
7. China's Gas Market Liberalisation

The impact on China–Australia gas trade

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Introduction

The regional and global impacts of activity in China's gas sector have become increasingly significant but are a relatively new issue for most energy researchers. Building on the remarkable growth of its economy since the 1980s, China has been an engine for the world economy. China's impact on the global energy and commodity markets has also been growing and has become significant since the 2000s. While much attention has been focused on the case of oil and minerals such as copper, nickel and iron ore, the emerging impact is evident in the world's natural gas and liquefied natural gas (LNG) markets in the past decade. With current consumption of about 180 billion cubic metres (bcm), China is the world's third-largest gas consumer and its gas consumption is projected to grow to about 600 bcm by 2035 (BP 2015). Given it is set to see the largest single volume of growth for any nation in the world in the next two decades, any swings in Chinese gas demand and supply options will affect the global gas market and gas trade. Thus, the Chinese gas sector should be an object for future energy study.

In addition to its size and growth prospects, two other factors in the Chinese gas sector have earned global attention. The ongoing domestic gas market liberalisation, which started in the past decade, may also have a significant impact on the world gas market. In the effort to establish a market-orientated economy, significant changes have been made in the past five years aimed at liberalising the gas sector. With the introduction of market forces, it is possible to generate prices that reflect the fundamentals of China's supply and demand. If successful, the ongoing efforts to create an independent pipeline operator will have a significant impact on future Chinese gas prices. Moreover, access to transport and storage infrastructure would lead to changes in Chinese market patterns at the national and provincial levels. Here, the literature has demonstrated that the evolution of market structure and organisation in gas-importing countries results in their domestic markets becoming increasingly subject to market forces, which further become a key determinant of international gas pricing.

The second factor is the effort to create gas trading hubs and gas benchmark pricing. As a result, China's gas liberalisation will improve in terms of infrastructure, size and liquidity of the market, as well as regulations, which are some of the prerequisites for trading hub formation (IEA 2002). A deregulated and competitive gas market would result in competitive price formation and the inception of financial contracts based on hub prices. Shanghai has announced its plans to create the Chinese 'Henry Hub' (China Securities Newspaper 2015). These efforts will create the dynamics for hub-building efforts in other countries such as Singapore and Japan. Moreover, China's gas pricing could be an important benchmark for the East Asian region, as it has the largest importing capacity in Asia, the most diversified (and relatively balanced) portfolios of supplies and the most diversified means of transport and transport routes (Chen 2014).

This chapter aims to examine the liberalisation of the Chinese gas market in terms of its domestic, regional and global impacts. The contribution of this report is fourfold: 1) it is potentially the first model to address the impact of Chinese gas market liberalisation on both domestic and international gas markets; 2) it will quantify the regional impact of China's gas market development on other regions, with a focus on Australia, which will be new to the literature; 3) the impact of the Chinese domestic market on Australia offers a new angle to study Chinese gas market issues; and 4) the study offers additional reference for market players, including policymakers, in the East Asian region as they develop their policy towards LNG trading hubs.

The chapter is structured as follows. It first introduces the motivations for the study, with a focus on the current situation in China's gas sector, placing it in a global context and its relationship with Australia's gas sector. Section three explains the methodology and data for further analyses. Section four reviews key features of the Chinese gas market and progress in gas market liberalisation policies against the backdrop of creating competitive markets. Section five explains the modelling methods and results, followed by the conclusion.

Motivations for the study

Overview of China's natural gas sector

As stated in the introduction, given its size, growth prosperity and ongoing efforts in liberalisation and building trading hubs, China will be a game changer in the regional and global gas markets. For almost four decades during China's rapid industrialisation, natural gas remained a secondary consideration as an energy source behind coal, oil and hydropower. The growth in natural gas consumption was slow in the period 1980–95 (with an annual growth rate

of 1.5 per cent) and modest from 1996–2002 (with an annual growth rate of 7.9 per cent). The twenty-first century, however, witnessed an emphasis on developing natural gas as the ‘fuel of the future’, with stress on its environmental benefits and promotion of it as a solution to urban pollution. Growth in natural gas consumption was dramatic from 2003 (with an annual growth rate of 16.9 per cent). Gas consumption increased from just 24.5 bcm per year in 2000 to 182.4 bcm in 2014. The share of China’s gas consumption experienced a dramatic increase in the 2000s—up to 4.8 per cent in 2013. From 2007, China became a net gas importer. In 2012, China became the world’s third-largest gas consumer after the United States and Russia (Figure 7.1). However, despite rapid growth in recent years, the level of gas consumption in China (5.9 per cent of total primary energy supply in 2014) is still below the government target and the international average.

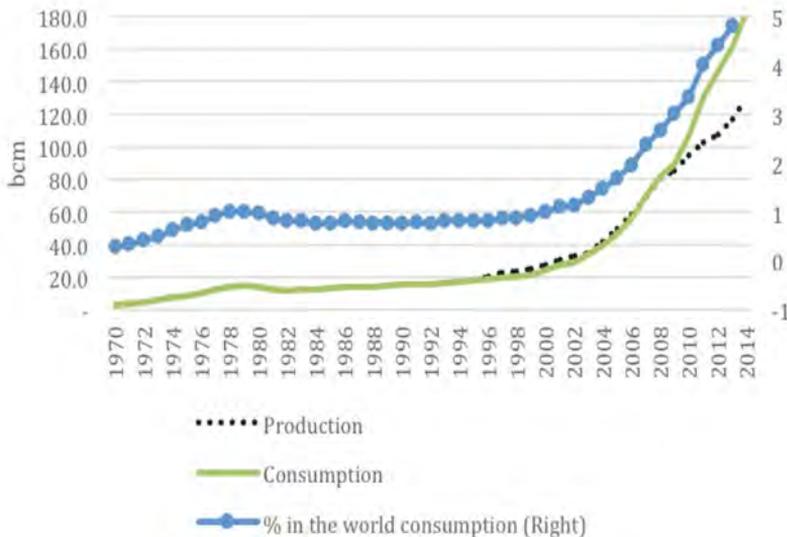


Figure 7.1 Evolution of the gas sector in China

Sources: BP (2014); NBS (2015).

According to the new Energy Development Strategy Action Plan (2014–20) released by the State Council (2014) in November 2014, the share of natural gas will be raised above 10 per cent, or 360 bcm p.a. Many observers (BP 2015; Reuters 2012) predict that gas consumption in 2035 will be about 608 bcm/p.a., with natural gas representing 12 per cent of the global energy mix by 2035.

As China’s domestic production gradually lagged behind consumption, importation of gas started in 2006 and grew dramatically. The first import was of LNG, which amounted to 20.16 megatonnes (Mt) in 2014. Pipeline gas imports started in 2010, bringing gas from Turkmenistan and other Central Asian

countries, and from Myanmar in 2014. In 2013, pipeline gas (PPG) imports overtook LNG imports, and in 2014 PPG accounted for 52.5 per cent of the total natural gas imports (Figure 7.2).

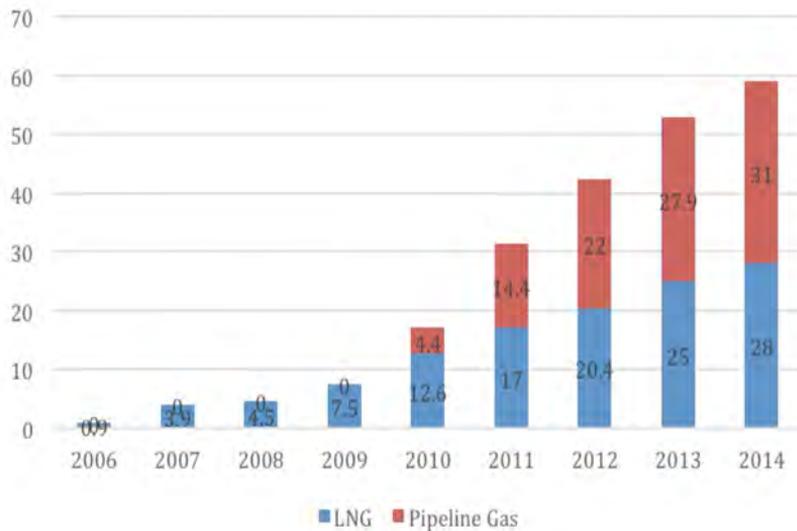


Figure 7.2 China's imports of natural gas, 2006–14

Source: China Customs data, cited from (Qian and Jiang 2015).

Qatar and Australia are China's major LNG import sources. In 2014, China imported 19.84 Mt of LNG. Representing the largest shares of supply are the four countries that have signed long-term contracts with China: Australia, Qatar, Indonesia and Malaysia. The remaining 18 per cent of supply share was purchased from Yemen, Equatorial Guinea, Nigeria and other countries through the spot market (Figure 7.3).

As a result of recent deals with Russia, more PPG is expected from the 'Power of Siberia' pipeline, as early as 2018. China's pipeline import capacity is projected to increase from 77 bcm in 2015 to 160 bcm in 2035 (Table 7.1). In comparison with our estimates, Henderson (2014) estimate a total of 165 bcm pipeline import capacity by 2030, with increased flows from Russia (68 bcm) and less from Central Asia (85 bcm). Central Asia (Turkmenistan) remains the largest pipeline import source. Based on forecasts from the International Energy Agency (IEA), US Energy Information Administration (EIA) and China National Petroleum Corporation (CNPC), China's LNG imports in 2030 are forecast to reach 120 bcm, while the assumed regasification capacity in 2030 is forecast to reach 157 bcm (ESI unpublished).

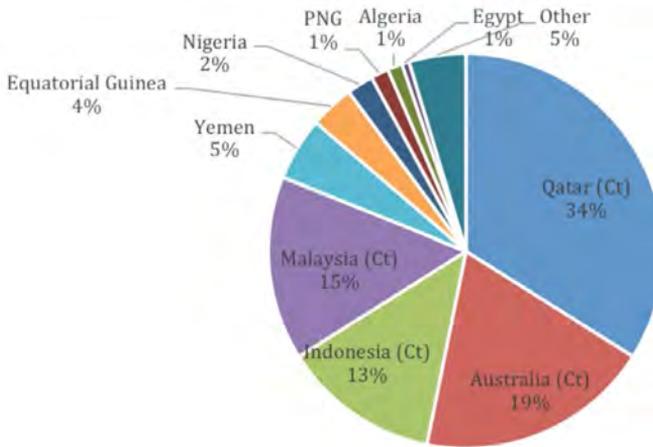


Figure 7.3 China LNG import sources, 2014

Source: Pang (2015).

