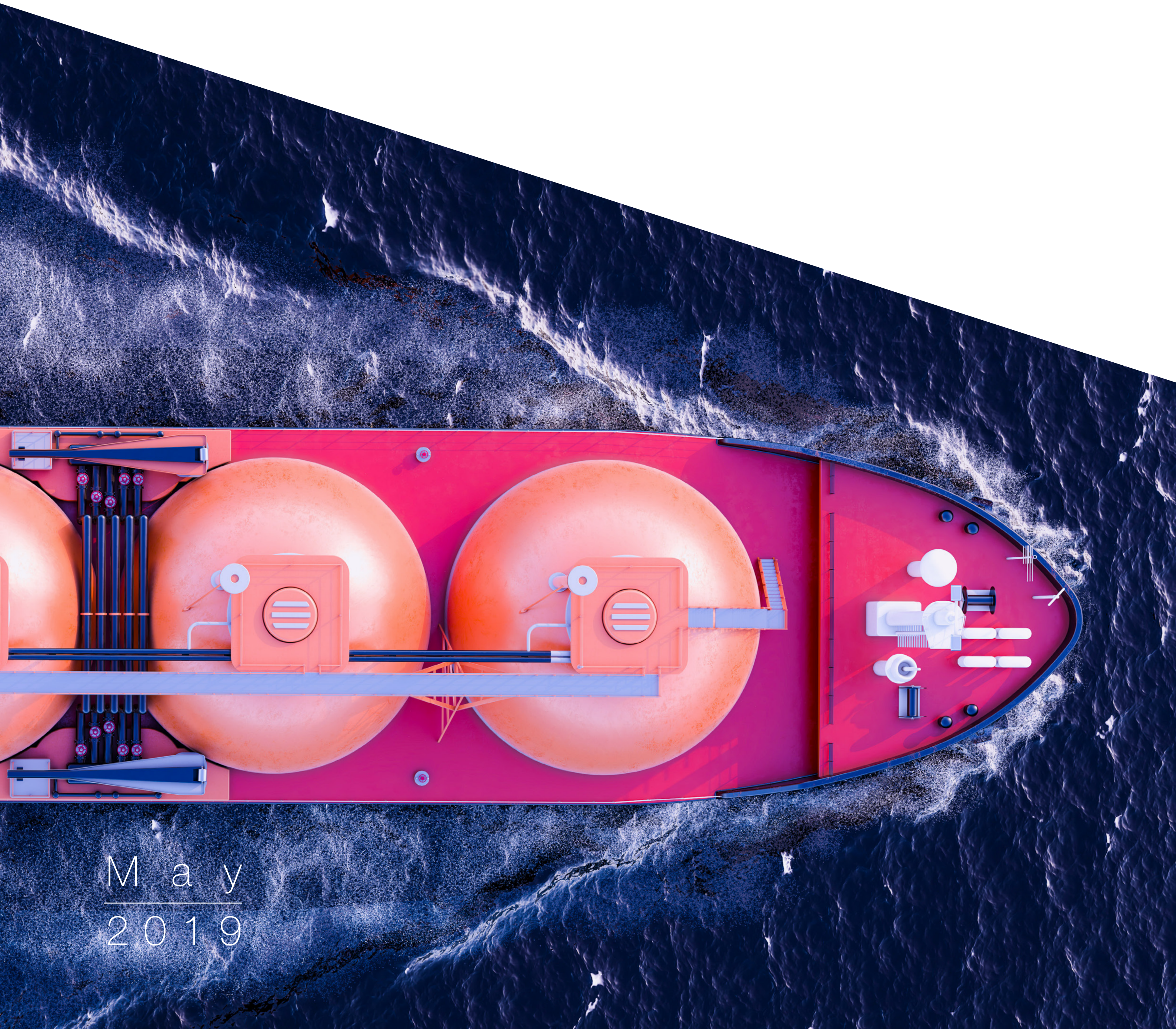
Gas Market Liberalisation Reform

Key insights from international experiences and the implications for China



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Abstract

This report systematically examines the key points for natural gas liberalisation and regulatory reform in Europe and the United States over the past decades. It addresses market design, third-party access, capacity allocation, trading centre formation, pipeline tariff setting, and regulatory measures. In addition, the report analyses the transition process itself and identifies the related measures that can help national markets become more openly competitive. Based on these international experiences, the report then looks at the current situation of natural gas liberalisation in the People's Republic of China, focusing on the importance of designing a suitable framework for the natural gas market by using best-policy tools.

The central goal of this report is to allow policy makers in China to benefit from international experiences to effectively promote the current liberalisation, the success of which will also greatly influence the global industrial development of gas.

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Executive summary

Global natural gas supply and consumption are growing rapidly, and this trend is expected to continue for decades. A new round of liberalisation reforms is also emerging globally, with more and more gas being priced by gas indices. The ongoing natural gas market liberalisation reform in the People's Republic of China's ("China") has attracted global attention. A successful reform will benefit not only China's gas industry, but also global natural gas development.

This report examines the key insights into successful gas liberalisation elsewhere and explores the implications and lessons learned for application in China. In terms of market-oriented liberalisation reforms, there are many lessons to be learned from Europe's and the United States' experiences that can help reduce the costs of trial-and-error efforts in the ongoing reform in China.

China's gas market reform

China has already made significant progress in its gas liberalisation reform, including some price deregulation, third-party access (TPA), and an ongoing approach to unbundling infrastructure. The core objective of the natural gas market reform is to increase competition among natural gas suppliers and consumers in the market, thus ensuring that resource allocation is more efficient. China has also established pilot gas exchange centres aimed at instituting a market price index.

Because a fully market-oriented system has yet to be established in China, the price of natural gas is still heavily subject to the regulated city-gate price. Upstream competition remains limited, and the interconnections of the infrastructure system (pipeline and liquefied natural gas (LNG) terminals) also impede full TPA. The complexity of the local pipeline systems remains another challenge to the gas reform. Similar to the gas liberalisation reforms in the United States and the United Kingdom, long-term contracts and other reallocations of benefits will need to be managed during the transition to an open market.

The opening of natural gas markets has unfolded at different rates in different countries, and countries have different market fundamentals – from being self-sufficient to net-importing countries, and from mature to growing markets. However, such processes have all proceeded from the same common objective to foster competition and market liquidity to the benefit of end users. China can learn from the experiences of other countries, especially in the development of policy tools to overcome obstacles that may impede the establishment of a fair and functioning market.

Proper market design is crucial

Proper market design will help to more quickly establish a fair and effective market. China's current gas market conditions and scale are unique; there is no ready-made experience that can be directly copied. That said, the physical United States-based trading centre and the virtual Europe-based trading centre frameworks have been successfully developed and may offer important lessons that can be applied to China's reform efforts. For instance, formulating several provincial-level virtual centres could be a "low-hanging fruit" for the ongoing grid unbundling reform. The successful design of the market structure and market arrangements is as important as the establishment of an independent natural gas pipeline network company.

Piloting local market centres should be encouraged. This is a situation in which it would be important to "cross the river by feeling the stones" in order to further market-oriented liberalisation reforms. By initially piloting market centres in major consumption or supply provinces, China can learn valuable lessons that can be appliedfor developing market centres across the country and forming an internationally acceptable, market-oriented price index. As demonstrated by international markets, the pace of development is likely to be uneven across sectors and regions.

Enabling third-party access to infrastructure

The separation of regulated gas transportation and commercial sales activities is a precondition to TPA to natural gas pipelines and LNG terminals. China is currently undertaking the ownership unbundling of this infrastructure, which can pave the way to fair TPA with the utilisation of proper policy tools.

Defining distinct "shipper" and pipeline transportation service roles enables the fair and efficient use of pipeline infrastructure and increases market participation. Anchor shippers could help solve existing long-term contract problems and also help to accelerate the construction of new pipelines. Shippers should be licensed and directly supervised by the regulator.

Establishing capacity allocation mechanisms (CAMs) and congestion management procedures (CMPs) is important. Moreover, certain open-season capacity should be allocated to newcomers to the market to foster competition. CAMs are needed to define the rules of primary access. A secondary capacity market can also be introduced to optimise the use of the transmission system capacity, with a view to granting system users the right to freely trade gas transmission capacities. Tariff-setting rules, standard contracts, gas specifications, and dispatching arrangements will need to be developed. CMPs also need to be introduced to manage not only physical capacity issues but also contractual congestion whenever a shipper does not use the capacity it booked in the network.

Creating a simple and clear pipeline tariff will help to encourage more new-entrant shippers. A mix of US and EU (European Union) methods in China may be more suitable, such as trunk line tariffs that are distance-based and a single tariff for the local regional market. A tariff review mechanism and related regulatory guidelines will also need to be established.

Pipeline interconnections are important for facilitating TPA. Considering the current situation, the rapid development of China's natural gas pipelines and improvements in their interconnections will help to accelerate TPA.

Putting the market at the centre

Transparency and the availability of data are essential for building confidence among market players. This represents a critical factor in preventing discrimination among shippers, encouraging access and competition, and ensuring the efficient operation of the market.

The experiences of the United States and the European Union with information transparency can provide useful lessons for China. In the process of unbundling, for example, a significant level of information disclosure from the pipeline operators will be required.

Price deregulation should aim at the establishment of a transparent price index. The establishment of gas hubs (or exchanges) is key to the establishment of transparent price signals, and the development of price indices has a widespread influence throughout the market. As hub liquidity matures, financial instruments may be developed and additional participants may be attracted to the market, which benefits both sellers and buyers. The derived futures products are the next step after the successful establishment of a spot market.

Liberalising the upstream sector

It is essential for China to establish an open gas market with a competitive upstream gas supply. Making better acreage blocks available, as well as data, to non-state-owned players in the future will be helpful for facilitating upstream competition. Establishing a mechanism for trading existing gas resources will help accelerate additional production more quickly. Shale gas, biogas, coalbed methane, and hydrogen are all diversified resources with the potential to encourage a more competitive upstream supply.

Research is needed on how to leverage the role of international companies in the upstream sector to provide more upstream competition for the natural gas market. LNG will also play an important role in diversifying the upstream sector in the short term, especially if the TPA to terminals proceeds smoothly.

An alternative approach could be based on mandatory gas release programmes where the incumbent is forced to resell a share of its supply to competitors bilaterally or via auctions. Auctions would be the preferred mechanism in order to increase market transparency. Upstream competition could be achieved before the opening of the upstream sector. The direct involvement of downstream users, such as large industrial users, could also help promote market liberalisation reform by increasing the number and activity of market players.

Enhance the role of the regulator

The independence of the regulator is necessary for a key factor of any successful market. The government is the main driving force behind the market changes in the process of promoting natural gas market liberalisation. Any progress towards natural gas market liberalisation is also largely dependent on execution, for which the role of the regulator is, again, crucial.

The requirements for regulatory capacity will increase along with the liberalisation of China's natural gas industry. Upgrading regulatory capabilities will help protect the market rules, enhance market transparency, and ensure the objectivity of China's natural gas market price signals.

Managing the transition process

Successful management of the transition process effectively is critical to the overall reform process. The market may be better able to handle price deregulation by step changes. Any changes, whether drastic or not, should be developed and signalled to the market well in advance. The transition process must consider how to develop appropriate mechanisms to deal with long-term contracts and cement the reform results. Given that liberalisation and hub development are lengthy processes, policy makers must be tenacious and resolute in order to enact reforms successfully.

Strengthening international co-operation

International co-operation is not only useful for learning lessons from other jurisdictions but also for developing a more transparent and open policy-making process to enhance the confidence of international investors. This will encourage foreign companies to supply more natural gas to China and play a more active role in the market. This is itself an important goal of the market-oriented reform.

Global trends in natural gas sector

Natural gas is a versatile fuel whose demand is growing in part because of its air quality and greenhouse gas emission benefits relative to other fossil fuels. The strong growth in global natural gas consumption observed in both 2017 (3%) and 2018 (over 4.6%) has been driven by both growing energy demand and substitution to cleaner fuels.

Fast-growing Asian markets have become the main driver of natural gas development

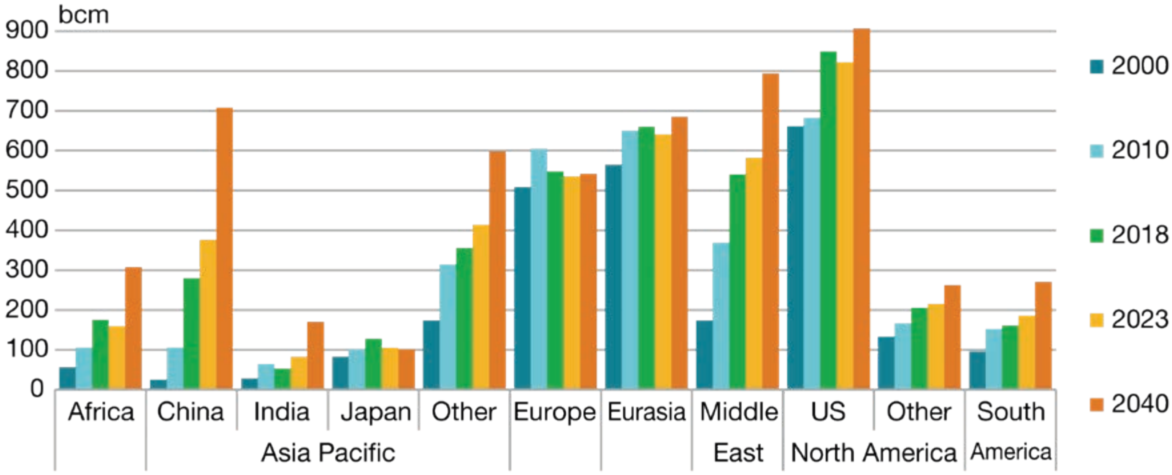
Natural gas is the fastest-growing fossil fuel in the International Energy Agency's (IEA) New Policies Scenario, as elaborated in the *World Energy Outlook* (IEA, 2018a). At an average annual growth rate of 1.6% until 2040, the scenario estimates that natural gas will overtake coal by 2030 to become the second-largest source of energy after oil. The year 2017 marked a turn in the recent evolution of natural gas markets, with the robust growth of the People's Republic of China ("China") and other fast-growing Asian economies, such as India, as major consumers and importers and the emergence of the United States as a major source of natural gas supply and future global trade growth. These transformations, which were further evidenced in 2018 (IEA 2018b), will be instrumental in the shaping the medium- and longer-term evolution of natural gas.

The Asia and Pacific region is the main source of growth in demand for natural gas and is expected to contribute half of the global consumption increase to 2023 (Figure 1). The region currently accounts for one-fourth of total natural gas consumption and will see its share increase to 28% in the next five years and eventually to 35% by 2040, according to the IEA New Policies Scenario (IEA, 2018a). Global natural gas consumption is expected to increase by over one-third over the next two decades, with the Asia and Pacific region accounts for over half of this total demand growth. China and India alone account for 38% of the total natural gas demand growth to 2040. For both countries, the drivers of natural gas demand combine continuous energy consumption growth on the back of sustained economic development and policy frameworks to curb air pollution.

The future share and expansion rate of natural gas will depend on a range of domestic energy policy and market design decisions, such as the security of supply, availability of infrastructure, fuel policies, and prices.

It is worth mentioning here that the rapid development of biogas and hydrogen will also diversify the gas supply and increase the market competition.

Figure 1. Natural gas consumption in selected countries and regions, 2000-40



Note: bcm = billion cubic metres.

Sources: IEA (2018a), *World Energy Outlook 2018*; IEA (2018b), *Gas 2018*; IEA (2019), *Natural Gas Information* (database).

Emerging Asian markets, led by China and India, will drive global natural gas consumption growth in the medium and longer terms.

Liquefied natural gas development has accelerated the transition to market pricing

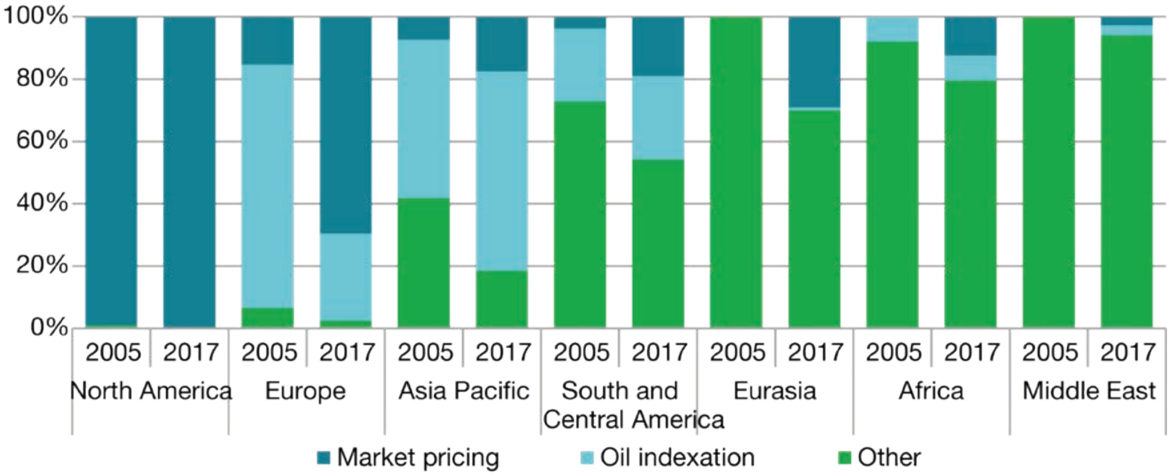
Natural gas pricing is transitioning from a system of indexation (usually against oil or oil products) and regulated pricing to market pricing determined and based on the fundamentals of supply and demand. The International Gas Union (IGU, 2018) has been reviewing the evolution of gas pricing mechanisms in its wholesale gas pricing global survey since 2005. Figure 2 shows the evolution of natural gas pricing by region for 2005 and 2017. The trend shows an overall shift from regulated and other forms of administered pricing to market pricing. Market pricing is progressing in all regions, particularly in Europe where the shift away from oil indexation has been massive.[1] This structural change in European gas pricing was enabled by market liberalisation and the development of natural gas hubs but was also triggered by the arrival of market-priced liquefied natural gas (LNG) in the European system in the late 2000s.

The international development of LNG trade has resulted in a strong increase in the number of players involved – from a limited club of mature buyers. The number of countries and territories with LNG import terminals grew from nine in 2000 to 41 in 2018 and is expected to increase to 47 by 2023. At the same time, there are more new players and entrants within these countries. New buyers have varying profiles, from fast-growing economies to mature markets seeking new sources of supply. The increasing number of LNG importers is accompanied by greater differentiation among buyers according to their domestic market requirements. Whereas traditionally, buyers were characterised by a strong share of long-term contracts within their LNG supplies, recent buyers have opted for different approaches, from using LNG as a means of diversifying their natural gas supply portfolio to regarding it as a backup or reserve fuel

[1] Oil indexation is the price-forming mechanism that links the gas price with certain oil products prices.

(especially in the context of hydro-driven power mix), or as a supply option depending on its competitiveness for the most price-sensitive buyers.

Figure 2. Evolution of natural gas pricing by region, 2005-17



Source: IGU (2018), *Wholesale Gas Price Survey 2018 Edition*.

Gas-to-gas competition increased in most regions with the development of market pricing, especially in Europe where it massively replaced oil indexation.

On the LNG supply side, diversity is also set to increase in terms of the number of sellers but also in terms of the commercial approaches to LNG trade, as the cargos sell on increasingly flexible and different terms. In the upstream of the LNG chain, the current wave of liquefaction capacity additions will result in a significantly changed supply map. Three major suppliers – Australia, Qatar, and the United States – will account together for 60% of global LNG export capacity by 2023.

The midstream part of the LNG supply chain is also undergoing structural change, with a growing share of short-term and flexible trade. Global portfolio players are providing LNG supply to various types of final customers according to their requirements thanks to their ability to aggregate different sources of supply. The conjunction of more flexible primary sourcing and intermediation offered by portfolio players has led to the emergence of secondary LNG markets, providing supply access to both traditional end users and new buyers, especially those that do not want or cannot have access to primary sourcing through long-term contracts because of the duration, volume, or financial inadequacy. The more recent arrival of trading houses as intermediary players completes this landscape; commodity traders have more appetite for short-term risk, providing additional flexibility and contributing to market diversification towards new buyers with weaker credit-worthiness than most of those served by traditional suppliers.

Gas market liberalisation development in Asia

The Asia and Pacific region accounted for more than 17% of global natural gas consumption in 2017 and 2018, and this region will be major source of demand growth in the medium-to-longer term. Market pricing and liberalisation in the region are still limited but progressing with the implementation of market reforms in several major importing countries.

Price reforms have gained momentum

Several Asian markets are undertaking structural reforms, thus enabling recent positive developments towards the establishment of more competitive markets and market-based pricing references:

- **Japan** has accelerated its domestic market liberalisation reform programme, enabling the full liberalisation of its downstream market as of 2017, the establishment of a Gas Market Surveillance Commission as a regulatory body, and the introduction of transportation unbundling, which is to be fully effective by 2022. In parallel, the Japan OTC Exchange, a subsidiary of the Tokyo Commodity Exchange, was launched in April 2017 with several LNG contracts products, including physical and cash-settled swap derivatives.
- **Korea** has a regulated natural gas market as per the Urban Gas Business Act, which grants exclusive selling rights to a single wholesaler, the Korea Gas Corporation, and 34 retailers. However, large-scale consumers, known as "direct importers", are allowed to import LNG for their own use but only for additional volumes that are not already committed to Korea Gas Corporation supplies. In 2017, the number of direct importers doubled from four to eight.
- **India** has been accelerating economic liberalisation in many areas, including gas, which was characterised by regulated prices for both domestic production and for consumption. In recent years, India has taken steps to improving the pricing for production, with the introduction in late 2014 of a basket of external market price references to replace the previous administrated pricing system and the development of a price ceiling mechanism in 2016 to incentivise investment in new, specific offshore developments instead of setting the wellhead price. In February 2019, the government granted marketing and pricing freedom to all new natural gas discoveries whose field development plans had yet to be approved.
- **Singapore** has unbundled natural gas transportation and competitive activities, with imports being granted through licences. Transportation activity is ruled by a Gas Network Code, which provides non-discriminatory access to infrastructure. The pipeline import control regime,[2] which prevented new pipeline imports in order to support the build-up of LNG imports, was lifted by the Energy Markets Authority in October 2017.

Developing new hubs

The above-mentioned structural reforms undertaken in several Asian markets enable positive developments towards the establishment of more competitive markets and market-based pricing mechanisms. In parallel, several trading places or contracts have been launched in the region, and more countries are planning to develop natural gas hubs.

[2] In August 2006, the government of Singapore introduced a policy on gas import control under which the energy regulator would not allow the import of new pipeline gas supply for commercial power generation until LNG imports reached reach 3 million tonnes per annum.

