and cost-efficient manner, but also provides market participants with price discovery, meaning, the actual and expected market value of natural gas.

Consequently, oil-indexed price formulae in gas sales contracts can be replaced with indices linked to gas products traded on the hub. As such, clients can opt for indexation based on the day-ahead, month-ahead, quarter-ahead or year-ahead gas prices.

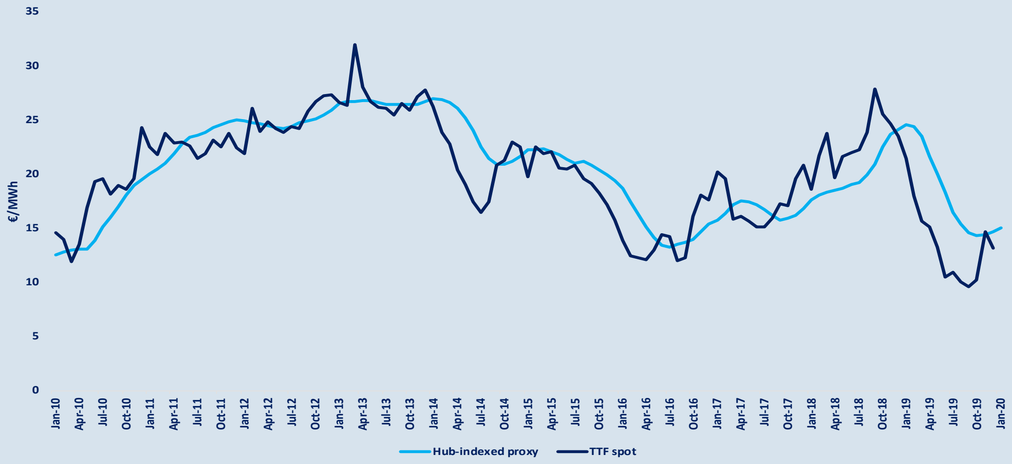
To reduce the relatively high volatility that prevails on the traded market, hub-based pricing formulae in gas sales contracts with end-consumers are usually based on an average of several months (the reference period) of multiple gas products traded on the hub.

For instance, the illustrative (and simplified) pricing formulae presented below, includes a six-month average of the month-ahead TTF contract with a weight of 50% (the most traded contract) + TTF quarter-ahead contract with a weight of 30% (to account for seasonal price variation) + TTF year-ahead contract with a weight of 20% (to further reduce price variations):

$$P= 0.5^* \bar{x}\ \text{TTF MA}\ (t_{ref6}) + 0.3^* \bar{x}\ \text{TTF QA}\ (t_{ref6}) + 0.2^* \bar{x}\ \text{TTF YA}\ (_{tref6})$$

As shown on the below graph, the damping option of averaging traded gas contracts over several months significantly reduces price volatility faced by end-consumers while providing the seller with a more stable cash-flow based on market prices.

**Contractual hub-pricing typically reduces spot volatility**






Source: IEA analysis based on Bloomberg (2020).

# Chapter 6. Distribution System Operators: Delivering natural gas to end-consumers

Before discussing international experiences in distribution services, it is important to briefly review the governance structure of distribution services in Brazil. As mentioned in the introduction, states are responsible to regulate distribution services, which ranges from granting the concession for services to defining specific rules (such as market design, tariffs and network codes). All other services are regulated at the federal level. This entails different governance models across the various states. For instance, regulation can be performed by either regulatory agencies or energy secretaries, and services are performed by state-owned, mixed capital or private companies. Additionally, the timeframe for concession contracts and tariffs' methodologies also varies from state to state.

While institutional reform of wholesale markets can be conducted at the national level, reforming retail markets will vary at the state level. This means that the federal government must consider state level goals and current institutional frameworks. For instance, regarding opening the market to free consumers, only twelve states have regulated the free market to date, with various rules regarding minimum consumption levels required and the separation of commercialisation costs. Another important aspect is the lack of legal provisions for distinct distribution and commercialisation activities. This absence of legal provisions could create obstacles to opening these retail markets.