Table 7.1 Pipeline gas imports into China

From	2015	2025	2035
Russia	0	38	58
Central Asia	65	90	90
Myanmar	12	12	12
Total	77	140	160

Source: ESI unpublished.

China and Australia's gas sector

Australia holds great potential resources for conventional gas (mainly offshore) and unconventional gas onshore. Estimated proven gas reserves are estimated to be 3.84 trillion cubic metres (tcm) (EIA 2014). Economically recoverable reserves of conventional gas are estimated to be 2.9 tcm. A recent study places technically recoverable reserves of shale gas at 12.4 tcm. If confirmed, this would place Australia on par with the United States, albeit with a much lower level of consumption: 25 bcm p.a. in Australia compared with 720 bcm p.a. in the United States in 2012.

Australia was the second-largest source of China's LNG imports as of 2014, and is expected to be the largest soon. China's first LNG import was from Australia in 2006. Since then, Chinese LNG imports from Australia have increased significantly, from less than 1 bcm in 2006 to about 5.3 bcm in 2014, which makes it the world's second-largest importer of Australian LNG. Moreover, China's 'Big Three' oil companies—China National Petroleum Corporation (CNPC),

China Petroleum & Chemical Corporation (Sinopec) and China National Offshore Oil Corporation (CNOOC)—have acquired interests in Australian LNG projects and have secured long-term purchase agreements. The total contracted LNG volume between Australia and China was only 3.5 Mt in 2014, and is expected to increase to 13.5 Mt in 2016 and to a maximum of 16.8 Mt in 2019. LNG trade could be further boosted by the Chinese–Australian free trade agreement.

Brief review of the literature

China's gas market and its regional impact have been intensively studied in recent years. Market-based pricing is a fundamental part of market liberalisation (IEA 2012). As a symbolic indicator of liberalisation, gas pricing was given particular attention. Zhang (2014) calls for a gas pricing system in which global pricing cues together with domestic supply and demand signals drive price formation. Furthermore, Chen (2014) discusses the implications of pricing reform for gas demand. In a report by the IEA (2002), reform in natural gas pricing and taxation policy was advocated as the best policy drivers in the national quest to increase the share of natural gas in the energy mix. The importance of supply diversity in price formation and supply security was addressed by Fernandez and Palazuelos (2011), Li and Bai (2010), Shi et al. (2010) and Lin et al. (2010), for whom competition between Russian gas and LNG prices relative to coal prices is seen as critical in price formation, creating incremental demand and the development of infrastructure, and attracting new investment. These studies can be summarised as eventual development of a pricing system based on market fundamentals with short-term contracts with flexible terms, influenced by gas and competing fuel prices in the domestic and world markets.

Gas market liberalisation is generally positive but could have a negative impact on some sectors. Economic theories often favour a market-pricing mechanism, as it is deemed to remove price distortions, improve efficiency of supply and use, and thus maximise the net benefits of gas. In gas markets, deregulation and gas-on-gas competition in a key market such as Shanghai are seen as benefiting the policy goals of liberalisation (Manuhutu and Owen 2010). A gradual breakdown of monopoly power in the three national oil and gas corporations in production, exploration, imports and transportation of gas was also seen as beneficial. Experience from studying liberalisation in other sectors has demonstrated that market liberalisation could have both positive and negative impacts. In the study of the deregulation of electricity markets in China, Chen and He (2013) demonstrated that deregulation has improved the efficiency of electricity production, employment and social welfare, but has also caused job disruption.

However, studies on the future of gas market liberalisation in China and its regional and global impacts are rare in the literature. The market-based discovery of natural gas prices and deregulated gas markets are extensively covered in the North American and European context, but are rare in terms of East Asian perspectives. No efforts have been made to simulate the impact of China's domestic market reforms on the regional and global gas markets. The lack of study on competitive pricing, however, is expected, as competitive pricing of natural gas is yet to be seen in China and even East Asia. Further studies of China's gas market liberalisation and associated issues would be valuable to the literature and to policymakers inside and outside China.

Given the likelihood of creating a competitive gas market and competitive prices in China, it would be interesting to examine the following questions:

1. What is the effect of a liberalised Chinese market on China's imports?
2. What is the effect of China's gas market liberalisation on Chinese spot market prices and key benchmark spot gas prices (Henry Hub, National Balancing Point, Australia Spot and Japan Spot)? Will the 'Asian premium' decline?
3. Will Australian LNG remain competitive against other major producers in a hub-indexed pricing system in China?
4. Will gas market liberalisation in China provide incentive for domestic production? Will the marginal cost of extraction of domestic gas increase in a liberalised market?

Methodology and data

This chapter consists of two main interrelated parts. The first part is a qualitative study. Here, relevant policies that have been implemented in the past decade are carefully surveyed to capture the development of gas sector policy. An analytical framework for studying the competitive market is proposed based on an IEA report. This analytical framework is employed to assess China's gas market liberalisation. The liberalisation efforts and associated increasing liquidity make it possible to create at least one gas trading hub in China. If the hub prices are deemed creditable, this hub may be used as a trade benchmark in China given the current efforts in Europe and East Asia to move away from oil-indexed prices in traded contracts.¹ The consequences of applying the Chinese hub prices as a benchmark for Chinese gas trade will be further examined in the second part of the chapter.

¹ As discussed in Stern (2012), the rationale for oil-indexed contract pricing is not tenable in a hub-price market.

The second part of the chapter focuses on modelling. The impact of China's gas market liberalisation on the trade flows and prices of pipeline gas and LNG was examined with the Asian Gas Trade Model (AGTM), which is based on the Nexant World Gas Model (WGM) (Nexant 2013). The WGM covers every country in the world that consumes or produces natural gas. The historical data are available for 2006–13 and the outlook period is up to 2035. The model captures flows at the country-to-country level by pipeline and LNG, with contracted and uncontracted flows identified separately.

Supply and demand for piped gas and LNG are balanced on a quarterly basis and include seasonal demand variations, supply swing and storage capacities (working volume and deliverability). Demand forecasts for each node are exogenously estimated based on considerations of gross domestic product (GDP) and population growth, usage share and energy intensity in each sector. Supply data are included as a cost curve for each of the natural gas fields for the producing country. Production capacity and forecasting data list all active and potential natural gas production fields in all natural gas producing countries.

The model includes all known sales contracts, and active and planned infrastructure (pipelines and LNG liquefaction and regasification terminals). Contract data include the source and destination of contracts, annual contract quantity (ACQ), contract start and end dates, and price formulae. The infrastructure information includes location, start and end dates of operation, source and destination, pipeline capacity, start and end dates of pipelines, and transportation tariffs.

The oil price assumption used in all our cases was based on World Bank (2015) and EIA (2014) forecasts of the Brent Crude average spot price. Previously, it has been reported that observed import gas prices follow developments in the oil price with a lag of about four to eight months (Siliverstovs et al. 2005). In order to capture this, we employed a three-month lag (one-quarter) whenever there is indexation to previous prices. For ease of analysis for our study, we have classified regions as in the Appendix (Table A7.1).

Flows within nodes were constrained according to the available infrastructure and within the bounds of long-term contracts where appropriate. If the export and import nodes were both specified, the model delivered at least the take-or-pay (TOP) level from the export node to the import node. Volumes above the TOP level could be delivered to the import node, diverted to another location or even shut in (not produced) based on least-cost grounds. Such contestable volumes were priced on a spot basis. The pricing of gas also took into account the tightness of the market (for spot contracts) and, in the case of contracts, the linkage with oil/oil product prices. For any demand above contracted

gas delivery, spot (uncontracted gas) trades occur subject to infrastructure availability. Hence changing the terms of contracts can influence the amount of spot trade in the future.

Using the scenario assumptions, the model matched supply to demand taking into account production costs, contract costs and transportation costs by pipe and LNG with the cost minimisation as the optimisation objective. For more details on the specifications of the model, please refer to the AGTM (Andrews-Speed et al. 2015; ESI n.d.).

China's market reforms towards a competitive gas market

This section introduces market liberalisation from the perspective of policy and regulation, gas pricing reform, infrastructure and market structure. Economic theory and past experience suggest that market liberalisation requires openness of the whole supply chain of the gas sector, from licensing and exploration in the upstream sector to trade and transportation and to the final customer (IEA 2012). An IEA analysis provides a useful framework to assess the development of gas liberalisation. According to this report, the initial steps to create gas markets include four goals: open access to infrastructure—that is, unbundling of transport and marketing functions and third-party access (TPA); introduction of consumer choice; reduction of regulation of wholesale prices; and application of competition policy in the sector (IEA 2013). Based on this framework, we provide a brief assessment of liberalisation efforts so far.

Policy and regulation

China's national gas policy emerged in the past decade with the rapid development of the natural gas sector. The policies include upstream development such as of shale gas and coalbed methane (CBM), liberalisation of LNG imports, midstream regulation featuring TPA, and downstream regulations such as environmental projects that require substitution of coal with natural gas. Involvement of the private sector and liberalisation of pricing are applied to the whole supply chain. These policies aim to encourage exploration, production, infrastructure development, efficient utilisation and competition in the gas sector.

Earlier policies focused on generating adequate supply of natural gas and efficient utilisation. For example, on 30 August 2007, China released its National Gas Utilisation Policy, which was intended to ease natural gas supply and demand, and optimise the structure of natural gas utilisation (NDRC 2007).

In line with the overall policy of marketisation and establishing a market economy that was promoted in the past five years, the focus of recent natural gas policy has shifted from gas supply and consumption to the gas market, with liberalisation the highlight. Measures promoted in these policies include pricing reform, opening up of the sector to private investors and TPA. For example, the State Council's policy on private investment issued in May 2010 explicitly encourages private investment in oil and gas exploration and production, storage and pipeline development for oil, gas and refined oil products (State Council 2010).