Box 1. Market reform gets a second wind in Japan

Japan has accelerated its liberalisation process in recent years. Three more phases of natural gas price deregulation were implemented in 1999, 2004, and 2007, and, in April 2017, the Japanese city gas market became fully open, enabling the entire natural gas consumer base to select its own gas supplier.

This deregulation process is a part of a broader set of energy system reforms, which include both power and gas systems. Under the 2017 reform, the chain of integrated gas businesses will be gradually segmented and restructured into three sectors: gas manufacturing business, pipeline service business, and gas retail business.

Another implication of the reform is the promotion of third-party access, which is to be implemented in phases, starting with LNG terminals. Businesses that own LNG terminals are prohibited from rejecting third-party use without a reason. This is also applicable to LNG terminals owned by electricity companies and other industries. Under the reform, LNG terminal owners must report and publish their annual utilisation plans and the benchmarks of their rate systems. If the terms and conditions of use are inappropriate, the government can order changes in the conditions. The unbundling of pipeline service businesses from the three major gas companies is also being targeted by 2022.

Based on the original Electricity Supervision Committee, the Japanese government added natural gas supervision and changed its name to the Electricity and Gas Market Surveillance Commission. The chairman of the committee is appointed by the Minister of the Ministry of Industry, Economy and Trade. The Electricity and Gas Market Surveillance Commission has a supervision office in major areas of the country. Three departments are set up at the Executive Board of the headquarters to conduct policy co-ordination, market supervision, and supervision of the network. The committee has also been given the functions of co-ordination and arbitration and, therefore, has a strong binding force on market players.

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Context and status of the Chinese gas market liberalisation

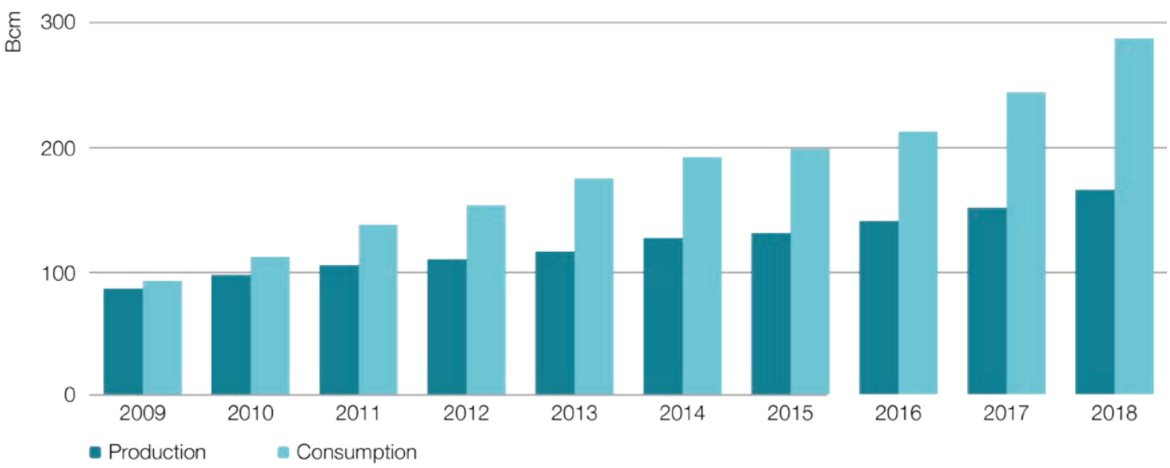
The People's Republic of China ("China") is at the forefront of the global natural gas growth trend. The country has enacted several reforms with the objective of liberalising its domestic prices. Gas market opening is also on the agenda of fast-growing markets throughout the world, with several reforms being enacted in major Asian consuming countries and supported by a background of positive trade with increasing liquidity and flexibility. This context provides the foundation for future consumption growth and market opening in fast-growing Asian markets, especially for China, which is expected to remain a leading contributor to global natural gas demand growth in the medium and longer terms.

General perspective

Fast-growing demand

China's natural gas consumption is rising rapidly. According to data from the National Development and Reform Commission (NDRC), the consumption of natural gas reached 280.3 billion cubic metres (bcm) in 2018, a year-on-year (y-o-y) increase of 18.1%. Since 2003, when consumption grew at over 16% (Figure 3), demand has maintained double-digit annual growth, except for a temporary slowdown in the growth rate from 2014 to 2016.

Figure 3. Natural gas production and consumption in China, 2009-18



Source: Data for 2009-16 from China Energy Statistical Yearbooks of the National Bureau of Statistics; data for 2017 from the Statistical Communiqué on the 2017 National Economic and Social Development of the National Bureau of Statistics; data for 2018 from the website of the National Bureau of Statistics.

China's natural gas consumption is rising faster than production.

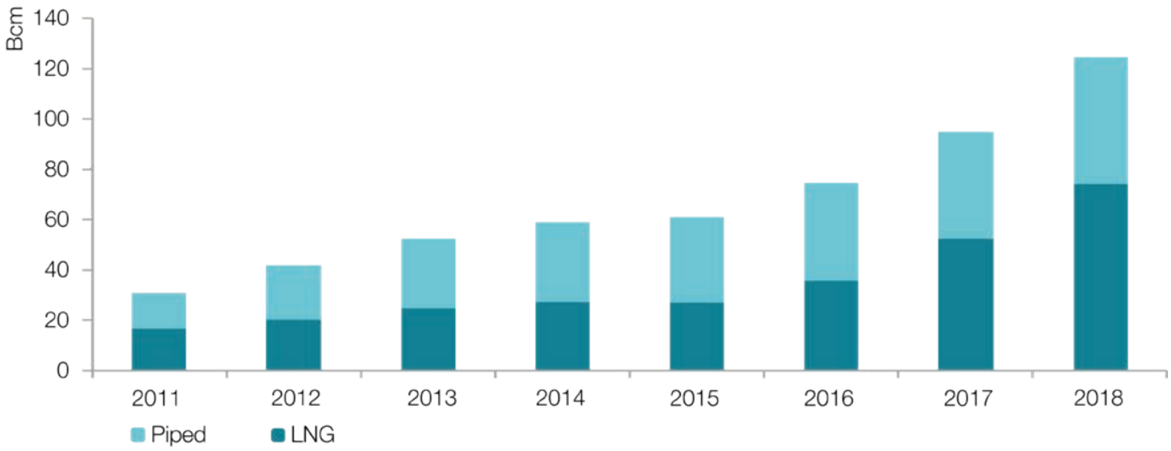
Driven by strong market demand, China's natural gas production has grown rapidly in recent years, with an average annual growth rate of 7.8% and reaching 157.5 bcm in 2018; however, consumption growth rate is more than twice that of production, and the increment volume of consumption is more than three times that of production.

Since production has not been able to grow as fast as consumption, China's natural gas imports have been rising rapidly in recent years. China imported a total of 124.7 bcm of natural gas in 2018, a y-o-y increase of 31.9%. The astonishing increases in natural gas demand in 2017 and 2018 have been policy driven, due to stronger environmental policies and the switching from coal to gas.

In 2017, China became the second-largest importer of LNG after Japan, marking a record for China's import growth, with imports of 52.6 bcm. In 2017, LNG was mainly imported from Australia at 46%, followed by Qatar at about 20%, and Malaysia at 10%. In 2018, LNG imports reached 73bcm, with 44% imported from Australia, 17% from Qatar, 10% from Malaysia, and 9% from Indonesia.

Pipeline gas imports grew by 19% in 2018 to reach 50.4 billion cubic metres (Figure 4). According to the General Administration of Customs, of China's pipeline gas imports from January to November 2018, 69% was imported from Turkmenistan, 13% from Uzbekistan, 12% from Kazakhstan, and 6% from Myanmar (NBS, 2018).

Figure 4. China's natural gas imports, 2006-18



Source: Data for 2006-16 from China Energy Statistical Yearbooks of the National Bureau of Statistics; data for 2017 from the customs information network.

China's gas imports are growing fast, especially LNG imports, which have significantly exceeded pipeline imports.

Infrastructure development

Gas storage

As of the end of 2018, China had 12 underground gas storage facilities in operation, with an effective working gas capacity of 8.8 bcm. This represents less than 4% of the annual gas consumption volume. Compared with the scale of consumption, China's storage capacity is much lower than in other major countries.

Long-distance pipelines

By the end of 2017, China had 74 000 kilometres (km) of transmission natural gas pipelines in operation, and the total gas transportation capacity of the trunk pipeline network reached 310 bcm per year. China's long-distance pipelines mainly include West-East Gas Pipelines 1, 2, and 3; the Sichuan-to-East Gas Transmission pipeline; Shaanxi-Beijing Gas Pipelines 1, 2, and 3; the Zhongxian-Wuhan Gas pipeline; the Zhongwei-Guiyang connect line; the China-Central Asia, China-Myanmar, China-Russian Federation gas pipeline ('Power of Siberia' expected before year-end) and other main trunk networks.

China plans to build (or is already building) 13 long-distance pipelines and 3 trans-provincial connecting lines and shale gas pipelines in 2017-20.It is expected that China's oil and gas pipeline scale will reach 170 000 km by 2020 (China Natural Gas Development Report, 2018).

China's territory is similar to the United States, but its gas consumption is about one-third, while its pipeline network is equivalent to around 77km of pipeline per 10 000 square kilometres of land area, only 15% of that of the United States. Considering China's rapidly increasing gas consumption rate, more pipelines are needed.

LNG regasification terminals

By the end of 2018, 21 LNG terminals were in operation in China, and the total LNG receiving capacity was around 96 bcm/year.

Due to the lower entry threshold for LNG terminal project, construction and investment will become more diversified and market competition will grow increasingly fierce. The LNG terminal operation mode will become more flexible and more in line with the market. The LNG terminals will, thus, provide a powerful engine for market reform.

Gas reform in China

Drivers and main objectives of the reform

The core objectives of China's natural gas market reform are to build a system in which the market determines the price and to form a market-determined natural gas price index that is internationally acceptable. Although China has started deregulating the natural gas price in many ways, its gas prices are still governed by the city-gate prices set by the government, essentially this reflect the current oligopoly market between the three state-owned companies, failure to effectively carry out third-party access to infrastructure, such as pipelines and terminals, and the lack of an independent regulatory body.

Such a system makes it difficult for China, as the world's largest importer of natural gas, to share the dividend of international natural gas development, since none of the major gas import contracts are based on Chinese prices index. In China, the current system is also unable to make the market play a leading role in resource allocation, which could lead to natural gas shortages on the one hand, and be detrimental to the enthusiasm of new entrants and cause the idling of facilities on the other hand. The core of the reform is to fundamentally change the system and build a mechanism for the market to play a more decisive role.

Pricing deregulation

China's natural gas price reform has been continuously advancing since 2005, when the NDRC issued the Notice on Reforming the Well head Pricing Mechanism of Natural Gas. Since the 12th Five-Year Plan, China has followed the general idea of "regulating the midstream and deregulating both upstream and downstream". The related deregulation policies are listed in Table 1. According to the regulations, most gas prices should be decided by the market, but this goal is still far from being achieved due to the lack of a systematic approach.

Table 1. Natural gas price reform process

Time	Policy	Key point content
End of 2011	Notice of the NDRC on Carrying Out Pilot Reform of Natural Gas Pricing Mechanism in Guangdong Province and Guangxi Zhuang Autonomous Region	Carry out the pilot reform of natural gas pricing mechanism in Guangdong Province and Guangxi. Adopt "net back" pricing, establish a mechanism to link the prices of natural gas and alternative energy, set the natural gas gate prices in the provinces (autonomous regions and municipalities) and deregulate the wellhead prices of unconventional gases, such as shale gas, coalbed gas, and coal-to-gas.
October 2012	-	Carry out the pilot reform of the natural gas pricing in the Sichuan and Chongqing areas.
July 2013	Notice of the NDRC on Adjustment of Natural Gas Prices	Promote the natural gas price reform nationwide: (1) adjustment of the incremental gas price; (2) three-step adjustment of the existing gas price and price increase by CNY 0.40 per cubic metre (m3).
September 2014	Notice of the NDRC on Adjustment of Natural Gas Prices for Non-residential Stock	(1) Increase the stock gas price by CNY 0.4 per m3 again; (2) deregulate the end user price of imported LNG.
April 2015	Notice of the NDRC on Rationalising the Price of Non-residential Natural Gas	(1) Decrease the benchmark price of the incremental gas by CNY 0.44 per m3 and increase the stock gas price by CNY0.04per m3 to realise the unification of the stock gas and incremental gas price; (2)deregulate the market price of the gas directly supplied for industrial users (except fertiliser gas).
November 2015	Notice of the NDRC on Reducing the Station Price of Non-residential Natural Gas and Further Promoting the Price Market Reform	(1) Decrease the valuation benchmark gate price by CNY 0.70 per m3; (2) implement "benchmark price + floating range" management and allow a rise in the price of the gas other than residential and fertiliser gas by 20% one year later.
October 2016	Notice of the NDRC on Clarifying Pricing Policies for Gas Storage Facilities	(1) The gas storage service price can be determined by the supplier and demander through negotiation; (2) the natural gas purchase and sales prices of gas storage facilities are formed by market competition.
November 2016	Notice of the NDRC on Promoting the Fertiliser Gas Price Market Reform	Fully deregulate the fertiliser gas price.
November 2016	Notice of the NDRC on Relevant Matters Concerning the Natural Gas Station Price Policies in Fujian	Carry out the pilot market reform of natural gas gate price in Fujian Province.

Time	Policy	Key point content
September 2017	Notice of the NDRC on Reducing the Benchmark Station Price of Non-residential Natural Gas	(1) Reduce the benchmark gate price of non-residential gas by CNY 0.1per m3; (2) deregulate prices of gas which are traded in the gas exchanging centres.
May 2018	Notice of the NDRC on Rationalising Residential Gas Station Prices	Integration of residential and non-residential gas prices.

Source: National Energy Administration.

Apart from the gas commodity price, some progress has also been made in the price regulation of the pipelines and infrastructure, as shown in Table 2. The aim is to strengthen the supervision of local natural gas transmission and distribution prices and reduce the cost. The policy document states that the pipeline transportation prices shall be set by the government in accordance with the principle of "permitted cost plus reasonable profit". The internal rate of return of the pipeline projects has been set at 8%.

It is required that all pipeline transportation prices of long-distance pipelines nationwide will be clearly marked, and the information will be fair and open, which is closely related to the midstream reform. The clarity of trans-provincial pipeline transportation prices will effectively promote the open access of the pipeline network to third-parties and promote market transactions of natural gas.

Table 2. Natural gas transmission and distribution price policies

Time	Policy	Main content
August 2016	Notice on Strengthening the Supervision of Local Natural Gas Transmission and Distribution Prices and Reducing the Cost of Gas for Enterprises	Comprehensively rationalise the prices of natural gas in each link, reduce the excessively high provincial pipeline transportation price and gas distribution price, reduce gas supply intermediate links, and rectify and standardise the charging behaviour.
October 2016	Measures for the Administration of Natural Gas Pipeline Transportation Prices (Trial)	The pipeline transportation prices are set in accordance with the principle of "permitted cost plus reasonable profit".
	Measures for the Supervision and Examination of Natural Gas Pipeline Transportation Pricing Costs (Trial)	The NDRC is responsible for organising and implementing the supervision and examination of pipeline transportation pricing costs, which are composed of depreciation and amortisation charges and operation and maintenance costs.
June 2017	Guiding Opinions on Strengthening Supervision and Control of Gas Distribution Prices	Clarify the framework of basic rules for the supervision of the gas distribution prices.
August 2017	Notice on the Approval of the Trans-provincial Natural Gas Pipeline Transportation Prices	Supervise and examine the pricing costs of 13 trans-provincial pipeline transportation enterprises and approve the relevant pipeline transportation prices.

Source: National Energy Administration.

Establishing trading platform

At present, the Chinese government has led the establishment of two petroleum and natural gas exchanges, Shanghai Petroleum and Natural Gas Exchange (SHPGX) and Chongqing Petroleum and Gas Exchange. In addition, some local commodity markets and private enterprises are also involved in the natural gas trading platform.

Box 2. Shanghai Petroleum and Natural Gas Exchange and Chongqing Petroleum and Gas Exchange

Shanghai Petroleum and Natural Gas Exchange (SHPGX) was registered and established in the Shanghai Free Trade Zone on 4 March 2015. The shareholders of SHPGX include Xinhua News Agency, China National Petroleum Corporation (CNPC), Sinopec, the China National Offshore Oil Corporation (CNOOC), Shenergy, Beiran, ENN, China Gas, Towngas, and China Huaneng. In September 2017, SHPGX carried out the first competitive price transaction of pipeline gas in China.

According to SHPGX, by the end of 28 December 2018, 60.455 bcm (bilateral) of natural gas had been transacted through the SHPGX system, and the transaction price was generally stable. Among them, the bilateral volume of pipeline natural gas was 55.541 bcm, mainly concentrated in East and North China; the volume of LNG was 3.329 million tonnes, mainly in East and South China.

Chongqing Petroleum and Gas Exchange was established in July 2017, with shareholders including national oil and gas companies, such as CNPC, Sinopec, China Resources Gas, ENN Energy, and China Gas; regional energy and chemical enterprises, such as Chongqing Energy, Chongqing Chemical & Pharmaceutical, Yanchang Petroleum, and Hubei Energy; and fintech innovation enterprises, such as Citic Global and BORN Technology.

Chongqing Petroleum and Gas Exchange completed its first pipeline natural gas transaction on 26 April 2018 and its first LNG transaction on17 May 2018.

Source: NDRC.Chongqing Dail.

In general, due to external constraints, these two exchanges mainly play the role of price discovery in limited spot transactions, far from the design goal of providing an internationally influential price index.

Third-party access to infrastructure

Fair and open access to natural gas infrastructure, including a pipeline networks and LNG regasification terminals, is the core of the natural gas market liberalisation reform. Over the years, similar to the early stages of major global gas markets, China's oil and gas industry has adopted integrated upstream and downstream operations and enabling the natural gas industry to develop rapidly at the early stages of natural gas development. However, as the natural gas market has developed to a certain scale, the disadvantages of such an infrastructure monopoly have become increasingly apparent, such as the effects on restraining newcomers, hindering competition, restricting natural gas price reform, and further restricting investment in the upstream oil and gas industry. From the successful experiences of natural gas market liberalisation around the world, third-party access is an inevitable choice.

The Measures for the Supervision of Open Access to Oil and Gas Pipeline Network Facilities (Trial), issued by the National Energy Administration in 2014 (NEA, 2014), stipulate that the access scope of oil and gas pipeline network facilities shall be the main and branch lines of oil and gas pipelines (including the oil and gas pipeline networks within provinces), as well as the relevant facilities supporting the pipelines. It also states that where there is surplus capacity, operators of oil and gas pipeline network facilities shall provide third-party market players equal access to the pipeline network facilities and provide new users with transportation, storage, gasification, liquefaction, and compression services in a fair and non-discriminatory manner according to the order in which contracts are signed. In addition, the measures propose that the calorific value and volume should be used as the measurement standards, and the quantity of calories as the basis for trade settlement.

The Order for the Construction and Operation Management of Natural Gas infrastructure, issued by the NDRC in the same year (NDRC, 2014), is the first legislative document to attempt to regulate the natural gas market and infrastructure, which clearly requires fair third-party access to infrastructure, such as pipelines and LNG terminals, and clarifies the responsibilities and rights of natural gas market players.

Due to the lack of implementing tools for these regulations, they did not achieve the expected implementation objectives, but they did provide a framework for the market liberalisation of natural gas. Although some LNG terminals had started to conduct third-party access tests in the window phase, they were not extended to the pipeline system, and there were very few successful cases.

Similar to Europe, the first two unbundling orders did not fulfil their expected roles, and access to natural gas infrastructure was difficult to implement, so unbundling of the infrastructure and gas ownership was subsequently proposed. This reform was widely being discussed in China. After years of deliberation, the separation of the oil and gas pipeline assets of China's three major oil companies and the formation of a "national pipeline company" are being considered. It anticipated that the three main companies, CNPC, Sinopec, and CNOOC, would divest their pipeline assets and employees and transfer them to a new pipeline company. The State Council approved the draft plan to establish a national oil and gas pipeline corporation, including details of the assets to be incorporated. In late March 2019, the Communist Party of China (CPC) Deepening Reform Committee reviewed and approved the Implementation Opinions on the Reform of the Operation Mechanism of Oil and Gas Pipeline Network. The next step will be to establish a state-owned diversified oil and gas pipeline company and reform the operation mechanism of the oil and gas pipeline network.

Box 3. Opinions of the CPC Central Committee and State Council on deepening the oil and gas system reform

In May 2017, the CPC Central Committee and the State Council published Several Opinions on Deepening Oil and Gas System Reform (hereinafter, referred to as "Opinions"), which clearly emphasised that the market should play a decisive role in resource allocation and embody the energy commodity attributes for deepening the oil and gas system reform. The direction should be problem oriented and market oriented. The Opinions point out the clear development goal for the reform of China's natural gas industry.

The key tasks related to the gas market reform of the *Opinions* include the following:

- Reform the operation mechanism of the oil and gas pipeline network and enhance the capacity of intensive transportation and fair service. Promote the independence of the trunk pipelines of large state-owned oil and gas enterprises step by step and the unbundling pipeline transportation from sales. Improve the mechanism for fair third-party access to oil and gas pipelines and allow the open access for third-party market players to the oil and gas trunk pipelines and intra-provincial and inter-provincial pipeline networks.
- Deepen the reform of competitive downstream segments. Make efforts to develop and foster the downstream natural gas market and promote fair competition in natural gas distribution and sales.
- Reform the pricing mechanism for oil and gas products to effectively enhance market vitality in competitive segments. Accelerate the development of oil and gas trading platforms, encourage qualified market players to participate in trading, and set prices through market competition. Strengthen the supervision of the pipeline transportation costs and prices and formulate pipeline transportation prices with the principle of "permitted cost plus reasonable profit".
- Deepen the reform of state-owned oil and gas enterprises. Encourage qualified oil and gas enterprises to develop equity diversification and various forms of mixed ownership. Support state-owned oil and gas enterprises in taking various measures to divest their social functions and resolve historical problems.
- Improve the oil and gas reserve system, enhance strategic oil and gas security, and guarantee the supply capacity. Improve the investment and operation mechanism of reserve facilities, increase government investment, and encourage social capital to participate in the investment and operation of storage facilities. Establish the natural gas peak-shaving policy and tiered storage peak-shaving mechanism.

The *Opinions* points out the direction, objectives, paths, and tasks of China's oil and gas industry reform from the top-level design. The *Opinions* has led a new round of reform in China's oil and gas industry. In the subsequent two years, some progress has already been made, including the looming of the state gas grid corporation.

Source: Xinhua News Agency 2017.