Another important obstacle for reform relates to the varying levels of development within the distribution infrastructure and demand across states. In 2019, the five states with the highest natural gas demand were São Paulo, Rio de Janeiro, Amazonas, Pernambuco and Bahia. Together, these represented more than 70% of natural gas demand, with Rio de Janeiro and São Paulo alone comprising more than 50%. However, while 60% of this demand from Rio de Janeiro was for thermal power generation, in São Paulo, power generation represented only 10% and industry dominated their consumption.

The federal government must seek an agreement with the states to address these disparities. This is the approach developed in the Novo Mercado de Gás programme.

Finally, several state level contracts will expire in the next ten years, which creates an opportunity to facilitate the transition to an open retail market, reducing the burden of legacy contracts.

# TSO and DSO categorisation

A clear categorisation of "transmission" and "distribution" activities is important, especially for Brazil, where substantial investment for developing gas networks is necessary and different regulations apply to transmission and distribution. Distribution is regulated by the states (possibly providing higher incentives for investment) while transmission is regulated at the federal level by ANP. In addition, the permitting procedures for distribution pipelines are less onerous than those for transmission pipelines.

In the European Union, *transmission* is defined as transport through a network that mainly contains high-pressure pipelines, while *distribution* is defined as transport through local or regional pipeline networks. There is otherwise no clear differentiation between the two. However, two elements can serve as criteria for differentiation: pressure level and purpose (inter-state vs. intra-state). In the United Kingdom, the difference between transmission and distribution is pressure level, where transmission typically operates at 70 bar and distribution at ±32 bar. Clear definitions should be included in Brazilian federal legislation.

# DSO unbundling

DSOs, as well as Transmission System Operators (TSOs), are important to gas markets, as they transport natural gas to end-consumers, while simultaneously guaranteeing the long-term ability of the system. As such, their independence to act as neutral market facilitators must be ensured through unbundling rules (among others).

In the European Union, under Gas Directive *2009/73/EC*, European gas distribution networks are subject to unbundling requirements that oblige member states to ensure the separation of vertically integrated energy companies (local distribution companies or LDCs), resulting in separation of the various stages of energy supply (production, distribution and supply). The basic elements of the EU gas DSO unbundling system are as follows:

- **legal unbundling** of the DSO from other activities of the vertically integrated undertaking unrelated to distribution
- **functional unbundling** of the DSO to ensure its independence from other activities of the vertically integrated undertaking
- **accounting unbundling**: requirement to keep separate accounts for DSO activities; and

- **possibility of exemptions** from the requirement for legal and functional unbundling for small DSOs (with <100,000 connected customers).

A DSO must have, at minimum, the necessary human, technical, financial and physical resources to act independently from the vertically integrated company utility in terms of its organisation and decision-making power. This includes DSO staff and management independence from the vertically integrated utility.

DSO independence can also be ensured through conditions defined in a Licence. In Great Britain, for example, a Licence contains key conditions for independence, including:

- restrictions for the disposal of network assets and receivables
- restrictions on non-DSO business activities
- certification requirements related to adequacy of financial and operational resources
- requirement to hold an investment grade issuer credit rating
- restrictions on indebtedness, lending and transactions with affiliates.

## Monitoring the performance of gas retail markets—How to measure the success of market liberalisation at the DSO level?

Retail market monitoring is vital to evaluate progress and ensure that its (positive) effects benefit all consumers. There is no single indicator to measure the performance of retail markets. Rather, a comprehensive interpretation of the following (non-exhaustive) aspects is necessary:

- **Market structure and entry/exit activity**: assessment of the number of new companies that entered retail markets and operate as alternatives to incumbent suppliers.

- **Market shares and market concentration:** in the early stages of liberalisation, there is usually a slow decrease in shares of the largest suppliers in many countries and persistent high levels of market concentration. Market indicators CR312 and HHI13 can be used to measure progress over time.

- **Switching rates:** customer switching rates are one of the key indicators for competitive development in energy retail markets. External switching is the voluntary action by which a customer changes his supplier. Internal

[12] CR is a traditional structural measure of market concentration based on market shares. The concentration ratio "CR3" measures the total market shares of the 3 largest suppliers in one market.

[13] HHI refers to Herfindahl-Hirschman Index which ranges between 0 for an infinite number of small firms and 10 000 for one firm with 100% market share. An HHI above 2,000 signifies a highly concentrated market with a small number of firms.

switching is a change of product or contract with the same supplier (renegotiation or choosing a different option).