According to a reform package issued after the Third Plenary Session of the Eighteenth Communist Party of China (CPC) Central Committee in November 2013, the principles related to the natural gas sector and their implications are that the administrative monopoly will be removed and thus access to some upstream resources for non-state-owned companies will be improved; the government's role will be regulation and not the operation of monopoly industries, thus creating a level playing field between state and private companies; network and operations (marketing) will be separated and thus could encourage private investment in monopoly sectors such as pipelines; restrictions on market access to competition-based operations will also be removed, such as those in the downstream gas sector; pricing of gas will be liberalised and there will be no intervention in any prices that can be determined by the markets (except network prices) (Central Committee of the CPC 2013). In mid-2014, the 'Energy Revolution' advocated calls for restoration of the commodity characteristics of energy products, which indicates that gas may be depoliticised and become a product open to more competition; market-based energy pricing mechanisms could be established; and there will be changes in governance and improvements in the regulatory system.

In the latest policy on energy issued by the State Council (2014)—that is, the Energy Development Strategy Action Plan (2014–20)—pricing reform and liberalisation for competitive prices are specified: ex-plant prices and retail prices will be determined by the markets while network transmission prices will be regulated by the government; network infrastructure and its transparent and non-discriminatory TPA will be gradually established; and laws and regulations on gas pipeline projection will be advanced.

A legal framework and a regulator are still absent from China's gas regulatory framework. In particular, there is a lack of independent and holistic gas regulators. The regulation for natural gas is divided between the central government and local governments along the supply chain—the central government, with the National Development and Reform Commission (NDRC) as the administrative agency, regulates gas prices from wellhead to city-gate terminals (wellhead

prices, processing fees and transportation tariffs);² while provincial and local governments regulate local distribution charges (including connection fees) and end-user prices (Chen 2014). After the wholesale transaction, the price is adjusted by the provincial government with consideration given to economic disparities and local distribution costs (IEA 2013). As residential gas tariffs are regulated by local governments, uniform reforms are not possible and the central government's policy goals may not be achieved at the local level.

Some recent environmental policies will likely have a significant impact on the gas sector. The first is climate change policy. China has a target to reduce carbon dioxide emission intensity by 40–45 per cent in the period 2005–25, and a national carbon market is expected to be launched within two years. Both policies will boost future demand for natural gas. Another policy relates to air pollution control. In 2013, the Chinese Government set ambitious targets to reduce air pollution by 2017; fine particulate matter (PM_{2.5}) is targeted to fall by 25 per cent, 20 per cent and 15 per cent, respectively, in the three economically developed coastal areas of Beijing–Tianjin–Hebei, Yangtze River Delta and Pearl River Delta from their 2012 levels, while all other cities must reduce their levels of PM₁₀ by 10 per cent. Given the relative cleanliness of gas over coal in terms of carbon emissions and air pollutants, the replacement of coal with gas is promoted as a key solution (NDRC and NEA 2014).

Gas pricing reform

Like the pricing of other energy commodities, gas pricing has experienced transformation from the planned to the market economy. The extent of regulations on gas pricing varies according to a few factors, such as the source of supply, the means and routes of transportation, and the type of end use of the specific region. Before 2011, when a trial market mechanism was introduced, there were four stages of gas pricing similar to other typical pricing of key commodities in China. The fifth stage featured market-based pricing; it started in 2011 and has continued (Table 7.2). A detailed account of the gas pricing mechanism can be found in the recent literature (Chen 2014; IEA 2014).

2 Offshore gas prices, which accounted for 10 per cent of domestic gas output, at the wellhead are not strictly regulated by the NDRC as offshore acreage has been open to foreign cooperation since the 1980s and therefore is subject to a more market-driven pricing system. Similarly, LNG prices are not subject to regulation. However, the sale of LNG (after regasification) via long-distance pipeline would be subject to the uniform city-gate price regulation (Chen 2014).

Table 7.2 Evolution of gas pricing reforms in China

Stage	Year	Event
I	1957–81	Gas production quotas and prices were set by the government. At this stage, gas prices were low
II	1982–92	Also featured 'dual pricing'. Production beyond quotas was allowed and was priced higher than that within the quota (not exceeding 10 per cent). This change in pricing aims to encourage investment in gas exploration and production
III	1993–2005	Along with the marketisation process, a government-guided price was introduced alongside the government-set price. Ex-factor prices were introduced to combine the wellhead price and processing fees in 2001
IV	2006–11	The dual pricing system was abolished and a guided-pricing system was implemented. A two-tier (classified according to the geological locations of the fields) price was introduced during this period. According to the plan, an annual adjustment not exceeding 8 per cent of the wellhead price for tier-two gas fields was allowed. ^a In reality, however, there was no annual adjustment

^a The reference is a five-year moving weighted-average price of crude oil, LPG and coal prices, weighted at 40 per cent, 20 per cent and 40 per cent, respectively.

Sources: Authors' summary based on various studies (Chen 2014; IEA 2013).

Under the cost-plus pricing mechanisms that prevailed until 2011, the ex-factory prices,³ including wellhead prices and processing fees, were often set according to production costs and could differ among producers (Chen 2014). The transmission prices were guided by government regulations. The city-gate price was calculated as the ex-plant price plus the pipeline tariff, and thus could be different for each sector in each city or region (Chen 2014). Cost-plus pricing was also used in the United States in the 1950s to 1970s; however, it changed from a wellhead to an area approach to reduce the burden on regulators. It is useful in maintaining low gas prices when the level of marketisation is low (IEA 2012).

Cost-plus pricing mechanisms have many shortcomings. The pricing mechanism can lead to market distortions—either too generous or too parsimonious—because it is almost impossible to reveal the true costs of gas production. The prices also will not reflect the market fundamentals and fail to send the appropriate market signals for upstream development and demand response (IEA 2012). Under the cost-plus gas pricing mechanisms, final gas prices are fragmented among different kinds of consumers and different regions, and cannot accommodate increasing imports of LNG (IEA 2013). Such divergences can be unfair and ineffective. Fragmented and uneven pricing regulation created tensions among producers and distributors, and discouraged investment in production and infrastructure, which are needed to meet demand and enhance market access

3 Currently, gas prices include ex-factory (plant) prices, transmission prices, city-gate prices and end-user prices. In this chapter, unless mentioned otherwise, 'gas price' refers to the wholesale price.

and regional connectivity. The increasing gap between regulated prices and supply costs causes significant financial losses for gas importers (Chen 2014). Moreover, government-regulated gas pricing will lead to less transparent price signals and an unstable investment climate, as government policy objectives to meet desired political, social, economic or environmental outcomes can easily change (IEA 2013).

To address these challenges, the Chinese Government introduced a trial netback market-value pricing mechanism at the end of 2011 to replace the fragmented, cost-plus onshore gas pricing regime. The trial was initially launched in Guangdong and Guangxi provinces, where a single regulated price ceiling for all piped gas supply to the provinces replaced previous cost-plus wellhead price controls (IEA 2014). This reform also indicates that the pricing control point was moved from the wellhead to the city gate. The purpose of the reform is to allow market forces to play a bigger role in determining the level of domestic upstream investment and the volume of imports (Chen 2014). Effectively, it is expected to generate more liquidity and help development of a nascent gas market without compromising sustainability and affordability (Chen 2014).

In July 2013, in order to facilitate pricing reform, secure gas supplies, promote energy efficiency and control emissions, the Chinese Government started to use a market-oriented approach by linking the price of incremental gas volume to the import prices of alternatives (40 per cent of LPG and 60 per cent of heavy fuel oil), which is an expansion of the pilot program (NDRC 2013). The reform introduced two categories of gas—existing gas volumes and incremental gas volumes—and planned a gradual transition of cost-plus pricing for city-gate gas to netback pricing for non-residential sectors (mainly industrial users and power generators), which accounted for 80 per cent of the total consumption in 2012 (NDRC 2013). In this initial adjustment, only 9 per cent of gas demand was affected and the industrial sector bore the majority of impacts (Chen 2014).

From 1 April 2015, netback pricing replaced the cost-plus pricing as the mechanism to price gas for non-residential use. In 2013 and 2014, the government steadily raised the prices of existing volumes three times, and the price levels in both categories eventually converged to a fully oil-linked gas price from 1 April 2015. With the introduction of such a market-oriented pricing mechanism, Chinese gas demand will become more closely correlated with pricing reform and natural gas will be able to compete against oil products across non-residential end-user sectors.

However, some issues with the netback pricing mechanisms remain. First, it is still arguable that this mechanism does not necessarily reflect the true gas market fundamentals. For example, this methodology fails to account for coal, which is the true competitor of gas for power generation. This will become

relevant when gas starts to compete with coal for power generation. The second issue is how to manage affordability under market mechanisms. Third, is how to differentiate city-gate prices among different regions, which differ in their ability to pay, the size of their resource endowment and seasonality. Fourth, what are the threshold and frequency of adjustment?

It is also not clear whether the government will follow the netback when oil prices return to high levels, such as above \$80 a barrel. Current low oil prices provide a chance to implement netback gas prices without a huge surge in gas prices; however, continuous application of market-oriented pricing will lead to a price surge when oil prices are high. Given the sensitivity of gas demand to gas prices, whether the netback pricing will be maintained in that scenario is an important question.

Pricing reform for the residential sector was announced in March 2014, although still not market oriented. According to this reform, gas for the residential sector will be priced progressively—the price will be higher the greater is consumption, and all cities connected to gas pipelines must establish the three-tiered tariff by the end of 2015 (NDRRC 2014). The regulation of prices—and thus limited pass-through of gas costs to residential end-users—will remain a long-term challenge to market liberalisation. This prevailing cross-subsidisation among gas end-users could distort the markets and could be counterproductive for gas use in the industry and commercial sectors (IEA 2012).