Challenges to China's gas reform

The market price is still limited

China's natural gas price reform has gone from the government guidance price to a cost-plus method and a gradually deregulated price. Although the prices of LNG, shale gas and coalbed gas and the coal-to-gas ex-factory, fertiliser gas, and gas storage service have been deregulated, the deregulation of gas prices other than the LNG has not exerted a significant impact. Because a market-oriented system has not been established, the natural gas price is still heavily subject to the city-gate price set by the government, and even LNG is largely influenced by the government guidance price in the overlapping market with pipeline gas.

The price deregulation is concentrated more in the upstream such as shale gas, LNG and storage, and in the case of limited upstream suppliers, this does not promote market prices; at the same time, detailed prices are still strictly regulated by the local government (Chen, 2015).

The seasonal characteristics of natural gas demand are generally not reflected in the current price, and the adjustment mechanism is not flexible enough to reflect changing needs. This is one of the main reasons for the gas shortage in China during the winter of 2017-18.

The Shanghai Petroleum and Natural Gas Exchange and Chongqing Petroleum and Gas Exchange carry out listed transactions and competitive price transactions for pipeline natural gas and LNG. However, due to the lack of effective market design at the macro level, they are unable to build a many-to-many trading system, and the negotiation power of the buyer and seller is severely unbalanced at present. For example, the competitive price transaction implemented in 2017 is mainly bidding for buyers to compete, while the auction for sellers to compete has not yet been realised; the competitive price transaction is often made at the maximum price. The main problem issue is the diversified buyers versus the limited suppliers – in particular, the onshore pipeline gas is mainly dominated by a single company.

The lack of market price signals makes it difficult to reflect the real supply and demand, and there is still a long way to go to establish a futures market. Without a functional spot market, it is impossible to establish a real futures market for achieving a better price discovery function. Therefore, the market players in the natural gas industry are directly exposed to the risk of market fluctuations rather than hedging in the market.

Not in line with the global market

China is the biggest importer of natural gas in the world. However, when Chinese enterprises sign long-term contracts for natural gas or LNG imports with international market players, their prices are often linked to Japanese Crude Cocktail (JCC) prices in Japan and some contracts are linked to fuel prices in Singapore or natural gas prices in Henry Hub. No long-term contracts are currently priced according to China's natural gas price index.

The Souths China LNG trading price index and the China LNG producer price index, exclusively released by Shanghai Petroleum and Natural Gas Exchange, mainly reflect the domestic LNG price trend. There is still a gap between the measurement of these two price indexes and common international practices. Although they play some role in the Chinese market, they have little influence on the international market.

Limited upstream competition

CNPC is the primary owner of natural gas resources in China, followed by CNOOC and Sinopec. CNPC supplied 172.4 bcm of natural gas in 2018, accounting for about 61.5% of China's annual gas consumption in 2018. LNG terminals are mainly owned by CNOOC. PetroChina and Sinopec also have terminals, and there are some private owners, such as Jovo, ENN, and Guanghui. The major three national oil companies (NOCs) supply more than 95% of the gas to the Chinese market.

Although the diversified non-state-owned investors are attracted to the exploration and development of shale gas, the current situation of exploration and development is lower than expected, and enterprises other than CNPC and Sinopec have not yet developed commercial shale gas exploration and production capacity. The limited number of upstream sellers inevitably leads to a lack of effective competition in the upstream market (Pan, 2017).

Poor interconnections and third-party access

The Chinese government has stepped up efforts to connect the pipeline networks among CNPC, Sinopec, and CNOOC and guarantee natural gas supply security to ease the impact of frequent gas shortages. The National Energy Administration has made great efforts to promote the interconnection of natural gas infrastructure and even set up a special office for co-ordination since 2017, which has achieved positive results. However, in order to realise the real pipeline network interconnection, the ideal scenario of "one national pipeline network" still requires further confidence in the decision makers of the reform and may take more time. In particular, it is difficult to connect the main pipeline network and the provincial pipeline networks (GUO, 2017).

Due to the integrated model, third-party access to the pipelines is limited, which also impedes interconnection. The urban gas and large electric power enterprises are highly motivated to import LNG directly. However, there are still great challenges facing third-party access to LNG terminals. In 2018, CNOOC launched its window bidding for LNG terminals on Shanghai Petroleum and Natural Gas Exchange, but efforts were limited. In March 2019, CNOOC announced it is preparing to open up its LNG terminals to TPA. According to the company, each TPA user must take four cargo units per year over a ten-year period.

Incumbent long-term contracts

Similar to the United States and the United Kingdom in their early stages, most gas contracts were signed as long-term contracts, i.e. “take-or-pay” contracts. Almost all of China's imported pipeline gas and LNG contracts have been signed as long-term take-or-pay agreements, especially the Turkmenistan gas deal and the LNG deals from Qatar and Australia. During the signing time, there was no other choice for Chinese buyers. Transitioning from the current system of long-term take-or-pay gas plus transportation contracts to a system with separate transportation and gas sales contracts may entail either upstream company or pipeline company losses. The reform effort needs to anticipate the potential issues and identify the solutions to address the interests of the many stakeholders involved.

In the domestic market, take-or-pay contracts also comprise the majority of contracts, such as the West-East Pipeline contract. However, it is relatively easier to deal with them than the international contracts, partly because the prices are not as high.

Complexity of the local pipeline system

Another important challenge in promoting natural gas market reform is to balance the interests of provincial pipeline networks and other main pipeline networks.

With the construction of long-distance land pipelines, provincial natural gas pipeline companies have emerged, mainly led by local governments. In 2001, provincial natural gas pipeline companies were established in Jiangsu, Zhejiang, and Shanghai along West-East Gas Pipeline 1. After that, a number of provincial natural gas pipeline companies were established with the construction of West-East Gas Pipeline 2, Sichuan-to-East Gas Pipeline, and West-East Gas Pipeline 3. When the West-East Gas Pipeline 3 was connected to Fujian, the Fujian Provincial Government immediately established Fujian Natural Gas Pipeline Company in September 2015.

The Yunnan Provincial Government approved the establishment of Yunnan Natural Gas Co., Ltd. in August 2016. At present, provincial pipeline companies have been established in a total of 17 provinces in China.

After years of development, these provincial pipeline companies have formed a complex pattern of equity and interests. Most pipeline companies are joint ventures between local state-owned enterprises and CNPC, Sinopec, and CNOOC, and some are also owned by private enterprises. CNPC, Sinopec, and CNOOC invest in the provincial pipeline companies selectively, often based in the regions where they have market advantages. CNPC has invested in five provincial pipeline companies, Sinopec in six provincial pipeline companies, and CNOOC in two provincial pipeline companies. Sinopec is the most active upstream company to share in the provincial pipeline companies and its shares are mostly along the Sichuan-to-East Gas Pipeline.

Many provincial pipeline companies were designed according to the concept of provincial natural gas resource dispatching platform, namely the policy of "unified purchase". However, as the policy changed, the provincial pipeline operation mechanism has gradually changed from "unified purchase and sale" to "overall allocation" and "gas transportation". Only the “gas transportation” service could be done when the provincial pipeline could not get the gas for "overall allocation" from the upstream gas suppliers. On the one hand, the upstream gas suppliers have a strong desire to directly sign a supply agreement with the downstream large users; on the other, the downstream users complain about the price mark-up by provincial pipelines and gas distribution companies, which places the provincial pipeline companies in a difficult situation, they are unable to get the benefits balanced (HUANG, 2016).

Straightening out and balancing the relationship between the provincial pipeline companies and the main pipeline companies are real challenges to promoting natural gas market liberalisation. The benefits of the provincial pipeline companies must be considered, regardless of whether the national pipeline companies that may be established will include provincial pipelines or promote the reform of pipelines through other market-oriented ways. The right way should be found to relieve the challenges and encourage provide provincial pipeline company initiatives to promote the market liberalisation reform so as to promote the overall reform in China.

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Implications for China's gas market liberalisation

The People's Republic of China's ("China") natural gas consumption was 33.9 bcm when the first West-East Gas Pipeline was completed in 2004. By 2018, natural gas consumption had increased nearly ten times. China is now the world's third-largest natural gas market after the United States and the Russian Federation ("Russia"). The development and reform of China's natural gas industry have had a huge impact not only on the development of related domestic industries but also on the global natural gas market.

The previous section illustrated the challenges faced by China's gas market liberalisation. There were also similar problems during market liberalisation in the United States and Europe decades ago. These countries successfully overcame the obstacles through systematic approaches with effective policy tools, which are illustrated in more detail in the Annex. Learning from the European and US experiences can help reduce the costs of trial-and-error efforts in the ongoing reform in China.

Common features in gas market opening

The natural gas market opening process has unfolded at different times in different countries and due to different market fundamentals, such as in self-sufficient and net-importing countries, in mature and growing markets. However, it has proceeded towards the same common objective of fostering competition and market liquidity for the benefit of end users.

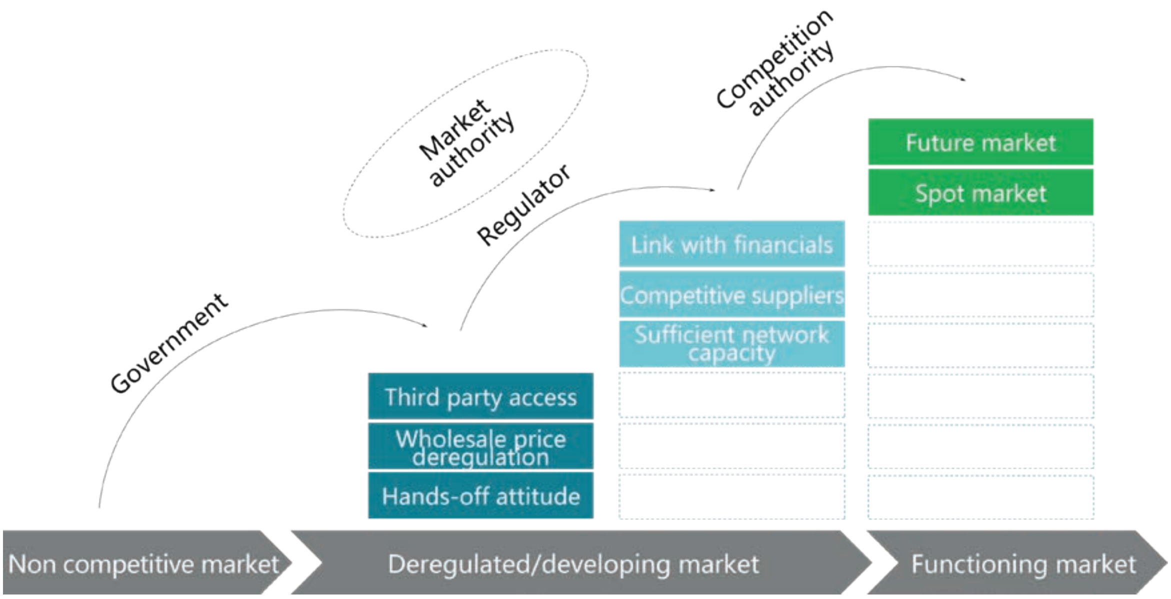
The primary goal of market opening is to increase competition among natural gas suppliers and consumers in a market. The move away from a monopolised natural gas market will lead to a mature, functioning market with full retail competition. Such a process encompasses several steps towards progressive market deregulation, which include contributions from stakeholders (market participants, regulators, and government agencies, etc.) covering the different aspects of market opening. There are common features such as the following:

- Regulatory measures are necessary to provide a framework to promote market competition. These include the separation (or unbundling) of commercial activity from infrastructure operations for integrated companies to guarantee fair access to networks, the enactment of third-party access rules to monitor this fair and non-discriminatory access to infrastructure, and a price deregulation framework to accompany wholesale and retail competition development.
- Market participants (both commercial players and infrastructure operators) are at the centre of the process, which should provide sufficient incentives to foster competition. Competition supposes reaching a sufficient number of market participants in order to develop market liquidity and avoid price distortions. This, in turn, supposes adequate network capacity, with the active involvement of network operators to develop additional capacity if required by the market to ensure full liquidity. Additional participants, such as pure traders and financial institutions, are also to be involved to provide supplementary services, such as credit financing or hedging.

- Governments steer the whole process with a progressive transition from direct policy making and a market involvement to market monitoring through an independent agency. However, the particular institutional arrangements to withdraw direct government influence from the market may differ significantly from one country to another.

The experiences from the North American and European cases show that the overall process towards the development of functioning hubs is quite long (a decade more or less) and follows several steps (IEA, 2012).

Figure 5. Creating a natural gas hub



Source: IEA (2013), *Partner Countries Series – Developing a Natural Gas Trading Hub in Asia*.

Establishing a functioning wholesale natural gas market is a long, multi-step process that implies a transition from government to regulator to competition.

The first stage is to ensure that institutional requirements are met to support competition. These early conditions have to be developed by governments and include an unbundling of commercial and infrastructure-related activities to enable third-party access to networks, as well as deregulating the resulting wholesale price (that includes commodity, services, and commercial margins and excludes network tariffs as per the unbundling). This crucial first step needs to be carried out by governments, implying a shift from direct policy making and market involvement to market monitoring through an independent agency.

In addition to institutional requirements, some structural requirements – that need to be maintained and monitored by governments – are also required to ensure the continued functioning of a spot market. Once non-discriminatory third-party access to networks is established, it is essential to ensure that sufficient capacity will exist to ensure liquidity and the development of trade. To guarantee these structural requirements, an independent system operator and a clear and unbiased investment regime founded in a well-developed network code are essential. The diversification of competitive suppliers will also be ensured by involving financial parties, both as counterparts to cover financial and operational risks and as sources of funding to invest in infrastructure needs to foster future market growth. Such structural requirements are essential to initiate a natural gas market and should be guaranteed by an independent regulator.

The most advanced phase of development – towards a functioning market – implies the establishment of a platform for the ownership exchange of natural gas, which will ensure that the resulting price reflects the current and future state of the market. The physical hub (which could be either geographical, such as in the United States, or virtual, such as in Europe), initially resulting from bilateral trade and progressively moving to centralised, exchange-based trading, will thus be completed by "paper" or "financial" trade for future delivery.

Reform is a systematic project that needs time to be carried out gradually and effectively. The primary goal of market opening and liberalisation should be to deliver benefits to consumers through access to efficient market pricing, better and innovative service offerings from suppliers, and improved security of supply delivered through creating investment opportunities. Establishing functioning competition in the market is the best way of achieving this, and it should be co-ordinated, matched, and implemented step by step. With reference to the international natural gas market liberalisation reform process, China's reformers should fully realise the long- term nature and complexity of the natural gas reform and have maintain determination to make unremitting efforts towards achieving its goals.

China will develop a unique market model

The United States, the European Union, and other countries have established market-reflective natural gas pricing mechanisms and natural gas spot trading centres, which form the basis of natural gas futures markets and other derivative financial products markets. The establishment of natural gas trading centres has promoted the efficient allocation of natural gas resources in these markets and also created conditions for the natural gas market to achieve a higher level of development.

The United States provides a best-practice example of highly liquid natural gas commodity and pipeline markets. The trading models and instruments gradually formed in the US market, as well as the numerous market-based solutions help address resource allocation problems and investment, are of referential significance for other countries to liberalise the natural gas market. The experiences and lessons of the United States, Europe, and other countries in building gas exchanges can serve as a beneficial reference for the construction of natural gas markets in China. However, it should be noted that the market design and route of natural gas reform cannot be completely consistent in any country as the resource conditions, market foundation, and energy management systems vary among each country. The regulations and implementation of efforts to liberalise these gas markets were different in each market and the path for China will be unique. While, the models of the United States, Europe and other countries cannot be copied in their entirety for China's natural gas market path design, they can provide valuable insights and lessons as China explores its market reform considering its national conditions and basic conditions.

Comparison to the US model

The features of the US natural gas market are similar to those of China in many aspects, such as the wide geographical scope, the remote gas source from the consumption centre, and a large-scale natural gas market. Therefore, how the United States achieved its competitive market model is of important reference value for China.

The US natural gas market is highly interconnected and has thousands of market players, including upstream natural gas companies ranging from small independent companies to companies affiliated with large multinational companies, regional distributors, independent traders, and large end users, etc. with equally fair access to infrastructure. At present, China lacks diversified upstream market players and widespread TPA. China has realised diversification in downstream natural gas sales, but the diversification of the resource supply has been relatively slow, and the main natural gas sources are still controlled by CNPC, Sinopec, and CNOOC. China has adopted the independent tendering model for shale gas development, and the number of LNG import enterprises has been gradually increasing, but there are still very few market players that can provide resource supply. Diversified market players are not only an important indicator for the success of a market but are an important factor that affects liquidity.

China's natural gas pipeline network is still in fast development period, with poor connectivity between the pipelines. At present, the natural gas pipeline network in China is mainly composed of trunk lines and provincial pipeline networks (NEA, 2018). There is a low degree of interconnection between trunk lines, and provincial pipeline networks, and between coastal LNG terminals and main pipelines. There are many isolated islands of regional gas sources or LNG stations and few hub stations with interconnections or pipelines with two-way gas transmission. Because the pressure of the pipeline networks also does not match, surplus gas sources and LNG terminal capacity cannot be effectively utilised. These factors make it difficult for China to form many-to-many transactions similar to the United States.

The greatest step adopted by the United States in achieving its current market participation came in 1992-93 with Federal Energy Regulatory Commission (FERC) Order 636, which required the complete separation of sales from pipeline transportation ("unbundling") so that customers could select their supply from any competitor in any quantity and arrange transportation with a regulated pipeline operator. Interstate pipelines were no longer allowed to sell natural gas and were restricted to providing transparent, non-discriminatory transportation services. Due to this radical change, many producers and end users did not want to incur the expense of having to hire staff to either directly market or procure supply and transportation services. Thus, a niche developed for gas marketers, companies that neither own equity production nor are end users, but instead purchase gas supplies and either sell these volumes directly to end consumers or resell them to other marketers. FERC Order 636 also spurred the development of market centres, which further drove additional pipeline interconnections. Pipelines offering transportation services were incentivised to connect with other pipelines to increase the value of their transportation services. These steps have promoted the participation of a wider range of market players in natural gas pricing and the timely discovery and control of natural gas prices by the market. These conditions are also very limited in China.

Comparison to the EU model

European countries share similarities with China in terms of their natural gas industry systems (for example, most countries had only one or two natural gas pipeline monopolies, and most natural gas suppliers were oligopolies in the initial stages of reform). Europe also imported a lot of gas, much as China does now. Some European countries do not have liquid competitive markets like North America and are working to further develop their markets, which is similar to China's situation. Although the national conditions and background of natural gas exchange hubs in Europe are different from those in China, the fresh experience in establishing natural gas exchange hubs in Europe and the different pace of development in different countries can still provide valuable experiences for developing natural gas exchanges in China (DENG, 2017). However, it should also be noted that the market reform of natural gas in European countries is also in progress. China's national conditions and regional characteristics vary from the EU member states, making it impossible to exactly copy the member states' model in China.

Considering the small national territorial area of the EU countries and the short distances for pipeline transportation, it is feasible to realise a highly interconnected network to create a single virtual hub to enable the "one price for one country" vision. China is geographically much larger than the individual countries in the European Union and, hence, is too big to have one virtual trading location across the entire country.

However, the European country-specific virtual hub model is worthy of reference for some Chinese provinces. Like the European Union, multiple hubs could be developed regionally (in member states for the European Union or in the provinces for China) to reflect the local market policy and supply and demand conditions. The virtual centre may be piloted first in the provinces with abundant gas resources or major consumption demand that have relatively complete infrastructure and good supporting conditions.

Well-planned market design is critical

Adopting local market centre pilots

Under the existing natural gas infrastructure conditions and management system in China, it will be very difficult to adopt a certain fixed model to promote market liberalisation reform nationwide, regardless of whether a national pipeline company is established. Under the constraints of various complicated contradictions, it is less likely to achieve obvious reform results in the short term like the United States and European Union did in the early reform stage. This will be a great challenge to Chinese reformers and may even cause doubts and reversals of the reform. Therefore, it may be realistic and valuable to pilot reform in regions with good conditions.

The ongoing unbundling of the pipeline will be a strong signal of reform and greatly promote the reform pace, further stimulate the vitality of the upstream and downstream, and promote the transformation of China to a competitive market. It will also be a chance for the regional gas reforms to follow, as mentioned above, in trying to establish the local competitive gas market and trading centres, which could be the virtual hub illustrated below or the physical hub in the major pipeline conjunctions.

Piloting virtual exchange centres

In the United Kingdom, the entry/exit transportation system enabled the development of the virtual trading point, the National Balancing Point (NBP). In the context of China's overall promotion of the natural gas market reform (the establishment of a national pipeline company is being planned). China is also taking the lead in piloting the regional exchanges in the regions with many gas sources, improved infrastructure, good supporting conditions and setting the internationally acceptable market price index will play a leading role in the national oil and gas system reform and natural gas price reform and conduct valuable exploration for the national natural gas market liberalisation reform path. If a virtual exchange trading point runs smoothly, it is likely to form a gas price index with regional and even global influence, which will open up a new path for the success of China's gas market liberalisation reform.

Based on the pipeline and gas resource conditions of China's provinces, it is feasible to pilot the establishment of a virtual exchange in major resource or consuming provinces, such as

Guangdong province, similar to what has been done in Europe. Guangdong province has a comparable market size, infrastructure conditions, and diversified market participants compared with major European countries, such as the United Kingdom. The construction of "one network for the whole province" in Guangdong province has obtained partial results and preliminarily achieved "multi-source complementarity and interconnection". In addition, Guangdong province has also carried out price policies, such as the "same price for same network", and thus can provide valuable experience.

Box 4. Gas market structure in Guangdong

Guangdong province has achieved the phased results of "one network for the whole province" and "same price for same network" and has the basic conditions for the establishment of a regional virtual exchange.

In July 2007, CNOOC, Sinopec, and Guangdong Yudean Group established the provincial pipeline company according to the share ratio, which was responsible for the construction, operation, and management of provincial main gas pipelines in line with the principle of "multiple gas sources supply, one network for the whole province, gas price classification, unified purchase and sale, and government approval". After CNPC took a stake in the provincial pipeline network company in 2011, the operation mode of the provincial main pipeline network was adjusted operate in line with the principle of "one network, ensuring residential usage and having competition", and combined with "overall allocation" and "gas transportation". Under the mode of "gas transportation", the natural gas resources are transported to the provincial main pipelines, which provide gas transportation services and collects reasonable pipeline transportation fees at the same price for the same pipeline network. Promoted by these reforms, Guangdong province has preliminarily realised "multi-source complementarity and interconnection", accumulated valuable experience, and has the basic conditions for the establishment of the NBP virtual exchange similar to the in the United Kingdom.