- **Offers:** in competitive retail markets, energy suppliers differentiate their offers and provide consumers with choice.

To monitor developments over time, it is useful to focus on a stable set of indicators rather than changing them from year to year. Furthermore, state regulators should co-operate on the approach to gas retail market monitoring and apply a consistent set of indicators across the states.

# DSO allowed revenue and tariffs

Distribution of natural gas is considered a natural monopoly. The regulation of DSO activities is therefore usually focused on attaining (operational) cost efficiency along with adequate service coverage and quality. Within this framework, DSOs must adapt their infrastructure to the needs of demand growth as they are pushed to increase operational efficiency through incentive measures on allowed revenues.

It could make sense for state regulators to share experience regarding the design of regulatory frameworks for DSOs as well as distribution tariff structures, and to aim for a certain level of harmonisation.

# Chapter 7. Special focus: The role of gas in Brazil's energy transition

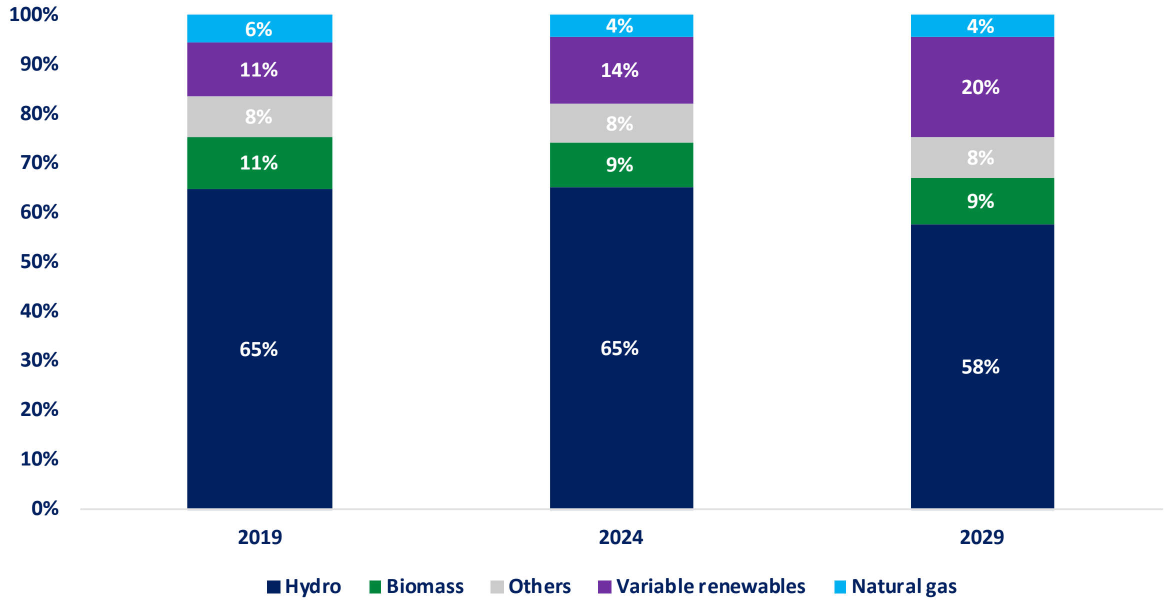
Natural gas and low-carbon gases (such as biomethane and hydrogen) can play a crucial role in Brazil's energy transition in both the medium and long-term. Flexible gas-fired power generation assets provide fast-responding back-up capacity to balance intermittent renewable energy sources (such as wind and solar), which have rapidly become an important part of Brazil's power generation mix. In the longer-term, deployment of low-carbon gases (including biomethane and hydrogen) could further decrease the emission intensity of Brazil's energy sector, create additional opportunities for growth and add value to the country's resources.

## Integration of intermittent renewables

The share of intermittent renewables in Brazil's electricity mix has been rapidly increasing. Wind power generation quadrupled between 2014 and 2018 from just 2% of the power generation mix up to a share of 8%.