Pipeline and third-party access

The midstream, the pipeline, is dominated by national oil companies and provincial grid companies. China's limited long-distance and high-pressure transmission network is still being expanded (IEA 2012). China's pipeline transmission is neither sufficient nor open. China had more than 75,000 km of long-distance gas transmission pipelines by late 2014 (Su 2014). Although the Energy Development Strategy Action Plan (2014–20) projects that the backbone of natural gas pipelines will extend to at least 120,000 km by 2020, China seems to have a long way to go to develop its network infrastructure to the level of Germany or the United States. Furthermore, CNPC is the dominant player here, owning 80 per cent of the pipeline network (IEA 2012). As for LNG receiving terminals, the first privately owned LNG import terminal, the Zhoushan LNG terminal, owned by ENN, was approved in January 2015 and may be completed by 2017 (Platts 2015).

The midstream is still in the early days of privatisation and plans for full ownership unbundling. According to the decisions of the Central Committee of the CPC (2013), privatisation is the politically preferred direction for state-owned companies, creating momentum for privatisation of the Big Three.

For example, Sinopec announced in September 2014 that it had sold almost 30 per cent of its retail unit, comprising a wholesale business, more than 30,000 petrol stations, more than 23,000 convenience stores, as well as oil-product pipelines and storage facilities (Aldred and Zhu 2014).

CNPC has also made moves to privatise its pipeline assets and its recent privatisation plan is quite radical. East–West Pipelines (EWPs) started to undergo privatisation by PetroChina, a subsidiary of CNPC, in 2012. It was further reported in January 2015 that the PetroChina board had approved the plan to fully privatise its Shanghai-based PetroChina Eastern Pipelines (CNPC News Centre 2015). Once completed, the pipelines would be completely unbundled from PetroChina's market activities. This separation of pipeline activities from CNPC's production and marketing activities makes it possible for the private sector to invest in pipelines and for independent gas producers to bypass PetroChina and make deals directly with consumers. However, the unbundling does not necessarily improve TPA, thus continuous development of TPA policy and enhancement of regulatory capacity are still needed.

The regulation of TPA was announced in February 2014, mandating gas pipeline operators to provide non-discriminatory TPA whenever they have spare capacity. The regulation also allows downstream distributors to negotiate directly with upstream suppliers over gas supply, while pipeline operators may provide only transmission services (NEA 2014). The TPA regulation, however, has a major limitation in that it mandates TPA only when the operator has spare capacity, which is difficult for third parties to monitor. The current shortage of network capacity renders the concept of TPA useless. It is also not clear who will judge where there is a surplus capacity. Furthermore, process, terms of conditions and tariffs for the TPA are not publicly available (and may have not been determined by the NEA). Nevertheless, in the case of LNG import terminals, the first successful TPA happened in December 2014, when EEN received 6 Mt of LNG through the PetroChina-operated Rudong LNG terminal in China's eastern Jiangsu Province (Platts 2014).

Market structure and number of players

The Chinese gas industry is dominated by the Big Three national oil companies (NOCs): CNPC, CNOOC and Sinopec.⁴ About 75 per cent of China's natural gas is produced by CNPC, which is also the biggest owner and operator of pipelines, in which it has a share of about 90 per cent. CNOOC was the first company to import LNG and it is likely to remain the main LNG importer (IEA 2014). CNOOC

⁴ While the major oil and gas companies are partially privatised, the state is still the majority shareholder of these companies.

also has exclusive marketing rights and buys offshore gas from its production-sharing contract partners at the wellhead (Chen 2014). Shaanxi Yanchang Petroleum (Group) is the only local oil and gas enterprise apart from the Big Three that is qualified to undertake exploration and development (IEA 2012). Other small and medium-sized gas producers have a small share in production due to their limited market access—they have to either sell their supplies to CNPC or develop the gas for local consumption. Gas imports, such as LNG, are, however, not restricted (IEA 2012).

In the downstream sector, there are no nationally dominant players. A variety of domestic suppliers with various ownership structures⁵ exist, often supported by local governments. These distribution companies usually receive gas at the city gate and have limited direct access to gas sources (IEA 2012). These distribution companies may have monopoly power in their local market, often owning the local gas pipeline, as is the case with ENN Energy Holdings. These distributors face new competition from the Big Three NOCs, which are currently trying to take over some of the domestic markets (IEA 2012). Such integration attempts may give the Big Three larger market power and thus impede competition.

Overall, the number of market players is still not sufficient for meaningful market competition even at the wholesale level. To achieve a fully competitive market, the gas industry will have to transfer its vertically integrated structure to smaller, less vertically integrated energy companies. Experience from the IEA countries suggests that in closed markets with one or only a few dominant market players on the supply side, market openness along the whole gas value chain—in particular, in transmission—is necessary because it takes time for new entrants to build up confidence, set up business and gain market share (IEA 2012). The US experience suggests that liberalisation and open access to pipelines starting in 1985 are what led to the creation of the competitive wholesale gas market (IEA 2012).

Long-term structural reforms, such as the privatisation of existing gas business, opening up TPA and the emergence of new LNG importers, will increase the number of market players so that more liquid and thus price-competitive gas markets can be generated. The development of shale gas will provide an option not available in the past to create new market players. Shale gas may increase competition because private firms, as well as non-oil companies, are participating in the development of this sector.

5 Some companies are privately owned—such as ENN Energy Holdings and China Gas—while others belong to local governments.

Simulating the impact of China's gas market liberalisation

The scenario setting

For the current study, a baseline scenario is developed as a reference case to study how the international gas market might evolve to 2035. Policy changes were simulated in policy scenarios. The differences between the impacts of the baseline scenario and the policy scenarios on regional trade patterns, prices, production and consumption are then analysed in detail to understand the effects of liberalisation, from which we draw our conclusions.

In the *baseline scenario*, we have all active LNG contracts in China, of which 94 per cent are indexed to Japan Customs-cleared Crude (JCC) and only one contract is indexed to Henry Hub (HH). For pipeline gas, all contract prices are indexed to oil products. Thus, 98.4 per cent by volume of LNG and 100 per cent of the pipeline gas are indexed to oil products. All the contracts have 'take-or-pay' (TOP) and destination clauses built in. This is the reference case with which we compare the results from our policy scenario simulations. Details can be found at Andrews-Speed et al. (2015).

In the natural gas liberalisation *Scenario I – 'China spot'*, China's Shanghai spot prices become the benchmark for both pipeline gas and LNG trading in China—a pricing mechanism that is similar to how natural gas is currently priced in the United States and the United Kingdom. The Shanghai spot price is formed within the range of the marginal cost of supply of gas (shadow price) in Shanghai and gas-on-gas competition with LNG prices in the region.⁶ All new contracts starting from 2020, and all existing contacts from 2025, will be indexed to the regional benchmark.

In the 'China spot, no TOP' scenario, in addition to the assumptions of Scenario I, TOP and destination clauses are removed for all contracts in China (post-2025), effectively making China a spot-only market.⁷

Baseline scenario

A detailed explanation of the baseline scenario can be found at Andrews-Speed et al. (2015). In this section, we report results relating to China and Australia.

⁶ The competing fuel prices used in calculation were average China LNG Contract DES price; Japan spot price; and average LNG contract price from Australia.

⁷ Removing TOP and destination clauses from a contract makes that supply contestable by other demand regions. Hence, removing the contract clauses is similar to making all purchases in a spot-only market.

Prices

A decline in oil prices is the main reason for a decline in spot and shadow prices⁸ for consumers (China, India and Japan) until about 2020 (Figure 7.4). This is due to 1) spot gas competing with oil and oil products in the region; and 2) predominantly oil-indexed long-term contracts in the region. The increasing cost of gas extraction in China (unconventional gas) is the reason for an increase in shadow prices in China. Increased shadow prices and increased domestic demand is expected to make the Chinese market the highest spot-price market in the region by 2035. Ample supply of shale gas and moderately rising demand result in a less tight market in the United States. This leads to steady HH prices. Spot prices in Russia and Australia increase due to increased tightness in the domestic market and increased costs of gas extraction.

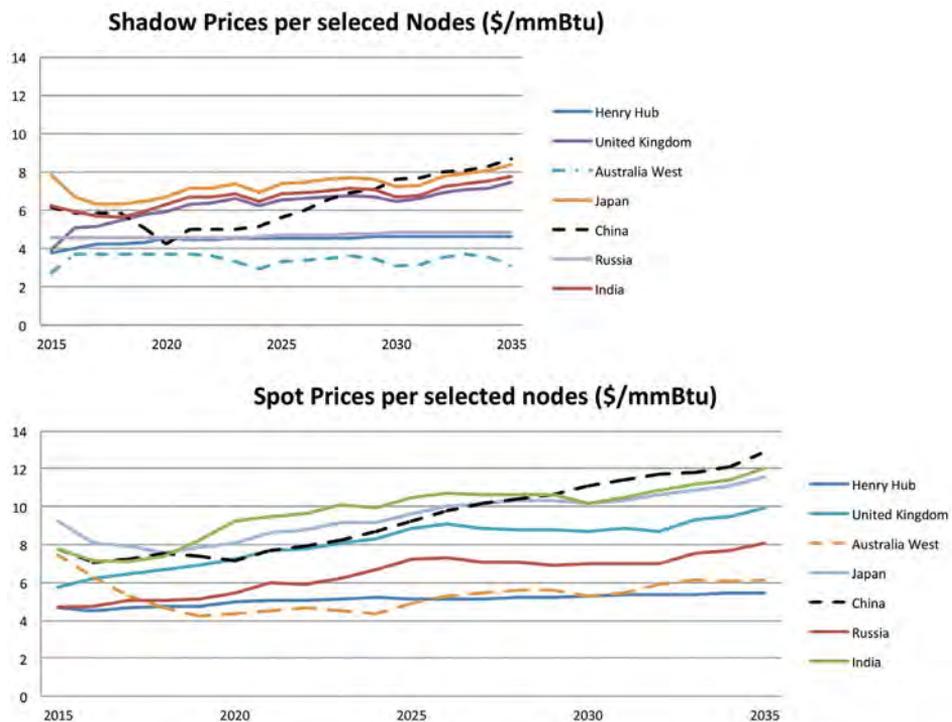


Figure 7.4 Spot price and shadow price (all prices in 2012 US\$ per mmBtu)^a

^a mmBtu = one million British thermal units.

Source: Authors' projections.

