THE OXFORD INSTITUTE FOR ENERGY STUDIES

July 2014

The Development of Chinese Gas Pricing:

Drivers, Challenges and Implications for Demand

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OIES PAPER: NG 89

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ISBN

978-1-78467-007-8

Preface

The spectacular growth of the Chinese economy since the early 2000s is a phenomenon familiar to all with an interest in the global economy. Clearly its impact on commodity markets in general has been both significant and observable. While China's consumption of natural gas grew dramatically in the 2000s it was only in the second half of that decade that demand began to significantly outstrip domestic production, requiring pipeline and LNG import infrastructure and supply lines to be put in place. With pipeline imports secured from Myanmar, Turkmenistan and Central Asia and more recently East Siberia, as well as a range of LNG suppliers, China is rapidly becoming 'connected' to a portfolio of international supplies. As its demand growth increases, the scale of its import requirements will influence both regional and global trade flow dynamics.

The vast geographic extent of China, the dispersion of its several gas producing regions and the location of import pipeline and LNG facilities, relative to centres of consumption, raise the related challenges of providing sufficient connecting pipeline infrastructure and a rational framework for city gate gas prices which reflect border prices and transportation costs.

This paper by Michael Chen describes, within the context of China's continued rapid gas sector development, the evolution and current status of Chinese gas price reform, which establishes city gate benchmark prices, most notably at Shanghai. These provide the basis on which sectoral prices are determined for consumption and well head prices at the various producing regions. The paper also discusses the likely future path of pricing evolution and identifies the likely response of different demand sectors in various regions within China, both to price levels and supply availability.

On the OIES Natural Gas Research Programme we frequently acknowledge the increasing importance of understanding the key high growth Asian importing gas markets, and especially their impact on other world regions through competition for supply and price arbitrage. I am therefore most thankful to Michael for this very comprehensive paper which significantly progresses our understanding of this highly important market in its continuing period of growth and transition.

Howard Rogers

Oxford, July 2014

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Introduction

The evolution of global gas pricing has been shaped by far-reaching changes in regional market fundamentals and project economics as well as higher competing fuel prices. In North America the easing of difficulties in the inter-state gas trade at a time of supply abundance and a fragmented and competitive production base gave rise to a liberalised market and the adoption of Henry Hub gas trading hub in the late 1980s (Rogers and Stern, 2014). In 1996 the UK established the National Balancing Point (NBP) as a reference price (or virtual trading hub) for gas-to-gas competition. Similarly, competing gas trading hubs have been established in Continental Europe, resulting in the negotiated reduction of the oil-indexed long-term contract price of gas and an increase in the number of long-term contracts based on a hub-priced formula. In Asia, which accounts for 60% of global short-term LNG consumption, the LNG trade has been based on the Japan Crude Cocktail (JCC) oil-indexed price mechanism.

In North America and Europe, the evolution of gas prices from cost-plus to oil-related and finally to spot and futures prices (formed at hubs and exchanges) suggests that liberalisation and the introduction of competition can be considered a natural market development. As market structure and organisation in gas-importing countries changes over time, domestic gas pricing becomes increasingly subject to market forces – in other words, reflecting gas supply and demand as well as opportunity cost at the margin. But at the same time it becomes a key determinant of international gas pricing (Stern, 2012).

The evolution of international gas prices is of particular relevance for China as it enters a 'golden age' of natural gas. Rising incomes, rapid urbanisation, concerns about air pollution and increasing oil prices have favoured the switch from oil and coal to natural gas. Gas consumption in China rose by nearly seven times between 2000 and 2013 – from 25 Bcm/y to 168 Bcm/y. In 2012 China overtook Iran to become the world's third-largest gas consumer after the US and Russia; but despite double-digit annual growth in gas consumption, only 16% of China's population had access to piped gas, while gas accounted for just 5.9% [1] of total primary energy supply. The many uncertainties notwithstanding, the absolute growth potential is enormous: the China National Petroleum Corporation (CNPC) predicts that Chinese gas demand will reach – and possibly exceed – 230 Bcm by 2015 and soar to 400 Bcm in 2020[2].

The import dependency has been rising and reached 32% in 2013. Meanwhile, the enormous potential for gas demand growth in China will be tempered, above all, by i) supply availability and delivery infrastructure; ii) pricing mechanism and price level relative to other fuels and other Asian LNG importers; and iii) government policy and funding to replace coal with gas.

Policymakers often have to strike a balance between providing affordable gas supplies to encourage gas penetration and setting a price that will serve as an incentive for more domestic production and higher import levels amid ever-growing demand. To accommodate increasingly diverse and costly imports, the government introduced a pricing reform trial at the end of 2011; the aim was to replace the fragmented, cost-plus onshore gas pricing regime with one that features China's regional prices based on netback market values of competitive fuels at Shanghai city gate, and indexation to oil products. In July 2013 this approach was taken one step further in a nationwide reform that aims to

[1] It is expected to reach 6.5% in 2014 by National Energy Administration (NEA, 2014).

[2] On April 24, 2014, the State Council issued a statement approving the proposal by the National Development and Reform Commission to establish a mechanism that would ensure the stability of long-term gas supply. That statement noted China's goal of achieving a gas supply capability of 400 Bcm – with an upside of 420 Bcm – by 2020 (State Council, 2014).

index the price of incremental gas (the volume that exceeds gas supply in 2012 for non-residential sectors) at the city gate to LPG and fuel oil prices and the price of existing gas (2012 gas supply) will converge with the incremental price by the end of 2015. By moving the pricing point downstream from the wellhead to the city gate, the government is attempting to allow market forces to play a bigger role in determining the level of domestic upstream investment and the volume of imports. Put another way, it expects more liquidity to be created and the nascent gas market to be developed in a sustainable and affordable manner.

The Chinese gas sector and energy mix is undergoing a profound transformation. On the supply side, the gradual emergence of domestic unconventional gas, the ramping up of China's conventional gas output as a result of higher domestic prices and pipeline imports from Central Asia (and Russia towards the end of 2010s) all coincide with additional Australian LNG supplies, US LNG exports to Asian markets in the medium term and the major expansion of East African and other frontier gas exports that is expected towards the end of this decade. On the demand side, the uncertainty of timing and pace of nuclear restarts in Japan and newly emerging Asian LNG importers pose significant competition particularly for Chinese LNG imports, which are being encouraged by ambitious government plans to combat pollution. Oil price volatility, the growing internationalisation of pricing due to the expansion of the LNG trade and liberalisation and competition among emerging Asian importers suggest Asian pricing dynamics are set to change. Given this complex picture, understanding the evolution of Chinese gas price formation is as important as comprehending the price level.

This paper addresses both the level and formation mechanism of the Chinese gas pricing. At the same time, it critically assesses the drivers of the development of Chinese gas pricing, as well as the challenges and implications for demand.

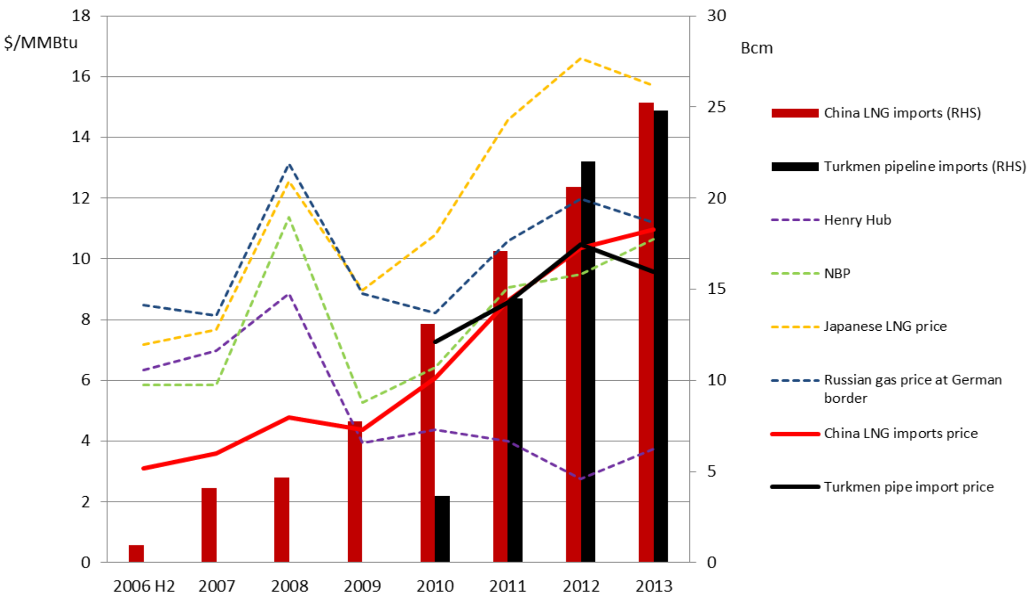
Chapter 1 puts Chinese domestic and import prices into the context of major regional prices. Chapter 2 reviews the evolution and structure of China's pricing mechanisms with reference across the various regions. Chapter 3 looks in detail at the drivers for change in, and the challenges faced by, Chinese gas pricing. Chapter 4 examines the impact of Chinese gas pricing on demand. Chapter 5 provides a summary and conclusions.

1. Chinese gas prices in the international context

1.1 Chinese gas imports prices in comparison with international prices

Figure 1 shows Chinese gas import prices and key regional gas reference prices for the period June 2006 (when China started to import LNG) to 2013. China's gas import dependence reached 32% in 2013, compared with just 2% in 2006. Over the same period, LNG import sources increased from just one (Australia) to include another 15 countries. The average Chinese LNG import price exceeded the NBP in 2012 and was around two-thirds of the average Japanese LNG import price. At the same time, the price of imports from Turkmenistan via the West-East Pipeline (WEP) II overtook that of LNG imports in 2012 – reaching a level of around 85% of oil-linked contract prices at the German border.

Figure 1: Chinese import prices vs international prices, H2/2006 – 2013

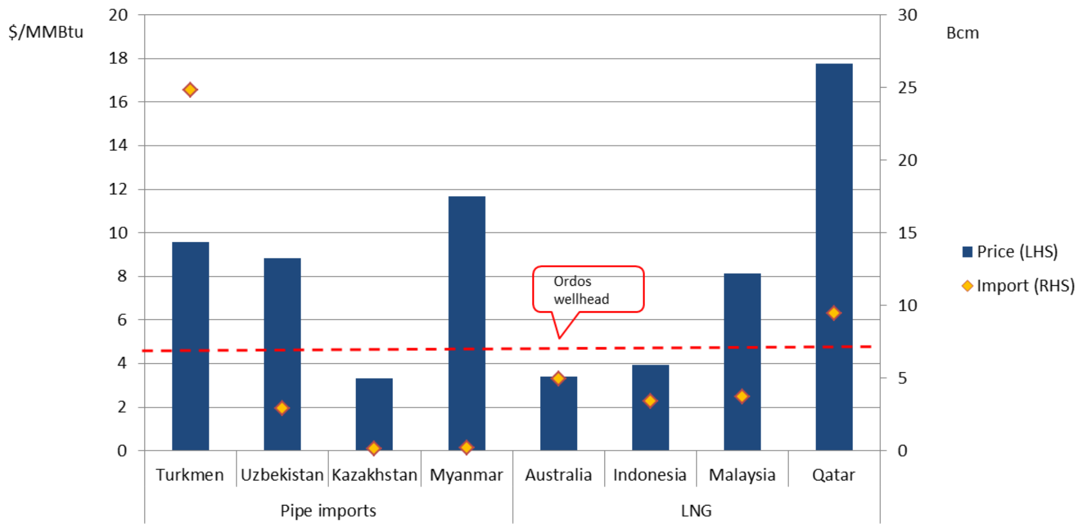


Sources: China Customs Statistics, IMF, Rogers and Stern (2014).

1.2 Major imports and pricing-development

While the Chinese gas import price has risen significantly in recent years, the range of prices is wide, and a substantial gap remains between the domestic wellhead and import price. Figure 2 below compares the domestic wellhead price of gas from the Ordos Basin (which supplies 20% of Chinese demand) with the prices of pipe and LNG imports (24%). In 2013 the wellhead gas price at Ordos Basin was slightly more than half the weighted average import price and 50% higher than that of Australian and Indonesian LNG imports, which started in the mid-2000s and now constitute 33% of total LNG imports[3]. In 2013, pipeline gas imports surpassed LNG imports, accounting for 53% of the aggregate imports.

Figure 2: Chinese pipeline imports and LNG prices, 2013



Source: China Custom Statistics, NDRC, author's estimate

China received around 28 Bcm of Central Asian pipeline[4] gas imports in 2013 (or 17% of total gas demand) with 25 Bcm coming from Turkmenistan (46% of total Chinese gas imports). Supplies from Turkmenistan are to reach 65 Bcm by 2020 under a gas contract agreed and signed in early September 2013. Uzbekistan signed a framework agreement in June 2010 under which it will feed 10 Bcm/y into the Central Asian Pipeline. It has supplied more than 3 Bcm to China since August 2012 and might increase the total volume to 7 Bcm by 2015. Kazakhstan has also agreed to supply 10 Bcm/y to China. By 2020, total Central Asian pipeline import capacity could reach 90 Bcm/y and could account for 23% of Chinese gas supply, assuming the 400 Bcm/y supply target set by the government is met.

Oil-indexed Turkmen gas at the Chinese border costs more (around $9.6/MMBtu in 2013) than other Central Asian contracted gas, owing partly to transit fees that are paid to Uzbekistan and Kazakhstan. In 2013 the Myanmar Gas Pipeline (12 Bcm/y capacity) started to supply various regions in Myanmar as well as Guangxi and Yunnan regions of China and is expected to deliver 2.5 Bcm by the end of 2014. The price of gas supplied via this pipeline is higher than that of Turkmen gas as it is sourced from the offshore Shwe field and because of the harsh terrain that the pipeline has to cross en route to China. It provides a critical supplementary gas supply for China's southwestern gas market.

[3] Those early contracts were agreed at prices far below subsequent market levels (see below).

[4] Line C (which has a design capacity of 25 Bcm/y by the end of 2015) of the Central Asian Pipeline network has started to supply gas to China in early June 2014 on top of line A and B (30 Bcm/y) which have been transporting to West East Pipeline 2 (30bcm/y) within China. Construction of Line D (25 Bcm) is expected to start in 2015. West East Pipeline 3 (30bcm/y) is scheduled to be completed in 2014 to transport gas from line C.

China and Russia finally signed the 30 year agreement for importing 38 Bcm/y gas deal from Eastern Siberia pipeline (with design capacity of 61 Bcm/y) to the border of North-East China on 21 May 2014 with a widely reported value of the deal at around $400 billion. This could imply a price of around $10/MMBtu though this depends also on the reported $25 billion upfront payment that China will pay and calorific value of gas transported among other factors (Interfax, 2014). However, this deal could potentially enhance the chances of agreeing on a western route (30 Bcm/y) which together with the Eastern route, LNG options and potential non-Gazprom exports could imply Russian capacity to supply gas to China in the 2020s to reach more than 100 Bcm/y or around a quarter of Chinese gas supply, provided field development is on track and a favourable industry policy is implemented. In the 2020s, Russian gas imports could provide a firm Northeast gas corridor for China and its price could potentially become an important benchmark for the gas market in Northeastern China. However, Central Asian supply which provides a firm Northwestern gas corridor for China will continue to be the main driver of pipeline import growth and a significant benchmark in determining the Chinese gas import price before 2020.

In 2013, China imported 23 Bcm of LNG (14% of total Chinese gas demand). Cheaper LNG supplies from Australia and Indonesia under contracts from the mid-2000s still accounted for 33% of total gas imports. Long-term oil-indexed Qatari LNG with a 'slope' of more than 17% accounted for 38% of LNG imports in 2013, while Malaysian LNG with a slope of 7-10% constituted 15%[5] .The majority of current LNG imports are based on long-term JCC-indexed contracts, while medium and spot cargos account for less than 15% of total LNG imports, despite increasing in recent years. By 2020, China's total regas capacity is expected to be over 100 Bcm/y[6], accounting for a quarter of China's total supply capacity with contracted volumes increasingly from emerging LNG plays of Australia, North America and East Africa.