Through the medium-term, Brazil aims to reduce its reliance on hydropower, which accounted for 65% of the country's electricity mix in 2019, to below 60% by 2029. According to EPE's Ten-Year Energy Expansion Plan 2029 (Plano Decenal Expansão De Energia 2029), distributed generation capacity (including distributed PV, biogas, micro-hydro and micro-wind) will grow from 1 GW to 12 GW, wind capacity from 15 GW to 39,5 GW and solar PV from 2.1 GW to 10.6 GW between 2019 and 2029 (Figure 7.1).

**Figure 7.1. Brazil's future electricity mix in the Ten-Year Energy Expansion Plan**



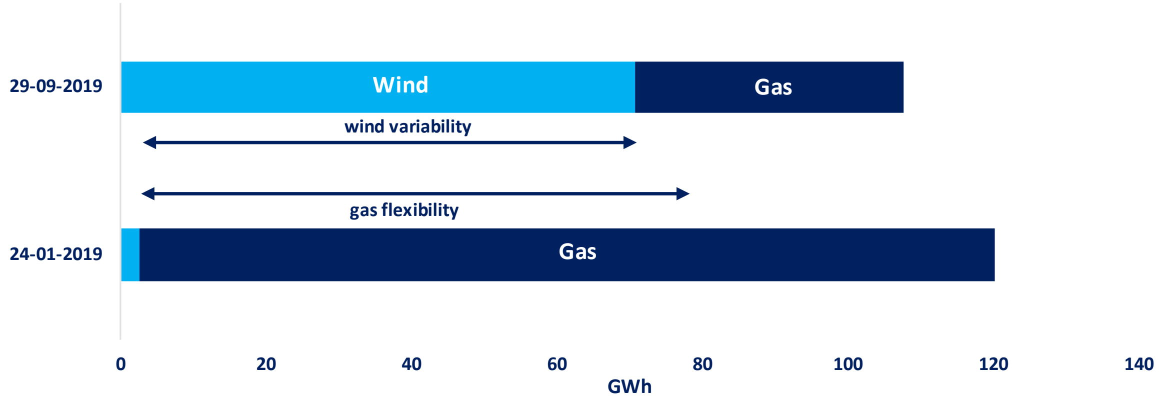



Note: Variable renewables includes small-hydro, biomass, solar and wind.
Source: IEA analysis based on MME/EPE (2019), *Plano Decenal de Expansão de Energia 2029.*

**The share of intermittent renewables in Brazil's electricity mix is expected to reach 20% by 2030, increasing the call on flexible thermal power generation capacity, including gas-fired power plants.**

European power systems, with a high share of intermittent renewables, demonstrate the importance of flexible back-up power generation capacity that ensures a secure electricity supply. Figure 7.2 provides an example of the interplay between the variability of wind power and the flexibility of gas-fired power generation in Belgium.

**Figure 7.2. Gas- and wind- power generation in Belgium**






Source: IEA analysis based on ENTSO-E (2020), *Transparency Platform*.

**Flexible gas-fired power generation assets enable integration of variable renewables by providing back-up capacity to the power system and a secure electricity supply to consumers.**

To support deployment of renewable electricity sources and their integration into the power system, the Ten-Year Plan considers the expansion of gas-fired power capacity from the current 12.9 GW to 36.2 GW by 2029.

Deploying renewables in combination with gas-fired power generation also reduces reliance on more carbon-intensive fossil fuels, such as coal and oil products in the power sector. The end-Year Plan sees a reduction of coal-fired power generation capacity from the current 2.7 GW to 2.1 GW and fuel oil/diesel generation capacity from 4.7 GW to 0.4 GW by 2029.