In addition, the natural gas supply capacity of Guangdong province has been continuously enhanced, and a gas supply pattern of coastal imported LNG, onshore trans-provincial pipeline natural gas, and offshore natural gas has been formed. Relatively complete pipelines and LNG facilities can provide a basic guarantee for the supply and demand balance and physical delivery in the exchange. The Guangdong's financial market has perfect software and hardware facilities, professional management teams, and effective risk-control measures, which can provide mature preparation experiences and strong technical and financial support for the regional natural gas exchange.

Enabling third-party access to infrastructure

Separation of regulated and commercial activities

As third-party access to natural gas pipelines and LNG terminals is the key precondition for the establishment of price signals, the unbundling of the infrastructure was a major step during the

US and European gas liberalisation. During the EU gas reform, it is stated "ownership unbundling as the most effective tool by which to promote investments in infrastructure in a non-discriminatory way, fair access to the network for new entrants and transparency in the market" (BG, 2012). The separation of regulated and commercial activates is also what China is doing now, which will pave the way to fair third-party access.

Defining the shipper's role

The result of unbundling is the emergence of a specific player defined as the "shipper". The shipper should be licensed and supervised by the regulator. The shippers should obtain the relevant qualifications to have the right to use the natural gas transportation system. Once the right to use is obtained, the pipeline companies must allow all shippers to use the network without discrimination. The shipper can buy gas from natural gas producers, other shippers, or on exchanges and sign pipeline capacity contracts with pipeline companies.

An "anchor shipper" is a design to find the long-term capacity usage. It can support new pipeline development and could also be used to protect the existing major users with long-term contracts during the transition period, such as the major three NOCs in China. At the same time, certain open session capacity should be allocated for the newcomers to foster competition.

Establishing capacity allocation mechanisms (CAM) and congestion management procedures (CMP)

Capacity allocation mechanisms are used to define the rules of primary access. Pipeline capacity auctioning is a powerful policy tool in the European Union and has been managed through the development of a platform (PRISMA) that enables a high level of transparency for both market players and regulators. A secondary capacity market can be introduced in order to optimise the use of the transmission system capacity and with a view to granting system users the right to freely trade gas transmission capacities.

Congestion management procedures also need to be introduced not only to manage physical capacity issues but also contractual congestion whenever a shipper does not use the capacity it booked in the network. The introduction of the "use-it-or-lose it" (UIOLI) mechanism has been implemented to release unused capacity and prevent contractual congestion, which can result in balancing issues and/or speculative behaviours with proportionate impacts on prices. In the US and the European countries, the dispatch of the physical gas is implemented by the pipeline companies/transmission system operators (TSO).

Tariff setting

Making a simple and clear pipeline tariff will help to encourage more new shippers. In the United States, pipelines are generally divided into several zones, and the pipeline transportation fee is the cost for transportation from one zone to another. In the European Union, there is often a single price for the entire network. A mix of these methods for China maybe more suitable, with a distance based tariff for the trunk line, and single tariff for the local regional market.

The tariff review mechanism and related regulatory guidelines should be established. Transparency in process will also help to set a fair tariff.

Improving infrastructure development and interconnection

Various measures taken by the Chinese government to increase the diversification of upstream gas suppliers are being pushed forward. No matter whether a breakthrough can be made within a certain period of time, the current challenges, such as insufficient length and density of China's natural gas pipelines and low level of interconnection, need to be solved quickly. Therefore, it is urgent to accelerate the construction of pipelines, LNG terminals and other projects in the planning, and accelerate pipeline interconnection.

The pipelines interconnection is important to facilitate the TPA. Both in the United States and European Union, the interconnections of the infrastructure are all crucial to the TPA. In the United States, there are more than 1 400 interconnection points, and in the European Union, there are 183 cross-border pipeline interconnection points.

Putting the market at the centre

Transparency

Transparency and availability of data are essential for building confidence among market players. This ranges from transparency regarding pricing, to the availability of the terms and conditions of access to the pipeline system, and potentially to LNG import terminals and storage facilities. This represents a critical factor in preventing discrimination among shippers, encouraging access and competition, and ensuring efficient operation of the industry.

In the United States and the European Union, the transmission system operator (TSO) or pipeline companies are responsible for managing gas flows the and gas quality. Effective management is inseparable from transparency.

The regulator could also require that the pipeline companies set up similar electronic bulletin boards (EBB) to display the pipeline transportation capacity (location, designed pipeline transportation capacity, operating pipeline transportation capacity, planned gas transportation volume, available pipeline transportation capacity, and interruptible pipeline transportation capacity) and customer information (shipper name, whether affiliated or not, the rate, effective date of contract, bilateral negotiation rate, etc.).

The experiences of the United States and the European Union on information transparency are worth learning for China. Information platforms, such as EBB, would be a useful tool for transparency. In the future, the supervision of China's National Gas pipeline corporation will involve much information disclosure.

Deregulate the price and have the price index

The gradual deregulation of the price should be another way to proceed instead of a sudden deregulation. In the United Kingdom and the United States, it took a several years to achieve true market gas price. The establishment of gas hubs (exchanges) is the key to establishing price signals. However, there are some previously mentioned preconditions for the success of natural gas hubs: putting market players at the centre (by fostering competition from both supply and demand and creating the adequate conditions for market-driven investment in new capacity expansions) and the transition from direct government intervention to regulatory oversight. With such preconditions, exchanges are in a position to see their trading activity develop and diversify with the introduction of additional market products, such as derivatives, to increase liquidity and hedge price risk.

China has made significant efforts to deregulate the gas price in recent years. Until the current policy in China, the major sources of the gas price could be set by the market. With more effective implementation of TPA and proper market design, as mentioned above, the local trading centres, such as SHPXG and CQGXC, could become more influential in the coming years (BAI, 2015). Price indices have a widespread influence throughout markets, so the development of the indices and data reporting need to be accurate and safeguarded from manipulation. As hub liquidity matures, financial tools become possible in attracting additional participants, which further benefits the sellers and buyer. The derived futures products are natural fruits after the spot market.

Liberalising the upstream sector

Diversified market players are necessary for China to promote the natural gas market. How to cultivate the upstream gas source supplier is a big challenge facing China at present. Making better acreage blocks and data available to non-state-state-owned players in the future will be helpful for facilitating upstream competition, and establishing a trading mechanism for trading the existing gas resources will get additional production quicker. LNG, Biogas, Coal Bed methane, and hydrogen are all potential diversified resources for achieving more competitive upstream supply. There are big potential unconventional resources in China. According to the United States' experiences, working to minimise environmental (including water resource, etc.) and social impacts is another important issue for sustainable development of upstream gas.

International companies that co-operated with China's NOCs in the upstream do not have natural gas sales rights, and it is worth examining giving the sales rights of natural gas to these companies and fostering upstream competitors.

An alternative option for creating supply competition before the upstream sector ever opens is to order mandatory gas release programmes, where the incumbent is forced to resell a share of its supply to competitors via auctions or bilaterally (although auctions would be preferred to increase market transparency). In the UK, in order to cultivate diversified market players, BG is forced to release gas supply to market competitors, from 10% to 40%. As a result, the monopoly position of BG in British gas supply market was greatly restricted and narrowed.

There is also another way indirectly driven by to increase upstream competition would be to utilise the market power of downstream users. For example, the natural gas market liberalisation reform in the Europe was mainly driven by large industrial users. Many industrial users bought gas from different countries, and more and more gas suppliers gradually entered the European market, directly promoting Europe's market liberalisation reform. To cultivate diversified market players in China, it can take such international experience into consideration and take multiple measures to increase the number and activity of market players.

The role of the regulator

In both the United States and Europe, the government is the main driving force behind market changes in the process of promoting natural gas market liberalisation, and any progress of natural gas market liberalisation is also largely dependent on execution, in which the role of regulators is crucial. A toothless regulator is as bad as no regulator.

Federal and state regulators in the United States play an important role in promoting the market liberalisation of natural gas. The FERC has more than 1 400 workers and performs independent regulatory duties (FRRC, 2019). At the state level, regulators are also powerful, such as the California Public Utilities Commission, which has thousands of workers.

In terms of functions, the FERC and its corresponding state regulators cover a wide range of areas, including examining and approving the construction of infrastructure, such as pipelines, and setting relevant rates and accepting and solving disputes. With the functions of standards enforcement and arbitration, it has a large voice for the industry. While the commission has relatively independent appointment and supervision, its own power is also subject to supervision.

With the in the degree of liberalisation of China's natural gas industry, the requirements for regulatory oversight have also increased. In China's natural gas industry in the future, market players will be diversified, third-party access to infrastructure will face many technical problems (the supply and demand balance of pipelines and gas quality control under the highly liquid market transactions), the transaction varieties in the exchanges will be increased (pipeline transportation capacity, LNG terminal window phase transaction, and the establishment of the secondary market), the spot market will be further deepened and upgraded, and the futures market will be established. In order to better deal with these complex new situations and to ensure the healthy development of the industry, it is imperative to build a professional regulatory team. Other important issues are the environment and issue is environmental safety, including addressing methane leakage, which is of great concern as a major greenhouse emission source.

The United States and Europe have many useful experiences in their regulatory systems and content. The regulatory content is especially enlightening for China. The upgrading of regulatory means and capabilities will help ensure that market rules are not violated, enhance market transparency, ensure the objectivity of China's natural gas market price signals, and contribute to the recognition by the international market.

Manage the transition process

In both the United States and the United Kingdom, the transition from an integrated system to liberalisation was difficult and expensive. The reform process also involved long-term experience of continual trials, errors, and readjustments. There were also many TPA exemptions during the process. Proper management of the transition process will help consolidate the reform.

One outstanding issue involves the historical long-term bilateral contracts; the expensive ones which will become a burden after the opening of the gas market. The United Kingdom chose to compensate and renegotiate the long-term contracts, while the United States allowed pipeline companies to pass on up to 75% of the transition costs to producers, distribution companies, and large consumers by using the "transition accounts" for many years.

Another important issue is the price deregulation. A market price is the biggest fruit of the reform, but it takes time. It requires a gradual process, not shock therapy. Both the HH and the NBP took more than ten years to be liquid enough and produce competent price signals. The good news is that China will be likely to have a market price more quickly like the Title Transfer Facility (TTF), which learned many experiences from the predecessors.

Any reform means the readjustment of benefits. In the long term, successful reform would benefit many, however, in the short term, the formerly integrated corporations are likely to suffer losses in some way. It will require strong political will and good arrangements to ensure a smooth transition. For these regard, the Chinese government has more advantages than many others.

Enhancing international co-operation

The IEA has forecast that China's natural gas demand increase will account for a quarter of that in the world by 2040, as well as about a quarter of global gas trade. China's natural gas market liberalisation reform will give China a stronger international voice, including a more important role in international gas pricing. Given China's pivotal role in global energy supply and demand, it is inevitable that China will participate in the global market liberalisation process, which is not only in the interest of China's domestic energy security but also in the interest of global energy security. A more transparent and liberalised Chinese market contributes to the stability and balance of the global market and is vital to the interests of both suppliers and consumers.

It is of vital importance to deepen international exchange and co-operation, and enhance international mutual learning. This importance lies not only in the sharing of knowledge but also the integration of advanced international management experience, international standards, and design concepts into the design of China's natural gas market policies (JING, 2018). Meanwhile, establishing a market that complies with international rules can give international oil and gas companies more confidence and make them willing to actively participate in China's market reform process and provide more gas resources in the Chinese market, trade according to transaction rules they can accept, and bring more diversified market players to the exchanges to constantly improve the transaction liquidity and international level of exchanges. This is an important goal for market-oriented reform.

Although China has the Shanghai Petroleum and Gas Exchange and Chongqing Petroleum and Gas Exchange, it is not attracting many international buyers and sellers as intended, so it has been unable to effectively form a wide range of international influence, and an internationally recognised market price index has been very slow to form. Attracting more international gas suppliers to participate in China's natural gas market transactions will help promote the formation of an internationally recognised price index sooner.

This report is also the embodiment of such an international co-operation team. Although this is a report organised by the IEA, major contributors to the report are governments, enterprises, research institutions, and international organisations from China, the United States, the United Kingdom, and other countries. The research process has deepened mutual understanding and enhanced confidence in the success of China's natural gas market reform.

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General annex: Key insights of international practices towards liberalised markets

This section will identify the key points of successful market in the United States and in European countries, providing more details, including the market design, TPA, transparency, and price index price index. It will also explore how these markets managed the transition from a regulated market to a liberalised one.

Gas market liberalisation increases the efficient use of infrastructure and gas in energy markets. Liberalisation is not a one-size-fits-all approach; numerous frameworks exist for gas market structure. Liberalisation is a lengthy process, but the process is often necessary to improve gas markets. The improvements include the following: more efficient price setting and determination by markets; optimised allocation of resources by value chain segments (often achieved through the breakup of monopolies); efficient use of infrastructure; increasing the number of market participants (i.e. sellers and buyers); transparent price signals to end users and to reduced system cost; increased building of infrastructure supported by market signals; and increased use of gas as an energy source.

Box 5. Lessons from other market liberalisation processes

This section shares the evolution of the US and EU gas markets. The regulations and implementation efforts to liberalise the gas markets were different in each market, and the path for the People's Republic of China ("China") will be unique, but there are sharable principles. There are several observations that can be drawn from the experiences of moving from a monopolistic market framework to a liberalised gas market.

- There is no single model to create a successful gas market. Though a single correct model would be convenient, individual markets face a variety of specific issues to which market structures must adapt. The starting point for a liberalisation effort is different in each market.
- New or revised legislation and regulations need to be clear and unambiguous. There also needs to be a balanced industry consultation process to ensure policies are not enacted "in a vacuum" and to ensure that objectives are achieved without unintended side effects.
- Transitions often take substantial time to demonstrate material effects. This can be frustrating but happens as roles and rules change and participants adjust. Initial policies and regulations in the reform process will likely need to be modified, and stakeholders should be prepared for such adjustments. The political willingness to progress reforms and to monitor market liberalisation progress and adjust course as needed is imperative for successful change. A task force empowered with the authority to enact change will be needed to

propose and guide the transition to a liberalised market.

- Throughout the reform process, it is important to continue to maintain a sustainable and predictable investment climate with the sanctity of contracts and a common set of rules and norms for all entrants and participants to reduce risk and instil confidence in the market. Participants are looking for assurance that the agreements they enter into will be honoured, even in potentially unstable market fluctuations.

Source: © 2019 Exxon Mobil Corporation.

Gas market designs

This section addresses the key practices and policies that underpin the success of US and EU gas markets. Table 3 lists the key features of the US and EU natural gas markets.

The United States and the European Union are the largest liberalised gas markets in the world. Natural gas is an important energy resource in each of these markets and accounts for approximately 25% of the total energy consumed. With the shale revolution, the United States has increased its domestic supply significantly, which made it a net exporter in 2017 for the first time since 1957. The European Union produces approximately 22% of its demand and relies on pipeline gas and LNG imports to satisfy its demand. The United Kingdom and the Netherlands had been self-sufficient for decades, but, due to the decline of domestic supply, both countries became net importers in 2004 nd 2018, respectively. The markets have significant interconnected pipeline systems providing natural gas to all reaches of their market areas. There are thousands of receipt and delivery points within the market areas.

Table 3. US and EU market summaries

	United States	European Union
Demand	75 bcf/d (2.1 bcm/d) demand Gas is 25% of energy used	50 bcf/d (1.4 bcm/d) demand Gas is 23% of energy used
Domestic production	Domestic production equals >100% current demand	Domestic production equals 22% current demand
Imports	Imports: 8.1 bcf/d (Canada)	Pipeline imports: 33 bcf/d (Russia, Norway, North Africa) LNG imports: 6 bcf/d
Exports	Exports: 9.9bcf/d (Mexico) 4.5 bcf/d other	N/A
Trading hubs/locations	70 trading locations/hubs with published indices	>11 trading hubs with published indices
	Henry Hub is the NYMEX benchmark	The TTF and NBP are the most liquid points
Regulators	The FERC regulates interstate pipelines. State Public Utility Commissions regulate intrastate pipelines.	ACER and national regulators regulate pipelines.
Pipeline systems	>200 gas pipeline systems 305 000 miles	44 gas transmission systems 150 000 miles

	United States	European Union
Storage	>4 TCF(113 bcm) storage capacity	~4 TCF(113 MMcm) storage capacity
Delivery and receipt points	>11 000 delivery points >5 000 receipt points	>20 000 delivery points < 1 000 receipt points
Interconnections	>1,400 pipeline interconnection points	183 pipeline cross-border interconnection points
Border connections	Multiple border connections with Canada and Mexico	Multiple EU border connections with Russia, Norway, and North Africa
LNG import and export terminals	12 import and 4 export LNG terminals	24 LNG import terminals in service

Notes: bcf/d = billion cubic feet per day; bcm/d = billion cubic metres per day.
* The European Union includes the United Kingdom and excludes Norway.

There are similarities and differences between the market designs in terms of infrastructure and market hubs, but both markets demonstrate the attributes of effective market regulation and transparency requirements.

Box 6. Shippers

The shipper is the owner the gas which would be transported in pipelines and the shippers sign the transport contract with the pipeline company according to the related regulations. Shippers may be gas producers, consumers, distributors, or marketers who contract the capacity of pipeline to move their gas to different market areas. In the United States, pipeline companies are not allowed to ship their own natural gas on their pipelines, but a legally separate marketing affiliate of the pipeline may compete for pipeline capacity. In the United States, shippers and other physical gas market participants are not regulated by a national or federal regulatory agency but require and have to abide by contractual agreements with pipeline companies or infrastructure owners, who are regulated by national or federal regulatory agency. The terms and conditions of the shipper and pipeline owner contracts require regulatory approval.

In the United Kingdom, the independent national regulatory authority must grant a shipper a licence before it can operate their business. In the UNITED KINGDOM, there are over 200 licensed shippers including major producers (e.g. BG Group, Equinor, and GAZPROM) and major suppliers (e.g. Centrica, Uniper). Many suppliers are also shippers. Shipper is in the core of the market players as the chat shows.

In UK and EU there are requirements set by the regulatory agency of the gas market, such as gas possession, payment guarantee etc.

The relationships between the shipper and other market players

Source: BG and China5e (2014), *What Experiences and Lessons Can China Learn from the UK and US Gas Liberalisation & Regulatory Practices*, China5e, Beijing.

US design

In the United States, natural gas pipelines are owned and operated by non-state-owned investor entities. The pipeline companies offer gas transportation services and have to make gas transportation capacity available to all interested shippers.

In the United States, there are many pipeline companies. Large-diameter pipelines that transport natural gas across state boundaries are called interstate pipelines. Pipelines that transport gas within state borders are called intrastate pipelines. The 30 largest interstate pipeline companies own approximately 76% of all interstate natural gas pipeline mileage and have a capacity of about 280 billion cubic feet (bcf) (8 billion cubic metres), which is 61% of the total capacity available within the interstate natural gas pipeline network (EIA, 2017).

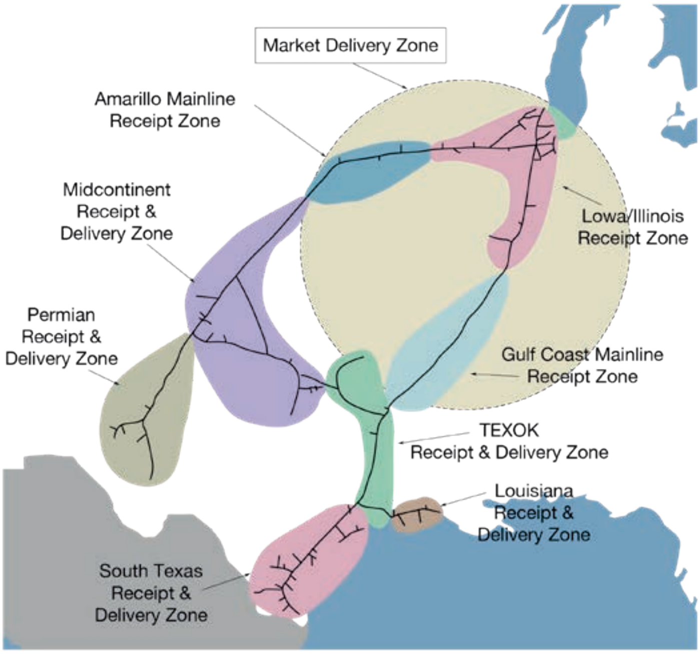
A single midstream company can own and operate many pipeline systems across the country. For example, Kinder Morgan owns approximately 19% (over 57 000 miles) of all interstate natural gas pipelines, and its pipelines transport approximately 40% of the natural gas consumed in the United States (Kinder Morgan, 2017).

Many different pipeline companies can also own and operate pipeline systems within a single state or region and within close proximity to each other. For example, in the El Paso-Permian section of the state of Texas, there are more than ten different pipelines companies operating.

Pipeline companies usually divide their pipeline systems into smaller parts or sections– such as zones, laterals, segments, production aggregation areas, market areas, or sections bound by compressor stations– which helps their operations and simplifies tariff development. Pipeline tariffs are often based on moving gas from section to section versus tariffs for specific receipt and delivery points. Pipeline capacity is offered and reserved by these sections and by individual points within the section.

As an example, Figure 6 is a map of a pipeline called the Natural Gas Pipeline Company of America (NGPL), owned by Kinder Morgan. It transports gas across eight different states within the United States and is divided into zones, each highlighted by a different colour on the map.

Figure 6. NGPL system map



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

Sources: Jim Simpson (2015), *Kinder is a Cowboy, on a Steel Pipe He Rides – Kinder Morgan, NGPL and Natural Gas Markets*, RBN Energy, Houston, https://rbnenergy.com/kinder-is-a-cowboy-on-a-steel-pipe-he-rides-kinder-morgan-ngpl-natural-gas-markets.