The weighted average price of pipeline imports (including VAT) was around $10.4/MMBtu, close to that of LNG ($10.5/MMBtu) in 2013. With the arrival of more expensive Australian LNG, which could account for almost 40% of aggregate LNG imports in 2015-16, the weighted average price of LNG imports is expected to remain higher than that of pipeline imports at the border. However, some LNG could remain competitive at the city gate vis-à-vis pipeline imports as it does not need to be transported long distance to reach end-users and it is used for peak-shaving in power generation and transport to replace oil products.

[5] The 'slope' of a Pacific LNG contract refers to the degree of indexation and is a measure of how much the gas price changes relative to a change in the oil price (Stern, 2012).

[6] However, there is great uncertainty over both the future sanctioned terminals and the potential volume to be contracted as they depend on each other and the price expectation.

2. The structure and evolution of natural gas price regulation

2.1 Chinese pricing structure and key determinants

Domestic gas prices in China had traditionally been regulated at each point along the value chain. From well-head to city gate terminals, gas prices (well-head prices, processing fees and transportation tariffs) are regulated by central government and administered by National Development and Reform Commission (NDRC). Local distribution charges (including connection fees) and end-user prices are regulated by provincial and local governments (Figure 3).

The degree of regulation usually varies according to the source of the gas, the means and routes of transportation and the type of end-use of the specific region in question. More recently, in order to limit surging incremental demand, which is increasingly being met by imports that cost more than domestic gas, the government has been attempting to link the price of incremental gas volume (in excess of 2012 volumes for non-residential sectors) to the import prices of alternatives (LPG and fuel oil). This reform applies only to pipeline imports and onshore domestic gas production (accounting for 73% of demand). Domestic conventional onshore gas is the predominant source of gas (more than 85% of domestic gas output).

Ex-plant prices, which include wellhead prices and processing fees, have been traditionally set by the NDRC for each well and each region in the case of onshore conventional gas. They are based on the type of end-user – for example, industrial, residential and the fertilizer and power sectors, which are supplied (via different pipelines) (Ni, 2009).

Consumer affordability has been the key driver of ex-plant price regulation; but the main determinant is the production cost, which depends on the source of local gas. Well-head prices are calculated from a base price (which takes into account project cost, taxes and loan repayments) as well as processing fees and an appropriate margin for producers. Processing fees are determined by the quality of the gas and subject to negotiations between the NDRC and producers. The ex-factory price serves as 'price guidance' against which producers and buyers can negotiate a final price within a +/-10% band. It applies only to conventional gas since the price of unconventional gas price is based on market rates (see below).

Transmission tariffs (long distance and inter-regional) were set by the NDRC and vary according to pipeline and city terminal. Besides taking into account consumer affordability in the various regions, the tariff is determined mainly by the date of construction of the pipeline and the distance of the gas source to each city gate; it is based on the cost of and payback period for project construction and operation plus a margin for the operator ('cost plus reasonable profit') – namely, PetroChina, Sinopec or the China National Offshore Oil Corporation (CNOOC). The most recent tariff increase was in April 2010, when the NDRC increased some tariffs by $0.32/MMBtu. The tariff for pipelines built before 1995 is based on distance; however, for long-distance pipelines built from the mid-1990s onwards, both ex-plant prices and transmission tariffs have been set according to both distance and end-user. Current city gate pricing regulation means that the transmission tariff would be the difference between city gate and well-head prices.

City-gate prices for each sector in each city or region are normally calculated as the ex-plant price plus the pipeline tariff. (Previously, a matrix of ex-plant prices for each gas field and each sector and transportation tariffs for each pipeline for each city was used to determine those prices.) It is on the basis of the city-gate prices that each provincial government sets retail prices or the sales prices of local distribution companies, which, again, vary from sector to sector. At the end of 2011 the NDRC attempted to introduce net-back pricing in Guangdong and Guangxi provinces to gradually replace cost-plus wellhead price controls with a single regulated price ceiling for all piped gas supply to the provinces, thereby moving the pricing point downstream from the wellhead to the city gate. In July 2013 the NDRC announced city-gate price ceilings for 29 provinces and municipalities with the price of incremental gas volumes (in excess of 2012 volumes for non-residential sectors) linked to LPG and fuel-oil import prices while the price of existing gas volumes (2012 gas sales for non-residential sectors) will also follow prices of LPG and fuel oil imports by 2015. This implies a gradual replacement of cost plus pricing for city gate by net back pricing.

End-user prices for bulk users are essentially city-gate prices for direct customers (that is, those who do not buy from local gas distributors), including bulk industrial users, fertilizer producers and power plants. Gas used as an industrial fuel and in chemicals production (including small industrial users that buy gas from local gas distributors) accounts for the largest share of gas consumption – around 47% in 2011. The price of such gas is increasingly subject to negotiations between industry users and producers. Traditionally, fertilizer producers have paid the lowest price – 30% less than small industrial users – to facilitate the development of the agricultural sector. Gas use in the power sector amounted to 30.2 Bcm or 18% of total gas consumption in 2013. The price of such gas is determined by the provincial government and varies from region to region, depending on the source of the gas and the on-grid electricity tariff, which has yet to favour gas relative to other fuels.

Local distribution fees are usually paid to provincial grid or local distribution (e.g. city gas) companies that deliver gas to end-users through infrastructure that they own and operate, including medium- and low-pressure pipelines and processing plants. Different pricing methods are used for residential and commercial/industrial customers and various additional local charges apply. For residential customers, there is a flat connection fee based on the types of gas appliance in the property, such as stoves, water heaters and boilers. Many local governments have stakes in joint ventures with gas distributors in city gas distribution projects. It is in their interest to facilitate the eventual pass-through of gas costs to end-users.

End-user prices beyond the city gate are regulated by provincial and local governments. They are based on the cost of supply (the city-gate price set by the NDRC) plus a local distribution fee (including a cost-plus margin). They also take into account the following factors: the type of end-user, the user's ability to pay, the competitiveness of gas against other fuels, gas demand structure and efficiency, and a cost estimate for converting coal gas distribution networks to natural gas. In theory, when the NDRC adjusts ex-plant prices, provincial and local pricing bureaux pass costs downstream by raising retail prices; if the wellhead price of a source crosses a threshold set by the province, the project developer submits a proposal for a price change to the local pricing bureau for review, adjustment and approval. In practice, making price adjustments downstream following increases in upstream tariffs is a slow process: for example, it normally takes longer to review a price change for the residential sector than for other end-user groups since a public hearing is usually required. This has squeezed the distribution margin of city gas distributors, which tend to be private companies. End-user prices vary significantly from location to location and from sector to sector (according to local development priorities). The wealthier coastal regions, which are located a long way from key inland sources of gas, pay higher prices.

Offshore gas prices at the wellhead are not strictly regulated by the NDRC as offshore gas accounts for only 10% of domestic gas output and offshore acreage has been open to foreign cooperation since the 1980s – hence the need for a more market-driven pricing system. CNOOC holds sole marketing rights and buys gas from its production-sharing contract partners at the wellhead. It negotiates the sale price on a project-by-project basis and revises it (for some companies) annually. At the same time, CNOOC's listed E&P subsidiary (CNOOC Ltd) negotiates with the group's wholly owned downstream subsidiary, CNOOC Gas and Power Group (which is in charge of the group's gas distribution and gas-fired power plants), as well as local and national regulators.

Unconventional gas[7] prices are not included in the NDRC's netback pricing regime. Prices for coal-bed methane (CBM), coal-to-gas and shale gas remain unregulated and are determined in negotiations between the seller and the buyer – unless, that is, the gas is pumped into a long-distance pipeline and then transported and sold together with conventional onshore or imported pipeline gas. Such gas is subject to the regulated city-gate price ceilings announced in July 2013. Most CBM projects supply small local markets directly but are increasingly seeking richer markets in the coastal region. The government provides a subsidy of $0.8/MMBtu for CBM production as well as other incentives.

Pipeline import prices for Turkmen gas are indexed to oil prices paid by PetroChina at the Chinese border while the recent Sino-Russian pipeline gas deal is also believed to be indexed to crude and also oil products prices. The mechanism of netback to the wellhead was introduced in July 2013 for incremental gas to reflect growing pipeline imports and the increasing role of alternative fuel substitutes for gas.

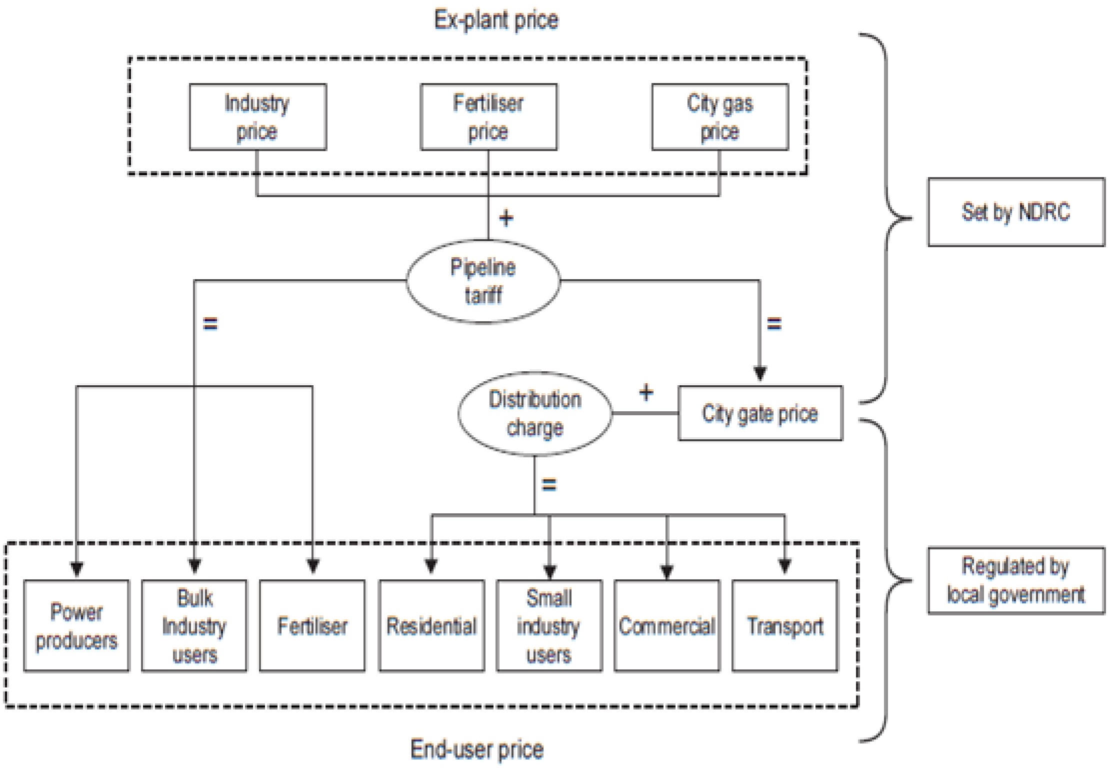
LNG imports prices are determined at bilateral negotiations between suppliers and importers. The importers, primarily NOCs, are obliged to negotiate terms for the resale of LNG on a wholesale basis (i.e., to distribution companies) or directly to large industrial or power companies (Higashi, 2009). The pricing terms for these negotiations have generally not been bound[8] by regulated city-gate prices as it mainly applies to onshore conventional gas and pipeline imports. However, the sale of LNG (after regasification) via long distance pipeline would need to follow the uniform city gate price regulation in the case where LNG seller and pipeline transmission company are the same market entity. The regasified price[9] to the distributors normally requires the local pricing bureau's approval.

[7] Tight gas is regarded as conventional gas in China. Total output amounted to 30 Bcm in 2012 and accounted for more than a quarter of domestic gas production.

[8] The city gas operator would find it increasingly difficult to differentiate gas source from LNG (after regasification) and pipeline imports as pipeline connectivity accelerates,

[9] It normally includes storage cost and local transmission tariff (from LNG terminal to city gate in order to feed into local grids)

Figure 3: Chinese gas pricing structure

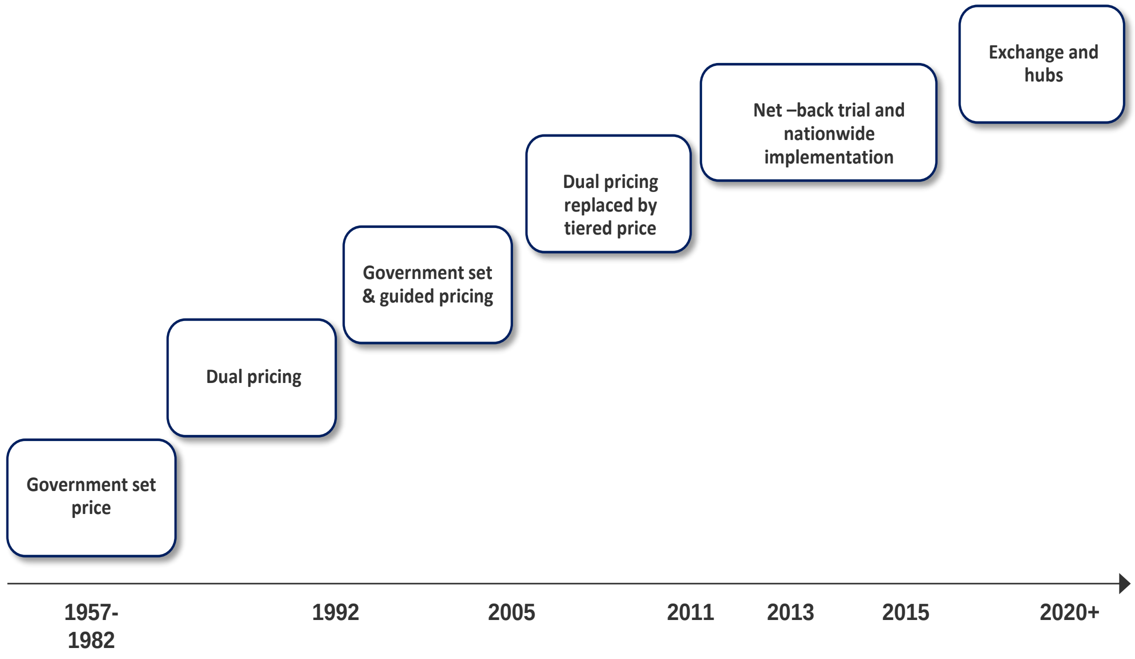


Source: Stern (2012) – Figure 10.1, p. 311.

2.2 The evolution of Chinese domestic pricing reform

Figure 4 below shows that to date, Chinese gas price regulation has evolved in five stages that are closely related to China's economic development.

Figure 4: Evolution of Chinese gas pricing regulation



Note: The government-set price is a fixed price set by the pricing authority, while the government-guided price is the benchmark price set by the pricing authority but open to negotiation by producers and wholesalers.

Sources: Wang, 2007; author's own analysis.

Stages of pricing regulation in China:

1) Until 1982 the government set gas production quotas and prices.

2) To reverse the decline in gas production and to encourage investment in gas E&P, the government raised the ex-plant price and adopted a 'dual pricing' system (1982 – 1992); under that system, companies were allowed to produce gas beyond the quota set by the government, although the price of such gas was higher than that within the quota. Onshore well-head prices were set according to end use from 1992 onwards.

3) From 1993 to 2005 the gas pricing system comprised both a government-set price and a government-guided price as the Chinese economy moved towards marketization. A benchmark wellhead price was set by the government, and E&P companies were allowed to raise or lower benchmark prices for marketed gas by up to 10%. At the same time, the wellhead price and processing fees were combined to form the ex-plant price. Nevertheless, ex-plant prices were relatively low until the late 1990s because associated gas dominated production and natural gas use was limited. Sichuan province was a forerunner of the nationwide pricing reform as dual pricing (except for fertilizers) was abolished there in 1997.

4) In December 2005 the NDRC implemented a guided-pricing system to replace the dual pricing system. This simplified regime introduced two tiers for ex-plant prices for gas fields and

combined residential, commercial and small industrial users in cities into 'city gas consumption'. In principle, it allowed for an annual adjustment of the wellhead price for Tier 2 gas fields[10] (the plan was to allow the price of gas from Tier 1 gas fields to catch up with the price of gas from Tier 2 gas fields within three years), according to a five-year moving weighted-average price of crude oil, LPG and coal prices weighted 40%, 20% and 40%, respectively, and with the price adjustment not exceeding 8% annually. However, from 2005 onwards there was no price annual adjustment. The pricing reform of June 2010 abolished the 'two-tiered pricing' system for natural gas whose production began between 2006 and June 2010. Besides an increase of $0.93/MMBtu in the onshore wellhead price, the price range for onshore gas was expanded to allow producers and buyers to fix various natural gas prices based on ex-plant benchmark prices and to raise or lower benchmark prices by up to 10%.