8 The shadow price is the marginal cost of gas supply to each node and is thus indicative of the true cost of gas. Spot prices are market-driven prices that customers pay for consumption of the gas. The spot price is dependent on the cost of procurement (shadow price) and the tightness of the market. Tightness of the market is a measure of overall flexibility of supply in relation to demand in a regional market. In a market with fewer supply options, market tightness will be high if supply is relatively constrained. The exact position within this range is determined according to the state of supply and demand assumed for the model run. In an oversupplied market, the spot price should lie close to the marginal cost and in a tighter market the spot price will be influenced more strongly by competing fuel prices (Nexant 2013).

Production & consumption in China

China sees a more than twofold jump in total production from 149 bcm in 2015 to 341 bcm in 2035, and the increase in consumption is projected to be 256 per cent, from 207 bcm in 2015 to 532 bcm in 2035 (Figure 7.5). The weighted average cost of production increases from \$1.32 per mmBtu in 2015 to \$2.54 per mmBtu in 2035.

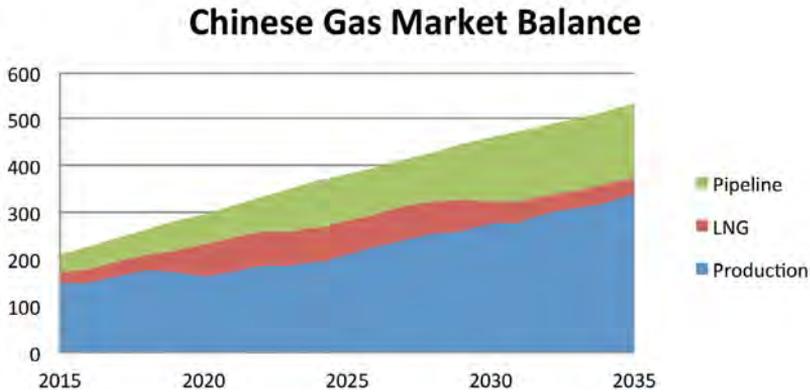


Figure 7.5 Chinese gas market balance (production and imports) (bcm)

Source: Authors' projections.

Australia's LNG production and exports will also dramatically increase. Production is expected to increase from 72 bcm in 2015 to 126 bcm in 2019 and to stay relatively stable in the forecast period. LNG exports is projected to increase from 26 Mt in 2015 to 62 Mt in 2019, and decline slightly to 55 Mt, on average, in the period 2030–35. Meanwhile, domestic consumption is expected to be relatively stable with a mild growth trend. About 60 per cent of production will be exported, even in 2035 (Figure 7.6).

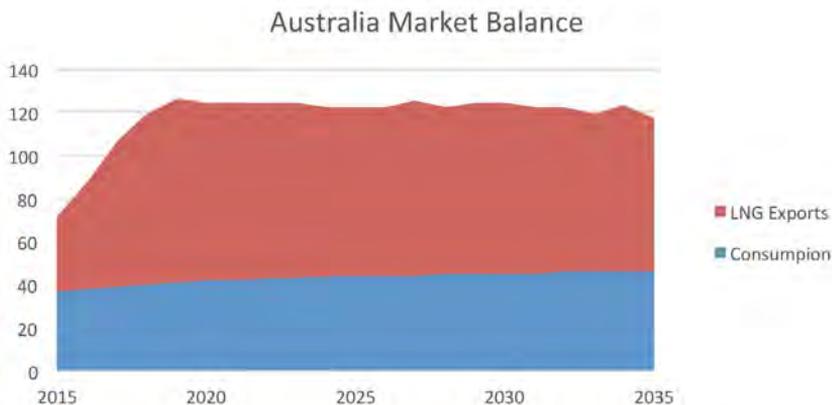


Figure 7.6 Australia's gas market balance (production and exports) (bcm)

Source: Authors' projections.

Inter-regional trade flows for China and Australia

There is a significant increase in pipeline imports to China, from 37 bcm in 2015 to 156 bcm in 2035, and PPG remains the largest source of imports. This increase in pipeline imports and increased domestic production (341 bcm in 2035) result in decreased dependence on LNG imports, as seen in Figure 7.7. Australia remains the dominant supplier to China after 2030, while South-East Asian exporters (mainly due to their decreased export capacity) are expected to lose market share.

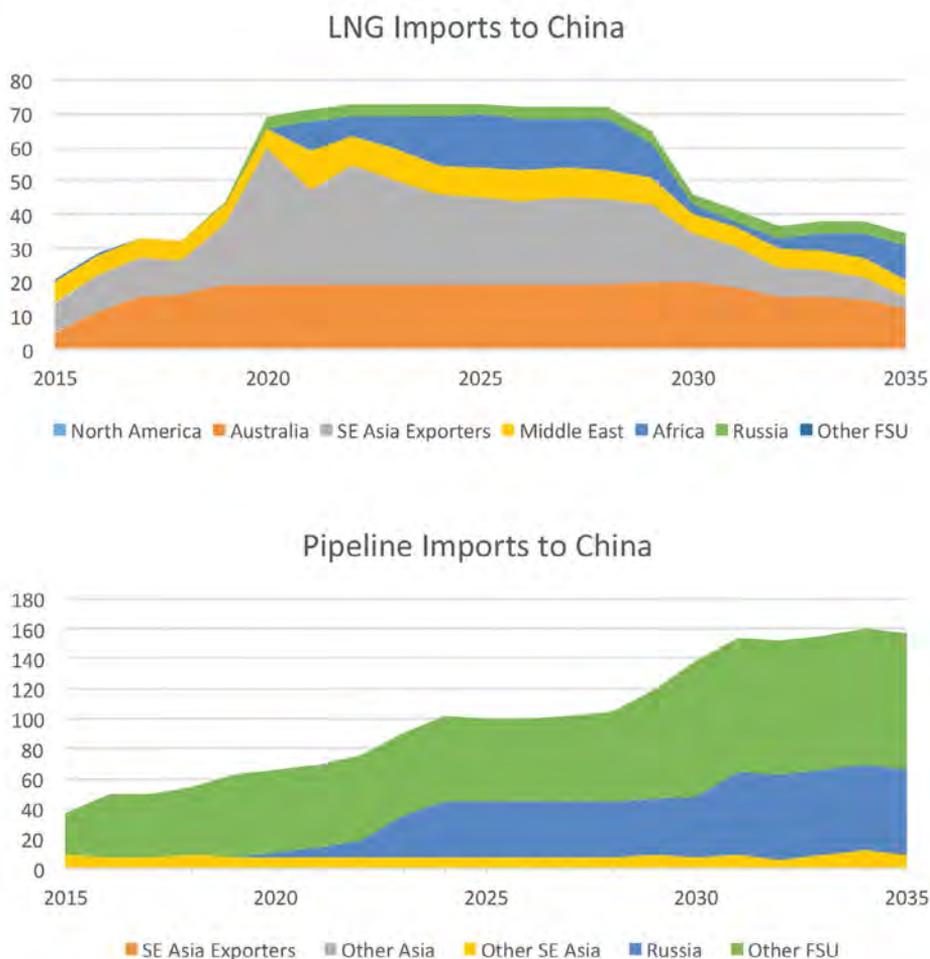


Figure 7.7 China's pipeline and LNG imports (bcm)

FSU = Former Soviet Union.
 Source: Authors' projections.

In this baseline scenario, Australia remains the overall largest exporter of LNG to China in the forecast period (2015–35). Australia exports the majority of LNG to China and North-East Asia during our forecast period. Exports to China will decline after 2030 due to competition from Russia and Central Asia (Figure 7.8).

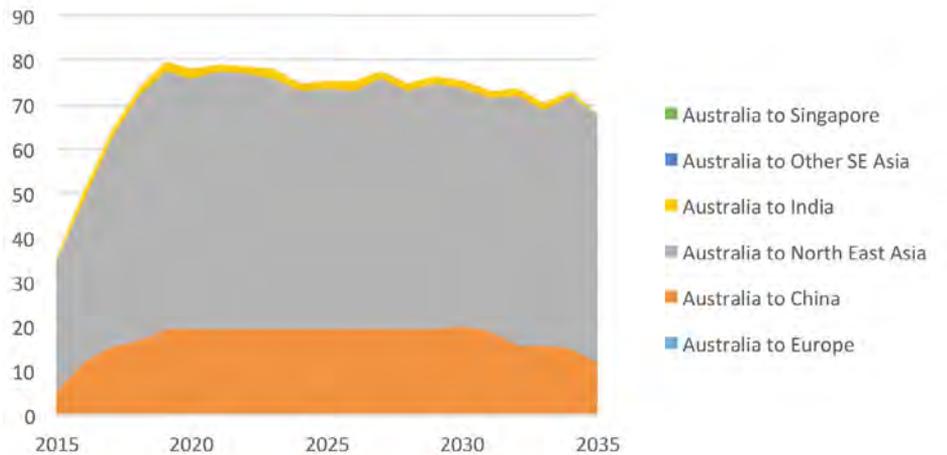


Figure 7.8 Australia's LNG exports: baseline scenario (bcm)

Source: Authors' projections.

Modelling results

Impact of China's gas market liberalisation on China's gas sector

As seen in Figure 7.9, Chinese spot prices start to decline (with reference to the baseline scenario) from 2025—the start of hub-based pricing—while hub prices in all other major markets remain largely the same. This is due to 1) gas-on-gas competition leads to lower competing prices in China; and 2) domestic market is less tight due to increased supply options from contract and spot LNG and pipeline gas. The same market price for both contracted and spot gas is more efficient in bringing in supplies to match demand, resulting in lower spot prices.