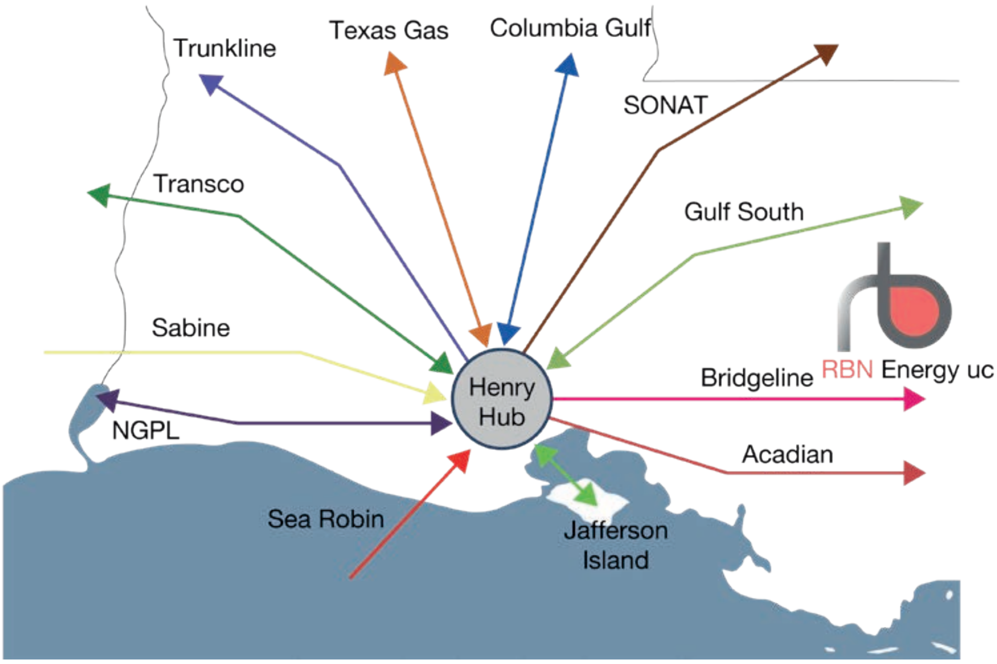
In the United States, pipeline companies may configure and promote certain parts of their pipelines as market centres. The key characteristics for a market centre are receipt and delivery access to two or more pipeline systems, transportation between these systems, and availability of storage or supply. The infrastructure configuration of these market centres varies within the United States.

Market centres can be on a short section or lateral of a pipeline connected to a gas processing plant or storage facility on a highly interconnected section of a pipeline system, or they can cover an entire pipeline system. The length of the pipeline section developed as a market centre can be many miles and even can cross multiple states.

Examples of different market centre configurations include the following:

- Pipeline segment connected to a processing plant:
  - The Henry Hub is a market centre developed on a short section of the Sabine pipeline, which had been connected to the Henry gas processing plant, prior to its shutdown. This portion of the Sabine pipeline interconnects with 13other pipelines and a storage facility, all within a few miles, as shown in the circled area in Figure 7.

Figure 7. Henry Hub infrastructure (should change to the new draw one by PIP without right part)



Note: These maps are without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: Sheetal Nasta(2015), The evolution of the Henry Hub natural gas benchmark in the US, RBN Energy, Houston, http://www.shaledispatch.com/the-evolution-of-the-henry-hub-natural-gas-benchmark-in-the-us.

- Highly interconnected pipeline section:
  - NGPL manages sections of its pipeline system – which can be a part or the whole of each zone shown in the map in Figure 6 –as independent market centres. Many of these market centres on the NGPL have developed sufficient liquidity (more than 10 to 20 transactions) to have a published physical market price index. The NGPL Midcontinent market centre is one of these liquid hubs located on NGPL within its Midcontinent Receipt and Delivery Zone, highlighted in purple in the NGPL system map in Figure 6.The section of the NGPL pipeline that supports this hub runs through four states and has many receipt points from production in the area, a storage facility, and other interconnecting pipelines.

- Entire pipeline system:
  - Southern California Gas (SoCal Gas) and Pacific Gas and Electric (PG&E) are the two major intrastate pipeline networks that serve the California natural gas market. More than 90% of the natural gas consumed in California comes from out-of-state natural gas production and is transported via interstate pipelines into the SoCal Gas and PG&E systems at receipt points along the border of these networks. PG&E manages all its city-gate delivery points as a single market centre. SoCal Gas manages its entire network except for the border points as a single virtual market centre, similar to the EU market infrastructure configuration. In the SoCal Gas system, gas can be transported from any of the border points to anywhere within the network for the same rate (postage stamp tariff).

In a pipeline network owned by multiple pipeline companies and configured with multiple physical hubs, shippers arrange the physical flow of gas across the network including capacity on multiple pipeline systems or swaps with other shippers.

European design

The European Gas Target Model was developed in 2011 as a vision to provide guidance for the development and implementation of EU Network Codes. The European Gas Target Model is with a limited number of liquid hubs in the European Union connected by entry-exit gas transmission systems with a uniform design.

An entry point is a physical point that receives natural gas into the pipeline system from domestic production, cross-border imports, LNG facilities, or storage facilities. An exit point is a physical point, or a cluster of physical points in a general area, that delivers gas out of the system to large consumers, local distribution companies (LDCs), storage facilities, and cross-border exports. Some of these entry and exit points can be bidirectional. Typically, the number of entry points is much fewer than the number of exit points because of the limited sources of supply within European countries.

The transmission system operator (TSO) is the entity that owns and operates the pipeline network that connects these points. Similar to in the United States, TSOs are not allowed to be shippers on their own systems. The TSOs can have private as well as state ownership. A TSO affiliate may use the system provided it complies with the EU unbundling rules, is under separate management from the TSO, and is not involved with the TSO operation and network development.

Physical gas may be shipped anywhere within the TSO's pipeline network with the purchases of just two capacity contracts (one entry contract purchased by the shipper adding gas and one exit contract purchased by the shipper taking gas from the network) even if the gas is transported across several pipeline segments. Shippers do not have to plan their physical route through the system to get gas from an entry point to an exit point. As an example, a seller can add gas to the system at any entry point and may have an agreement with a buyer to take gas off the system, but the seller does not need to know nor be concerned with which exit point is used by the buyer or how the physical gas is transported between these points.

The TSO is responsible for physically transporting gas across its pipeline network and determining the amount of capacity that can be offered at the entry and exit points. The TSO monitors and optimises the physical gas flow routes and manages incremental capacity development to enable its pipeline network works as a single virtual market hub.

Most European Union member countries have achieved a single TSO and single virtual market hub design as laid out by the European Gas Target Model. The United Kingdom and the Netherlands have been the most successful in implementing this design. In the Netherlands, the natural gas pipeline network is owned and operated by a sole TSO named Gasunie Transport Services (GTS). GTS maintains separate systems for different gas qualities (high-calorific gas and low-calorific gas) but operates a single virtual hub on the system, called the Title Transfer Facility (TTF).

In a pipeline network configured with a single virtual hub, the TSO is responsible for managing the physical flow routes within the network, and shippers only contract entry or exit capacity.

Some European Union member countries are still working towards the target model and have more than one market hub and several individual TSOs operating within their countries. This is most often a residual effect of how these countries' natural gas markets originally developed.

For example, Germany has 15 TSOs and two virtual market hubs, namely GASPOOL and NetConnect Germany (NCG).The five TSOs in the northern region of Germany joined together to create subsidiary company, GASPOOL, which is responsible for operating and balancing the entire market entry-exit network system. However, each individual TSO retains ownership of its system and continues to manage capacity bookings and network infrastructure development and investments.

The interconnection points between TSOs in different countries are called cross-border interconnections. TSOs offer capacity on entry and exit points at cross-border interconnections as a bundled product. Instead of purchasing two products separately – one for exit capacity from one TSO and another for entry capacity into the other – shippers can purchase both products together in a single transaction as one bundled product. The main reason for the bundling of capacity products is to remove the ability of shippers to trade at the border points, instead forcing trades to the virtual trading point of one system or the other. This may require shippers to be registered in adjacent systems and can add complexity or be a barrier to entry for smaller shippers.

Across the European Union, there are 44 TSOs. Adjacent TSOs are required to enter into interconnection agreements that specify rules for co-operation and dispute settlement.

The network code on interoperability and data exchange rules issued in 2015 enables the necessary harmonisation of interconnection agreements, units used, gas quality management, odourisation, and common data exchange, leading to effective market integration. The European Network of Transmission System Operators for Gas (ENTSOG) is responsible for monitoring the implementation of this network code, and the country's national regulator has the authority to issue sanctions against a TSO if it does not follow the EU Network Codes.

The EU Network Codes give some flexibility for national regulators to implement code requirements within a country's context. If there is conflict among national regulators, then the Agency for the Cooperation of Energy Regulators (ACER) has the authority to decide if the national regulators are not able to reach an agreement or upon a joint request from the regulators.

Hub infrastructure characteristics include two or more pipeline interconnects with available capacity and a single operator. Local domestic production facilitates the initial establishment of a hub. In the United States, there are combinations of different pipeline system and market centre configurations that have been developed by the pipeline companies to serve the varied market dynamics. In the European Union, the TSOs follow central EU planning guidance to develop pipeline systems and hubs with relative uniformity across the region. TSO and pipeline company designs ultimately require regulatory approval.

The following sections will discuss gas infrastructure development and TPA measures, which work together with the market design to ensure the establishment of a fair and completive open market.

New project development

To accommodate increasing demand and production, new pipeline capacity must be added, which can be done by building a new pipeline, adding new lateral lines, adding new compression facilities on an existing line, or laying a new looped pipeline in the same right of way. In the United States, these projects are initiated by individual pipeline companies, and in Europe by the TSOs, and in both cases, these projects need the approval of their federal or national regulators.

From the initiation of a project to start-up, a new pipeline project could take from three to five years in the United States and European Union. In the construction phase, the pipeline company or TSO may incur higher costs than the estimate submitted and approved by the regulatory authority. Higher than estimated costs could arise if the project faces opposition or requires a change in route. Higher costs are typically covered from the pipeline company's or TSO's return margin. In the European Union, the TSO may submit a request for inclusion of these additional investment costs to the national regulatory agency (NRA), but if the NRA decides the cost increase is not efficiently incurred, then the request for a change in the tariff may be denied. In the United States, if the additional costs rise substantially, then the company is likely to abandon the pipeline project.

The regulatory process for new pipeline or incremental capacity development must be transparent, publicly available, and detailed, with pre-defined approval criteria and clear timelines. The process must include time for public consultation and the approval authority must lie with an independent regulatory agency. Market demand and economic need for additional capacity must be tested. Eminent domain rights support pipeline development.

In the United States, market signals and private investment drive incremental capacity additions. In the European Union, the TSOs primarily drive incremental capacity development based on central planning targets.

US process

In the United States, long-range natural gas transmission pipelines were first built starting around the late 1920s. Nearly half of natural gas pipelines (approximately 142 000 miles) currently in service were constructed in the 1950s and 1960s (EIA, 2017).

After the Natural Gas Policy Act (Sec 311) in 1978, interstate pipelines started interconnecting with each other and other pipelines for commercial reasons to create a highly integrated network. New infrastructure construction continues to be active. In the United States, 11 new pipeline projects were already completed in 2018, and 33 new pipeline projects have been announced or are underway in 2019 through 2025 (EIA, 2017).

The primary regulators of interstate pipelines in the United States are the Federal Energy Regulatory Commission (FERC) and the Department of Transportation, among others. The FERC does not plan, develop, or require capacity build-out. It is not responsible for ensuring adequate capacity exists to meet market demand. Instead, pipeline companies identify needs for new capacity and act in the interest of capturing a new market opportunity. For a pipeline company to build a new interstate pipeline or construct major expansions, it must obtain a Certificate of Public Convenience and Necessity ("certificate") from the FERC.

Prerequisites to new project proposals – market signals and anchor shippers

Pipeline companies propose incremental capacity projects in response to market signals. For example, a futures price difference between market hubs caused by upcoming new production or demand growth and constrained capacity between the hubs would signal the need to build capacity to move gas from the lower priced market to the higher priced market.

For new pipeline projects and expansions, a pipeline company first solicits commercial proposals from interested shippers to identify anchor shippers for their project. An anchor shipper is a shipper that is willing to purchase capacity reservation on a new pipeline project for a long duration. The commitment of anchor shippers is essential to the pipeline company soliciting and receiving funding for the project. Banks typically prefer gas producers, distributors, or consumers as anchor shippers because of their long-term position in the market.

Historically, regulated utilities were the predominant anchor shippers because they were allowed to recover costs from end users and, thus, were more comfortable entering into long-term transportation contracts. This was the key reason why pipelines were able to secure long-term commitments in a short-term wholesale market. More recently, producers have also started becoming anchor shippers to ensure incremental capacity is built in production areas with highly constrained infrastructure.

The pipeline company negotiates the rates, reservation volume, contract term length, and other general terms with the anchor shippers. These negotiated rates are typically lower than the eventual maximum tariff proposed in the FERC certification process due to their long-term backing of the project. These negotiated contracts with anchor shippers remain untouched by the FERC tariff approval process (refer to the Tariff Setting section below).

Market demand test and non-discriminatory allocation – open season

After the anchor shippers are identified, the pipeline investor will hold one or multiple binding or non-binding open seasons. An open season is a specific period of time when interested shippers are allowed to bid for capacity on a potential new pipeline project. Open seasons help bolster the pipeline company's funding prospects, contribute to a better understanding of market demand, and help optimise project design (such as sizing and connections, etc.) before the company begins the certification process.

The Natural Gas Act mandates that pipeline companies hold an open season to ensure a fair and equitable offering and the rewarding of new pipeline capacity without undue discrimination or preference. Pipeline companies are obligated by regulation to hold open seasons; however, the FERC does not regulate the open season process.

The pipeline company must publish notices that an open season will be held. The pipeline company must disclose the names of its anchor shippers, the negotiated rates and terms for the anchor shippers, the pipeline design capacity, the expected maximum firm transport tariff, and sometimes the interruptible transportation tariff as well. Pipeline companies may require a minimum term, volume, and rate bid.

Shippers can bid any price up to the maximum tariff for FERC filing, contract term, and volume quantity for the capacity offered. Submissions are typically completed via email. Pipeline companies award capacity to shippers based on pre-defined criteria approved by the FERC.

Typically, pipeline companies use a net present value calculation to compare bids with different price, volume, and contract term combinations to select the winners.

If the market signals the need for incremental capacity on an existing pipeline, the FERC requires the pipeline company to hold a reverse open season to give existing shippers the opportunity to return their contracted capacity. If sufficient capacity is returned, the pipeline may not need to expand or build incremental capacity else the pipeline proceeds with a regular open season.

Regulatory approval – public interest and market need

Once anchor shippers and demand are identified, the investor seeks funding from banks for the project and proceeds to apply for the certificate with the FERC. The FERC is charged with authorising interstate pipeline projects and determines whether a proposed project is needed and in the public interest (INGAA, 2013).

The FERC conducts environmental and other public interest reviews, and then the entire record is considered by the FERC's commissioners. The commissioners decide, after conducting a review, whether to issue a certificate. This review includes an evaluation of the need for the project, the costs of transporting natural gas by the pipeline, financing, the environmental impact, and market competition.

Right to access land – eminent domain

The pipeline company will attempt to acquire as much of the right of way as possible through negotiation with landowners prior to applying for an FERC certificate to avoid delays in construction. Sometimes, a landowner and the pipeline company may be unable to reach an agreement. In such cases, the pipeline company can access the land through eminent domain proceedings as the government's right to expropriate private property for public use with the payment of the fair market value to the landowner. The right of eminent domain is granted when a certificate is issued by the FERC under the Natural Gas Act (INGAA, 2013).

Regulatory governance post-approval – transparency and safety

By applying for an FERC certificate, pipeline companies agree to FERC regulatory governance, which requires extensive transparency in terms of the reporting requirements and the cost of service rate making.

The FERC has no jurisdiction over the safety of the pipeline after construction. The US Department of Transportation regulates pipeline operations, integrity, and safety.

EU process

In Europe, most of the pipeline system was in place at the time of the Third Directive. New investments are generally limited to interconnections between member states, new supply pipelines (e.g. TAP and Nord Stream), new LNG terminal connections, and connections within member states to reduce the number of hubs (e.g. France and Germany). Recent declining volumes have reduced the need for capacity expansions. According to the Third Gas Directive, ENTSOG is required to develop an EU-wide Ten-Year Network Development Plan (TYNDP). The ENTSOG TYNDP is not a requirement for the TSOs to invest. The ultimate decision on whether an investment is made lies with the national regulator of the individual country.

Prerequisites – network development plans

ENTSOG develops a forecast of required actions to ensure sufficient interconnectivity within the system and indicate and prioritise where investments are required. ENTSOG's planning forecast also includes an estimate of the expected demand for capacity at each point to determine tariff calculations for each point.

TSOs also develop network development plans (NDP) biennially for their respective pipeline systems. NDPs document a TSO's investment plan for the upcoming year and provide input to the ENTSOG plan. The TSO's NDP includes operational data, such as constraint points and typical gas flow routes, etc. Market participants who want interconnections to their facilities, such as production/processing plants, power plants, and LNG facilities, may submit a request to the TSO for consideration.

Market demand test and public consultation

In odd-numbered years, TSOs offer planned incremental capacity during the annual auctions for yearly capacity contracts. TSOs use these auctions to test market demand for the planned incremental capacity offer. If the market signals interest in this incremental capacity, then the TSO uses this information along with its biennial NDP and ENTSOG's TYNDP to develop a demand assessment, which the TSO publishes on its website and ENTSOG's website 16 weeks after the start of the annual auction. The TSOs use the demand assessment to develop several technical design offerings (capacity size, number and locations for entry-exit points or interconnects, route, etc.) and estimate costs for each offer level. They also conduct economic analyses to test the viability of the different design offers. The TSO makes its incremental capacity proposal available for public consultation prior to submitting it to its NRA for approval. The TSO also publishes the offer levels and project timelines on its website (Figure 8).

The NRA has six months to review and receive public consultation prior to publishing its decision. If the proposal is approved, the NRA also approves and publishes the mechanism that will be used to allocate this incremental capacity, whether it is via auction or an alternative method.

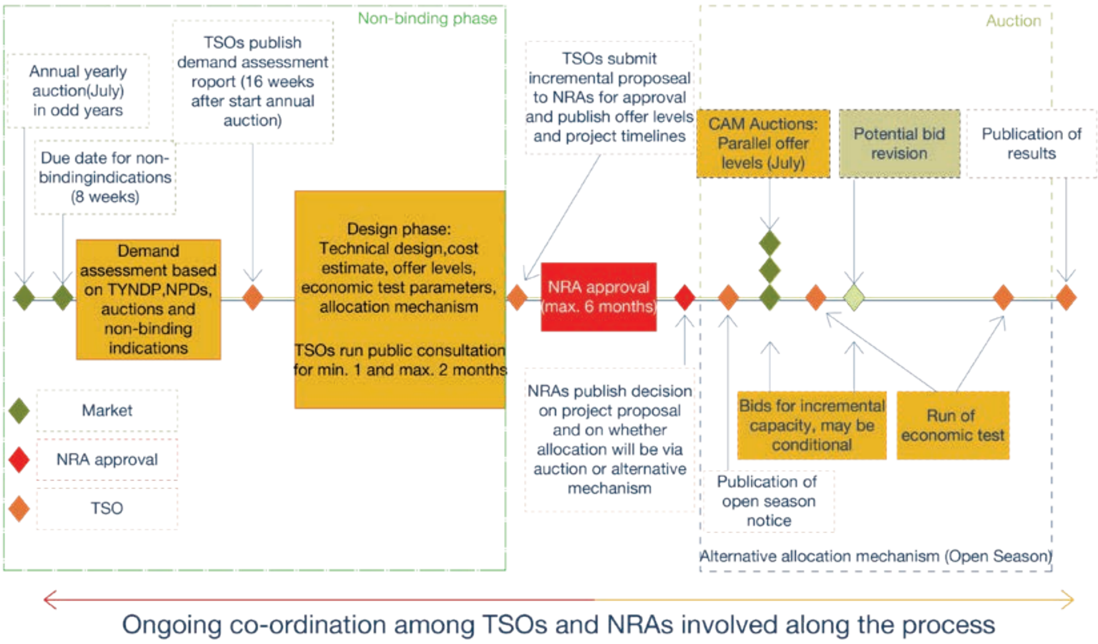
Non-discriminatory allocation – auctions and open seasons

Auctions are typically used to offer incremental capacity at a single point. An alternative allocation mechanism, typically referred to as an open season, is used when the incremental capacity being offered involves more than one interconnect point and/or crosses multiple countries. Open seasons allow conditional bids. For example, the bid may be contingent on a certain condition being met, such as receiving capacity at another interconnect point or making a final investment decision for an upstream project and having the right to withdraw the bid if conditions are not met. Open seasons are for more complex capacity offerings and allow for bilateral communications.

In long-term auctions, only up to 80% of the new incremental capacity may be offered. Typically, 20% of the capacity must be made available for shorter-term (less than a year) contracts. Sometimes if the TSO is unable to get 80% of the capacity reserved, the project may still get approved for security of supply reasons.

Different design offer levels may be offered at the long-term auction. Depending on the interest for one offer level versus another, there is a possibility for bid revisions. Take, for example, an auction that offers two offer levels, 15 units of capacity and 25 units of capacity. The auction results show that there is a high demand for the 15-unit offering resulting in bid prices with surcharges and, on the other hand, only 20 units of the 25-unit capacity offering get subscribed. After the bid, the TSO runs an economic analysis on the results. If the 25-unit offer level does not pass the economic test because the revenue from only 20 units of capacity subscribed is not sufficient to build 25 units of capacity, then the TSO may apply a bid revision to offer a level greater than 15 units but less than 25 units at the same base tariff. This is to get sufficient demand for the offer level to pass the economic test and avoid bids with surcharges to the base tariff. The TSO publishes the results of the auction or open season after it runs a final analysis to test the economic viability of the demand and bids for the incremental capacity.

Figure 8. EU process for the development of incremental capacity



Tariff reviews and adjustments

As part of the certificate application, the pipeline company submits a tariff proposal to the FERC for the remaining capacity not committed by the anchor shippers. The tariff proposal is developed by the pipeline company and includes the revenue from the anchor shippers and cost of service. The tariff proposal may be based on the bids received during the open season. The tariffs include a fixed-price component called the reservation charge, and a variable component, called the commodity charge. The reservation charge is paid whether gas flows or not.

The FERC scrutinises the proposal and approves the minimum and maximum tariffs effective for the life of the pipeline. Pipeline companies have an opportunity to earn higher effective returns by being efficient and maximising throughput over the life of the pipeline.

In the United States, the minimum and maximum tariffs approved by the FERC during the certification process are set for the life of the pipeline. However, there may be reasons to either increase or decrease the tariffs.

Pipelines may want to request an increase to the tariffs if their actual return is lower than the currently acceptable returns for utility services. To increase the tariff, the pipeline company has the right to file a rate case with the FERC under NGA 1938 Section 4. The burden of proving that the rate requested is just and reasonable is on the pipeline, i.e., the requestor of the rate case. FERC staff scrutinise the new tariff proposal and then meet with the affected shippers to develop and propose a counter-offer. This initiates a settlement negotiation process between the FERC staff, the shippers, and the pipeline company. If the negotiations are not successful, then the case proceeds to litigation under an administrative law judge provided by the FERC.

Shippers or the FERC can also challenge a pipeline's tariff in a rate case under NGA 1938 Section 5 if the pipeline is seen to have become more efficient or has increased its throughput, and the FERC or the shippers can prove the pipeline is getting a return higher than the currently accepted rate of return. The burden of proof is again on the party bringing the case.

In practice, Section 5 is not highly utilised because pipeline companies' detailed operations and maintenance expenses are not publicly available unless litigated and, hence, proving that its tariffs are higher than what is just and reasonable is a difficult undertaking.