5) The 2011 reform

The fifth stage of the evolution of gas pricing regulation was towards netback pricing. Fragmented and uneven pricing regulation had created tensions among producers and distributors and posed challenges to encouraging more investment in production and infrastructure to meet demand as well as improve market access and connectivity between regions. Price adjustment had not caught up with rampant demand, which was growing at 20% annually, or the diversification of supplies. There was increasing need to reduce financial losses as a result of the difference between the domestic city-gate price and the Turkmen pipeline import price as well as to accommodate future imports. In December 2011, gas price reform introduced a netback pricing system, establishing one city gate price ceiling for each province, applying to all onshore piped gas supplies (LNG and unconventional gas are excluded), regardless of source or end use. Trials were launched in Guangdong and Guangxi provinces with the aim of eventually introducing such a system nationwide.

The new pricing system is in stark contrast to the cost-plus system as it moves the pricing point downstream from the wellhead to city gate. While under the cost-plus system prices are based on production costs, city-gate prices are linked to market-determined oil-product prices (substitutable for gas). Taking into account the direction of major gas resource flows and transmission tariffs, the Shanghai city-gate price was selected to serve as the national city-gate benchmark price. This national city-gate benchmark price is linked to the prices of fuel and LPG weighted 60% and 40%, respectively. A price setting formula is:

[10] Tier 1 comprises gas produced at the Chuanyu gas field, the Changqing and Qinghai oil fields and associated gas from the Xinjiang, Dagang, Liaohe and Zhongyuan oil fieldsIt accounts for 85% of total domestic gas production. Gas produced at all other fields is categorized as Tier 2.

$$P_{gas} = K \times (\alpha \times P_{\text{fuel oil}} \times \frac{H_{gas}}{H_{\text{fuel oil}}} + \beta \times P_{LPG} \times \frac{H_{gas}}{H_{LPG}}) \times (1+R)$$

P_{gas} — Natural gas city-gate price (inclusive of taxes) in Rmb/cm
K— Discount rate (0.9)
α, β— Weighted percentage of fuel oil and LPG (60% and 40%, respectively)
$P_{fuel\ oil}$, P_{LPG} — Import price during the period in Rmb/kg
$H_{fuel\ oil}$,H_{LPG}、H_{gas} — Heat content of fuel oil, LPG and natural gas (10,000 Mcal/kg, 12,000 Mcal/kg, and 8,000 Mcal/kg, respectively)
R— Natural gas VAT rate (13%)

City-gate prices in Guangdong and Guangxi are based on the 'Shanghai-hub price', which takes into account gas flows and transmission tariffs as well as social affordability in the two provinces with a 10% discount against a weighted-average of imported fuel oil (60%) and LPG (40%).

The 2013 reform and beyond

The move towards establishing a dynamic pricing adjustment mechanism that reflects gas-market fundamentals and resource scarcity through linkage to the prices of alternative fuels was further modified in June 2013 by the NDRC in acknowledgement of the huge annual growth of incremental demand and its adverse fiscal impact. It announced the extension of the 2011 trial reform to 29 provinces and municipalities out of a total of 33. More important, tiered pricing for existing (2012) gas (91% of the total volume in 2012) and incremental gas (in excess of the 2012 volume) was introduced (excluding residential use).

Under the new pricing regime, each province will have two city-gate price ceilings: one that applies to new (incremental) gas for non-residential users and the other to existing gas. For existing gas for non-residential use, the increase will be no more than Rmb 0.4/m³ ($1.6/MMBtu) and for gas used to produce fertilizers it will not exceed Rmb 0.25/m³ ($1/MMBtu). For incremental gas, the price will be set at 85% of the import cost of alternative fuels (60% for fuel oil and 40% for LPG). The goal is to increase gradually the price of existing gas so that it eventually equals that of incremental gas. The NDRC has stressed that these prices will converge by the end of 2015. Currently, the price ceiling for incremental gas is on average 40% higher than that of existing gas though there is great variation across and within regions.

Provincial city-gate price ceilings are higher under this latest reform than under the 2011 reform. The new tiered measures are recognized as transitory and the intention is to introduce netback pricing nationwide for both existing and incremental gas use and target sectors that are more able to pay. At the same time, it should be noted that tiered pricing for the residential sector has been implemented in various cities since 2012 with considerable success and a deadline for nationwide implementation has been set by NDRC (on 21 March, 2014) for the end of 2015[11]. Residential tiered gas pricing implementation plans are gaining momentum in several munitipalities and provinces such as Shanghai, Zhejiang and Shandong in 2014. If used on a larger scale, tiered pricing would enhance efficiency, reduce cross-subsidies and improve distribution margins, thereby promoting a more sustainable downstream market.

[11] Climate and temperature vary significantly from region to region in China, which means diverse gas use in the residential sector. For example, residents in northern China use far larger volumes of gas for heating than do residents in the south of country.

However, a successful pricing reform would need to include policies aimed at encouraging investment along the entire value chain and regulatory changes to allow increased participation of suppliers and traders in the upstream and mid-stream, thereby better reflecting market signals and creating more supply liquidity. As the implementation of the current net-back pricing model gathers momentum and gas pipeline connectivity accelerates, prices for each province could start to be developed on a 'differential cost of supply' basis, provided third party access, storage and their charges are developed and regulated effectively. This would be the point where China might gradually move to hub-based pricing (at least for a portion of its supplies and facilitated by regional exchanges) in order to allow gas to go to regions that have the highest demand and are most able to pay. In this way, the pricing system could also reflect price of alternatives other than oil products. This, however, would depend on the price and industry reforms of other fuels such as coal and electricity.

2.3 Regional variations in market fundamentals and pricing reform

There are huge variations in price levels and reform experience across regions[12] in China as it consists of a set of regional markets, with different abilities to pay netback gas prices and different fundamentals. The coastal and central regions combined account for 60% of national gas demand, while the western region produces 60% of national gas supply. A diverse range of factors – including production costs, accessibility and transport route, sectoral needs, local-government priorities and economic affordability – all have a potential impact on pricing reform. Besides taking into account the enormous regional differences in resource endowment and development needs, policymakers need to strike a balance between providing affordable gas to encourage penetration and setting attractive prices that will serve as an incentive for more domestic production and higher import levels.

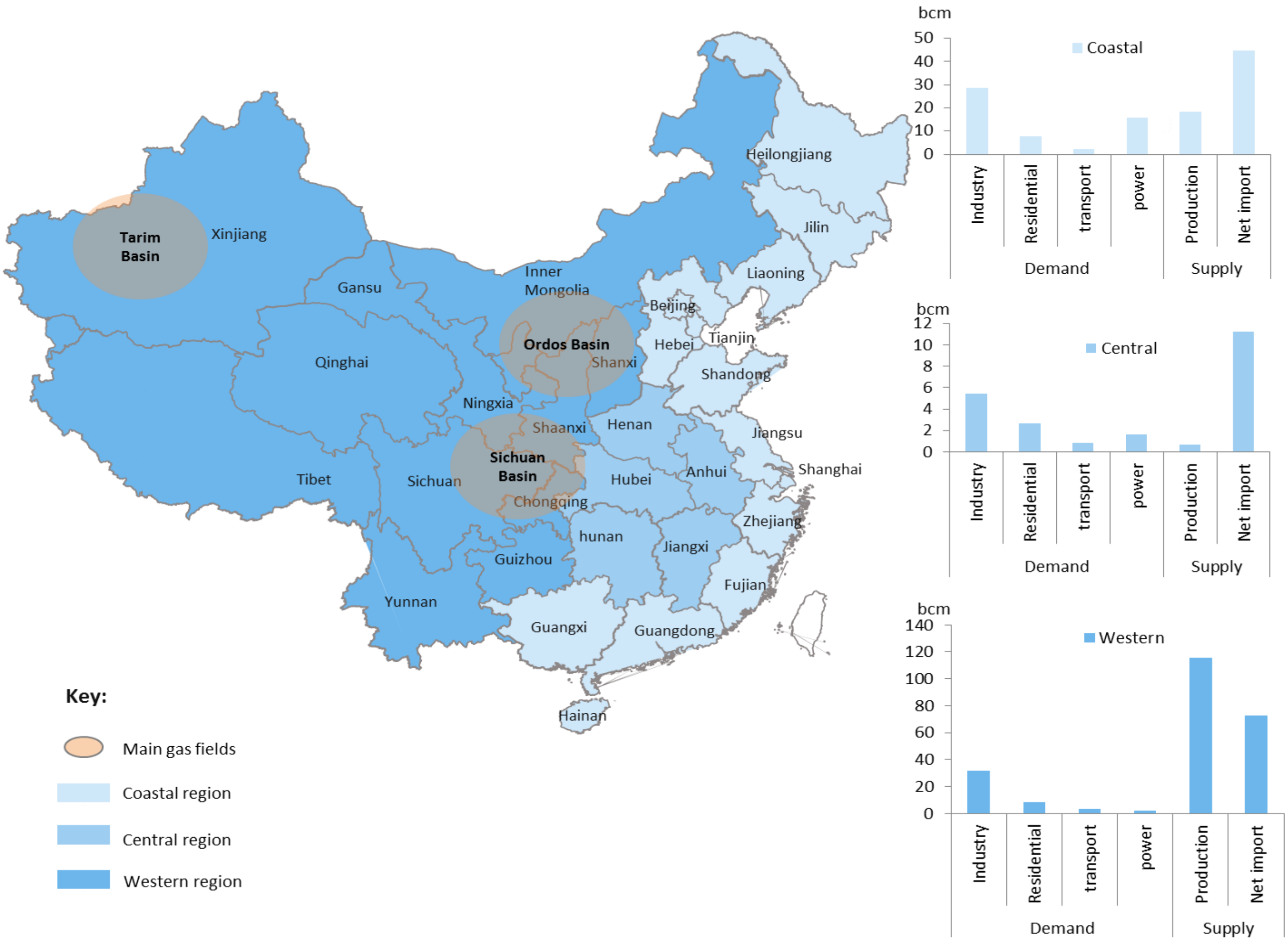
Figure 5 below shows the variations in sectoral gas demand and net gas imports position across three regions in 2011. Industry and power combined account for more than 70% of the coastal region's gas consumption (46% and 25%, respectively), while residential users make up 12% in the coastal region compared with 22% in the central region. In the coastal provinces that are located above the Yangtse River[13], which are classified as 'cold' and 'severely cold' heating zones (where heating is required by law), heating accounts for around 7% of aggregate gas demand compared with a national average of 2%. In the central region (where mostly hot summer, cold winter weather), industry (45%), residential (22%) and power-sector (13%) usage accounts for more than 80% of gas consumption. On the other hand, industry (61%), residential (16%) and transport (6%) uses of gas account for the majority of gas consumption in western region (cold and severe cold weather).

The western region is a net exporter of gas to the central and coastal provinces: on average, it exports more than 60% of indigenous supplies, although some provinces in the region import from Central Asia, Myanmar or neighbouring provinces. It has China's three top-producing basins – Ordos, Sichuan and Tarim – which accounted for almost 60% of national gas production in 2012. The central region imports almost 100% of its gas supplies from the western region and is a transit corridor for Central Asian and western-region gas to the coast. The coastal region imports more than 70% of the gas it consumes.

[12] Regions can be classified in various ways – for example, based on similarities in sectoral demand and economic development status. Such an approach is aimed at helping identify major regional differences; however, it could overlook some variations.

[13] Namely, Shandong, Hebei, Beijing, Tianjin, Liaoning, Jilin and Heilongjiang.

Figure 5: Sectoral gas demand across the regions, 2011



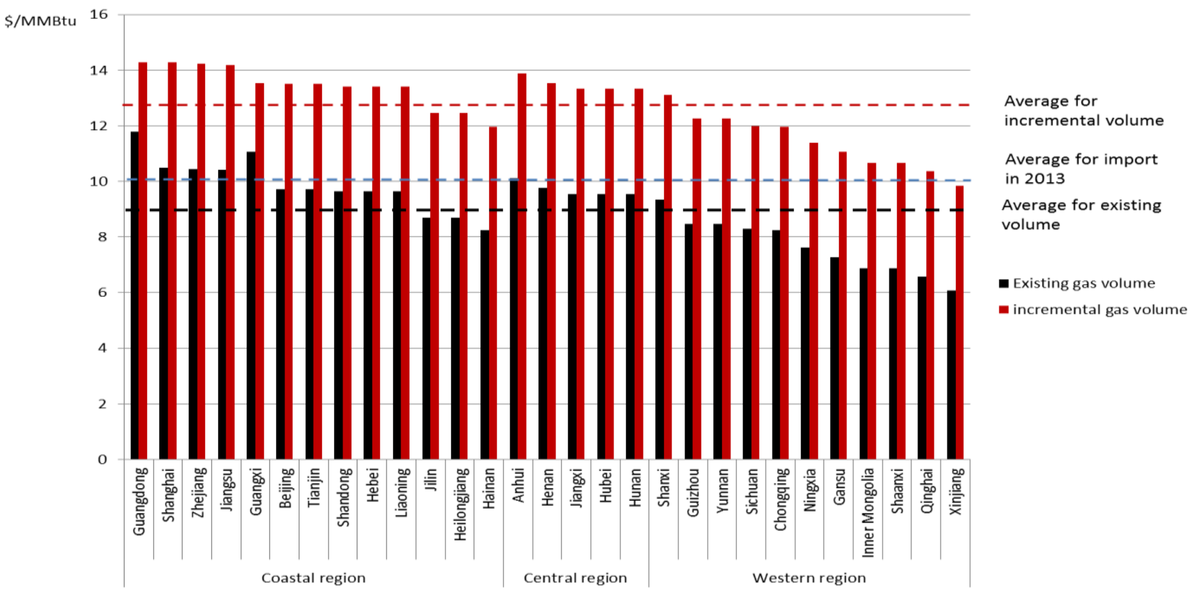
Source: CEIC

These enormous variations in demand and complex dynamics of gas flows imply that gas pricing is determined primarily by regional dynamics, which depend to a large extent on indigenous characteristics, market structure, type of industry and sustainability plans, among other factors. Sectoral emphases will differ across regions when gas policy and pricing reform and energy supply options (e.g., fuel mix and transit routes) are being considered.

Coastal regions – especially those in the upper Yangtze River area – will continue to see growing demand for power and heating as the government is determined to replace all coal boilers with cleaner fuel such as gas by 2017 (which will mean an increase in demand of close to 50 Bcm). The central region will continue to experience urbanization and industry relocation from the coastal region as well as a boom in residential and industrial use. The arrival of Central Asian gas and enhanced regional pipeline connectivity will improve access to gas. The price of gas for industrial users will need to remain competitive in order to facilitate the development of industry. The western region will drive demand for gas used in transport owing to the relative abundance of indigenous gas – as will the coastal region, where the oil and gas price differential is more pronounced. Provincial or regional pricing development will have to take these sectoral growth differences into account.

Figure 6 shows the variation across regions of the latest pricing ceilings set by NDRC for city gate prices which are highly dependent on distance from the gas source and the availability of gas besides price of fuel oil and LPG. In most western provinces, except Shanxi, the gas price is below the national average as those provinces are, or are close to, major gas-producing areas (as well as being closer to pipeline import sources). In the central region, which is a junction of various gas pipelines, most city-gate prices are higher than the national average, while the price of incremental gas was higher than the average price of imports in 2013. The same applies to the coastal region, whose industrial development is more advanced and where the competition between gas and oil products is stronger than in the other two regions.

