An investigation of the regulation of the natural gas pipeline system in Australia, the United States and the implications for China

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Table of contents

1 Executive summary

This report describes and analyses the regulations of the natural gas pipeline in Australia, US and China.

Gas pipelines are critical infrastructure for Australia, and important for the energy industry. There are currently over 25,000 km of gas transmission pipelines performing this task in Australia. The Australian Energy Regulator （AER） has been the economic regulator for covered natural gas transmission and distribution pipelines in all States and Territories (except Western Australia). The Economic Regulation Authority(ERA) plays a role in ensuring equitable access to all gas pipeline users in Western Australia. There are two forms of access regulation under the National Gas Law (NGL), “full” regulation and “light” regulation.

Governing statues of natural gas pipeline in US is Natural Gas Act and Natural Gas Policy Act of 1978. Order 636 in 1992 ordered restructuring of the industry. The Federal Energy Regulatory Commission (FERC) regulates primarily two aspects of interstate pipelines: construction of new facilities and expansion; rate and services. Pipelines/storage providers do not allowed to buy and sell gas. Shippers must have title to transfer/assign capacity, use FERC’s capacity release process. Gathering and intrastate pipelines are exempted from jurisdiction of FERC, but both two are fact-based and require analysis.

China is the world's most populous country with a fast-growing economy that has led it to be the largest energy consumer and producer in the world. China has quickly risen to the top ranks in global energy demand over the past few years. Natural gas use in China has also increased rapidly over the past decade. China continues to invest in natural gas pipeline infrastructure to link production areas in the western and northern regions of the country with demand centers along the coast and to accommodate greater imports from Central Asia and Southeast Asia.

There are important differences between regulation of natural gas pipeline of Australia, the US and china, which have important implications for the regulation framework in china. In the meantime, Chinese government need to take account of specific national circumstances, including the upstream and downstream infrastructure and pipeline network, the ownership structure of the gas industry. Some recommendations for china might be summarized as follows: A timely imposing third party pipeline access，Gradually using the two-part pipeline price，Improving legal laws and regulations，Adopting discriminatory policy on the situation.

1.1 Introduction

China faces many challenges in the coming years to achieve the 12th Five-Year Plan (FYP) target of significantly increasing domestic gas use by 2015. All sources of gas supply – domestic production, including unconventional sources, as well as imports of liquefied natural gas (LNG) and pipeline gas – will be necessary in order to satisfy a demand level by 2015 which could be up to twice that of 2011. Bringing sufficient gas supplies is only one part of the equation: gas needs to be transported to the final end-user, and to support regional developments while ensuring that security of gas supply is met. This requires therefore significant investments on the midstream and downstream sides as well.

China is looking at doubling its natural gas consumption from 130 bcm in 2011 to 260 bcm in 2015. This step increase is challenging, not only in terms of attracting gas supplies and building the infrastructure, but also in terms of pricing. The pricing issue is by far the most important issue as it interacts with all the other aspects. This includes dealing with more expensive imports, incentivising future unconventional gas production, and avoiding cross-subsidies between large users and residential users. Also the pricing structure, whereby the upstream and pipeline tariffs are regulated based on a costplus
approach and differ depending on the end user must be changed. Incentivising efficient investments along the gas value chain, from upstream, import infrastructure to midstream (pipelines and storage) is essential to ensure a timely and safe development.

Over the past decade, a reform had started to create a more market oriented oil and gas sector, including the state-owned companies. But this reform stopped at some crucial elements for the gas market, and is still characterised by a patchwork of targets and strategies, institutions and companies as well as regulations and practices. The gas market has a fragmented and monopolistic structure, regulation of prices at different stages based on a cost-plus approach, lack of access for small, medium-sized and foreign companies to existing infrastructure and thus markets, and a lack of a clear, efficient and transparent regulatory framework as well as diffuse and overlapping regulatory authorities.

Despite these issues, China has managed to build significant import infrastructure allowing for diversified supply from Central Asia, Myanmar (2013) and various LNG sources. This import infrastructure has a relatively diversified ownership structure, even if the Big Three NOCs dominate on the LNG side and CNPC on the pipeline import side. Infrastructure has been built at a relatively rapid pace, and the main challenge is to continue such growth and attract gas supplies to fill this infrastructure. The challenges in terms of pricing and regulations can be grouped into four categories: pricing levels and pricing structure; incentivising efficient investments along the gas value chain, from production to import infrastructure and transportation/storage within China; oligopolistic structure of the gas industry dominated by three companies; and overlapping powers from different agencies and from the central and local governments.

The comparison of natural gas pipeline regulation in Australia ,the US and Australia may have significant implication to the regulation of natural gas pipeline in china . China will benefit from the regulatory reform in natural gas pipeline sector (eg. pricing and the third party pipeline access).