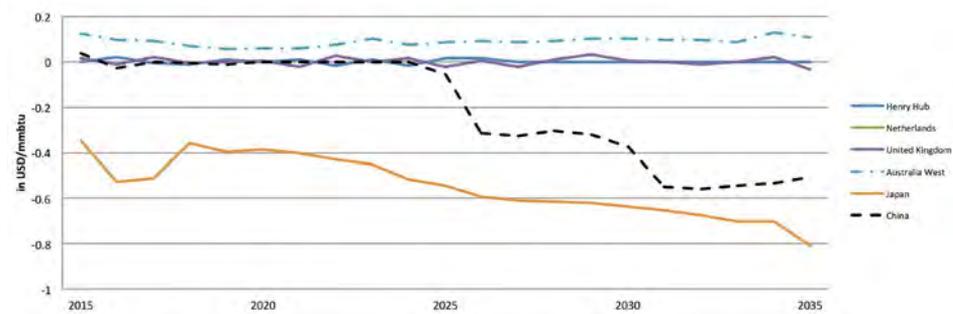


Figure 7.9 Selected spot price comparison: baseline versus China spot price

Source: Authors' projections.

Production and consumption patterns remain unchanged. LNG and pipeline trade patterns are also largely unchanged in such a scenario. This is to be expected as demand is unchanged and supply through contracts is also unchanged as contract terms remain the same, leading to similar levels of spot purchases (both pipeline and LNG) in China, as in the baseline scenario. Total LNG and pipeline trade flow patterns to China are therefore relatively unaffected in the 'China spot' scenario (Figures 7.10 and 7.11).

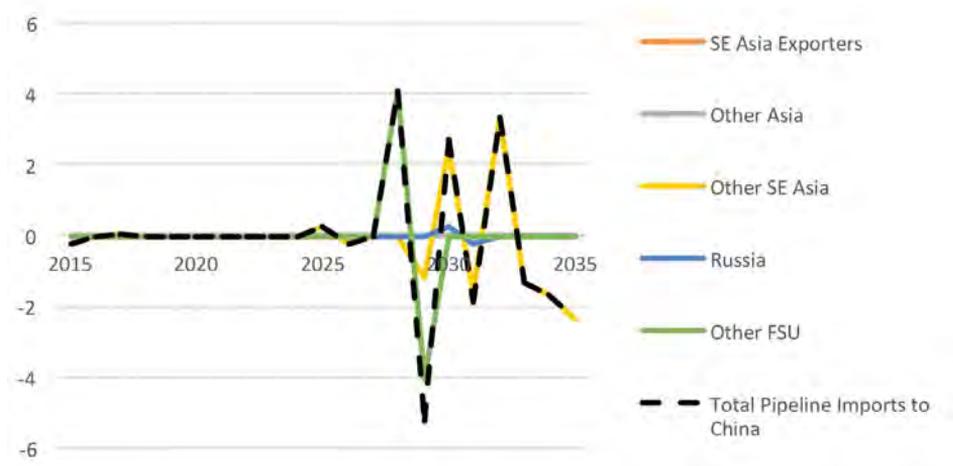


Figure 7.10 Pipeline imports to China: baseline versus China spot (bcm)

Source: Authors' projections.

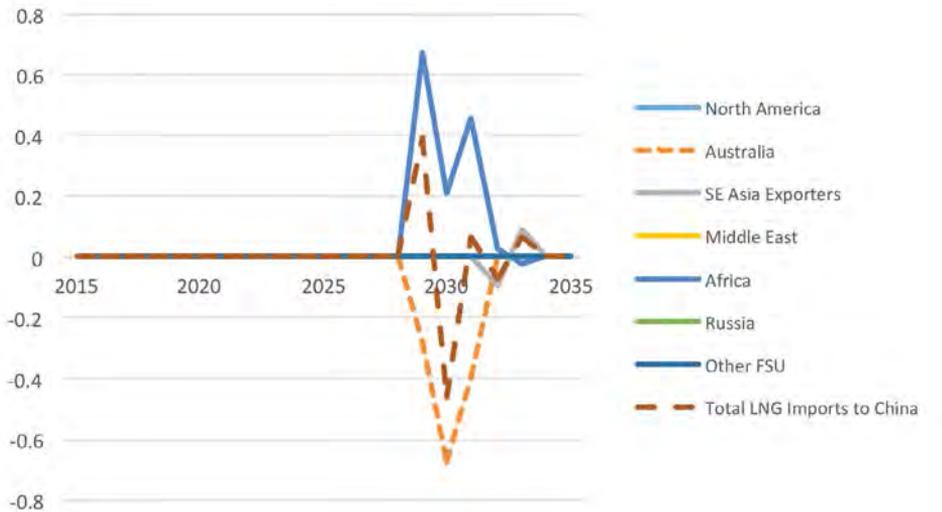


Figure 7.11 LNG imports to China: baselines versus China spot (bcm)

Source: Authors' projections.

In the second scenario, in this spot-only market (without TOP and destination clauses), China has to compete for spot gas (both pipeline and LNG) to satisfy all its demand, and demand may only marginally decline (<1 per cent). Here the optimisation of costs sees China developing more of its costlier unconventional gas resources compared with the baseline scenario.

The spot price in China increases in a market where all Chinese imports are procured from spot rather than the baseline scenario (Figure 7.12). This is due to the fact that in a market where all import purchases are from spot market supply, security is reduced. This provides incentives for domestic production from new, unconventional sources at higher cost. This leads to the marginal cost of gas production (shadow price) increasing in China after 2025, and in Asia after 2030 (Figure 7.12). Second, competition for spot gas from the market increases the tightness of the domestic gas market in China. Therefore, in a spot-only market, where China is forced to compete for contestable gas volumes at higher prices and also produce gas at higher cost, the spot price in China increases. This increase in China spot price leads to increase in spot prices in the region due to trade arbitrage.

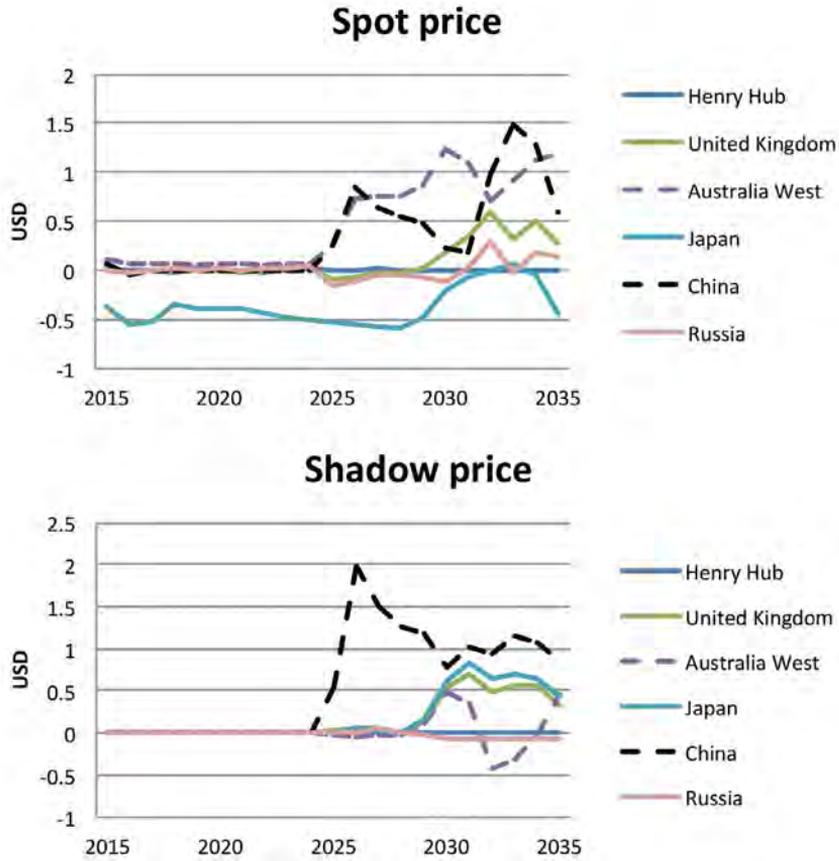


Figure 7.12 Spot and shadow prices: 'China spot, no TOP' versus baseline (US\$)
 Source: Authors' projections.

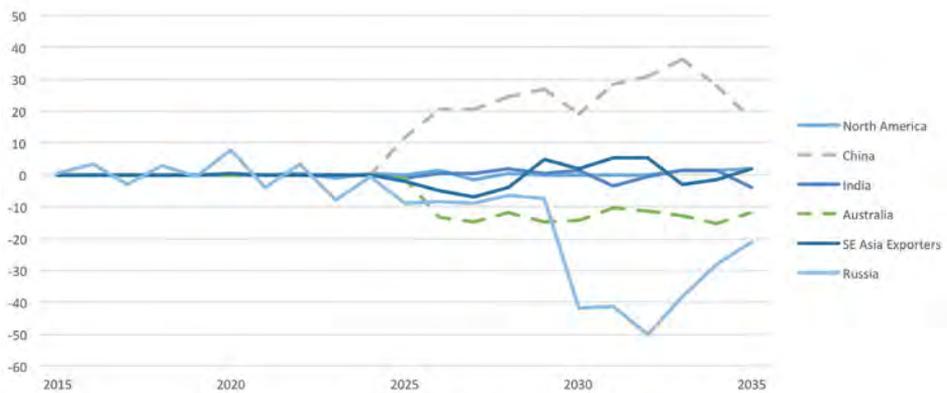


Figure 7.13 Production comparison: baseline versus 'China spot, no TOP' (bcm)
 Source: Authors' projections.

Domestic production of natural gas increases, on average, by 7.4 per cent, while the production cost rises by 13.1 per cent (Figure 7.13).

This increase in production (and therefore less dependence on contestable spot gas from global markets) leads to changes in trade patterns, for both LNG and pipeline gas.

Overall, there is *only* marginally lower import of LNG compared with the baseline scenario during this period. Hence LNG import is seen as favorable in a fully liberalised market. Although the impact is different among different LNG producers. China imports more LNG from South-East Asia, the Middle East and Africa and less from Australia and Russia. LNG imports from the first three regions are favoured due to the fact that 1) a higher spot price means marginal LNG volumes from South-East Asia, Africa and the Middle East are no longer priced out; 2) as contracted volumes are displaced by spot gas, cost competitive regions (Table 7.3) are expected to dominate the market; and, most importantly, 3) the decrease in cost of LNG is higher than decrease in cost of pipeline gas, as compared to base case scenario. Australian LNG exports to Asia decrease, on average, by 20 bcm, while Russia is able to compensate for the loss of Chinese exports by exporting more LNG to North-East Asia (Figure 7.14).