Figure 6: Provincial city-gate prices across the three main regions, July 2013

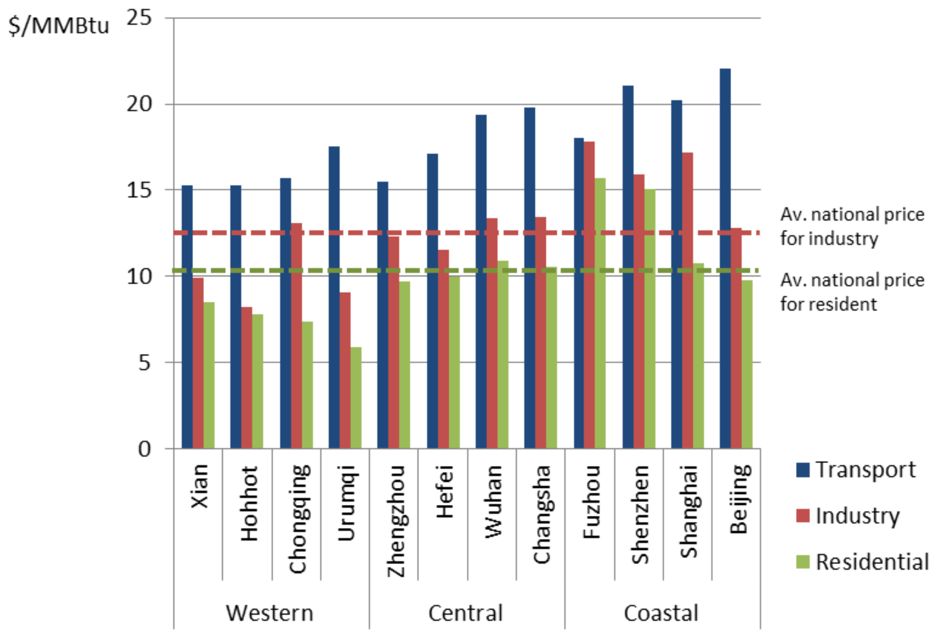


Note: The original announced price ceilings were denoted in RMB per cubic metre. Annual exchange rate for 2013 from the People's Bank of China and unit conversion factor for energy content (1 MMBtu=27 cubic metre) is used for conversion of the prices into US dollar per MMBtu. It should be noted that there is considerable variation in the value of energy content across gas fields in China and imports.

Source: NDRC (2013).

Similar trends are manifested in Figure 7 which shows the end use price across sector and three regions in 2013. Many cities in richer coastal region are paying a higher gas price (above national average) for industrial and residential users, while prices are higher in the central region than in the western region which is closer to gas sources. The price of gas used for transport in Beijing is 50% higher than in Xian (a western gas-producing region), while the residential gas price in coastal Fuzhou is close to three times that in Urumqi. At the same time, there are large differences within regions – the price of residential gas in Xian (in the western region) is 50% higher than in Urumqi. In general, it is in regions that are resource-constrained and more affluent that gas prices are higher and more closely linked to the prices of alternative fuels. Growing demand and affordability drive the average gas price higher.

Figure 7: End-user prices for the three main regions, 2013



Source: CNPC (2014), CEIC, author's calculation

The coastal region accounted for half of national consumption in 2011, while smaller demand centres accounted for the remainder. This situation could change as pipeline infrastructure is being rapidly developed. Table 1 below shows developments in gas pricing in the three main regions since the July 2013 nationwide pricing reform. There have been increases in non-residential city-gate prices – especially for industry and transport – in some provinces, although the speed with which they have been implemented and the extent to which they apply varies from province to province. Some southern coastal provinces and central provinces have already experimented successfully with tiered residential gas pricing while others are attempting to link wellhead to end-user prices. Moreover, on-grid tariffs for gas-fired power generators were increased in September 2013 in several coastal and central provinces to promote the use of gas in the fight against pollution. The recent rise in netback city-gate prices nationwide for incremental gas will introduce a degree of uniformity in pricing, thereby reducing regional price variations.

Table 1: Regional pricing developments since July 2013

Region	Province or municipality (% of national gas consumption)	Developments in gas pricing	Import dependency
Coastal	Beijing (6%)	July 2013 pricing reform adopted	100%
	Shandong (4%)	39% increase in price of incremental gas Business tax replaced by VAT on pipeline tariff	90%
	Jiangsu (7%)	Sichuan to Jiangsu pipeline tariff lowered Several cities (Nanjing, Xuzhou, Wuxi and Nantong) took a progressive approach to raising prices for the residential sector; On-grid tariff for gas-fired power plants hiked by 5% in 2013	99%
	Shanghai (4%)	Non-residential gas price adjusted; residential price hike by 21% in July 2014; to introduce residential tiered pricing Differentiated pricing for bulk industrial users and power companies continued On-grid tariff for gas-fired power plants hiked by 5% in 2013	95%
	Guangdong (9%)	Launched first netback trial and on-grid tariff for gas-fired power plants hikes by 5% in 2013	100%
Central	Henan (4.2%)	Most cities increased the non-residential price Tiered residential pricing implemented (with a view to eventually linking the residential price in effect to the wellhead price)	91%
	Hubei (2%)	10 cities raised the non-residential price On-grid tariff for gas-fired power plants hiked by 5% in 2013	100%

	Anhui (1.5%)	Link established between wellhead and end-user price	100%
Western	Sichuan (12%)	Unified provincial city-gate price of $8.5/MMBtu introduced (excluding residential gas, compressed natural gas [CNG] and gas for fertilizer industry)	36% of production exported to other provinces
	Chongqing (4%)	Non-residential prices adjusted – the biggest increase was for CNG (11.28%), while the CNG surcharge was abolished	54% (from other provinces)
	Shaanxi (5%)	One-step price increase introduced for incremental gas Pipeline and grid tariffs rationalized	77% of production exported to other provinces

Sources: Websites of various local pricing bureaus, CEIC.

2.4 Chinese gas price along value chains – A case study of Shanghai

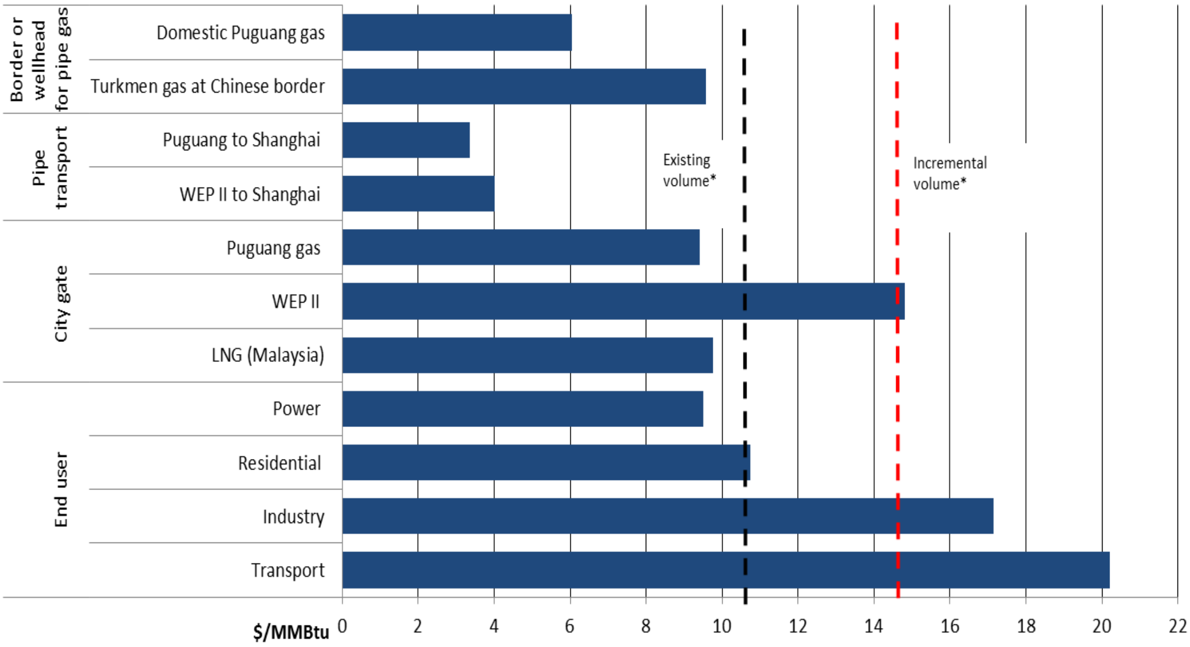
Figure 8 below shows the gas price along value chains to end-users in Shanghai, which was considered a national city-gate reference as it receives gas from diverse sources. The net-back city gate price ceiling for incremental gas set by NDRC in 2013 has substantially reduced the financial losses resulting from the sale of Turkmen gas (via West East Pipeline II, following transit across 11 provinces in China), which was previously sold at the city gate at the same price as more cheaply produced domestic gas (in this case, Puguang gas from Sichuan province) that is closer to Shanghai. Industrial and transport users, which accounted for 65%[14] of Shanghai's total final gas consumption in 2011, pay more than the new city gate price for incremental gas. On the other hand, the city gate price ceiling for existing gas after the price hike is close to that of residential end use price. On 2 July, 2014, the Shanghai government announced a 21% hike of residential gas price (subject to public hearing) as well as plans to introduce tiered pricing for residential gas use. This will reduce the risk[15] of losses on natural gas imports. Turkmen deliveries to Shanghai which are set to increase to 2 Bcm/year by 2015 are faced with stiff competition from diversified gas supplies, among others, long-term LNG supplies and domestic offshore gas (Pinghu gas) that will account for 43% of Shanghai's total gas supply in 2015 (Shanghai NDRC, 2011). Potential Russian gas arrival at Shanghai city gate towards 2020s could also compete with Central Asian supplies as the distance (henceforth transmission cost) between Chinese-Russian border to Shanghai is considerably shorter than that from Chinese border with Central Asian countries to Shanghai.

The latest increase in city-gate prices is expected to result in higher domestic wellhead prices and to increase somewhat the incentive for domestic upstream investment. This, in turn, will lead to a closer

[15] The risk is also lowered by the increase in proportion of industrial users of gas in Shanghai who have been paying higher prices in recent years.

linkage between the upstream and the market (although the local distribution margin will be squeezed).

Figure 8: Gas prices and tariffs along value chains to Shanghai, 2013



Note: The NDRC set the price ceilings for non-residential existing (2012 volume) and incremental gas (in excess of 2012 supply) for Shanghai on June 28, 2013.

Sources: China Customs Statistics, CEIC, NDRC.

3. The drivers for change and the gas-pricing challenges

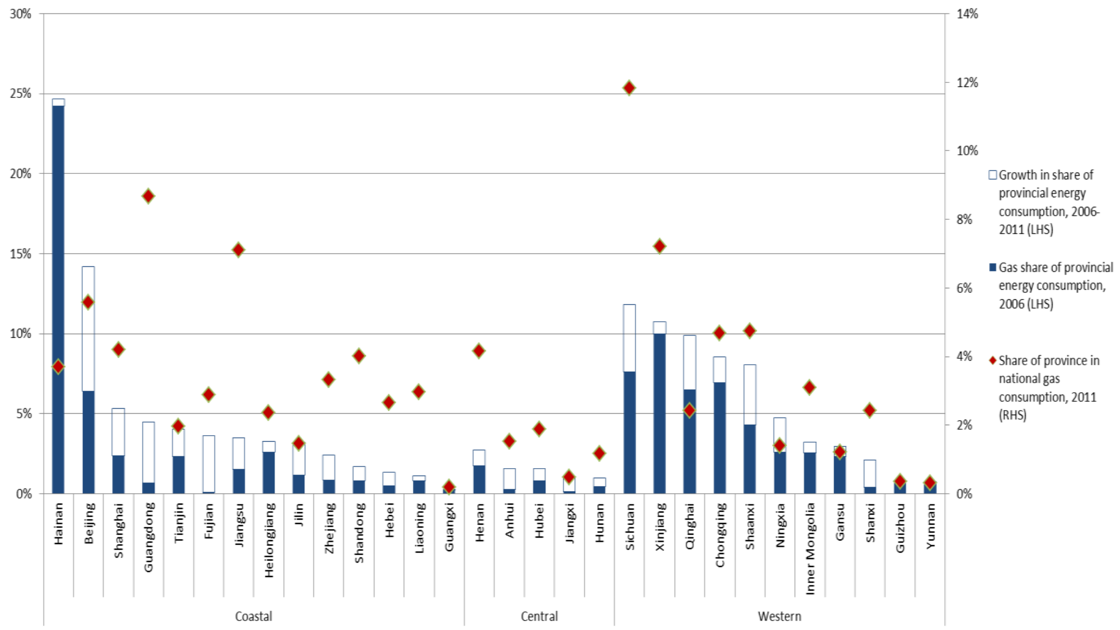
3.1 Key drivers

1) The growing importance of gas in the regions' energy mix

From 2006 to 2011 the share of gas in overall energy consumption rose in most provinces. Of the three main regions of China, the coastal region recorded the largest average annual increase – 2% (or 44 Bcm over the period). Within the region itself, the growing importance of gas varied significantly from province to province: Beijing took the lead with the share of gas in the city's total energy consumption more than doubling. The Western region recorded the second-largest increase in the share of gas in overall energy demand; its proximity to production centres and imports from Central Asia contributed to gas playing a larger role there. The Central region witnessed a more modest increase. However, with the arrival of pipeline gas via WEP II and WEP III, gas is set to play a bigger role in this region too as several provinces of the central region (e.g., Hubei and Jiangxi) are key transit points.

Figure 9 below shows that of the three main regions of China, the coastal region also saw the biggest increase in the share of national gas demand during the period 2006 – 2011. Combined with the central region, which recorded a marginal increase only, it accounted for 60% of national gas consumption in 2011, while the share of the western region declined from 53% to 40%. The top 10 gas-consuming provinces accounted for two-thirds of national gas demand; no less than half of these are located in the coastal region. However, despite the more than a 70 Bcm increase in overall gas consumption during this period, gas accounted for just 5.9% of China's total energy consumption in 2013. This means there is still huge potential for further increases in the share of gas in the local energy mix.

Figure 9: Growth of gas share of total provincial energy consumption, 2006-2011



Source: CEIC

2) The economics of gas across sector and region

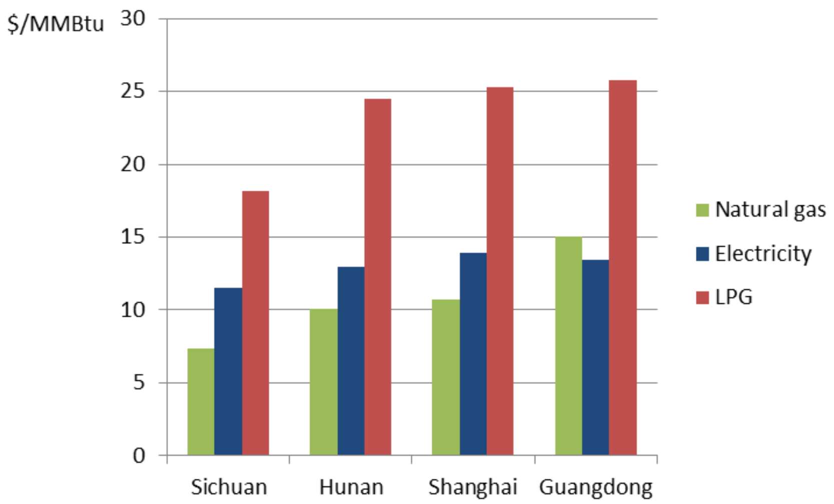
The economics of gas varies from sector to sector, although in all three regions gas is competitive vis-à-vis alternative fuels, except in the power sector. The price of gas used in transport and the commercial sector is the highest relative to other sectors. At the same time, increased inter-regional connectivity has improved local accessibility to gas and led to regional market interaction.

Residential gas pricing

Residential gas use accounts for 20% of total national gas demand. It has been boosted by the rapid development of the pipeline network, which enables more than 20 million urban residents to gain access to gas each year, and the recent campaign in the north of the country to replace coal boilers used for winter space heating. Price competitiveness vis-à-vis alternative fuels and the relative low share of gas bills in household expenditure and income, combined with improved connectivity and availability, point to the further rapid growth of residential gas use.