In the European Union, the NRAs review and approve the revenue that TSOs are allowed to recover from tariffs. TSOs can recover their operational costs and capital costs plus a regulated return. The TSO decides how to split the collection of this revenue between the entry and exit points.[3]

The default allocation of the revenue collection methodology is 50% from entry tariffs and 50% from exit tariffs, but some TSOs allocate greater than 50% of costs to exit points. TSOs may allocate a higher percentage to exit points if they want to encourage gas to enter their system or want to reflect the lower cost per unit of capacity for large-diameter entry pipelines versus smaller diameter exit connections.

Each TSO is free to determine its exact tariff calculation methodology; however, it must be justified and approved by the NRA. There are several different methodologies in use. The two most common are the "postage stamp" and the "capacity-weighted distance" methodologies. However, there is an increasing trend in the European Union to move towards the postage stamp methodology because it is a simpler method.

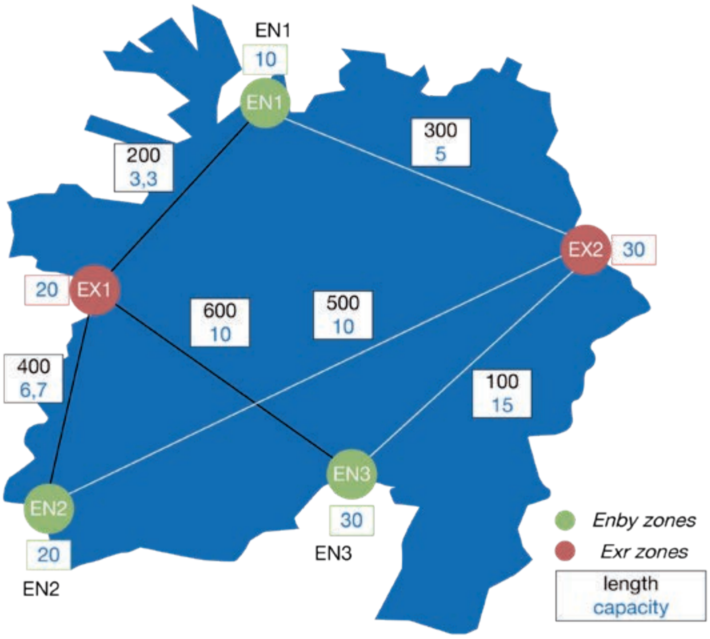
In the postage stamp methodology, the allowed revenue to be collected from entry tariffs is divided by the total capacity of all entry points, and, similarly, the allowed revenue to be collected from exit tariffs is divided by the total capacity of all exit points to establish the entry and exit tariffs. Thus, the result is the same tariff for every entry or exit point irrespective of how close or far these points may be from the supply or demand centres.

In the capacity-weighted distance methodology, each entry point gets a weight factor based on the technical capacity at that point and the capacity-weighted average distance to all exit points in the system. The tariff at each entry point is the allowed revenue to be collected from all entry points multiplied by the weight factor of that point divided by the expected capacity sales. The same applies to each exit point.

[3] Regarding the incremental capacity process, more information can be found in the following document: https://entsog.eu/sites/default/files/entsog-migration/publications/CAM%20Network%20Code/2017/CAP0727_170307_CAM%20NC%20Implementation%20Workshop%20Final.pdf.

Figure 9 shows an example of the entry and exit points within a single TSO network and denotes the distance (length) and capacity between these points. If the TSO in this example is allowed to collect revenue of 3 213 units from its entry points, then depending on the methodology used by the TSO to calculate the tariffs, the tariffs at each of these points can vary significantly, as shown for this example in Table 4.

Figure 9. Example of entry zones



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

EN1 and EN3 entry points are closer to the exit points and have lower capacities than entry point EN2. For EN1, the capacity-weighted distance is: (200*3.3+300*5)/(3.3 +5) = 260 and for EN3 it is (600*10+100*15)/(10+15) = 300.The capacity-weighted distance for EN2 is (400*6.7+500*10)/(6.7+10) = 460.The tariff at each point is the ratio of the point's capacity-weighted distance to the sum of all of the capacity-weighted distances multiplied by the total allowable revenue for the entry points. In a postage stamp tariff methodology, all entry points have the same tariff.

For cross-border interconnect points, each TSO includes the investment costs for its portion of the interconnect development in its cost estimate and economic analysis. Each TSO sets its own tariff for its side of the interconnect point. If there is a misalignment between the costs and benefits or revenue collection between the TSOs, then compensation may be paid by one TSO to the other, subject to regulatory approval. The NRAs of each affected country need to approve inter-TSO compensations. If the NRAs cannot agree, then ACER makes the final decision.

Table 4. Examples of tariff methodologies

Point	Postage stamp methodology (calculated units)	Capacity-weighted distance methodology (calculated units)
EN1	1071	819
EN2	1071	1449
EN3	1071	945
Total revenue	3213	3213

Sources: Refer to ACER Tariff Methodologies: www.acer.europa.eu/en/Gas/Framework%20guidelines_and_network%20codes/Pages/Harmonised-transmission-tariff-structures.aspx.

In the European Union, the tariffs, cost of service, investments, and rates of return are reviewed and approved by the NRAs annually. The TSOs submit their financial data, allowed revenue determinations, and tariff proposals to their NRAs, which scrutinise the proposals and engage in public consultations prior to granting approval for the new tariffs. A newly approved tariff, which could be different by season, is effective for the next 12 months. A similar review is conducted in the United Kingdom twice a year.

Although the tariffs are reviewed and may change annually, the methodology selected to develop the tariff (postage stamp or capacity-weighted distance, etc.) typically stays in effect for multiple years. Depending on the NRA rules, the TSO must recommend and get its tariff calculation methodology tested at least every five years. The TSO develops a proposal for the methodology of choice and then allows for public consultation prior to submitting to the NRA.

The capacity-weighted distance methodology is considered the benchmark methodology, and if a TSO chooses to use another methodology, then it has to provide a justification and comparison to the benchmark in its submission to the NRA.

Before the NRA makes a decision on transmission service tariffs, it may engage in public consultation of its own, and it also sends the proposal to ACER for review.

Box 7. Tariff rate modification

Tariff rates are intended to enable the recovery of variable costs and capital costs with a reasonable rate of return.

In the United States, once a tariff is established for a new pipeline, it is effective for the life of the pipeline. However, pipeline companies have the option to file for a tariff increase if its return reduces over time. Pipeline companies have the opportunity to earn higher effective returns by being efficient and maximising their throughput over the life of the pipeline.

In the European Union, the tariffs are reviewed and set annually. Any operating efficiencies are reflected in the updated tariffs. In order to incentivise the TSOs to increase the efficiencies, the TSOs are also rewarded by the efficiency improvement.

Capacity allocation

In the United States, if existing capacity becomes available due to contract expiration or other similar events, the pipeline company must offer the capacity through an open season.

The open season process for existing capacity is similar to the process conducted for new pipeline projects (refer to the section above). However, the established maximum applicable FERC approved tariff remains in effect, and the pipeline company cannot accept bids greater than it. If the capacity is oversubscribed, the pipeline utilises a pro-rata capacity allocation method that has been approved by FERC during the certification process, to determine how much capacity each shipper is awarded.

In the European Union, the TSOs use auctions or the "first come first serve" procedure to market available capacity. Capacity for some Norwegian interconnects, UK cross-border points, and all other points in most European Union member states can be booked or traded on the European Internet platform called PRISMA (PRISMA, 2018).

PRISMA is the platform used by the TSOs to market their capacity. All transportation contracts and obligations are solely between the shippers and the TSOs, and PRISMA is not a party to such contracts.

The cross-border or interconnection entry and exit capacities between two TSO networks within the same country must be auctioned and are allocated as a single bundled product in auctions. If the pipeline capacity amounts vary on either side of an interconnect, then the bundled capacity offered in auctions will meet the lesser of the two sides of the interconnect. The TSO with the greater capacity markets that additional capacity as an unbundled product.

Capacity at the production entry points and at exit points to large users and LDCs is not auctioned. It is offered on a first come first serve basis. Any of the shippers may submit a request for capacity at these points, and if the capacity is available, it is granted to them (PRISMA, 2018).

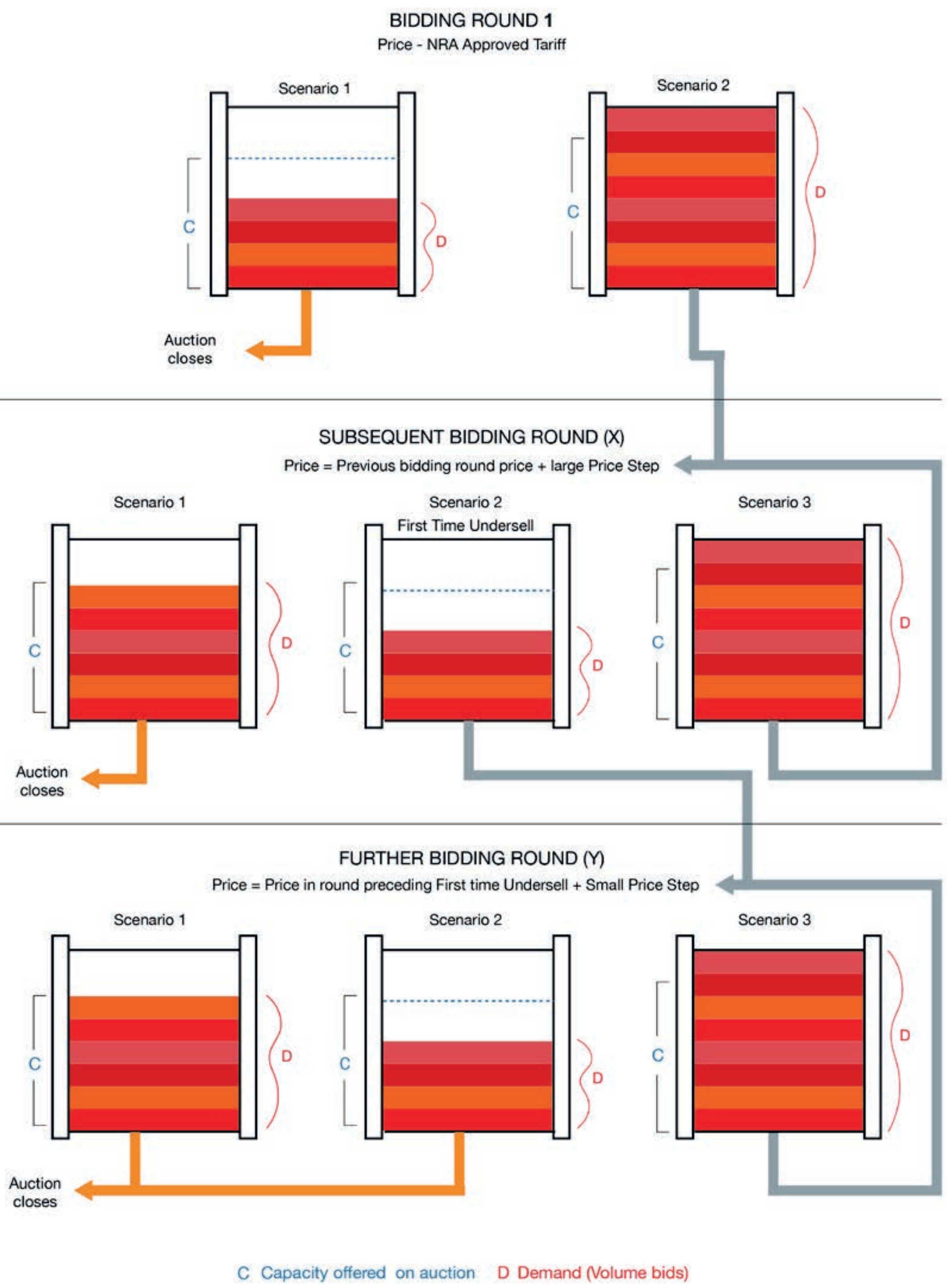
Capacity contracts for yearly, quarterly, and monthly products are auctioned in "ascending clock auctions" and capacity contracts for day-ahead and within-day products are auctioned in "uniform price auctions". Auctions for all capacity contracts follow an auction calendar. The calendar details the auction frequency, products offered, publication dates, auction start dates, bidding rounds, notification requirements, and auction type (e.g., ascending clock or uniform price). Before an auction starts, the amount of capacity to be marketed is published on the PRISMA website.

Ascending clock auction process

Ascending clock auctions may have multiple rounds if there is more demand than available capacity at a point. Shippers place volume bids against escalating prices announced for consecutive bidding rounds. Figure 10 illustrates how the auction works.

The price for the first round of the auction starts at the base tariff approved by the national regulator. The "large price step" and the "small price step" are the prices defined for each point and the contract term offered in an auction in advance to the beginning of the auction. These are used to make stepped price adjustments to each subsequent bidding round. To participate in an auction, it is mandatory for a shipper to place a volume bid in the first bidding round. In each consecutive bidding round, the shipper can only place a volume bid equal to or less than its volume bid in the previous round. If the total demand for the capacity in the first bidding round is less than or equal to the marketed capacity at the end of the round, then the auction closes. If not, then the auction begins the next round with a price equal to the price in the previous round plus the large price step.

Figure 10. Ascending clock auction



During the second or any subsequent bidding rounds, if the demand for the capacity is less than the offered capacity, then that bidding round is called the "first time undersell". If a first time undersell occurs, then the price in the subsequent bidding round is reduced to a price equal to the price used in the bidding round preceding the first time undersell plus the small price step.

Typically, these price adjustments and subsequent bidding rounds continue until the total demand for the capacity equals the amount of capacity offered in the round, at which point the auction closes. The results are published no later than the next business day.

If an ascending clock auction does not end by the scheduled starting of the next auction for capacity covering the same period, the first auction will close and no capacity will be allocated. The capacity will be offered in the next relevant auction.

Uniform price auction process

In a uniform price auction, there is a single bidding round due to the shorter time available to make capacity allocations. Shippers submit bids for price as well as volume. A shipper's price bid may include a premium to the base tariff. After the close of the auction, the capacity is allocated to the highest-ranked bidders and then to the lower-ranked bidders per their volume bid. The results are published within 30 minutes of the close of the auction.

Secondary capacity release

A primary firm transportation (FT) shipper is the party that originally contracted with the pipeline for capacity. The primary FT shipper can post unused capacity they would like to release on the pipeline's EBB or PRISMA.

A secondary FT shipper is the party that assumes the capacity made available by the primary FT shipper.

The primary shipper is incentivised to release unneeded capacity via a secondary capacity release to offset its payment obligation to the pipeline company or TSO.

If the primary shipper does not release its unused capacity by a certain point, the pipeline company or TSO is allowed to make available this unused capacity to secondary shippers, but the primary shipper is still obligated to pay for the unused capacity. The pipeline company or TSO can retain the revenues from both the primary and secondary shippers, depending on the regulations.

US process

In the United States, interested secondary shippers must have a contract and be creditworthy with the pipeline company to bid for FT capacity made available by the primary FT shipper. Primary and secondary shippers contract directly with the pipeline.

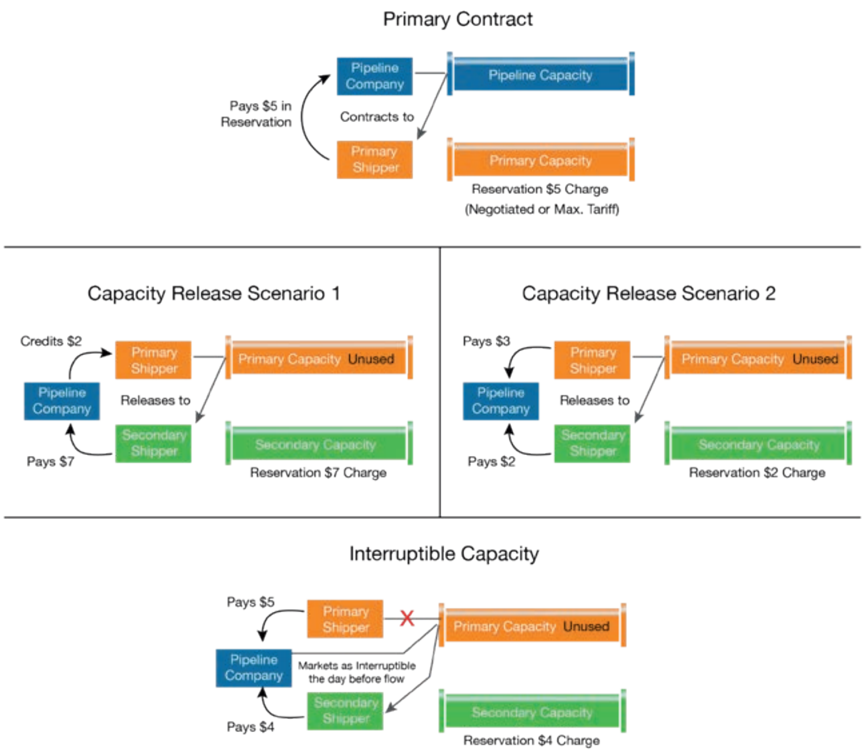
Even after the capacity is released by the primary FT shipper to the secondary shipper, the primary shipper is still responsible for its full reservation charge obligation to the pipeline company. However, the revenue received from the secondary shipper for the released capacity is credited on the primary FT shipper's monthly invoice. As illustrated in Figure 11, the primary shipper may either make money (scenario 1) or offset a portion of its reservation charge obligation (scenario 2) by releasing capacity.

Capacity release is non-mandatory in the United States. A primary FT shipper does not have to post or release capacity it does not plan on using. The financial incentive for releasing capacity is the primary reason why shippers actively try to release their unused capacity, and this contributes to the efficient utilisation of pipelines.

To ensure the fair, open, and transparent utilisation of the capacity release provisions, the FERC has the following two requirements to mitigate shippers bypassing capacity release:

- Pipelines have a "shipper must have title" requirement to prevent a primary shipper from shipping gas that belongs to another entity.
- FT shippers cannot use buy-sell agreements (in an attempt to comply with the "shipper must have title" requirement) and avoid capacity release. This means the primary FT shipper cannot purchase gas from an entity at one end of the pipeline capacity it holds and sell the gas to the same entity at the other end.

Figure 11. Example of secondary capacity release



Capacity release on interstate pipelines must follow the guidelines established by the FERC. Depending on the term (duration) of the release, primary shippers may have to post their capacity release for biding, or they may be allowed to release the capacity to a pre-arranged secondary shipper of their choice.

The guidelines limit the rate a secondary shipper may offer for released capacity to the established maximum tariff for release durations greater than one year. However, the guidelines allow secondary shippers to bid rates greater than the established maximum tariff for release durations less than or equal to one year. This allows the market to determine how to prioritise pipeline utilisation during peak demand. For example, say an industrial and a utility company each have 50 000 units of capacity on a pipeline. The utility's demand typically varies between 40 000 and 50 000 units during winter, and the industrial company has an alternate fuel option. During a major snowstorm, assume the utility's gas demand increases to 60 000 units and the gas prices in that region spike. In this situation, the industrial company's alternate fuel option may become more economical, and there may be a premium value for their pipeline capacity. This may provide financial incentives for the industrial company to release some or all of its pipeline capacity, which can be purchased by the utility company, who may be more willing to pay a premium for the additional pipeline capacity to secure supply to their end users versus other large consumers who have other fuel options.

If the primary shipper does not use or release its capacity to a secondary shipper, then the pipeline company can market this unused capacity as interruptible transportation (IT) capacity the day before gas flows but for one day only. The primary shipper is still responsible for paying the pipeline company its full reservation charge, and the pipeline keeps any revenue it collects from marketing the capacity as IT. This financial incentive to the pipeline company encourages the pipeline company to actively market unused capacity and maximise pipeline utilisation.

The offering of a primary FT shipper's unused capacity as IT acts as a mechanism to prevent capacity hoarding. IT shippers are given firm status after the last nomination cycle for intraday service.

EU process

The EU system offers similar incentives for shippers and the TSO to release unutilised capacity. A primary shipper may release capacity through three methods:

- Transfer of use – the primary shipper keeps its contract and reservation charge payment obligation with the TSO and sublets the capacity to a secondary shipper. The secondary shipper pays the primary shipper directly.
- Assignment – the primary shipper assigns its contract with the TSO to the secondary shipper, who takes on the responsibility of paying the TSO the primary shipper's reservation charge. The primary shipper is relieved of its obligation to the TSO but may have to pay the secondary shipper the difference between the amount the secondary shipper is willing to pay for the capacity and the primary shipper's original reservation charge if the secondary shipper values the capacity less than the primary shipper's original reservation charge.
- Surrender – the primary shipper surrenders its unused capacity to the TSO, and the TSO offers this capacity in auctions. If the TSO finds a secondary shipper for the capacity, the primary shipper is relieved of its reservation obligation to the TSO.

Irrespective of the method used, the amount the TSO earns on the capacity remains the same. However, the primary shipper can either make money or mitigate the losses on the unused capacity reservation costs in the Transfer of Use or Assignment methods. Similar to the United States, this financial incentive in releasing capacity is the primary reason why shippers actively try to release their unused capacity, and this contributes to the efficient utilisation of pipelines.

The capacity release must follow the rules established by the EU Network Codes and implemented by the TSOs and capacity booking platforms, such as PRISMA. Primary shippers must post capacity release offers on PRISMA but may pre-arrange the release to a secondary shipper and indicate so in their post in PRISMA, similar to the process in the United States. The primary shipper must state the tariff they want for the unused capacity when posting it on PRISMA and may ask for any rate without restriction.

If capacity at a point is fully contracted but a trend develops of primary FT shippers not using the full capacity, then the TSO may offer additional capacity (more than the point's physical capacity counting on the low utilisation) as interruptible transportation (IT) in a short-term auction. The original primary shippers are still obliged to pay the TSO their reservation charge for that capacity and, unlike in the United States, may interrupt the secondary shipper at any time they choose to utilise the capacity again.

Congestion Management – Use it or lose it

TSOs have congestion management mechanisms such as use-it-or-lose-it (UIOLI) rules to optimise its pipeline network utilisation and avoid capacity hoarding.

- Short-term UIOLI – If a point is contractually congested and a shipper initially nominates between 20% and 80% of its total capacity, then a renomination within the day of flow can only be increased up to 90% of the shipper's total capacity or reduced down to 10% of the shipper's total capacity. This rule exists to allow the TSO to sell 10% of the shipper's capacity as firm capacity on the day before flow and to count on at least 10% of the gas for managing the physical flows within the system. This mechanism is commonly used.
- Long-term UIOLI – If a shipper is systematically reducing their nomination within the day or not using their capacity at a congested point, the TSO can offer the unused capacity as firm capacity, after proper notification to the shipper and haven given time for the shipper to respond. This mechanism is not common practice due to potential legal disputes that may arise, but it exists to prevent systematic hoarding.