Figure 7.14 LNG imports to China: baseline versus 'China spot, no TOP' (bcm)

Source: Authors' projections.

Increased domestic production leads to less demand for piped gas, and most of the curtailment applies to Russian gas. Russian gas imports to China decrease, on average, by 40 bcm from 2025 to 2035. In contrast, there is an increase, on average, of 23 bcm in gas exports from Central Asia, which compensates for Russian gas until about 2030. Thereafter, Russian gas is compensated by an increase in production than an increase in imports. Other pipeline imports to

China are mostly unchanged (Figure 7.15). There are three reasons for this. First, Russian piped gas is costlier (at \$12.33 per mmBtu) than Central Asian piped gas (\$12.07 per mmBtu) during the period 2025–35. Second, China buys gas in the market for contestable pipeline spot gas. The Russian spot gas market is expected to be more competitive as Russian gas can be sold in Europe, the former Soviet Union (FSU) and Asia. The marginal cost of procuring spot gas away from the Russian pipeline is therefore higher compared with the Central Asian gas market. Third, when the incremental Central Asian contestable gas capacity that can be cost effectively diverted to China is exhausted, it is more economical to develop domestic resources for production.

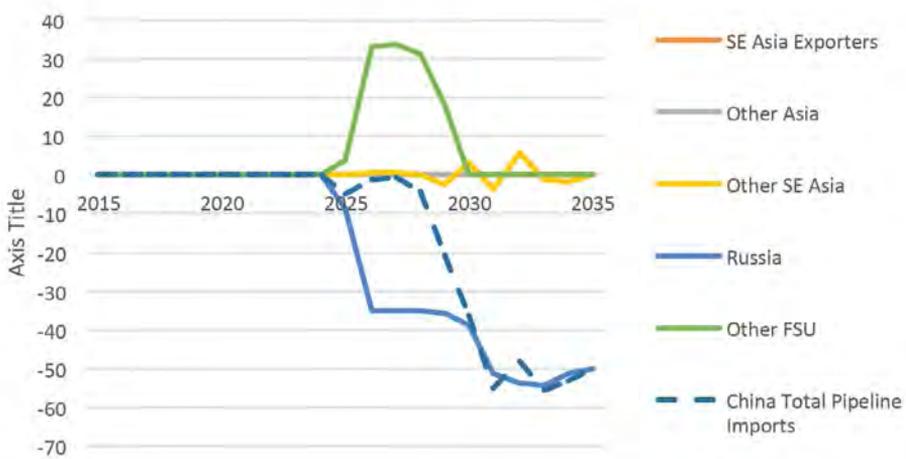


Figure 7.15 Pipeline imports to China: baseline versus ‘China spot, no TOP’ (bcm)

Source: Authors' projections.

Impact of China's gas market liberalisation on Australia's LNG exports

In a contracted world, due to TOP and destination clauses, Australia sees a very small (less than 0.1 per cent) change in overall production and exports to Asia even with a spot-indexed market. Therefore, in the ‘China spot’ case, the trading pattern remains unchanged. The total change in export volume is not more than 1 bcm during the study period (Figure 7.16). Despite the low spot prices in China, due to contractual obligations, the demand for contestable gas is lower, and Australia with its proximity and cost competitiveness compared with North America can supply it at the margin.

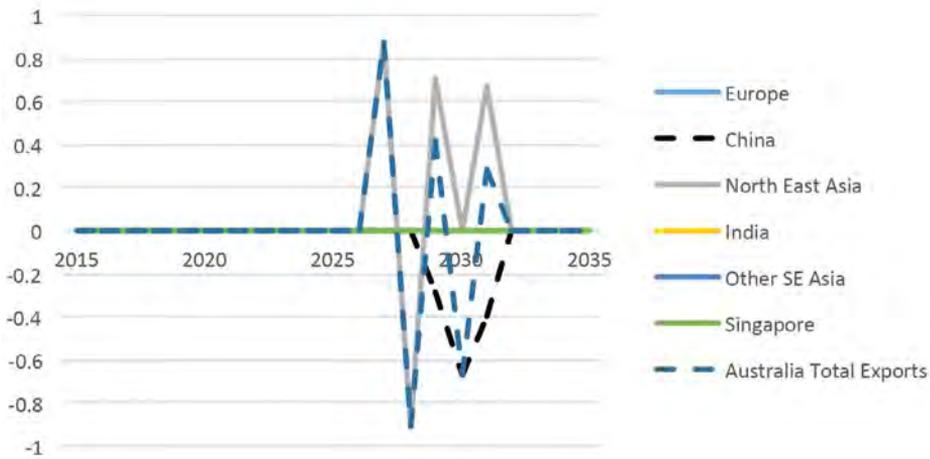


Figure 7.16 Australian LNG exports: 'China spot' scenario

Source: Authors' projections.

In a market where the demand for spot gas is high and flexibility of supply is also high ('China spot, no TOP' scenario), higher-cost producers such as Australia could, however, lose some of their export volumes to lower-cost producers supplying in the region. When all Chinese contracts change to pure spot (without TOP and destination clauses), Australia's LNG is displaced from China (all contracted flows) and there is little compensation from increased flows to North-East Asia. Total Australian production therefore decreases by 8.5 per cent and exports decrease by 28 per cent, on average (Figure 7.17).



Figure 7.17 Australian LNG exports: baseline versus 'China spot, no TOP' scenario

Source: Authors' projections.

The decline can be explained by the marginal cost and average cost of production of gas from Australia compared with other major producers. Australian gas is of comparable cost with that of the United States and Russia, while disadvantaged against that from Qatar, Nigeria and other major producers in South-East Asia (Table 7.3). Moreover, factoring in the transportation cost to Asian markets, Australia will lose out to Middle Eastern producers (Qatar, United Arab Emirates), Africa and South-East Asia, and is at a slight disadvantage compared with Russian gas due to the lower transportation costs for Russian LNG from Sakhalin through the pipeline to China (Ledesma et al. 2014). It is seen as competitive with North American gas in Asia, hence Australia (with contracted gas) continues to supply all of its exports to Asia.

Table 7.3 Marginal cost of production of gas^a

\$ mmBtu	2015	2020	2025	2030	2035
Australia	2.79	4.56	4.34	4.19	3.70
Qatar	1.99	1.99	1.99	1.99	1.99
United States	3.73	4.40	4.44	4.45	4.45
Russia	3.36	3.62	4.31	4.41	4.45
Nigeria	1.69	1.07	1.35	2.20	2.20
South-East Asia exporters	3.12	3.62	3.43	4.67	5.69

^a Shadow price at the node = marginal cost of production of gas for producers.
Source: Authors' calculations.

Financial impact assessment

In the 'China spot' scenario, liberalisation of the gas market leads to lower procurement costs for China (Table 7.4). It is instructive to compare the total cost of gas in China during the forecast period in the baseline scenario with that in the 'China spot' case—total consumption is the same, but the procurement costs are reduced. Due to lower domestic spot prices for the same demand, pipeline costs are lower by 5.9 per cent and LNG contract and spot purchase costs are lower by 11.7 per cent. Overall procurement costs are lower by 6.3 per cent. Uncontracted volumes increase and contracted volumes are kept to the minimum TOP amount.

In the 'China spot, no TOP' scenario, the total cost of procuring gas for China during the forecast period increases by 6.8 per cent compared with the baseline scenario. There is a production cost increase of 13 per cent due to increased production from higher-cost fields, a 10.5 per cent increase in total pipeline procurement costs (even though total pipeline deliveries decline), and an 11 per cent decrease in LNG import costs due to reduced imports from Australia and Russia.

Table 7.4 Total production, import and procurement costs for China across scenarios, 2015–35

Cost calculation	Volume (bcm)			Procurement cost* (US\$ million)		
	Baseline	Spot	Spot, no TOP	Baseline	Spot	Spot, no TOP
Production	4,732	4,735	4,997	353,114.40	353,378.20	399,398.00
PPG contracted	4,337	4,435	1,886	780,341.50	689,221.40	279,063.60
PPG uncontracted	4,439	4,447	6,194	1,618,756.00	1,566,592.00	2,373,357.00
LNG contracted	690	688	350	463,525.20	394,801.80	208,463.40
LNG uncontracted	416	417	810	141,484.40	139,285.70	329,525.60
Regasification	n.a. ^b	n.a.	n.a.	28,805.57	28,924.07	30,125.56
Consumption	7,938	7,938	7,927	3,386,027.00	3,172,203.00	3,619,933.00

^a Production cost = production per field; LRMC, contract price = delivered quantity; Contract price, spot price = spot quantity; Spot price, calculated for each production field, contracts and spot purchases for the duration of forecast in the case of China.

^b n.a. = not applicable.

Source: Authors' projections.

Chinese liberalisation is expected to cause a net profit loss to Australia's LNG exports, caused by a decrease in export prices as well reductions in volume of exports. In the 'China spot' scenario, Australia's LNG export volumes do not change, but average prices will decrease. With the removal of TOP and destination clauses, Australian LNG exports further reduces with little in compensation from an increase in spot prices.

As we analyse the export revenue for Australia (Table 7.5) under different scenarios of Chinese market liberalisation, in the 'China spot' scenario total export revenue declines by 4.1 per cent, while in the 'China spot, no TOP' scenario total export revenue declines by 9.4 per cent. Contracted and uncontracted export volumes remain unchanged in the 'China spot' scenario, while decline in prices result in decline of overall revenue. An increase in spot prices is more than compensated by a decline in the export volumes 'China spot no TOP' scenario, resulting in decline of overall revenue.

Overall net profits, accounting for costs of production and liquefaction,⁹ show that profits are expected to decline when China liberalises the market (price and volume flexibility). Average LNG prices (\$ per cm) are \$0.5209, \$0.4999 and \$0.5149 under the three scenarios of baseline, 'spot' and 'spot, no TOP', respectively.