Figure 10 below shows that natural gas prices (on an energy equivalent basis) are much more competitive than those of LPG and electricity (the dominant fuels) in the Chinese residential sector; the exception is Guangdong, where gas is the primary fuel for power generation. Robust income growth targets in the 12th Five-Year Plan and the low share of gas expenditure in disposable income reinforce arguments about its affordability. In the long term, the residential gas price in China is expected to follow the experience of OECD countries since it currently remains higher than the industrial gas price. Tiered residential gas pricing is being tested in some coastal and central provinces as the solution to rationalize demand. Residents in southern China use gas mainly for cooking and water heating; their annual consumption is lower than that of residents in the north of the country, who use gas mainly for space heating. The impact of tiered pricing would be lower on residents in southern China as annual consumption per household falls below the first tier (600 cm). In acknowledgement of the constraints, the NDRC announced on March 22, 2014 that residential tiered gas pricing will be implemented nationwide by the end of 2015 (a price ratio of 1:1.2:1.5 for the three tiers).

Figure 10: Residential fuel prices across four major provinces/municipalities, 2013

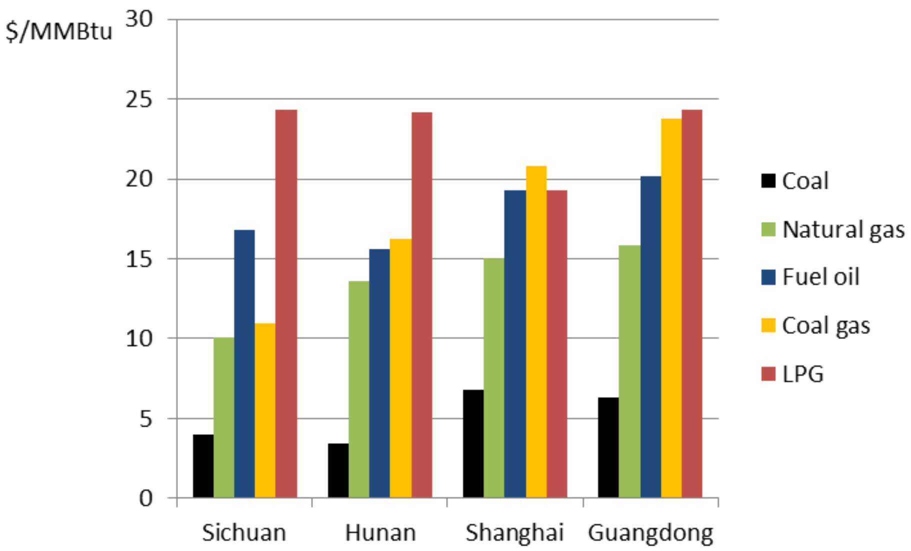


Sources: CEIC, CNPC, author's calculations.

Industrial gas pricing

On average, industrial gas prices are 30% higher than residential prices and 9% lower than those for transport. Although industrial gas use has declined from 55% of total gas consumption in 2000 to 43% in 2012, volumes more than tripled from 19 Bcm to over 60 Bcm during the same period. Several provincial governments are promoting the replacement of coal and oil by gas. As infrastructure construction accelerates and local emission reduction policy is implemented, industrial gas demand is expected to remain robust. The average tariff for industry in 36 major Chinese cities was $14.3/MMBtu in 2013. Fuel prices for industrial users of coal gas, fuel oil, coal, LPG and gas in four major provinces/municipalities show that gas is very competitive against coal gas, fuel oil and LPG (see Figure 11). Industrial gas users are those that require clean and controllable industrial process heat such as glass and ceramics manufacturers. The western and coastal regions (especially in southern China) have taken the lead in replacing oil products with gas in industry (which accounts for more than 60% of total final consumption), although the price of gas is higher in the coastal region than in the western. Post-2013 price increases are affecting the western region more than the coastal one, which was already paying prices above the national average.

Figure 11: Fuel prices for industrial users across four major provinces/municipalities, 2013



Sources: CEIC, CNPC, author's calculations.

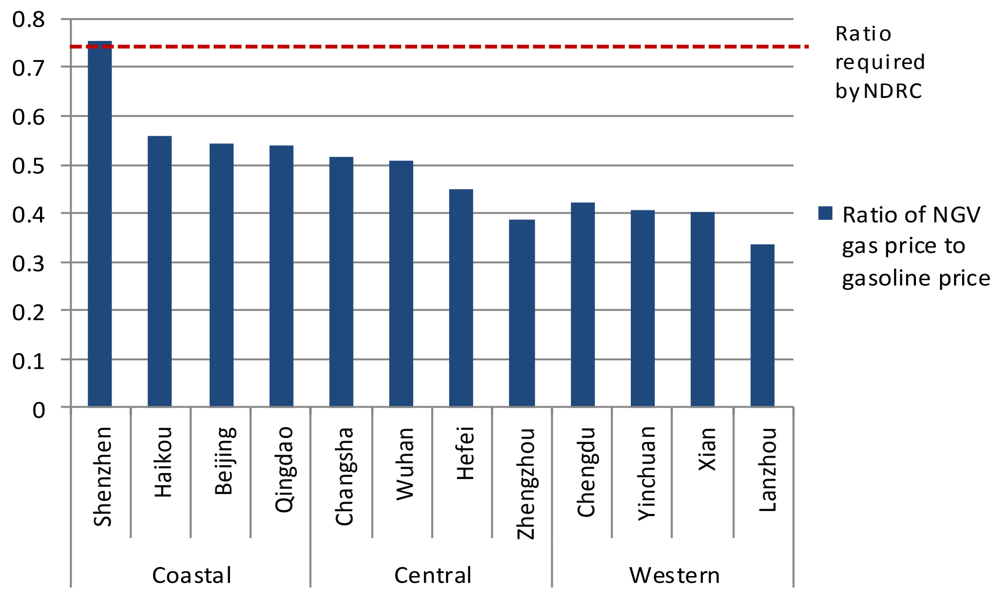
Adjustments in city-gate prices for commercial and industrial gas users are normally passed through to end-users relatively quickly. For residential users, the pass-through can be more gradual as it is subject to a public hearing review process.

Transport gas pricing

Despite natural gas vehicle (NGV) owners having to pay the highest gas price of all end-users, China's NGV fleet has grown from 693,000 in 2004 to around 1.8 million in 2013 (the majority of those vehicles run on CNG). Gas use in transport accounts for around 13% (or 21.2 Bcm) of total gas consumption, not least thanks to the government's gas-use policy (especially its subsidy for LNG trucks), zero VAT on transport gas, favourable oil and gas price differentials and the rapid growth of natural gas refuelling stations. Western provinces such as Xinjiang and Sichuan combined have the largest NGV fleets (84%) as they are close to domestic gas production centres and have the lowest ratio of the NGV gas price to that of gasoline.

Figure 12 below shows that in general, the average ratio of NGV gas prices to gasoline prices is highest in the coastal region – 60% (of the gasoline price), compared with 47% in the central region and 38% in the gas-producing western region. Thanks to gas grid connectivity and the availability of supply, NGVs and gas stations are no longer based only in the gas-rich western region but are spreading eastwards. The coastal region now accounts for 12% of the overall NGV fleet; the number of natural gas filling stations multiplied rapidly in Shandong[16], Hainan, Jilin, Hebei and Guangdong in 2013. Even if the NGV gas price is raised to 75% of the gasoline (retail) price – which is the ratio required by the NDRC in a May 2010 directive– natural gas will still be cheaper than alternative fuels for transport.

Figure 12: Ratio of NGV gas price to gasoline price across major provinces/municipalities, 2013



Source: CEIC, CNPC, author's calculation

Power-sector gas pricing

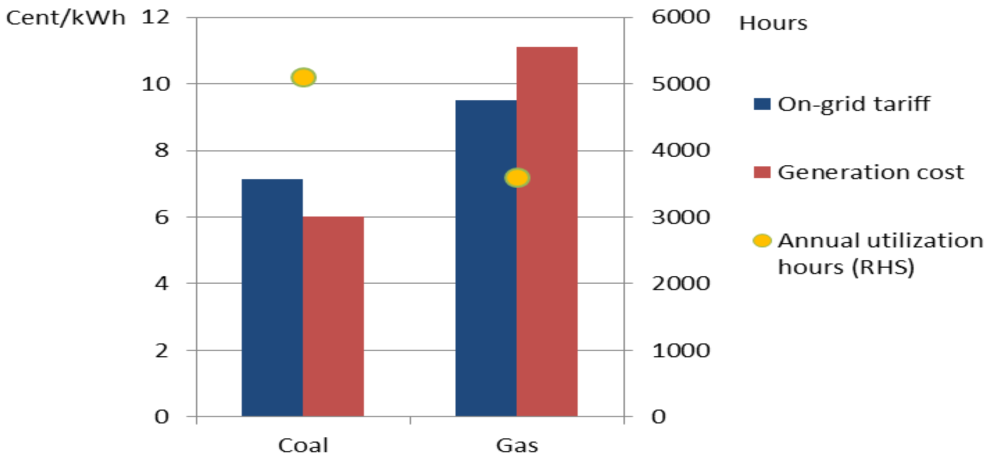
Gas use in the power sector increased from 1 Bcm to 30.2 Bcm from 2000 to 2013, accounting for 18% of total gas consumption at the end of that period (CNPC, 2013). Gas-fired power plants accounted for 3.3% (or 41.5 GW) of total installed capacity in 2013, which is a much smaller share than in most OECD countries. As noted above, under the 12th Five-Year Plan for the power industry, gas-fired power capacity is set to reach 60 GW, by 2015. Gas policy guidelines issued in 2012 placed gas-fired combined heat and power (CHP) plants in the 'prioritized' category, which could improve the capacity factors of combined cycle gas turbine (CCGT) plants. Currently, gas-fired power plants are located mainly in the more affluent coastal regions, primarily for peak shaving; for example,

[16] Shandong is well supplied by indigenous gas from the Shengli and Zhongyuan fields as well as by imports via WEP I from Xinjiang. More than 100 new CNG refuelling station were opened in the province in 2012 alone.

Guangdong province (Pearl River Delta) and Shanghai (Yangtze River Delta) had a combined 16 GW of installed gas-fired power capacity. Meanwhile, some central provinces, such as Hubei, have been promoting power-sector gas use too.

Besides the high construction costs of CCGT plants and the lack of continuity of supply, the development of gas-fired power plants continues to be constrained by cost competitiveness vis-à-vis coal and the highly regulated electricity market (see Figure 13). The on-grid tariff for coal-fired generation is 25% lower than that for gas-fired generation, while the utilization rate is significantly less than 4,000 hours for gas-fired power plants and more than 5,000 hours for coal-fired power plants. However, some coastal provinces provide incentives to gas-fired plants in order to help them improve their competitiveness in peak shaving, which has proved crucial in recent years owing to higher seasonal demand; for example, the gas price for power plants is set at around 20% lower than that for industry. Meanwhile, in October 2013, the on-grid tariff for gas-fired power plants increased by 5% to take into account the relatively higher fuel-related cost of generation.

Figure 13: Coal- and gas-fired power plants: tariffs, generation costs and utilization hours, 2013



Source: China Electricity Council.

With its higher purchasing power, the coastal region is expected to remain the key driver of gas use in the power sector as the coastal provinces gain improved access to supply and take advantage of the decline in capital expenditure of gas plants (due to indigenous gas-fired equipment manufacturing) and stricter environmental regulations to combat pollution. The ability to procure relatively cheaper imports and the establishment of a more flexible fuel price pass-through mechanism are key to the sustainable use of gas in the power sector. Experiments with tiered residential electricity pricing have been undertaken in several provinces; such pricing regimes could improve the economics of gas-fired power plants.

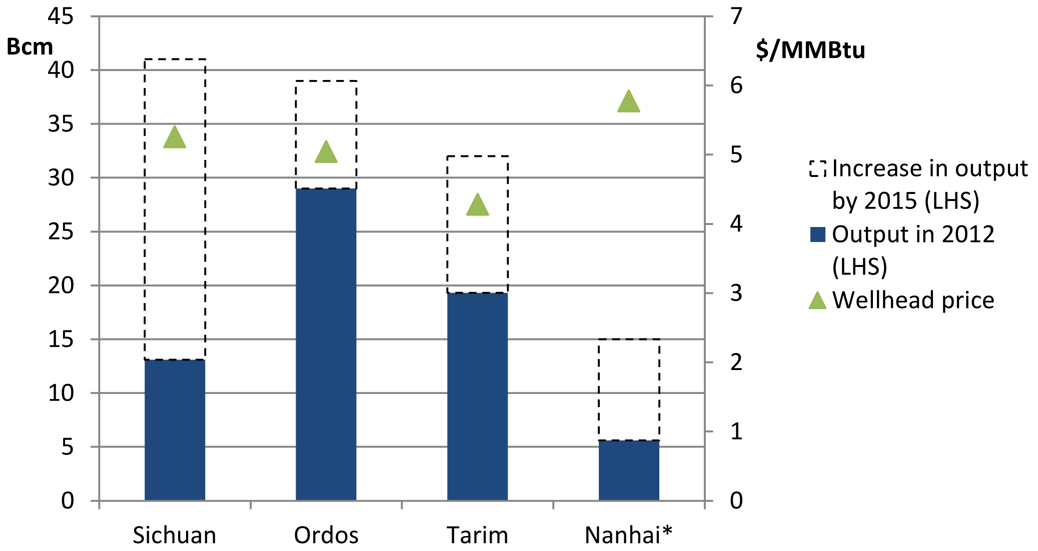
3) Impact of the cost of domestic production and the supply prospect

The 12th Five-Year Plan for the gas industry foresees a substantial increase in production in China's major gas-producing basins by 2015. Figure 14 below shows the four major gas-producing regions, whose combined production totalled 67 Bcm or 62% of total domestic output in 2012 and its production capacity is expected to increase to 127 Bcm by 2015. The average wellhead price of gas in the Sichuan basin, which is expected to record the largest increase in production, is higher than in the Ordos and Tarim basins and slightly lower than in the Nanhai deep-water gas basin. With the development of unconventional gas, an increase in the wellhead price is expected as an incentive for upstream investment.

The growth and range of the costs of domestic production will affect not only the development of imports but also the speed with which regional gas pricing reform is implemented and the extent of the reform. In recent years Ordos, which is China's second-largest sedimentary basin (with 11 Tcm of proven reserves) and includes Sulige, the largest gas field in China (producing 13.5 Bcm/y), has become a hub for gas supply and transport especially to northern China via Shaan-Jing (30.3 Bcm of capacity) and the West-East Pipelines in recent years. The average wellhead price in Ordos, combined with the region's ability to attract more supplies, will have a strong influence on gas pricing reform in northern China as well as on import negotiations.

Both the commercialization of unconventional gas at Sinopec's Fuling block, where horizontal wells produce an average of 150,000 cm/d of shale gas, and the earlier successful commercialization of CNPC's three shale blocks (average daily production of around 100,000 cm) have rekindled hopes for increasing the availability of competitive domestic unconventional gas. However, there are enormous challenges – such as complex geology, the high cost of initial wells, the relatively long drilling time for wells and acreage ownership issues – to overcome if the economics of domestic shale gas is to improve. Other problems include water shortages and lack of third party access to infrastructure.