Although these mechanisms exist, they are no longer utilised as TSOs prefer to enforce congestion management through auctions and IT.

Depending on the national regulator's incentive regulations, which vary by country, the TSOs may either be able to keep the additional revenue generated through offering unused contracted capacity as IT or from implementing UIOLI rules as a bonus to their regulated return, or they may have to include this additional revenue in the tariff determination for the following year.

Shippers are obliged to pay reservation charges for capacity regardless of whether they use the capacity. Purchasing capacity to hold and release during peak demand periods to make profits is likely not economic over the contract duration.

Storage

Storage facilities are required because heating and power generation demand varies with weather but production remains relatively flat all year. Local distribution companies and large consumers put natural gas in storage to ensure reliable service to their customers during peak demand in winter months.

In the United States, most of the storage facilities were developed more than 25 years ago and are now predominately owned by pipeline companies and utilised by local distribution companies. In the European Union, most storage facilities were developed before the gas market liberalisation by the former national gas supply and distribution companies.

Rules for the ownership, usage, development, and tariff setting are similar to those for transmission systems in the United States. Member states in the European Union are allowed to choose how they organise third-party access to gas storage facilities and can either implement a regulated third-party access model with the NRA setting or approving the rates and conditions, or a negotiated third-party access model. Seasonal price differences could provide an economic incentive for the development, operation, and utilisation of gas storage facilities.

In both the United States and the European Union, there is a lot of transparency on the volume of gas in storage, and this information greatly influences price trading. For the United States, the EIA publishes a storage report every week, and in the European Union, the information is provided through a centralised platform, called the Aggregated Gas Storage Inventory.

In addition to access to physical gas storage facilities, some hubs offer virtual storage services to the market. Such services do not require the potential user of the service to book transportation capacity to and from a physical storage location, but instead, the party offering the virtual storage service either has capacity at one or more physical storages or some other means of flexibility to manage user storage needs at the hub. Traders can also construct a similar product by selling gas at the hub in the summer months while buying the same amount of gas on the forward market for delivery at the hub in the winter.

In the long run, storage helps in maintaining operational stability, meeting peak demand, and narrowing seasonal price differentials.

Gas trading hubs

Liquid market hubs are the most important element of competitive markets. A gas hub is a location or platform where wholesale gas trading occurs. Market hubs provide easy access to current commodity prices, facilitate competition, promote efficient use of capacity, make it easier for participants to trade with each other, and lower transaction costs. In this section, we will describe some hub services offered in the United States and the European Union.

Domestic production, imported supply, and demand profiles can greatly vary over a year, month, or even a day. Based on their supply or demand reliability and market conditions, market participants determine the amount of natural gas to trade on longer-term (yearly or seasonal) contracts or shorter-term (quarterly, monthly, daily, or within-day) contracts.

The option to buy or sell to cover existing contracts helps not only to create additional buyers and sellers but also to increase transaction activity and the liquidity of the market hub.

Marketers also play a critical role in the market and especially in advancing market liquidity. They have the ability to aggregate supply and demand and offer flexible sale or purchase options to producers, LDCs, and end users.

Trading in the US and EU gas markets is relatively standardised. In the United States, a gas day starts at 9 a.m. and ends the following day at 9 a.m. The US physical gas markets only offer within-day, day-ahead, and month-ahead contracts. Longer contracts, such as seasonal or yearly strips, may be traded any time of the year, and typically these contracts reference a published monthly or daily index price versus a fixed negotiated price. Market participants need transportation or pooling agreements with the pipeline companies to trade physical gas at the market centres established by the pipelines. Shippers most often buy or sell gas at the closest liquid market to their facilities. Shippers may have to purchase capacity on one or more pipelines to transport their gas to a liquid hub or if they want to monetise differences in hub prices.

In Europe, a standard gas day normally runs from 6:00 a.m. until 05:59 a.m. local time on the following day. European markets offer a number of physical contract options, such as within-day, day-ahead, weekend, and consecutive monthly, quarterly, seasonal, and yearly contracts for up to two years ahead of delivery.

Forward contracts are contracts for delivery for periods farther than a month out from the time the transaction is conducted. Forward contract prices are the current value of a contract for gas deliveries in a future period. The market for forward contracts has its own supply and demand dynamics, driven primarily by the hedging of forward portfolio exposures but also by other factors, such as speculative trading flows.

The prompt contracts, such as day-ahead and month-ahead contracts, remain the most widely traded and liquid for most of the EU hubs. Only the NBP and the TTF show liquidity on some of the other forward contracts offered.

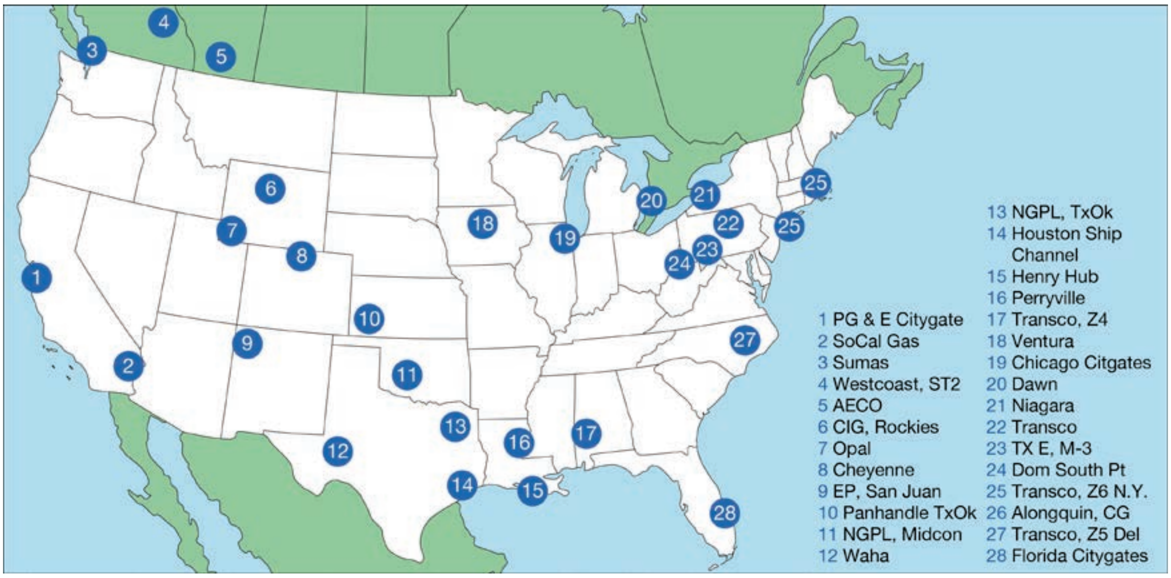
Unlike in the United States, there are no set times to trade specific contract terms. All contracts are available to be traded every day that the market is open until contract delivery.

US hubs

In the United States, the FERC does not mandate the creation of hubs but prohibits pipeline tariff provisions that would inhibit the development of market centres. FERC regulation ensures transparency and open access to infrastructure and allows hubs to develop and evolve to meet market and individual states' needs.

Many hubs emerged in the late 1980s after FERC Order 636 required service unbundling to promote a competitive gas market. Over the past few decades, the number and location of hubs have evolved; many new hubs have developed and some previously liquid hubs have ceased to exist. Figure 12 shows several key market hubs currently utilised in the United States.

Figure 12. Map of several key market hubs in the United States

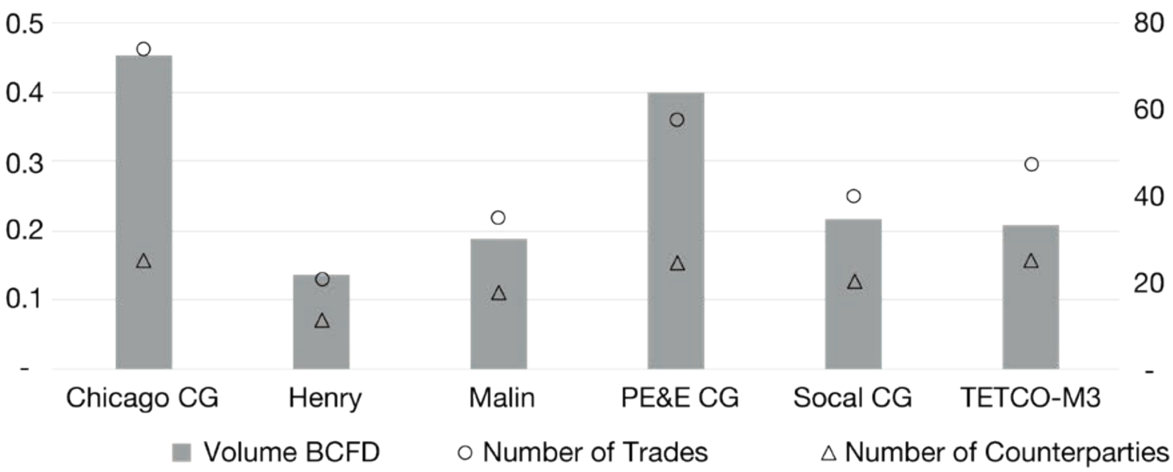


Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Infrastructure owners offer hub services to promote the utilisation of market centres on their pipelines, storage, or processing facilities determined by market activity and customer needs. The types of hub services offered vary by market centre and typically include transportation, electronic nomination, balancing, administration, accounting, and documentation of title transfers, but may also include storage, parking (short-term storage), peaking (short-term sale of gas), pooling, compression, etc., depending on the market centre configuration.

Henry Hub is the most well-known benchmark for the entire North American natural gas market. The New York Mercantile Exchange (NYMEX) selected Henry Hub as its delivery point for natural gas and started trading futures in April 1990, not only because it had many interconnects to other pipelines with plenty of available capacity due to declining production volumes in that area but also because of the innovative hub services promoted by the infrastructure (Sabine pipeline) owners. Among other services, Henry Hub offers its users imbalance services that simplify the physical delivery process and intra-hub transfers, which is a non-jurisdictional accounting service used to track multiple title transfers of natural gas at market centres. However, relatively little physical gas actually flows through Henry Hub. Today, most other spot market centres in the United States with published indices have a greater number of spot market transactions and traded volumes than Henry Hub. Figure 13 shows the average of spot market transactional data from ICE (trading platform) in 2017 for a few market hubs in the United States.

Figure 13. Average daily spot market transactional data from ICE (2017)



Source: www.eia.gov/electricity/wholesale/#history.

Pooling, which is the accounting and aggregation of volume from multiple points within the entire market centre, is another popular service offered at hubs. The SoCal City Gate and NGPL Midcontinent market centres described in the Pipeline Ownership and Operational Design section both offer pooling services. Customers can enter into a pooling agreement with the pipeline company, which keeps track of the gas being added and taken out of the pool. The customer can then buy and sell gas at the market centre pool (which can be a pipeline segment or the entire pipeline system) without needing to specify the receipt or delivery point respectively, similar to the European Union's entry-exit system. If customers offset their transactions to a net zero physical delivery by the time of physical delivery, they are not required to purchase transportation capacity but are still required to notify the pipeline company of their transactions through nominations.

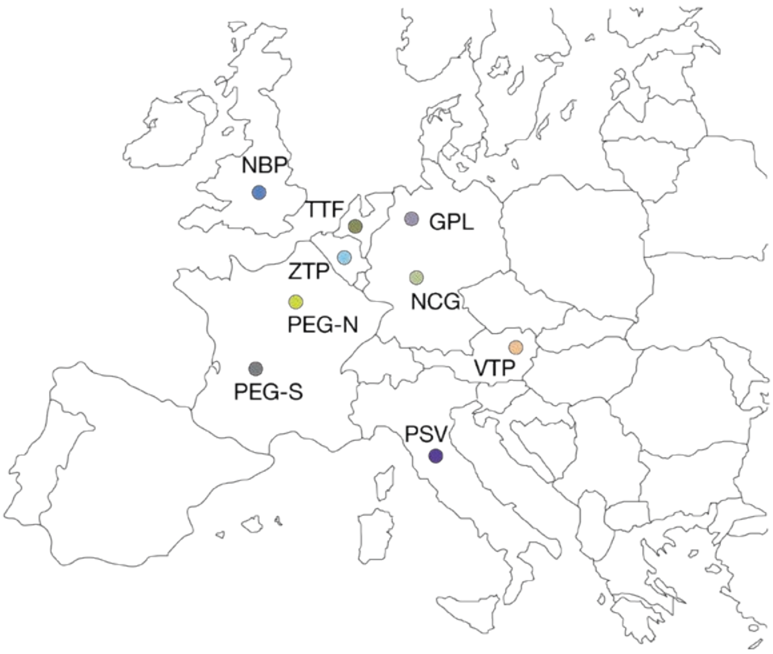
EU virtual hubs

The Council of European Energy Regulators developed the Gas Target Model (GTM) in 2011 to facilitate the implementation of the EU directives to establish a well-functioning, transparent, and competitive single EU natural gas market. The GTM vision consists of entry-exit zones with liquid virtual trading points where all parties come together to trade gas. EU legislation does not mandate the number of hubs per member state. However, the GTM provides guidance on the metrics for virtual trading hubs to have liquidity potential. This includes physical demand (volume) and is used to support the merger of virtual hubs in adjacent member states with a small gas market (such as Austria, the Czech Republic, and Slovakia).

Some of the larger EU member states (France and Germany) have multiple hubs and have made it a national policy to merge these into a single hub for the whole country to give all consumers access to the same virtual hub and avoid different gas prices for different regions in the country.

The TSO acts as a market manager for its hub and is responsible for managing energy accounts for all shippers and balancing the physical gas volumes on its system. The TSOs may offer many similar services to those available at the US hubs. Gas pooling services, across entire pipeline systems and sometimes across multiple TSO networks, as in the case of Germany's hubs, are key to enabling a system-wide virtual trading point. In Germany, where there are multiple TSOs operating within a single virtual hub, the TSOs create a joint entity to manage the virtual hub pool.

Figure 14. EU virtual hub map



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

To add gas to the virtual hub pool, a customer must purchase an entry capacity contract from the TSO, and, to take gas off the virtual hub pool, a customer must purchase an exit capacity contract from the TSO. Similar to the process in the United States, if customers offset their transactions to a net zero physical delivery by the time of physical delivery, they are not required to purchase entry or exit capacity but are still required to notify the pipeline company of their transactions through nominations.

The National Balancing Point (NBP) in the United Kingdom is the oldest hub and was the most liquid hub in the European Union until it was recently overtaken by the Title Transfer Facility (TTF) located in the Netherlands. The German NCG is the third-largest hub in Europe.TTF natural gas prices are referenced throughout the world and are the gas industry's main reference for the European continent as a whole. Figure 14 illustrates the locations of the EU virtual hubs.

Box 8. Trading transparency and churn assist market liquidity

In the United States and the European Union, the physical gas molecule may be bought and sold multiple times (churned) before actual delivery. Buyers and sellers have physical exposure and are obliged to take physical delivery and arrange for transportation or entry or exit capacity if they are unable to offset their transactions to zero before the time of delivery.

All physical transactions, irrespective of whether they go to delivery, have to be registered with the pipeline companies or the TSOs in the form of nominations. This enables the pipeline companies and the TSOs to keep track of the ownership of the gas throughout the churn. Market participants are also required to report all their physical transactions to regulatory authorities periodically.

Churn signals increase market participation and are key to increasing hub liquidity. With increased market participants, the ability of the influence of a few players to move the market diminishes. The transparency of transactions allows independent regulatory agencies to monitor activity and investigate actions that may be causing artificial price volatility and prosecute those actions if necessary.

Contract standardisation

Standardised contracts are essential for the development of markets and facilitate their liquidity and transparency. The advantage of a standardised contract is that it is well understood and so minimises transaction costs and provides a clear understanding of legal responsibilities. Pre-approved credit and/or credit-worthiness support the ease of trading and finalisation of contracts.

In the United States, the pro forma contract developed by the North American Energy Standards Board (NAESB) is the standard for gas sales and purchases at hubs. Buyers and sellers are allowed to agree on exceptions to this standard in bilateral transactions.

The NAESB is an American National Standards Institute accredited, non-profit standards development organisation formed with the support of the United States Department of Energy. The NAESB develops voluntary standards and model business practices that promote more competitive and efficient natural gas and electric markets. NAESB wholesale market standards have been adopted by the FERC and mandated as federal regulation for federal jurisdictional entities. The NAESB maintains a membership of over 300 corporate members representing the wholesale gas, wholesale electric, retail gas, and retail electric markets and has more than 2 000 participants that contribute to the development of the standards.

Interstate pipeline companies with well-developed or mature pipeline systems and tariffs typically establish standard non-negotiable agreements for the services it offers. Intrastate pipeline service agreements are generally negotiable.

In the European Union, the European Federation of Energy Traders (EFET) has developed standard contracts for the purchase and sale of gas at European gas hubs.

EFET is an association of European energy traders in markets for wholesale electricity and gas. EFET was founded in 1999 in response to the liberalisation of electricity and gas markets within the European Union. It is designed to improve the conditions of energy trading in Europe and to promote the development of a sustainable and liquid European wholesale energy market. EFET is steered by the secretary general and the chairman of the board. Membership of EFET requires approval by the EFET Board (EFET, 2019).

For transportation contracts, ENTSOG has developed a template contract of the main terms and conditions for bundled capacity products. The template is a requirement under the EU network code on capacity allocation mechanisms, but the application of the template remains optional for the TSOs.

Gas specifications

In the United States and the European Union, gas specifications are set by the pipeline company or the TSO in their transportation or entry-exit agreements with shippers. Shippers are required to meet the specifications to utilise the transmission services. Some pipelines or TSOs may accept off-specification gas if they can blend the gas with higher specifications to meet the market specifications.

In the United States, pipeline specifications for the composition of natural gas to be transported depend on the pipeline technical design. Pipeline companies set the gas specifications for their pipes and request approval from the FERC during the certification process. The FERC does not regulate pipeline specifications and merely ensures consistency within the market and other pipelines that may be connected to the pipeline filing the application.

A pipeline’s gas specification is defined in the general terms and conditions of the pipeline’s tariff in their agreement with the shipper.

In the European Union, the TSOs do not transfer off-specification gas between systems. LNG facilities manage pipeline specification requirements by injecting nitrogen if needed for higher British thermal unit gas prior to dispatch to the TSO pipeline network. In some countries, the TSOs have different systems for different gas qualities. Gases of different calorific values are traded separately in some countries, and in others, the TSO manages differences through nitrogen conversion without restricting shippers. For example, GTS maintains nitrogen injection in the gas grid to convert H-gas to L-gas, allowing gas to be transacted without specifying quality.

Gas is traded by its energy value, or calorific value, but during physical transportation, the natural gas qualities are different. In the United States and the European Union, shippers are required to deliver gas that meets pipeline system specifications. In the Netherlands, the TSO manages the calorific conversions of different specifications by nitrogen injection for shippers. Some markets may keep and trade the different gas specifications separately.

Dispatch and balancing

Nominations

The pipeline companies or TSOs register all physical transactions by means of "nominations". A nomination is an electronic notification stating the buying and selling parties, the volume of gas to be transferred, and the duration of the transfer. This ensures that pipeline operators always know who owns the gas in their system.

In the United States, shippers register their nominations using the pipeline companies' electronic bulletin boards (EBBs). If a shipper moves gas along multiple pipelines, they need to log into each of the pipeline companies' EBBs to register a nomination.

In Europe, shippers use electronic platforms set up by the TSOs for sending nominations. The EU network code on interoperability and data exchange requires the TSOs to develop a harmonised communication standard, making it more efficient and easier for shippers moving across multiple TSO systems.

The seller's nominations must be matched by a corresponding nomination by the buyer before a cycle closes. If one party's nominated volumes are lower or not entered by the time a cycle closes, then the nomination is confirmed by the pipeline at the lower nominated volume. If the pipeline has an upset that restricts or cuts back the throughput capacity after a nomination cycle, then the confirmed nominations are pro-rata allocated based on the available throughput capacity. Hence, it is important to have nominations confirmed correctly and in a timely manner for the volumes to be considered for any reduction allocations.

For the capacity allocations due to throughput capacity reductions or during high demand, firm (FT) shippers using points listed in their agreement have the highest priority; firm shippers using points not listed in their agreement have second priority; and interruptible shippers (IT) have the least priority.

Intraday nominations or changes are made after the gas day starts (at 09:00 Chicago Time) and some amount of the gas has already started flowing based on information entered on the cycle the previous day. So pipelines generally only allow a percentage of the nomination to be changed during the intraday cycles because they have less than 24 hours to make up for any flow changes.

In Europe, nominations may be entered at any time on the day before gas flows. But if a nomination does not have a match by 05:00. the day before flow, then the nomination is rejected; or if the nomination volumes do not match, then it is confirmed at the lower of the two nominations.

The TSO gets real-time production forecasts from production fields through an electronic platform using Edigas. Edigas is a common standard for TSOs to exchange messages as required by the EU code on interoperability and data exchange. Shippers are responsible for checking flows on Edigas and updating nominations on an hourly basis on the day of flow. The effective time for any changes made to a nomination on an entry point can only be set to start two hours after the change was made.

For example, if a nomination is changed during the hour starting 11:00, then the earliest effective start time for this nomination change would be the hour from 13:00.

For a nomination to be confirmed and for the TSO to allow gas flow, both parties of the transaction have to register their nominations within two hours of each other. If this is not done, then the nomination of just one party is rejected from the system.

Balancing

Keeping their pipeline system balanced is a key responsibility of the pipelines and the TSOs for maintaining operational integrity. In the United States and the European Union, pipelines and the TSOs have devised different mechanisms to incentivise shippers to help them keep their systems balanced. Pipelines/TSOs and shippers have operational balancing agreements to manage the inevitable fluctuation between production and consumption versus the amount of gas nominated.

A shipper's imbalance volume is the difference between the actual volumes flowed versus the nominated volumes. A long position is when the actual flows were higher than the nomination. A short position is when the actual flows were lower than the nomination.

In the United States, shippers' transportation contracts are balanced on a monthly basis. The shippers are responsible for monitoring the imbalances and adjusting nominations and transactions to project and keep the cumulative imbalance within a certain tolerance (for example an imbalance less than 5% long or short of the total nomination for the month) by the end of the month.

Some pipeline companies allow shippers to roll their entire imbalance or up to the tolerance to the next month, and some cash out the imbalance at the end of the month. The operational imbalance specifics are defined in the terms of the pipeline contract and are not regulated.

A tiered cash out is the most typical form of settlement. In a tiered cash out, if the imbalance volume is greater than a certain tolerance, then the shipper cashes out a long position at a discounted market price or a short position at a premium to the market price. The market price is typically the average of the daily prices during that month. A flat cash out is less common and uses a pre-defined index price negotiated in the pipeline service agreement to settle the entire long and short imbalance.