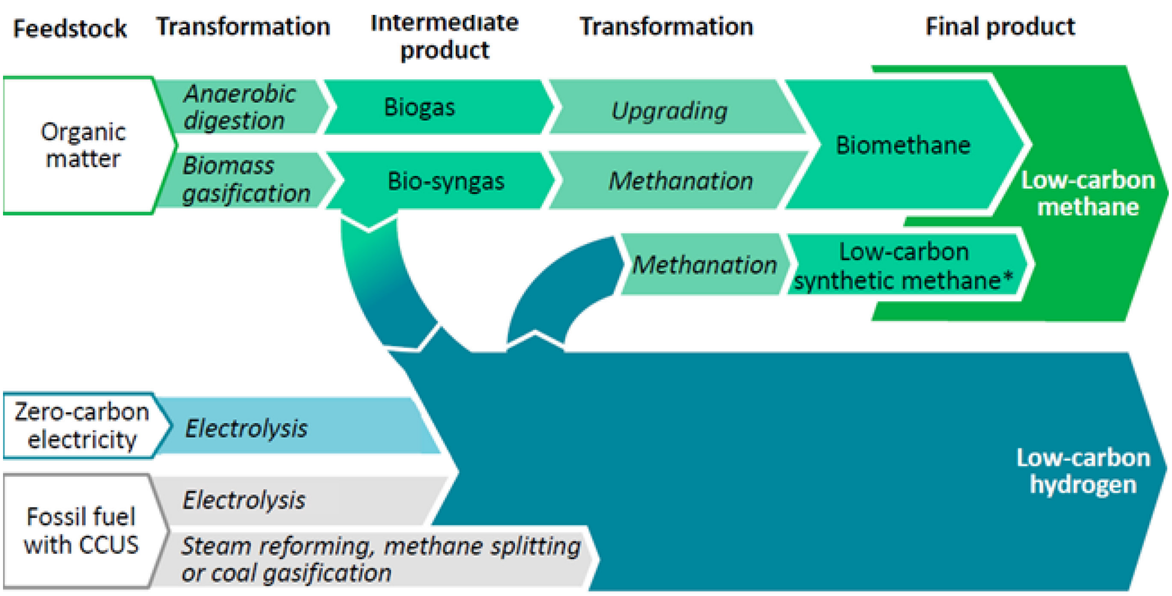
# Deployment of low-carbon gases

Long-term decarbonisation of the gas supply is a significant topic in global energy discussions. Countries with established gas networks benefit from diversification of energy sources, a high capacity to meet peak seasonal energy demand, long duration energy storage and, in many countries, convenient heating options for buildings and industry.

In the longer-term, Brazil's gas infrastructure could play a crucial role in the deployment of low-carbon and carbon neutral gases, further supporting Brazil's energy transition.

Figure 7.3 provides a summary of the multiple pathways to produce low-carbon gases, including biomethane, hydrogen and synthetic natural gas.

**Figure 7.3. Alternative supply routes to produce low-carbon gases**






Note: *Synthetic methane is only low-carbon if the $CO_2$ originates from biogenic sources or the atmosphere.
Source: IEA (2019), *World Energy Outlook 2019*.

**There are many pathways to produce low-carbon gases. Their deployment could be facilitated by the existing gas infrastructure, leading to a more cost-effective energy transition.**

## Biomethane

Biogas needs to be purified and upgraded to the quality of methane to be injected into the existing natural gas grid.

While Brazil's current biogas production is below the 1 bcm, country has huge production potential, notably in agribusiness. According to ABiogás (the Brazilian Biogas and Biomethane Association), the technical potential for biogas production in Brazil amounts to some 80 bcm/y. As such, Brazil has the world's third largest biogas potential after the United States and the People's Republic of China.

Regarding biomethane, the ANP estimated the immediate potential of biomethane injection into the natural gas grid at 0.1 bcm, which could increase to 12 bcm by 2030, according to the projections of ABiogás (CEDIGAZ, 2019).

Current market reform offers the opportunity to create a favourable regulatory framework for biomethane development. Focus should be prioritised for the standardisation of biomethane quality, the harmonisation of rules to grid access and assessing possible subsidy schemes (both production and connection), that are economically sustainable and do not negatively impact final consumers.

# Hydrogen

Alongside biomethane, hydrogen holds much promise in terms of decarbonising gas grids. Either low-carbon electricity or natural gas coupled with carbon capture, storage and utilisation (CCUS) can be inputs to produce low-carbon hydrogen (IEA, 2019).

There are two key advantages to maintaining natural gas infrastructure during a transition to low-carbon energy. First, in the next decade, gas distribution pipelines can transport the output of new hydrogen production facilities at low marginal costs without significant modification to infrastructure or end-user equipment, provided the share does not rise above 5-20%. This reduces the need to build new dedicated infrastructure during the scale-up of hydrogen production. Second, using the existing gas grid to carry 100% hydrogen avoids the considerable investment required in the long-term for creating an equivalent fully electrified infrastructure to meet gas demand (IEA, 2019).