Figure 14: Output and wellhead prices at the major gas basins



*Nanhai's production is based on 2011 CNPC data

Source: NDRC, CNPC

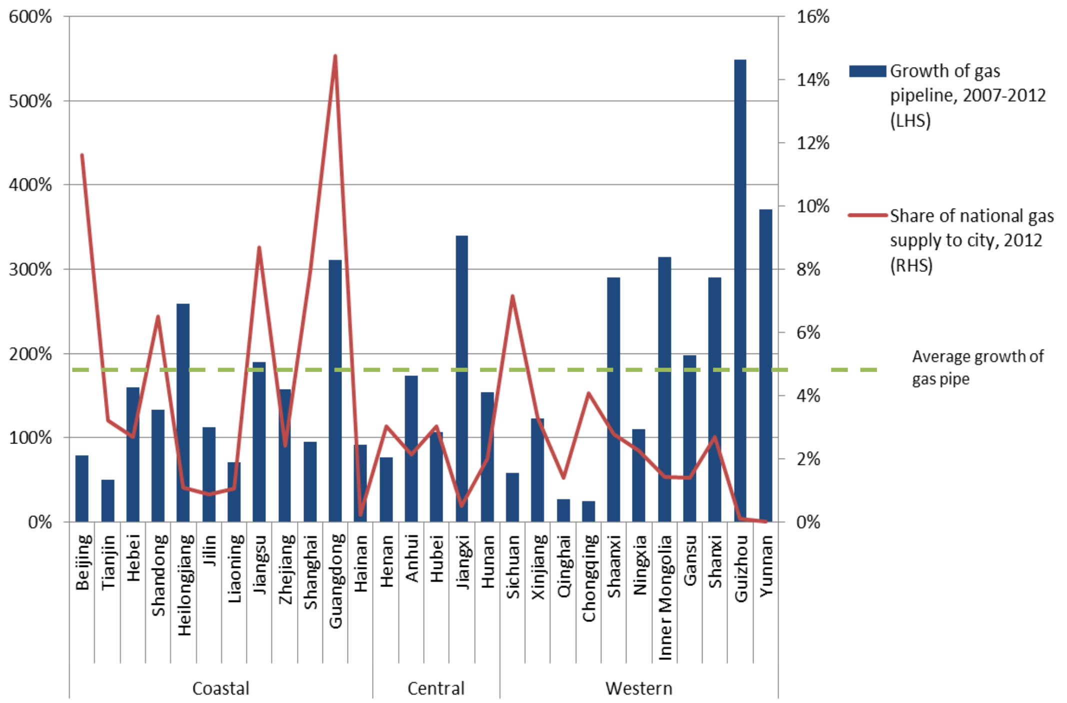
4) Transport, transit and gas supplies to cities

In 2012 the coastal region accounted for the largest share of national gas supplies to cities (61%), while western and central regions accounted for 27% and 11%, respectively (see Figure 15 below). During the period 2007 – 2012, the central region recorded the second-largest average growth of the gas pipeline network17 (171%), after the western region (214%). Gas penetration in the residential

[17] In 2012 the coastal region had the highest share of gas pipelines (58%), while the central and western regions accounted for 17% and 22%, respectively.

and commercial sector has been accelerated by both long-distance inter-regional transmission and the development of the local distribution pipeline network, as a result of which 210 million urban residents had access to gas in 2013. This shows the government is on track to meet its gas penetration target of 250 million people – or 18% of the population – by 2015.

Figure 15: Growth of gas pipeline network across regions and share of national gas supply to cities



Source: CEIC

In key demand and transit provinces such as Guangdong, Jiangxi and Shandong, regional grids have expanded rapidly to allow gas imports to flow. The provinces that have recorded the fastest growth of the pipeline network and have the largest share of city-gas supply are Guangdong, Shandong and Jiangsu provinces in the coastal region, Sichuan province in the western region (where the pipeline network is more mature) and Hubei province in central region, which together account for more than one-third of China's gas consumption. They tend to be more active or advanced in implementing pricing reform than other provinces and have set price ceilings for incremental gas at around 10% above the national average (with the exception of Sichuan). In the future, there may be a trend towards increased convergence of prices among coastal provinces (especially as pipeline developments result in improved market connectivity), but inland provinces are likely to maintain discounted price levels.

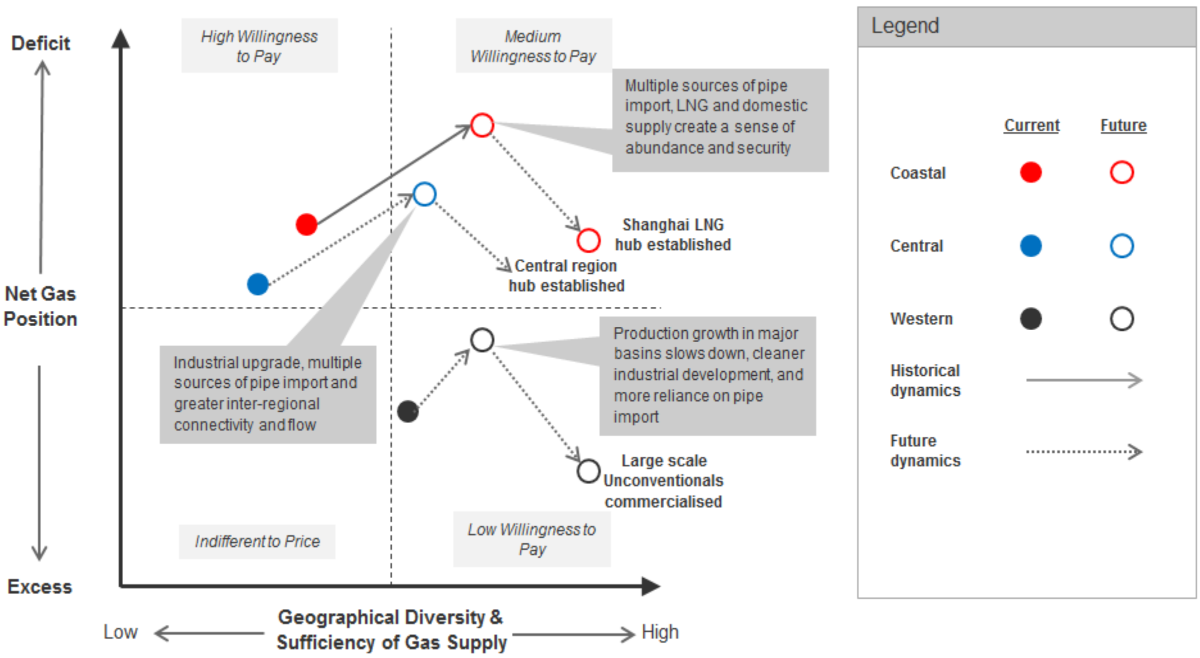
Meanwhile, there is growing regulatory emphasis on third-party access in a bid to break down the barriers between suppliers and markets. On 13 February 2014 the National Energy Administration unveiled the 'Administrative Measures on Opening up Fair Access to the Oil and Gas Pipeline'. Under those measures, pipeline operators are required to provide non-discriminatory third-party access whenever they have spare capacity; downstream distributors are allowed to negotiate directly with upstream suppliers over gas supply, while pipeline operators may provide only transmission services. Achieving third-party access will take time and require the huge investment in the pipeline network to be sustained, but it will eventually result in enhanced connectivity and improved mobility of gas supply. Downstream gas distributors will have more optionality and pricing will respond more to connectivity with regions that have greater access to diversified sources, thereby creating a more competitive provincial gas market. In addition, enhanced connectivity will help overcome the large price differentials between cities.

5) Relationship between reliance on gas and willingness/ability to pay

Of the three main regions, the coastal region is the most reliant on gas, importing either from neighbouring regions via pipeline, trucks or LNG imports. In addition, the coastal provinces are also the most willing to pay owing to their relatively large gas deficit and high level of GDP per capita. Over time, however, the region will develop greater diversity of supply and foster competition between supply sources. A gas trading hub around a coastal demand centre such as Shanghai would improve the liquidity of the coastal gas market and its security of supply, which could lead to less willingness to pay high prices. The central region is less willing than the coastal region to pay higher gas prices as it is closer to domestic gas sources and has an abundance of coal (accounting for 20% of national coal supplies in 2011), and therefore has lower city gas supply. However, its grid connectivity has been significantly enhanced and many of its major cities are key transit points for gas from Central Asia. As dependence on gas imports grows, the central region will seek other supply sources; and since it lies at the intersection of various gas import routes, it will be even less willing to pay higher prices which could be detrimental to its ambition to replace the coastal region as the industrial heartland of China. The formation of an inter-regional gas trading hub and storage build-up will be among the region's plans for attracting more liquidity of supply and hedging against local shortages.

As regards the western region, if production growth in the major basins slows and if industry becomes 'cleaner' as reliance on pipeline imports increases, its willingness to pay higher prices will grow. However, in the event of the large-scale commercialization of unconventional gas, the region would have more optionality and abundant supply would reduce its willingness to pay higher gas prices. Hence the ability of the various regions to increase optionality and improve liquidity could transform their gas position and impact on the price levels they are willing and able to pay (see Figure 16).

Figure 16: Dynamics of the relationship between regional reliance on gas, supply diversification and willingness to pay



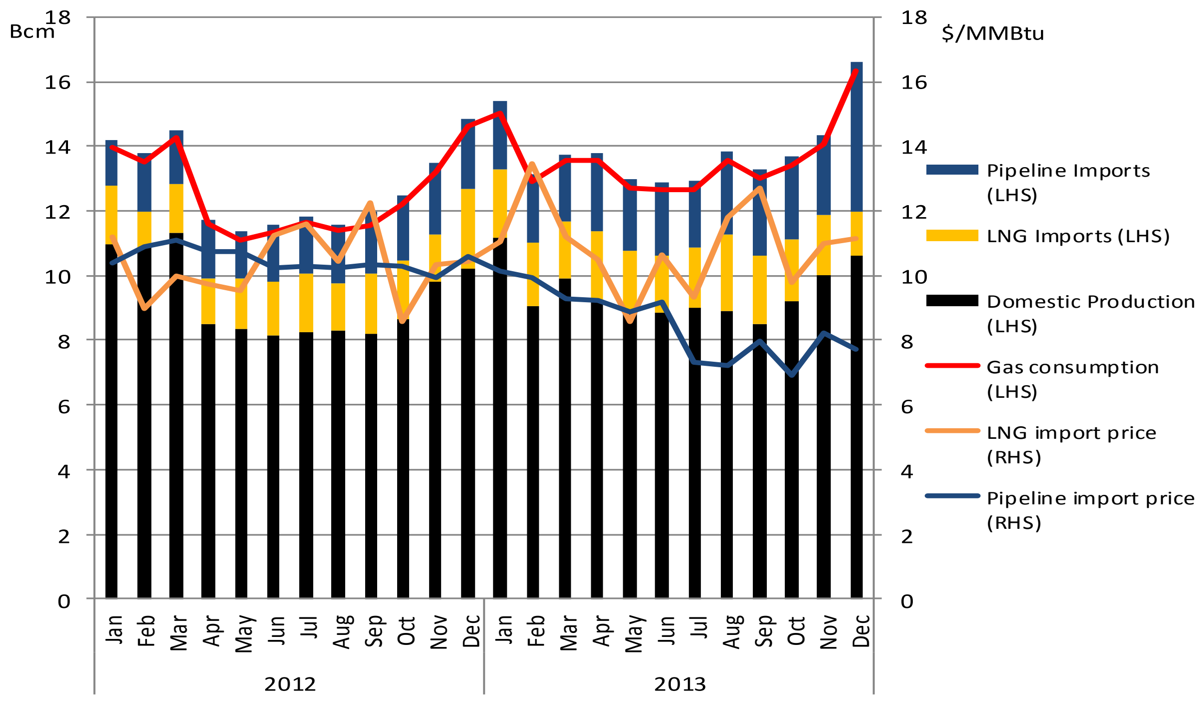
Source: author's analysis.

6) Impact of seasonality

Chinese gas demand is affected by seasonality across the various parts of the country. In the north, which has severely cold winters, domestic production is at its highest level in the first quarter of the year owing to the (gas) heating season. When the heating season starts in the fourth quarter, the shortage of storage facilities for peak shaving makes for a tight market; when it ends in the second quarter, gas consumption falls and market tightness eases (Figure 17). The hot summer in southern China – in particular, around the Yangtze River Delta and the Pearl River Delta – boosts demand for gas in the power sector, which results in a tight market and an increase in the LNG import price in the south. Beijing's peak gas consumption in winter is around 11 times higher than that in summer (boosted by a 50% increase in new gas boilers to reduce pollution), while the ratio is 3:1 for Shanghai and 2:1 for Chongqing (in the western region).

Growing demand for gas space heating and coal boiler replacement in the north, and the tremendous use of air conditioning in the summer (increasingly peak-shaved by gas-fired power plants) in the southeast (the coastal region) has increased the seasonality of gas demand, which, in turn, has driven demand for LNG spot cargos – especially in those locations where there is insufficient gas storage for peak shaving. Storage capacity was just 1.7% of total gas demand in 2012 – much lower than the global average of 12%. This could exert pressure on power and heating prices. Taking seasonality into account under the current pricing regime would serve as an incentive for developing storage, while an active regional hub would help the provinces react efficiently to shocks and improve their security of supply.

Figure 17: Seasonal demand and import prices, 2012 – 2013



Source: China customs statistics; CEIC

Gradual liberalisation of network access, combined with increased storage, will be fundamental to cater for the seasonality of gas demand and to establish a liquid gas trading hub that allows LNG to complement pipe gas more effectively.

7) Impact of environmental policy

In September 2013 the government set ambitious targets to reduce air pollution by 2017. For the first time, environmental rather than economic policy is driving energy policy through controlling coal consumption, developing de-nitrification facilities, phasing out obsolete industrial capacity and increasing clean-energy supplies. Responsibility for air quality has been shifted to local governments to ensure that the interests of central and local governments are aligned. In the three economically more developed coastal areas of Beijing-Tianjin-Hebei and Yangtze River Delta (in the east) and Pearl River Delta (in the south), which together accounted for 34% of China's gas consumption in 2011, PM2.5 is targeted to fall by 25%[18], 20% and 15%, respectively, by 2017 (compared with 2012 levels); all other cities must reduce the levels of PM10 by 10%.

At the same time, the share of coal in national primary energy supply is to be reduced from 70% in 2012 to 65% by 2017. These three regions need to reduce coal use and no new coal power plants should be built. Moreover, they need to phase out all small coal boilers[19] and speed up coal-to-gas conversion programmes. For Beijing-Tianjin-Hebei and Shandong, the target is to reduce total coal consumption by 85 million tonnes by 2017, which is equivalent to almost another 50 Bcm of gas demand. A number of provinces have signed agreements with the State Council on air pollution control and issued detailed action plans, which include capping or reducing coal consumption growth.

These postive moves will generate additional gas demand and encourage LNG imports as many of the coastal provinces have more aggressive pollution reduction targets. Some subsidies could be forthcoming in those provinces to promote coal-to-gas conversion, although their higher levels of GDP would allow them eventually to pay a more market-based price. The Western region, on the other hand, is becoming increasingly reliant on heavy industry and could find it more difficult to meet the target. More environmentally conscious provinces will tend to be more proactive in gas pricing reform as they recognize it as a means to attract cleaner energy for their development.

[18] PM2.5 can adversely affect human health. It is targeted to drop to 60 mcg/m³ in Beijing by 2017, down more than 25% compared with 2012, by 25% in Tianjin (20% by 2016 and another 5% in 2017) and by at least 30% in Hebei.

[19] Existing coal-fired boilers with 10 steam tonnes/hour capacity are to be phased out and the construction of new ones with 20 steam tonnes/hour prohibited by 2017. All coal-fired facilities of petrochemical companies are to be replaced by gas-fired ones or external electricity and/or steam supplies by 2017.

3.2 Major pricing-reform challenges

The transition from a cost-plus, wellhead controlled gas pricing regime to netback pricing that regulates city-gate prices indexed to alternative fuels (LPG and fuel oil) is a positive step towards i) developing more competitive gas markets with diverse sources of supply; ii) encouraging efficient investment along the gas value chain; and iii) establishing more effective regulation of pipeline imports, the volume of which has exceeded that of LNG imports since 2011. The netback approach is similar to oil-product pricing controls implemented by the government whereby a price ceiling is set at the provincial city gate [20].

Despite the progress to date in pricing reform, some key challenges remain, and these could compromise the effectiveness of netback pricing:

Lack of a clear frequent review. There is no published guideline for the frequency of price reviews which spells unpredictability and a price risk for gas importers that have oil-indexed contracts subject to regular price adjustments. Regular price adjustments in response to market changes in the coming years could help establish more transparency and ensure prices remain competitive.

Overriding socio-economic concerns. In principle, tight control over gas pricing helps the NDRC to control inflation and price expectations, which is a top socio-economic priority. In the July 2013 reform, it was decided that there would be no city-gate price change for residential users; this will determine the degree to which the pilot gas pricing formula is indexed to alternative fuels. Cross subsidies from other sectors to the residential sector will need to continue though this is mitigated by current active planning and implementation of residential tiered price reform across regions. Some gas projects planned for industry have been switched to coal owing to the uncompetitive price of gas, despite the fact that both the pipeline-construction and gas-use operating costs for industry are lower than for the residential sector. Besides distorting gas resource allocation and encouraging inefficient use of gas, this could result in an ever-growing fiscal burden for the government and/or companies. It could also cause demand destruction in industry and the transport sector owing to gas prices increasing beyond economically viable levels, while a growth in residential demand owing to low prices for that sector would mean restricted gas access for industry and/or power generators and lower industrial output.