However, if an imbalance is causing an immediate operational issue in the pipeline, then the pipeline company may issue an operational flow order (OFO) to protect the operational integrity of the pipeline. An OFO directs shippers to match their nomination to the actual flow for the period of the OFO (which could be a few hours or multiple days) within a tolerance or risk being cut off.

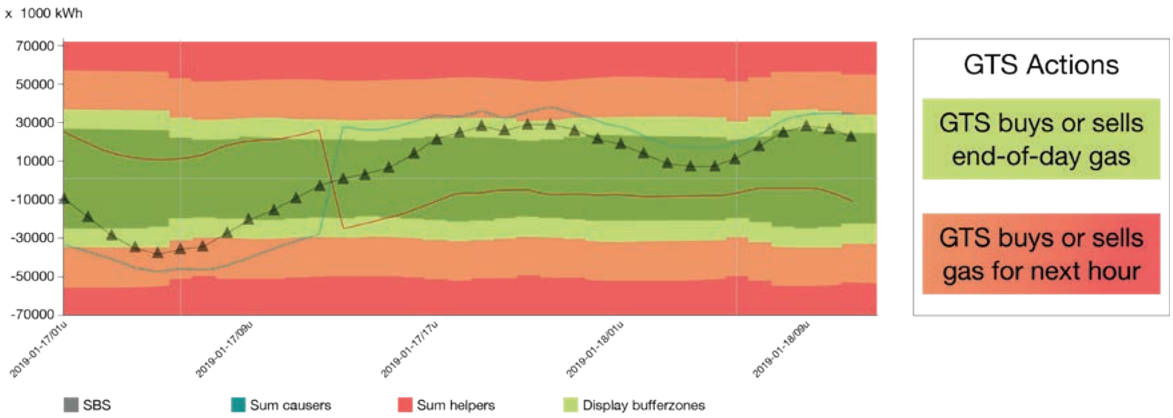
In the United States, in the month following the gas flow, shippers try to identify other shippers with an imbalance opposite to theirs during the flow month and enter into retroactive buy or sell transactions to offset their imbalances and have a lower net imbalance with the pipeline or TSO.

In the European Union, shippers are incentivised to be balanced by the end of the gas day to avoid fees, and several European TSOs also apply within-day balancing obligations on shippers.

Shippers who are out of balance are subject to imbalance charges. These charges are either the marginal buy/sell price of the TSO for restoring the balance or the weighted average gas price of the day plus a small adjustment. This small adjustment is to incentivise shippers to balance their own portfolios and cannot be more than 10% of the average gas price.

In the Netherlands, although the shippers are subject to within-day balancing obligations, they are not subject to penalties unless the whole system balance signal (SBS) exceeds specific tolerances. The TSO monitors the SBS continuously, and if it is outside the dark green zone, then the TSO takes balancing actions. The costs of GTS balancing actions are allocated only to the shippers that caused the imbalance. Shippers with an opposite imbalance, which helps the overall system balance, do not incur these costs. The TSO takes more immediate action for more significant imbalances (they buy or sell gas for the next hour versus the next day when the SBS moves into the orange or red zones as shown in Figure 15).

Figure 15. System balance signal example



Transparency requirements and price index publishing

Pipeline transparency

In the United States, per FERC Order No. 636, interstate pipelines must set up electronic bulletin boards (EBBs) that are accessible by the public on an equal basis. All information on the EBBs is available to the public, even to non-shippers. EBBs offer a high level of transparency on pipeline operations and increase shippers' confidence in the pipeline and the overall market. The required information posted includes capacity, gas quality requirements, an index of customers, service outages, operational flow orders, open seasons, imbalances, tariffs, standards of conduct, system maps, requests to purchase releasable capacity, nominations, pipeline affiliate names and addresses, and pipeline corporate legal disclosures, etc.

EBBs provide the shipper information, including the shipper name, its pipeline affiliation, the type of service contracted, its contract start and end dates, the negotiated rate indicator, transportation, and storage maximum quantities. This information can be used by interested parties to plan for open seasons (e.g. to know when contracts end) and identify primary shippers from which to request capacity release.

In the European Union and the United Kingdom, there are also similar requirements. On the website of the UK grid, the flow of each entry and exit point is updated every two minutes.

Price index publishing

The physical market price indices or assessments are published by energy trade press publishers in both the United States and Europe and represent the market value of natural gas in the wholesale market for a particular location over a specified period of time. Operators of electronic trading platforms also publish prices based on the trades made on their platform. Physical spot transactions in commodities markets are almost without exception linked to prices published by price-reporting agencies. However, all market participants in the United States and the European Union are required to report all transactions to regulatory agencies – the FERC (Form 552) in the United States and the Regulation on Wholesale Energy Markets Integrity and Transparency (REMIT) in the European Union – for the agencies to monitor the market status and investigate any manipulation.

Price indices have a widespread influence throughout markets, so the development of the indices and data reporting need to be accurate and safeguarded from manipulation. Price discovery guidelines should set clear and high transparency standards to dissuade manipulation.

Price-reporting entities must develop a methodology that accurately reflects the price under all market conditions, even extreme volatility, irrespective of the number of transactions or anomalies caused by low transaction volumes. The methodology must be publicly available and clear enough for market participants to calculate the resulting price for themselves given the same data, skills, and knowledge as the publisher.

In the United States and the European Union, buyers and sellers, and not regulators, decide whether to use a price index to benchmark a contract at the time of striking the deal.

The regulation of price-reporting activities is likely to act as a constraint on the ability of new entrants to enter the marketplace and could have the unanticipated consequence of reducing competition between reporting services. It could also move the focus of the market-reporting organisations from ensuring the robustness of their indices by evolving their pricing methodologies and improving their processes to meet the precise requirements of the regulations.

S&P Global Platts (Platts) and Intelligence Press Inc., more commonly known as Natural Gas Intelligence (NGI), are the most popular index developers in the United States. A majority of gas commodity contracts reference either Platts or NGI indices as a price term.

The two most popular price indices published by Platts and NGI are for the day-ahead and monthly bid week markets. The prices published by Platts and NGI prices are available only to parties who subscribe to their price-reporting news or data services. These index developers publish the traded volumes, the number of deals, and the ranges and averages of the prices.

Day-ahead indices are based on all physical fixed-price transactions negotiated each business day until the timely nomination cycle deadline (13:00 Chicago time) for next-day delivery, and the deadline for reporting these transactions is 15:00 Chicago time.

Platts monthly indices are based on all physical fixed-price deals negotiated during bid week, the last five business days of the month, for delivery throughout the following month.

At locations with robust trading activity, the index is the volume weighted average of all reported trades. However, the volume weighted average price does not always represent the average of the trading activity. Therefore, in less liquid or highly volatile markets, index developers may look at other means of determining an index price, which could include but are not limited to the median and average of the median and volume weighted average, locational basis relationships, transportation rates, bid/ask spreads, and historical pricing trends in order to assess what the price would have been for the flow dates in question. The index developers denote indices if assessed in a manner other than a volumetric weighted average.

Data providers are requested to submit each transaction separately and include the trading location, exact metre number if possible, transaction date, flow date, volume, price, and buy/sell indicator.

The methodology used to derive indices for ICE locations is different from the Platts locations. Indices for ICE locations only use data from the ICE Exchange trades from the ICE electronic trading platform (S&P Global Platts, 2018).

In the European Union, the NRAs require substantial transparency in the energy markets as a means of ensuring fair and open market structures. The REMIT regulation explicitly prohibits any action that manipulates or attempts to manipulate the energy markets.

To provide confidence to markets, regulators, and other governmental bodies, the price-reporting entities operating in the European Union created the Independent Price-Reporting Organisations (IPRO) code. This code creates an audited framework, within which signatories must operate, and it delivers confidence that assessments and indices produced under the code are robust and subject to best practices.

The IPRO code requires price-reporting organisations to publish their methodologies and editorial standards. These can be found on each organisation's website and ensure that there are "robust governance arrangements" and that they make freely available the methodologies used and "publish price assessments that are in accordance with its methodologies". The code also requires the parties to manage "conflicts of interests" and to prohibit staff from "engaging in any personal account trading activity" that may cause a conflict.

In the European Union, price-reporting agencies obtain information provided on a voluntary basis by various market participants about transactions, bids, and offers occurring at the established hubs. Operators of electronic trading platforms are required to publish prices based on trades made on their platforms.

Prices developed by ICIS, a media news organisation that offers natural gas price-reporting services and the ICE trading platform, are the most widely utilised in the European Union.

The ICIS Heren indices and assessments have evolved to cover both emerging and mature markets and now have over 200 assessments for the British NBP, Dutch TTF, Belgian Zeebrugge, German NCG and GASPOOL, French PEG Nord and TRS, Italian PSV, Austrian Virtual Trading Point, and Spanish PVB, as well as the Czech, Slovak, and Turkish markets.

The ICIS day-ahead and weekend assessments and month-ahead index are used as the price reference in contracts for hubs in the European continent. However, in the United Kingdom, the ICE index for the NBP is utilised as the price reference in month-ahead contracts.

Financial tools

As hub liquidity matures, financial tools become possible, attracting additional participants, which further benefit the sellers and buyers.

Futures markets allow producers, consumers, and marketers to manage their exposure to the risk of price changes. Risks are reduced because the price is set at the time the contract is transacted for delivery in a specified future month at a specified delivery location. This is known as hedging and helps reduce the cost to buyers by providing certainty in a volatile market. A producer who expects to have natural gas to sell for many years may lock in a sales price in a futures contract to guarantee a stable return on investment. Similarly, a local distribution company may buy natural gas futures contracts to reduce the price risk on behalf of its consumers.

Futures markets provide valuable information about supply and demand expectations in the physical market and give market signals for infrastructure development, putting additional gas in storage or fuel switching options.

Futures contracts are standardised agreements that typically trade on an exchange. The value of a contract is continuously changing as supply and demand expectations and information about weather, storage levels, and the physical market at the time of delivery change. Prices in the futures market tend to trend with the physical market prices and merge into one price when the futures contract reaches its delivery time (matures). Nearly all futures contracts are cash settled before the futures contract matures without the actual delivery of natural gas.

The futures market is also used by financial players, such as investment banks, hedge funds, and speculators, who seek to make money off of price changes in the contract itself for bearing risk or as part of a diversified investment portfolio. These players provide liquidity, act as counterparties to producers or companies that actually want to take physical delivery of the natural gas, and help the markets function effectively. The success of futures market prices depends on a high level of transparency of information. The various perspectives of many different participants benefit the market, thereby reflecting current and future supply and demand needs.

Transition management

The highly liberalised market in the United States was preliminarily developed over the course of several years, beginning in the 1980s. The US gas exchange was established and gradually developed with the changes in the natural gas market regulation policies by the energy regulation department. The reform process was also the long-term exploration of continuous trials, errors, and readjustments. The NBP was established in 1996 and was not originally ideally liquid. It gradually became active after 2005 and has developed into a highly liquid market after more than ten years. The gas market liberalisation reform in the Netherlands started around 2000 along with the overall reform of the European Union. The TTF, founded in 2003, has become the largest trading hub in Europe after ten years of reform. There are many games in this process, and the tools of reform have been constantly adjusted and strengthened with trial and error.

In the initial stage of reform, the European market was generally faced with a lack of upstream suppliers, and it difficult to form effective competition due to the long-term integrated upstream and downstream operation. In the United Kingdom, the state-owned gas company (BG) was forced to transfer its market share. After the mandatory regulations were issued, some independent gas suppliers started to sign short-term gas purchase contracts with producers and competed with BG on the spot market. In this way, the monopoly position of BG in the gas supply market was greatly restricted and narrowed, and new market players were further cultivated. The Netherlands has increased the market liquidity and transaction volume of the market by supervising third-party access to infrastructure, gradually developing traded products of various maturities, and providing convenience and confidence to market players through standardised contracts so that more players are willing to participate in the market.

Box 9. Transition from long-term contracts

In both the United States and the United Kingdom, the transition from long-term contracts was difficult and expensive. As spot markets developed and market conditions changed, pipeline companies (United States) or national gas companies (United Kingdom) were often burdened with long-term contracts with gas pricing bases that had become uneconomic. The renegotiations of contracts, settlements of take-or-pay obligations, and the transition from bundled contracts to transportation-only contracts were some of the actions taken to manage the transition.

In the United Kingdom, the historical long-term bilateral contract became a burden after the opening of the gas market, in particular due to the price differential that emerged between the old contract pricing and the new market price. Not only were the gas prices agreed between BG and the upstream producers linked to competing fuel prices and inflation but there were also no price revision clauses in the long-term contracts, so there were no means to adjust to changing market conditions. In the early 1990s, several factors contributed to an oversupply situation, e.g., excessive market entry, satellite field development, and BG's own production increases. The liberalisation and market opening meant that upstream producers were developing new gas fields in the hope of getting a piece of a growing market by selling their gas either to the new gas-fired plants or to the new marketers. In 1992 and 1993, the prices agreed in the long-term contracts related to these fields were in line with BG's purchase costs. Given the large share of associated gas fields, there was little incentive to shut down production when prices started to collapse.

The combination of mild weather in 1995 and delays in power plants and excess purchases by BG from the Morecambe field (one of the largest gas fields in the United Kingdom, also used as virtual storage in the past due to its high production flexibility) exacerbated the company's imbalance. BG had take-or-pay obligations to purchase 47.6 bcm (4.6 bcf/d) versus an estimated demand of 45.0 bcm (4.35 bcf/d), leaving it with 2.6 bcm (0.25 bcf/d) with a value of GBP 528 million (United Kingdom pounds). As BG's weighted average cost of gas was much higher than the spot price, this left the company with two options: selling gas at a loss (either on the spot market or to its own customers, and since the volume represented around 30% of the spot market at that time, there was a risk of making prices drop even further) or restricting supply and maintaining high gas prices. This led to the renegotiation of gas contracts and the de-merger of BG.

The company decided to split first into two parts in 1996; Centrica became responsible for gas sales, services, and retail business as well as the North and South Morecambe fields, and BG Plc., was allocated exploration, production, transport, and storage. The deal was finalised in early 1997. This de-merger, seen as a correction of the government's failure to restructure the industry in times of liberalisation, had a cost – the combined market value of the assets fell by half from GBP 15.5 billion to GBP 7.7 billion (World Bank, 1998). During the split, all the contracts went to Centrica, which had to renegotiate them, and this was done by the end of 1997. For example, in December 1997, Centrica announced that it had renegotiated the contracts with Conoco, Elf, and Total. However, in return, it had agreed to pay compensation of GBP 365 million (before tax), and further provisions were made for further potential volumes to Conoco. Then, agreements followed with Philips, Agip, and Fina for GBP 43 million, and contracts with Chevron were terminated. At the same time, due to the opening of the gas market for residential users as well, Centrica lost many household gas customers while it gained new electricity customers, so that the number of energy customers as a whole was increasing.

In the United States, with FERC Order 436, pipelines were open to third-party access and distribution companies, which could bypass the midstream companies and source gas more cheaply. They were given the opportunity to exit their contracts with pipeline companies, but the pipeline companies could not exit their contracts with producers. They negotiated new and cheaper supply contracts, further undermining the sales of the pipeline companies, which had to charge more for their gas to a shrinking customer base. This forced most such companies into litigation with producers and, therefore, required the FERC to set up a mechanism to distribute the costs among all industry participants. The FERC issued Order 500 in 1987, allowing the pipeline companies to pass on up to 75% of the transition costs to producers, distribution companies, and large consumers. The "transition accounts" were established during that time to deal with this transition cost, which could be decomposed into years afterward. Only then did the interstate pipeline companies begin to implement the open access regime on a large scale.

Source: IEA (2012), *Gas Pricing and Regulation*.

Regulatory oversight

Unbundling, together with regulated TPA, allows producers to market their gas to customers, lets customers choose their suppliers, and enables the efficient use of gas pipeline infrastructure. For competition to function, network access must be non-discriminatory, transparent, and fairly priced. To achieve these targets, regulations and the related authorities are necessary, and in the different countries, they appear in different forms. Many of these agencies have been already mentioned in the previous sections.

Independent transparent regulatory oversight is fundamental for promoting fair and competitive gas market design and performance. Effective regulators are knowledgeable on the detailed specific workings of the gas industry and are competent in multiple disciplines (law, engineering, economy, accounting, sciences, and other professions). Regulations must be enacted and enforced in a non-discriminatory manner.

In the United States, several federal agencies have jurisdiction and regulatory authority over interstate transmission line operations, and the primary agency is the FERC.

The FERC is organised into 12 departments with a staff of approximately 1 480 employees (FY 2017). It has a budget of USD 347 million (United States dollars), and its operations are funded by reimbursements from filing fees for individual filings assessed to the filing entity and by annual charges assessed generally to the regulated industries.

The FERC regulates the following:

- Rates and services for natural gas pipeline transportation, the certification of new facilities, and the abandonment of existing facilities, principally under the Natural Gas Act.
- Rates and services for electric transmission and electric wholesale power sales.
- Certification and decertification of qualifying facilities.
- Hydroelectric dam licensing and safety.
- Rates and services for oil pipeline transportation.

The FERC only regulates those matters specifically delegated to it by statute. Itjudges rates, terms, and conditions based on standards of "just and reasonable" and "not unduly discriminatory or preferential".

The Environmental Protection Agency is the federal agency charged with the protection of the environment. It is responsible for administering environmental laws. The Environmental Protection Agency comments on the Environmental Impact Statement prepared as part of the FERC certification process for new pipelines. It reviews and ensures compliance with the Clean Air Act and the National Pollutant Discharge Elimination System.

The Pipeline and Hazardous Materials Safety Administration Office of Pipeline Safety is the regulatory body responsible for carrying out a national programme to ensure the safe, reliable, and environmentally sound operation of the nation's natural gas and hazardous liquid pipeline transportation system.

In the European Union, the Agency for the Cooperation of Energy Regulators (ACER) was founded in March 2011. Its purpose is to assist the NRAs and, where necessary, co-ordinate their actions. ACER's activities include the following:

- Issues opinions and recommendations to transmission system operators, NRAs, and EU institutions (European Parliament, the Council, and the Commission).
- Submits to the Commission non-binding framework guidelines for the development of EU-wide network codes.
- Decides on cross-border issues where the competent NRAs have not been able to reach an agreement or upon a joint request thereto from the competent NRAs.

ACER has approximately 68 full-time employees. The Board of Regulators consists of senior representatives of the NRAs, one member for each member state, and one non-voting representative of the Commission. The board provides opinions to the director on the opinions, recommendations, and decisions that are proposed for adoption, and provides guidance to the director in the execution of his/her tasks.

The NRAs have the following general objectives:

- Promote a competitive, secure, and environmentally sustainable internal market in natural gas within the European Union, and effective market opening for all customers and suppliers.
- Develop competitive and properly functioning regional markets within the European Union.
- Eliminate restrictions on trade in natural gas between member states.
- Facilitate access to the network for new production capacity and new entrants of gas from renewable energy sources. Ensure that system operators and users have the appropriate incentives to increase efficiency in system performance and foster market integration.
- Ensure that customers benefit through the efficient functioning of their national markets.
- Achieve high standards of public service for natural gas and contribute to the protection of vulnerable customers. The NRAs set or approve the transmission and distribution of tariffs and the tariff methodologies.
- Set or approve the terms and conditions for access to the national transmission and distribution networks, the balancing services, and access to cross-border infrastructure.
- Monitor compliance with the obligations under the Third Package (e.g., rules on unbundling and network codes) and exercise the authority to require transmission, storage, LNG, and distribution system operators to modify the terms and conditions.

In the United Kingdom, the Office of Gas and Electricity Markets (Ofgem), which was formed in 2000 by a merger of the previously separate electricity and gas regulators, regulates the country's gas and electricity industries. The regulator has the principal duty of protecting the interests of present and future consumers where possible by securing effective competition between gas and electricity suppliers and electricity producers. Members of Ofgem's Board are appointed by the Secretary of State for a term of five years with the possibility of one additional term.

The main statutory powers of Ofgem are the following:

- Issue, modify, enforce, and revoke licences for downstream operators: all energy transmission, distribution and supply companies in the United Kingdom are regulated through these licences.
- Investigate and issue fines of up to 10% of the licensees' turnover, where they have been found to breach licence conditions.
- Set price controls over the prices charged by monopoly network operators, which gives Ofgem a direct influence on network charges.

In addition, Ofgem has a prominent role with regards to the Network Code and also has the power to carry out investigations into companies suspected of being engaged in anti-competitive behaviour. Ofgem liaises with Consumer Focus, a body which has the power to investigate and report on complaints about actual or threatened disconnection and complaints from vulnerable consumers.

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Abbreviations and acronyms

ACER	Agency for the Cooperation of Energy Regulators
bcf/d	Billion Cubic Feet per Day
bcm	Billion Cubic Metres
bcm/d	Billion Cubic Metres per day
BG	British Gas
CAM	capacity allocation mechanism
CMP	congestion management procedures
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
EBB	electronic bulletin board
EFET	European Federation of Energy Traders
EIA	Energy Information Administration
ENTSOG	European Network of Transmission System Operators for Gas
EPA	Environmental Protection Agency
EU	European Union
FERC	Federal Energy Regulatory Commission
FT	firm transportation
FY	fiscal year
GIE	Gas Infrastructure Europe
GTM	Gas Target Model
GTS	Netherlands Gasunie Transport Service
H-gas	high-calorific gas
ICE	Intercontinental Exchange
IEA	International Energy Agency
IGU	International Gas Union
INGAA	Interstate Natural Gas Association of America
IPRO	Independent Price-Reporting Organisations
IT	interruptible transportation
LDC	local distribution company
L-gas	low-calorific gas
LNG	liquified natural gas

NAESB	North American Energy Standards Board
NBP	National Balancing Point
NBS	National Bureau of Statistics of China
NCG	NetConnect Germany
NDP	network development plans
NDRC	National Development and Reform Commission
NEA	National Energy Act
NGA	Natural Gas Act of 1938
NGI	Natural Gas Intelligence
NGPL	Natural Gas Pipeline Company of America (owned by Kinder Morgan)
NMa	Dutch competition authority
NOC	national oil company
NRA	national regulatory authority
NYMEX	New York Mercantile Exchange
OECD	Organisation for Economic Co-operation and Development
OFGAS	Office of Gas Supply
Ofgem	Office of Gas and Electricity Markets
OFO	operational flow order
OTC	over-the-counter
PG&E	Pacific Gas and Electric
REMIT	Regulation on Wholesale Energy Markets Integrity and Transparency
SBS	System balance signal
SHPGX	Shanghai Petroleum and Natural Gas Exchange
SoCal Gas	Southern California Gas
TCF	trillion cubic feet
TPA	third-party access
TSO	Transmission System Operator
TTF	Title Transfer Facility
UK	United Kingdom
US	United States
UIOLI	"use it or lose it"
Y-o-y	year-on-year

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