Furthermore, a low-emissions gas supply based largely on hydrogen could continue to create significant demand for natural gas if it were cost- competitive to reform natural gas to hydrogen and prevent release of the by-product $CO_2$, such as via CCUS. Brazil appears well placed to undertake large-scale production of hydrogen with CCUS and already geologically stores captured $CO_2$ in the Lula field offshore. Existing gas infrastructure could move this hydrogen to a variety of sectors, including expanding natural gas use indirectly to transport.

Decarbonisation of the gas grid is an objective that requires near-term actions to manage the long-term cost of this transition. During deployment or refurbishment of gas pipelines, compressors and monitoring equipment, it would be wise to consider compatibility of this equipment with different levels of blended hydrogen from the outset, and to what extent they are practicable. Far-sighted planning can also focus new gas distribution on areas close to likely centres of future low-carbon hydrogen production. These areas might start looking at options for heaters that are flexible with respect to natural gas or hydrogen, including dual-fuel boilers and fuel cells. For the scale-up of hydrogen production, refineries are a source of hydrogen demand that can be converted from existing hydrogen supplies to low-carbon hydrogen at large-scale.

Brazil's natural resources could be an excellent fit for a switch to hydrogen as a low-carbon energy carrier, including stable supplies of hydropower or biomass that maximise the load factors of hydrogen production and minimise costs. Moreover, $H_2$ generation from biomass coupled with CCUS presents the potential to deliver negative emissions, which can contribute to offset emissions in other hard-to-decarbonise sectors. There is therefore scope for Brazil to build on its current R&D programmes for hydrogen, fuel cells and energy end-use electrification and align it with long-term objectives for gas infrastructure (IPHE, 2019).

# Table of Abbreviations

| | |
|---|---|
| ACM | Authority for Consumers and Markets |
| AECO | Natural gas hub in Alberta |
| ANP | Brazilian National Agency of Petroleum, Natural Gas and Biofuels |
| CADE | Brazilian Competition Authority |
| CBA | Cost-benefit analysis |
| CCUS | Carbon capture, storage and utilisation |
| CDO | Communication and Digital Office |
| CEGH | Central European Gas Hub |
| CMGN | Monitoring Committee for the Opening of the Natural Gas Market |
| CMP | Congestion Management Procedures |
| CNG | Compressed natural gas |
| CNPE | Brazilian National Council for Energy Policy |
| DSO | Distribution System Operator |
| EMS | Energy Markets and Security |
| ENTSOG | European Network of Transmission System Operators for Gas |
| EPE | Brazil's Energy Research Office |
| FGSZ | Hungary's Natural Gas Transmission Company |
| GCP | Gas, Coal and Power Markets Division of the International Energy Agency |
| GER | Global Energy Relations |
| GSA | Gas Supply Agreement |
| GTS | Gasunie Transport Services |
| HHI | Herfindahl-Hirschman Index |
| HSA | Hub Services Agreement |
| IEA | International Energy Agency |
| LFS | Linepack flexibility services |
| LNG | Liquefied Natural Gas |
| MME | Ministry of Mines and Energy |
| OTC | Over the counter |
| PDE | Brazil's Ten-Year Energy Expansion Plan |
| PIG | Brazil's Transmission Gas Pipeline Indicative Plan |
| PRISMA | European Capacity Platform |
| PV | solar photovoltaic |
| SBS | System Balance Signal |
| SINIEF | Brazil`s national system for economic and fiscal information |
| SJWS | Stakeholder Joint Working Sessions |
| SPA | Sale and Purchase Agreement |
| TCRR | Theoretical Capacity Restriction Rate |
| TID | Theoretical Interconnection Deficit |
| TPA | Third-Party Access |
| TSO | Transmission System Operators |
| TTF | Title Transfer Facility, the natural gas hub of the Netherlands |

| | |
|---|---|
| TYNDP | Ten-Year Network Development Plan |
| UGS | Underground gas storage |
| UIOLI | Use-it-or-lose It |

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