As we noted above, the NDRC recently announced tiered gas pricing for residents will be implemented nationwide by the end of 2015. The successful implementation of this policy will gradually rationalize residential gas consumption over time. Currently, less than 20% of households account for 40% of total residential gas consumption, while larger users receive bigger subsidies and exert pressure on winter peak shaving (NDRC, 2014).

Regulation and scope of pricing. In the case of oil products, the regulation of the end-user retail price is direct and effective. Because the range of natural gas users is more diverse than that of gasoline and diesel users, and because there are more types of private operator in downstream gas distribution than in the oil product segment, the central government has to compromise by regulating the wholesale price at the city gate rather than the end-user price, which is regulated by the local authority. As regards pricing beyond the city gate, the national and local pricing authorities need to improve coordination of provincial pipeline and city-gas distribution prices (as well as end-user prices) in order to avoid supply shortages and the excessive margin squeeze experienced by city gas distributors, partly owing to provincial grid's monopoly of wholesale gas supply. Finally, only onshore

[20] A key difference between the two mechanisms is that provincial gas price ceilings set by the NDRC are based on wholesale rather than retail prices.

conventional gas imports and indigenous production are included in the pricing exercise, leaving LNG import price regulation in the hands solely of local authorities. This could lead to the inefficient allocation and access of LNG, a growing fiscal burden from the widening differential between domestic and LNG import prices.

Storage costs. Storage sites are constructed as auxiliary facilities of pipelines, hence the cost of their construction is not factored into gas prices but into pipeline budgets (IEA, 2012). The current system favours companies with existing transmission assets since they are able to cross-subsidize the development of storage. Gas pricing needs to take investment in gas storage into account if seasonality volatility in pricing is to be effectively addressed and to mitigate the margin squeeze on city-gas distributors – who are forced to purchase more expensive gas but are unable to pass through the cost increase.

Alternatives. It is often argued that indexing to oil will only drive up prices and be difficult to implement in regions rich in alternative fuels, such as coal, which accounts for 70% of China's electricity generation. If the environmental cost of coal is not taken into account, it is difficult to effectively promote gas use in particularly for power generation unless unconventional gas is commercialised on a large scale before 2020.

Calorific value. Current domestic gas pricing is set on the basis of volume (Yuan/m³), not calorific value, though LNG and pipe imports are delivered and paid by calorific value ($/MMBtu). Increasing import dependence, diversified sources/type and transit routes of gas has created challenges for domestic gas distributors/end users which need to bind volume and heat quantity and check the calorific value of diverse distributed gas as it is also critical for their operational safety and efficiency[21]. Different quality of gas is being supplied into the pipeline at the same price, this is discriminatory against end users that use low calorific value gas. The differential in calorific value between gas from various sources[22] has affected the calculation, payment and procurement of imports and affected sales as gas import source diversified.

Underlying structural challenges

In addition, there are various structural constraints and competing interests that the authorities will need to balance in order for pricing reform to be effective:

1) **Upstream producer/supplier and, distributors (primarily provincial grid and city gas distributors).** Increases in the city-gate prices[23] may not always automatically generate a proportionate increase in gas supply, while the profit margins of downstream distributors have been squeezed as they cannot pass through the proportionate cost increase to end users. The central government is increasingly liberalizing the development of unconventional gas to increase supply. For their part, provinces are experimenting with indexing end-user prices to upstream and city gate price movements but have made only limited progress to date. However, this is changing

[21] For example, gas with different calorific value was fed into some gas turbine in Guangdong province. This is affecting the efficiency and life of turbine as well as safety. Current plan is to lock in gas source to resolve this issue.

[22] There is also large calorific value difference between domestic coal to gas, shale gas and CBM as well as conventional fields.

[23] The vertical integration of upstream producer and midstream supplier has bundled price for well-head and pipeline transmission tariff, making it difficult to account for relative change in the price of well-head and transmission once the city gate price is adjusted. This could also disincentivise upstream investment and production as upstream and midstream interests may not be in equilibrium. Recent CNPC's plan to inject its midstream assets from West East Pipeline I and II into East Pipeline company that allows private investors to hold stakes could be a positive step to unbundle well-head and pipeline transmission to improve industry efficiency.

with the introduction of residential tiered pricing and merger of prices of incremental and existing volumes by end-2015.

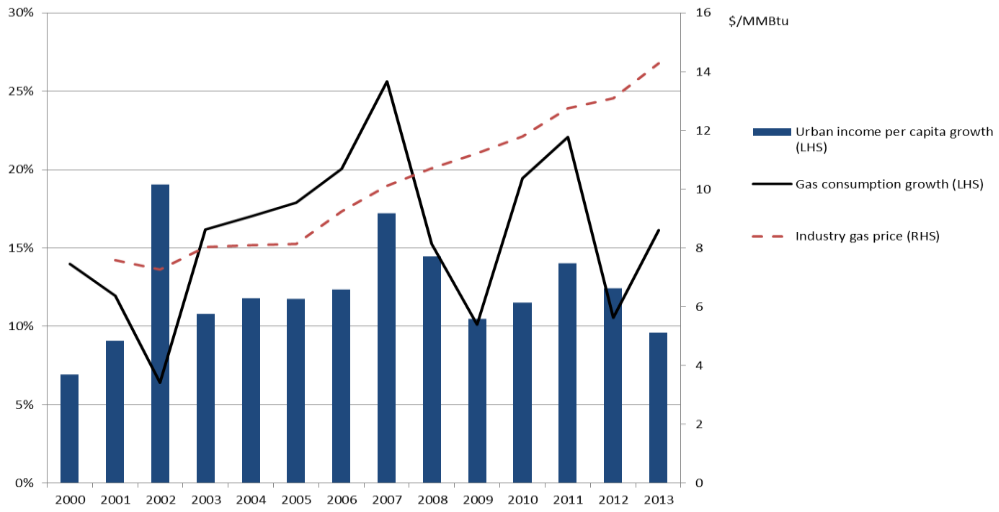
2) **Provincial grid companies and city-gas distributors.** So far, recent gas pricing reform has not been extended to pipeline, which is dominated by national oil companies and provincial grid companies that have to bear the cost of construction and maintenance. Insufficient competition in the inter and intra-provincial gas network and third party access has led to increases in the pipeline tariffs for city-gas distributors, substantially squeezing their margins. The next stage of gas market reform should focus, among other things, on growing accessible pipeline connectivity and supplier choice for end-consumers with effective pipeline tariff regulations that take into account more balanced interests of national oil companies, provincial grids and city-gas distributors and bulk industry users. A competitive mid-stream sector with third-party access would integrate and harmonize regional markets and send a strong signal to the market. However, structural reform of gas markets such as ''ownership unbundling''[24] has been traditionally complex and needs to be carefully assessed.

[24] It has been used to remove the conflict of interests and break down a broad series of barriers to cross border energy trade, investment and competition in EU by unbundling ownership of pipeline networks from gas suppliers. The barriers include the temptation of bundled groups to use their networks as a weapon against rival suppliers (Buchan, 2007)

4. Implications of pricing developments for gas demand

From 2000 to 2013 China's gas demand grew on average 1.4 times faster than urban income per capita, despite industrial gas price increases (Figure 18). Since the Chinese gas market is still suffering, above all, from supply and infrastructure constraints, additional latent demand could be unleashed once accessible connectivity is enhanced.

Figure 18: Growth of industrial gas price, gas consumption and urban income per capita, 2000 – 2013

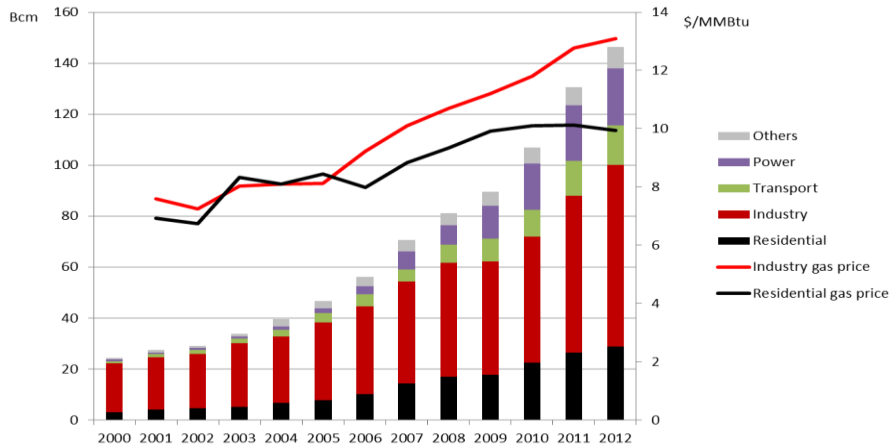


Source: CEIC

Implications for sectoral demand

From 2000 to 2012 industrial demand for gas grew four-fold. As a result, industry remains the largest end user (accounting for more than 40% of total consumption), despite the 170% increase in industrial gas prices during the same period. By contrast, residential demand increased nine-fold and accounted for 20% of total consumption, while the residential gas price increased at a slower rate. Gas demand in the power and transport sectors witnessed the largest growth (average annual growth rate exceeds 25%), albeit from a lower base. Subsidies for the power sector as well as the low gas-to-oil price ratio contributed to this substantial increase in demand (Figure 19).

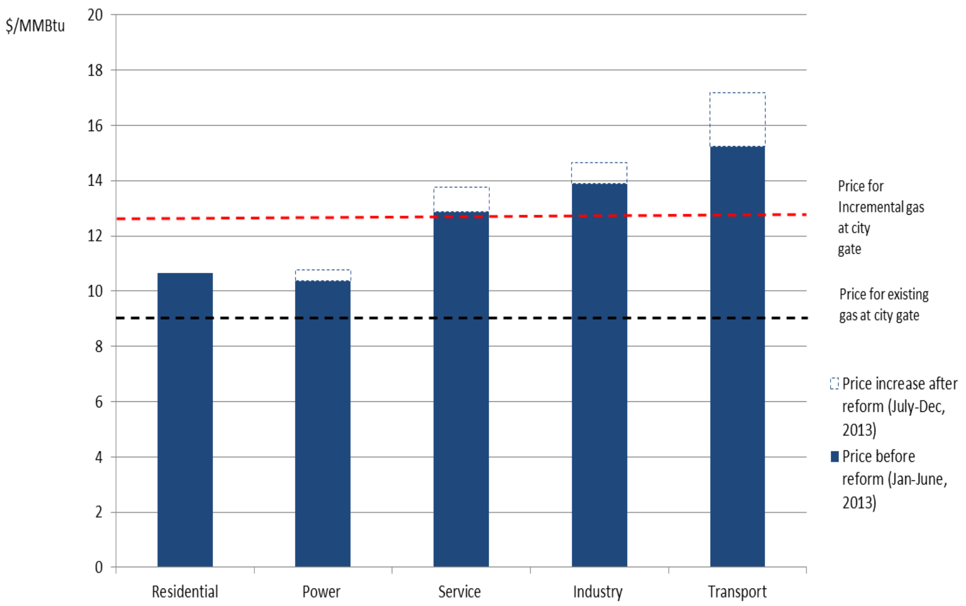
Figure 19: Sectoral gas demand and prices, 2000 – 2012



Source: CEIC

The 2013 price reform was aimed at eliminating inefficient industrial capacity, as well as narrowing the differential between domestic and import prices and providing an incentive for upstream investment. Although the price of incremental gas will be indexed to that of LPG and fuel oil, incremental gas demand accounted for just 9% of total demand in 2012; and the sectoral demand impact of price increases mainly affect the industrial sector. Because the reform is targeted at the non-residential sector, residential demand has not been affected though recent waves of local pricing reform and adoption of residential tiered pricing will have a significant impact on residential gas use. Cross-subsidization from the other sectors would continue, albeit potentially impacted by some demand destruction in those sectors in response to price increases and decline as residential tiered pricing rolls out. In 2013, several local governments have been making either one-step adjustments to the residential gas price (for example, Changchun, Handan, Tianjin and Suzhou, which on average have raised it by 15%) or progressive (tiered) adjustments (for example, Nanjing, Xuzhou, Wuxi and Nantong). Besides major coastal gas users such as Shanghai, Zhejiang and Jiangsu which are implementing residential tiered pricing, pricing reforms to further rationalize residential demand are expected in cities with large populations, relatively low residential gas prices and growing import dependency to meet the target of nationwide implementation of residential tiered pricing.

Figure 20: End-user price by sector and new city-gate price ceilings, 2013



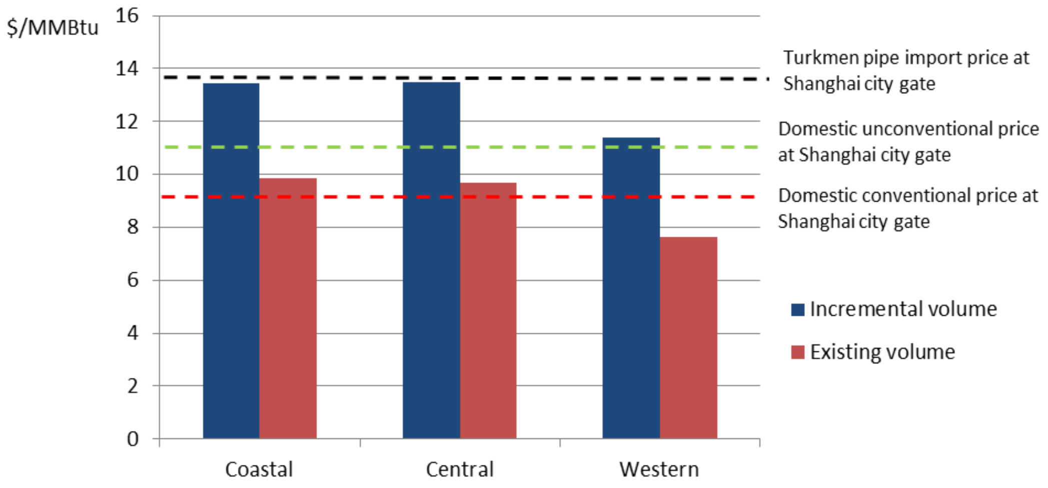
Source: CEIC, NDRC

More aggressive adjustment of industrial or transport prices is expected to continue as prices of existing and incremental supply are planned by NDRC to converge by the end of 2015. Figure 20 shows the average city-gate incremental gas price of $12.7/MMBtu will not have a substantial impact on transport demand as prices are still lower than those of gasoline or diesel and margins will be sufficient for distributors, though the narrowing of gas to oil product price ratio could deter some future demand as cost of retrofit is very sensitive to fuel economics. However, the increase may have destroyed some demand from price-sensitive industries – especially small and medium-sized companies. Some industry margin gains from oil product replacement have been eroded, and marketing gas to the power and heating sectors has become more difficult. In response, the government has increased on-grid tariffs for gas-fired generators. For this reason, gas pricing reform will increase pressure on local governments to push through power sector and tariff reforms.

Implications for regional demand

The July 2013 pricing reform implied a 15% increase in the average national city-gate price from $7.2/MMBtu to $8.4/MMBtu. The largest increase was in the central region, where gas demand has risen faster than in the other two main regions over the past three years. If the price realized at the city gate is close to the incremental gas price ceiling set by the NDRC, it implies that prices in eastern China could potentially increase to pipe import price parity, which would likely minimize losses on pipeline import contracts (Figure 21). Indeed, if the NOCs had been able to pass through the cost to provincial gas grid companies, the differential between the incremental gas price ceiling and pipeline imports from Central Asia at coastal city gates would have narrowed to 1% in 2013. The challenge, however, is to eliminate the 37% differential between the existing and incremental gas price by the end of 2015. Meanwhile, enhanced pipeline connectivity has eased shortages in some regions, while some end users have switched from trucked LNG ($17/MMBtu) to pipeline gas, which is more competitive and supplies of which are more reliable.