9 Price DES = cost of production + cost of liquefaction + cost of transportation + profit.

Table 7.5 Export revenue for Australia in different scenarios, 2015–35

	Exports (bcm)			Revenue (\$ billion)/average price		
	Baseline	Spot	Spot, no TOP	Baseline	Spot	Spot, no TOP
LNG contracted exports	1,251.6	1,250.3	1,072.3	697.0	670.9	601.1
LNG uncontracted exports	321.2	322.6	368.7	122.3	115.4	140.9
Total LNG exports	1,572.8	1,572.9	1,441.0	819.3	786.3	742.0
Production	2,481.6	2,481.6	2,349.7	n.a.	n.a.	n.a.
Production and liquefaction costs	n.a. ^a	n.a.	n.a.	485.6	486.9	441.9
Profit	n.a.	n.a.	n.a.	333.7	299.4	300.0

^a n.a. = not applicable.

Source: Authors' projections.

In contrast with the mixed results for China and Australia, the world is better off in China liberalised market scenarios, as seen in the global system cost. Global costs for 'China spot' and 'China spot, no TOP' are lower—1.24 per cent and 1.18 per cent respectively—compared with the baseline scenario. The procurement costs for major importers in East Asia are, on average, lower by 2.12 per cent for 'China spot' and 0.84 per cent for the 'China spot, no TOP' scenario (Table 7.6). This is due mainly to reduced LNG import costs in all countries (similar to China), while being independent of pipeline imports (in China, pipeline import costs substantially increase in the 'no TOP' scenario).

Table 7.6 Optimised system cost, 2015–35 (US\$ million)

	Baseline	Spot	Spot, no TOP
Procurement costs: India	568,988.8	562,563.4	570,893.1
Procurement costs: Japan	1,131,709.0	1,107,390.0	1,117,638.7
Procurement costs: Korea	549,608.0	538,492.7	544,446.3
Procurement costs: Taiwan	190,362.1	184,361.8	187,490.6
Global optimised system cost	13,157,315.0	12,994,139.0	13,000,958.0

Source: Individual country costs are calculated similar to China cost calculation, and global cost is an output of the optimiser of the World Gas Model.

Summary and implications

In an importing region with a marked dependence on long-term contracts (North-East Asia) and with China as the only fully deregulated market, China could potentially be worse off. This is due to a potential increase in the spot

price due to demand for contestable gas. Concern for supply security¹⁰ and the level and volatility in price for and supply of spot gas could potentially be a good incentive to develop costlier unconventional production, which would otherwise be shut down. Even with less import dependence, the overall procurement cost could potentially be driven up due to the twin effects of higher uncontracted pipeline gas and LNG spot purchases.

Australian LNG could face competition from a surge in the supply of piped gas from Russia and Central Asia. Australian LNG is, however, seen as competitive with North American LNG in the baseline scenario simulation. Both in the baseline scenario and in the 'China spot price' scenario, most of the Australian LNG is contracted and Australian LNG is cost competitive with spot gas from Russia, North America and South-East Asia by the end of 2030.

Australian exports could reduce in cases where China's gas market is fully liberalised in the 'China spot' scenario (Scenario I). The future of Chinese gas supply is well diversified, with an emphasis on domestic production and pipeline imports from Russia and Central Asia. This well-supplied market with liberalised prices could lead to lower spot prices in North-East Asia. In this market, Australian gas with higher marginal costs is expected to be priced out at the margin. Moreover, remaining contracted exports to China are transacted at this lower spot price, leading to lower export revenue. However, the TOP clause in contracts allows Australia to continue to export at least up to the TOP level.

In the scenario in which the Chinese gas market is fully liberalised 'China spot, no TOP' (Scenario II), the twin effects of increased domestic production and competition for spot gas from lower-cost producers in Africa, the Middle East and South-East Asia result in a decline in Australian exports to China. Here the impact on exports is due to competition with other producing regions (for both piped gas and LNG) to supply spot gas (contestable volumes) to China. Reduced supply security in an 'all-spot' market would provide incentives for domestic production in China, thereby reducing import dependence. Also, pipeline gas from Central Asia and Russia is cheaper than LNG. However, in this tight 'spot-only' market, higher spot prices would compensate for the drop in volumes.

Nevertheless, the world and the major East Asian buyers are better off, which justifies the liberalisation efforts. Comparing the two policy scenarios, however, a fully deregulated Chinese market increases the total global system cost and procurement costs for the major East Asian gas importers.

¹⁰ Supply security is reflected in the model as the tightness of the domestic market.

The simulations suggest that, first, for China, a market with a mix of contracted purchases (with TOP and destination clauses) and spot purchases at a single price is the most effective form of regulation. We have seen one possibility in which, in a balanced market (based on production and consumption forecasts), the optimum response for China is to take contracted supplies up to the level of TOP and bridge the gap with lowest-cost spot purchases, with a single price driven by local supply and demand characteristics.

In contrast, for Australia, from the perspective of maintaining export volumes, keeping TOP and destination clauses is in Australia's economic interest. However, when judged against total profit, the benefit becomes small. In any case, to compete in a scenario of full liberalisation of key consumer markets such as China, with a corresponding impact on domestic prices and emphasis on shorter-term contracts, Australia can look at 1) alternative key markets where spot prices are higher than Japanese and Chinese prices; and 2) retaining contract terms with some conditions on TOP and destination clauses.

Conclusion

Given the importance of China's current and future gas demand, its liberalisation efforts and the prospect of a hub of Chinese benchmark prices, Chinese liberalisation is an important topic for natural gas researchers and policymakers at home and abroad. Against the IEA's assessment criteria, it is clear that China's gas market is still developing and is therefore not ready for wholesale competition. Although non-residential gas prices are linked to oil products, they are still regulated. And although large customers are allowed to choose their suppliers in the full netback pricing from April 2015, TPA is a challenge due to the inadequacy of transmission capacity. Short transmission capacity will still prevent the access of third parties. Moreover, residential gas pricing is still regulated; and the current oil indexation for gas pricing will not lead to the more ambitious goal of establishing a spot market and competitive prices. The insufficient number of market players in the oligopolistic market structure will prevent the formation of a competitive gas market, even at the wholesale level. The dominance of NOCs also casts a shadow over market competition, if there is any.

The gas market liberalisation process in China, despite recent momentum, may require a few decades to be completed. To establish a spot market, the Chinese Government will need to take additional measures, including institutional changes such as wholesale price deregulation, separation of transmission

and marketing activities, sufficient network capacity with TPA, creation of a sufficient number of market players to enable competition, and the involvement of financial institutions.

Despite the challenges, looking forward a decade, a competitive market in China is possible. It is possible to develop a deregulated market through either pipeline-to-pipeline competition or wholesale market competition in a developing stage (IEA 2013). Gas market liberalisation has been reaffirmed by the current leadership and could be expedited in coming years. With the determination of the Communist Party to liberalise markets, more wholesale competition reforms—such as pricing liberalisation, separation of pipelines and building gas trading hubs—are on the way. Gas trading hubs, building on wholesale competition, could emerge in the coming decade.

Immediate improvements in the gas pricing mechanisms could extend the netback to other alternatives, such as coal; allow the publication of price-adjustment criteria and procedures; specify regional differentiation formulas; apply market prices to the residential sector; and redirect subsidies from distribution companies to underprivileged households. For the long term, improvement in gas pricing could be achieved by moving the pricing mechanism away from the netback and towards competitive hub prices.

The emergence of hub-based prices will have an impact on world trade, and prices and demand for natural gas. The emergence of competitive market (gas-to-gas) prices, if adopted as a trade benchmark, will have a significant impact on other gas producing and consuming countries.

Our estimations show that in an importing region with a marked dependence on long-term contracts (North-East Asia), with China as the only fully deregulated market, could potentially make China worse off. Even with less import dependence, overall procurement costs could potentially be driven up due to the twin effects of higher volume and prices for uncontracted pipeline gas and LNG spot purchases. A market with a mix of contracted purchases (with TOP and destination clauses) and spot purchases at a single price is seen as the most effective form of regulation.

Based on the modelling exercise and the nature of Chinese and Australian markets, the optimum response for China is to take contracted supplies up to the level of TOP and bridge the gap with lowest-cost spot purchases, with a single price driven by local supply and demand characteristics. Similarly, Australia would also potentially be better off in a predominantly long-term contract market.

The ongoing liberalisation process is important in achieving China's gas demand targets, which, in turn, is important to achieve its critical goals of improving air quality and reducing carbon dioxide emissions. Regulated and often capped gas prices make it difficult to pass through high gas prices to consumers and reward the comparative advantages of gas over coal in reducing carbon dioxide emissions and air pollutants. On the contrary, in a deregulated gas market, the prices of gas could be adjusted with oil prices. In this context, pricing carbon makes natural gas more competitive over coal in power generation and other industrial usage, and carbon taxes will be more effective. The liberalised gas market will make it possible to fully utilise the potential of gas in carbon-abatement technology, and thus could reduce carbon prices. These issues, although important, will have to be left for future study.

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Appendix

Table A7.1 Regional specifications used in the study

Regions	Countries
Australia	Australia
China	China
India	India
Russia	Russia
Singapore	Singapore
North-East Asia	Japan, South Korea, Chinese Taipei
Asia-Pacific exporters	Brunei Darussalam, Malaysia, Indonesia, Papua New Guinea
Rest of South-East Asia	Cambodia, Myanmar, Philippines, Thailand, Vietnam
Other Asia	Bangladesh, Hong Kong, Mongolia, Nepal, Pakistan, Sri Lanka, DPRK, Afghanistan, New Zealand
Africa	Algeria, Angola, Benin, Botswana, Cameroon, Congo, Côte d'Ivoire, DR Congo, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, Togo, Tunisia, Tanzania, Zambia, Zimbabwe
Europe	Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Italy, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Spain, Sweden, Switzerland, Turkey, United Kingdom, Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Macedonia (FYROM), Romania, Serbia, Slovenia, Estonia, Latvia, Lithuania
Former Soviet Union	Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, Moldova, Tajikistan, Turkmenistan, Ukraine, Uzbekistan
Latin America	Argentina, Bolivia, Brazil, Chile, Colombia, Cuba, Dominican Republic, Peru, Trinidad and Tobago, Venezuela, Uruguay, Jamaica, Puerto Rico, Panama
Middle East	Bahrain, Iraq, Iran, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, UAE, Yemen
North America	Canada, Mexico, United States

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