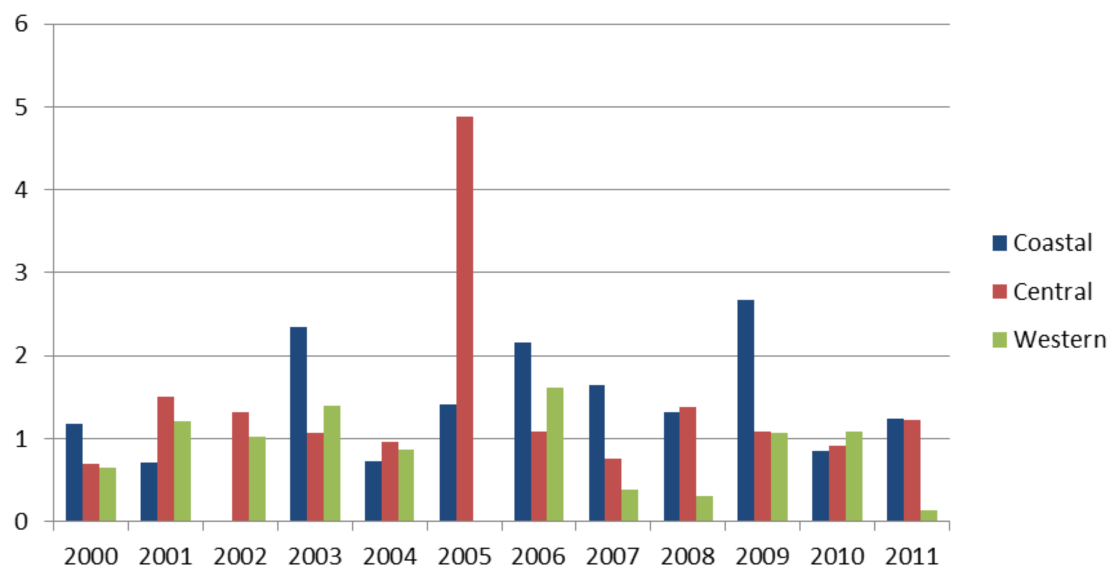
Figure 21: Regional city-gate price ceilings and delivered cost at coastal city gates, 2013



Source: China Customs of Statistics, NDRC, author's estimates

New city-gate prices will allow the central and coastal regions to utilize unconventional gas, should it be successfully commercialized. At the same time, there is also ample room for domestic conventional supply to achieve prices better than the current cost plus based price they have at the central and coastal city gates for existing gas. However, the price of existing gas in the western region still falls short of the average domestic conventional gas price at the city gate; this is because existing gas is one of the major fuel sources for production and must be lower to reach the local markets. In principle, higher incremental price ceilings should provide an incentive to further upstream investment and lead to higher volumes of imports, especially to the coastal and central regions, which are more supply-constrained than the western region.

Figure 22: Elasticity of gas demand growth to GDP growth by region, 2000 – 2011



Source: CEIC

From 2000 to 2011, the elasticity of gas demand growth to GDP growth in the coastal and central regions was 1.4 (Figure 22). Richer coastal provinces such as those in Bohai Rim and Yangtse River Delta, would be more willing to pay in return for an improved guarantee of supply. In the coastal and central regions, the price could be close to the ceiling. However, the NDRC price ceilings vary significantly, depending on local pricing practices and economic conditions. In the northern coastal region, the gas price is 8% lower than in the southeastern coastal region. However, marketing gas at higher prices in the less-developed inland market would be more challenging, and the price could be below the NDRC ceiling owing to less ability to pay, lower industrialization rates and poorer product quality. Gas has to compete with coal in many western provinces; but as the market develops over time, negotiations could favour suppliers.

Implications for distributors

Offtake agreements are usually signed between NOCs, on the one hand, and provincial gas grid distributors, city-gas distributors, large industrial and power sector customers (often accessible via NOC-built pipelines) or mini-LNG plants, on the other. The mix and affordability of customers are increasingly crucial in determining the volume of imports and the price that customers are able to pay. Most provincial gas companies, for example, have a provincial government stakeholder to defend their margins and impose a fixed tariff for gas sold within the province. They have become a major stakeholder in provincial energy development as they dominate provincial gas network and supply and to a certain degree the downstream market. The city gate pricing regulation has boosted the bargaining power of provincial grid *vis-à-vis* domestic upstream producer and importers as they can source diversified supply to meet the demand of provincial end users. However, higher prices resulting from the pricing reform could increase pressure from NOCs to gain direct access to medium-sized and large industry users, bypassing provincial suppliers.

For their part, city-gas distributors, many of which are private and have limited political clout, could see their margins squeezed as they face resistance to large price increases from small commercial and industry users and come up against competition from provincial companies, which often control supplies beyond the city gate. Because incremental gas price levels are close to those of imports and price pass-through to end users is not spontaneous, city-gas distributors will increasingly attempt to source direct supplies rather than relying on provincial gas distributors and NOCs. In addition, they will seek lower cost alternatives such as mini- LNGs if available and cost-competitive. Mini-LNG operators have seen their margins squeezed – especially in Shaanxi and Inner Mongolia (where feedstock costs spiked by $2/MMBtuin late 2013) – nevertheless they continue to enjoy high margins in certain sectors, particularly CNG-fuelled cars, which can afford higher prices.

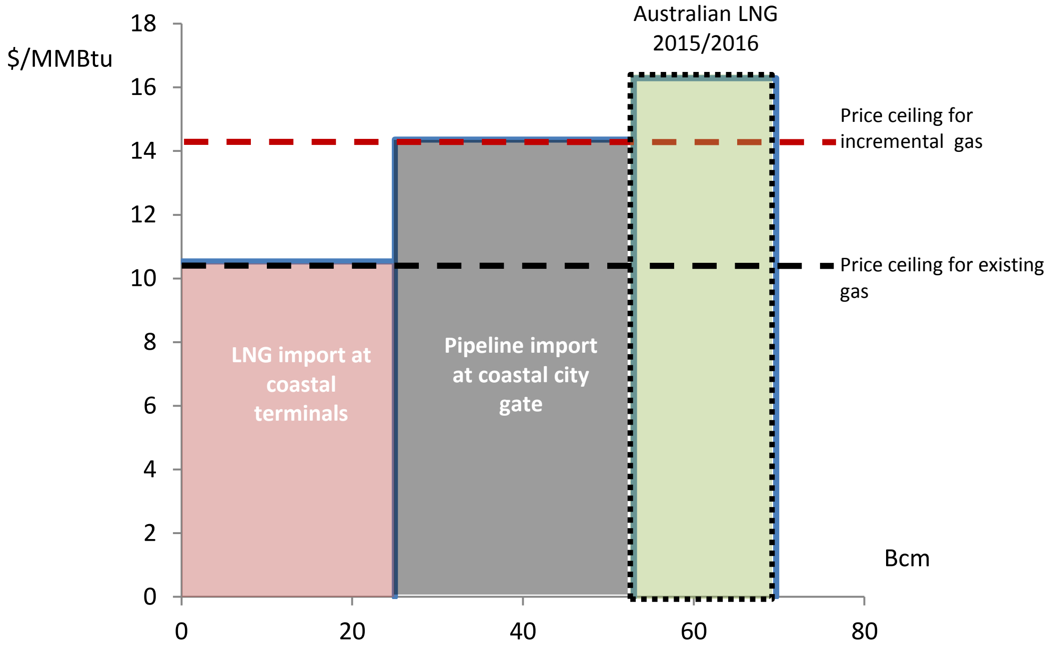
Implications for pipeline and LNG imports

The latest pricing reform in effect links the price of incremental gas to international oil-linked pipeline import prices and will in principle, help reduce the differential between these sources and domestic supply. Figure 23 shows that the ceiling for incremental gas in the coastal region strengthens the competitiveness of pipeline imports from Central Asia against imminent new LNG supplies from Australia that are scheduled to arrive in 2015/2016 (the former are 12% lower in price) at Shanghai city gate. The price ceiling for existing gas after the hike in 2013 is almost on par with average LNG import price at coastal terminals in 2013. Russian pipeline gas imports [25] could be potentially competing with current Central Asian imports if it is delivered at Shanghai city gate towards and beyond 2020, though the Northeast market in China would take up substantial share of Russian gas

[25] Russian gas from Russian-Chinese border to Shanghai enjoys a shorter distance (3000 km or even less depending on the domestic route) compared with Central Asian gas delivered from Central Asian-Chinese border to Shanghai (4000 km).

as their current price ceilings for incremental gas accommodates Russian supply. The scale and speed of piped gas and LNG terminal construction, as well as the timing of the start of such deliveries and destination flexibility, will be a crucial factor (besides evolution of local sectoral demand structure) in determining the competitiveness and market share of these fuels, which, in turn, will affect China's domestic pricing reform.

Figure 23: Gas import cost curve, 2013



Note. Price ceilings for incremental/existing gas are at Shanghai city gate. Price for new Australian LNG that China sources is estimated for its delivery at Shanghai city gate which takes into account the delivered price (assumed to have slope of 14-15 percent range), transport cost, regasification (and storage) charges and transmission cost to city gate (Stern, 2012).

Source: China Customs Statistics, CNPC, NDRC, Stern (2012), author's calculation

5. Summary and Conclusions

Despite supply and infrastructure constraints, Chinese gas demand has been growing faster than income levels and additional latent demand is expected to be unleashed once connectivity and supply security are enhanced. The State Council's recently announced the goal of establishing gas supply capacity of 400-420 Bcm by 2020 is further testimony of the central government's resolve to achieve high gas penetration levels in the longer term as part of a determined effort to combat pollution amid the softening and rebalancing of economic growth. To achieve that goal, annual gas demand will have to continue to grow by more than 10% over the next six years, implying a more than doubling of gas demand from the 2014 level. However, the share of gas in the total primary energy mix would most likely remain lower than 15%.

To meet this potential enormous demand, robust import growth in the medium term would be needed as well as increased domestic production. The pricing reform of July 2013 improves the economics of pipeline and LNG imports as it in effect links the city-gate price to oil-indexed contracts and is likely to lead to increased supplies, while strict environmental policies will enforce more gas use and help reduce industry overcapacity across the country. The level of future pipe and LNG imports depends critically on various factors such as the availability of their supply and relative price, the speed of China's domestic gas price and overall energy industry reforms, local affordability, the strength of domestic supply and robustness and evolving structure of demand under economic rebalancing.

With the introduction of a more market-oriented pricing mechanism, Chinese gas demand will become more closely correlated with pricing reform. The speed at which the price of existing and incremental gas converge and tiered gas pricing is introduced will have a strong impact on Chinese sectoral and regional gas demand, which is becoming increasingly sensitive to the economics of LNG and pipeline imports – the ability to pay netback prices and the size of resource endowments vary significantly among China's various regional gas markets which also have diverse seasonality. The degree to which gas demand will respond to price changes will depend largely on various regional market fundamentals, the level of accessible pipeline connectivity and the perception of gas import availability. Regions that are more developed economically and have relatively fewer alternatives tend to be more able to pay higher prices and pass through costs to end users. However, there is an increasing reluctance to pay premium LNG prices and a growing trend towards accelerating the sourcing of alternative supplies.

Ultimately, a more comprehensive gas pricing reform would need to reflect the relative price (and environmental costs) of coal and the degree of gas substitutability in the major consuming and producing regions in order to mobilize market forces to promote coal replacement – especially in the power sector. Assuming the gradual electricity market liberalisation would be more reflective of environmental costs and benefits of various input fuels towards 2020, a more effective gas price reform based more on the market price of alternatives would emerge along with end-user price sensitivity. This could unleash a further surge in gas demand that is more dynamically linked and sensitive to relative prices for alternative fuels and the import prices of LNG and pipeline gas. At the same time, the recent refocusing on nuclear and renewables as sources for power generation would create competition for gas and imports.

In general, natural gas has been able to compete against oil products across end-user sectors. While the recent rise in the price of natural gas has reduced its competitiveness, this would be mitigated by the increased stability of supply – especially via pipeline, which could be further enhanced if third party access were experimented and implemented in the future. Nevertheless, China has a relatively low degree of coverage for its potential future LNG requirements in the form of medium and long term contracted volumes, despite its ongoing rapid construction of import terminals and LNG has played a significant role in meeting peak gas demand. Like other Asian LNG buyers, China will need to sign new LNG contracts for delivery in the early 2020s, if not sooner. For this reason, many Asian buyers are increasingly seeking a price mechanism that reflects the anticipated gas supply/demand balance and the relationship between gas and competing fuels in their domestic energy markets; by the end of the 2010s this suggests the possible appearance of hub pricing in Asia (Rogers and Stern, 2014). Enhanced inter-connectivity between Asian gas markets would promote a more informed price discovery for LNG and, to a lesser extent, pipeline imports in new contracts.

At the same time, Chinese gas pricing hinges crucially on gas being delivered on time through the development of the already sizeable and growing domestic production base, import diversification, and the implementation of the ambitious unconventional gas programme. The successful commercialization of unconventional gas before 2020 will not only further boost gas consumption but also play a role in determining the long-term price of Chinese imports. However, import diversification enriches supply optionality and helps regional markets to develop a portfolio that is suitable for its own economic and environmental development roadmap. Moreover, long-term structural reforms, such as opening up third-party access, and the emergence of new LNG importers will complement pricing reform. The first private LNG imports in 2013 and the preliminary approval for the plans of two private companies to build LNG terminals are signs of the central government's ambition to create a more liquid and price-competitive gas market.

In the medium term (that is, before 2020), as connectivity is enhanced through the construction of new inter-regional pipelines, LNG terminals and storage facilities, gas prices in any one region in China will increasingly be influenced by developments related to supply and demand in other regions both within and outside China. Beyond 2015, the establishment of what in effect will be regional gas trading hubs[26] (such as Shanghai and Ningbo) will allow the increasing seasonality of demand to be addressed more efficiently as well as the allocation of flexible gas supply. Gas storage will expand and pipeline as well as LNG will become more integrated and unleash demand previously constrained by the lack of access to stable gas supplies and a wider network.

For the regions, enhanced accessible connectivity will mean not only diversification of supply but also price options, as it will coincide with the entry (by 2015) of large volumes of new pipeline and LNG imports into the Chinese gas market as well as the potential ramping up of both conventional and unconventional gas production. The new LNG imports could face more intense competition from pipeline imports – especially in some coastal provinces, which are supplied by Central Asian imports and domestic gas from the Sichuan and Ordos basins (and will receive deliveries from Russia towards the end of the 2010s). However, the enormous build up of LNG terminals and extensions have enabled LNG imports to be established as a reliable and flexible supply and contributed significantly to peak shaving of power plants in the coastal provinces. The speed and flexibility of gas deliveries are crucial, and there may be closer cooperation between city-gas distributors (or provincial grid companies) and importers or foreign companies to integrate the value chain and secure more markets[27].

By and certainly beyond 2020, China's gas pricing could well assume a wider regional significance as China will have the largest importing capacity in Asia and have the most diversified (and relatively balanced) portfolios of supplies, means of transport and routes[28] as a result of its relentless quest for

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[26] This development could be underpinned by both oil-indexed and domestic hub-priced contracts (gas-to-gas competition).

[27] One cannot rule out the possibility of more competition or takeover of city gas distributors by importers or other city gas distributors to advance their downstream market share.

optionality. This increase in its market power may allow China to create various domestic regional markets with benchmark price that interact with import price levels. But its ability to do so will also depend to a large extent on the progress in accessible connectivity, domestic unconventional gas, and robustness of demand in response to economic rebalancing and pricing reform.

[28] Over the years, China has established four different sources of supply: onshore domestic gas (increasing its efforts in unconventional gas), offshore domestic gas, international pipeline gas from Central Asia, Myanmar and more recently Russia (towards 2020), and imported LNG from a variety of sources.

Glossary

CBM – Coal-bed methane

CNG – Compressed natural gas

CNPC – China National Petroleum Corporation

CNOOC – China National Offshore Oil Corporation

JCC – Japanese Customs-cleared Crude Oil Prices – an internationally recognized crude oil price marker, sometimes referred to as the Japan Crude Cocktail

LNG – Liquefied natural gas

LPG – Liquid petroleum gas

NBP – National Balancing Point – the UK's virtual gas trading hub

NBS – National Bureau of Statistics (China)

NEA – National Energy Administration (China)

NDRC – National Development and Reform Commission (China)

NOC – National Oil Companies

Sinopec – China Petroleum & Chemical Corporation

NGV – Natural gas vehicle

WEP – West-East Pipeline

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