1.2 Scope of investigation of natural gas pipeline system

Transporting natural gas from the wellhead to the final customer involves several physical transfers of custody and multiple processing steps. A natural gas pipeline system begins at the natural gas producing well or field. Once the gas leaves the producing well, a pipeline gathering system directs the flow either to a natural gas processing plant or directly to the mainline transmission grid, depending upon the initial quality of the wellhead product.

The processing plant produces pipeline-quality natural gas. This gas is then transported by pipeline to consumers or is put into underground storage for future use. Storage helps to maintain pipeline system operational integrity and/or to meet customer requirements during peak-usage periods.

Transporting natural gas from wellhead to market involves a series of processes and an array of physical facilities. Among these are:

- Gathering Lines – These small-diameter pipelines move natural gas from the wellhead to the natural gas processing plant or to an interconnection with a larger mainline pipeline.
- Processing Plant – This operation extracts natural gas liquids and impurities from the natural gas stream.
- Mainline Transmission Systems – These wide-diameter, long-distance pipelines transport natural gas from the producing area to market areas.
- Market Hubs/Centers – Locations where pipelines intersect and flows are transferred.
- Underground Storage Facilities – Natural gas is stored in depleted oil and gas reservoirs, aquifers, and salt caverns for future use.

2 Natural Gas Pipeline and the Regulation in Australia

2.1 Gas Industry Overview

Australian natural gas production has increased sharply over the past decade as a result of new projects. Australia produces enough natural gas to cover its consumption and to be considered a leading gas exporter. Several recent discoveries and growing regional demand for gas have spurred more investment activity in the country's reserves. Australia's natural gas reserves vary by industry source and the category of commercial viability. According to Oil & Gas Journal (OGJ), Australia's proved natural gas reserves were more than 43 trillion cubic feet (Tcf) as of January 2014. Geoscience Australia estimated total proved plus probable commercial reserves at 132 Tcf (99 Tcf of traditional natural gas and 33 Tcf of coal bed methane-CBM) as of 2012. Most of the traditional gas resources (about 92%) are located in the North West Shelf (NWS) offshore in the Carnarvon, Browse, and Bonaparte basins. CBM proved and probable resources, primarily located in the northeastern Queensland Province in the Bowen Basin and the Surat Basin, have doubled in the past three years to 33 Tcf in 2012. Geoscience Australia anticipates the resource distribution of natural gas will shift from the offshore traditional gas production to CBM or other sources in the next two decades as key CBM developers are aggressively exploring and drilling in several areas. In addition to CBM resources, Australia had an estimated 437 Tcf of technically recoverable shale gas reserves in 2012, according to an EIA study. These resources are dispersed throughout the country in the inland Cooper Basin, the eastern Maryborough Basin, the offshore southwestern Perth Basin, and the northwestern Canning Basin.

The natural gas industry is regulated by the Department of Resources, Energy, and Tourism (RET) and the Ministerial Council of Energy (MCE). The MCE was created in 2001 to foster policy coordination between the Commonwealth and the state governments. The MCE functions as the national policy and governance body for Australia's energy market, and the group consists of ministers with responsibility for energy from the Australian government and all states and territories. Major domestic and foreign companies operating in Australia include Santos, Woodside, Chevron, ConocoPhillips, ExxonMobil, Origin Energy, BG Group plc, Apache Corporation, INPEX Corporation, Total, Shell, and Statoil. Chevron holds the largest amount of natural gas resources in Australia, and the company has made 21 discoveries in the Carnarvon Basin since mid-2009, adding 10 Tcf to proved gas resources. The recent stream of CBM for LNG projects in Australia has also attracted Asian companies such as Sinopec, China National Offshore Oil Corporation (CNOOC), Tokyo Gas, and China National Petroleum Corporation (CNPC) that are interested in purchasing both LNG for markets in China and Japan as well as the upstream assets slated to supply these projects.

Natural gas production in Australia reached nearly 2.2 Tcf in 2013 and has climbed overall from less than 1.2 Tcf in 2000 as a result of new developments. Traditional natural gas is largely produced in the Carnarvon Basin offshore Northwestern Australia, the Cooper/Eromanga Basin in central Australia, the Gippsland Basin in the southeastern Victoria Province, and the Bonaparte Basin in the offshore joint production area shared between Australia and East Timor. The Western Australia offshore region produced the largest share of total natural gas (58%) in 2012. The Carnarvon Basin supplied almost a third of the domestic natural gas market and the vast majority of the export market, according to APPEA. The Victorian state comprised about 18% of the total natural gas production. Queensland and New South Wales (NSW), Australia's main sources for coal bed methane, made up roughly 15% of natural gas production.

Even though Australia has experienced a steady rise in domestic natural gas consumption over the past decade, the market for domestic consumption of natural gas in Australia is somewhat limited. However, the government is interested in reducing carbon dioxide emissions through the use of cleaner fuels such as natural gas and renewables. Australia consumed less than 1.3 Tcf of natural gas in 2013, steadily rising about 37% over the past decade. On average, domestic markets consume a majority of the production. Since 2009, the gap between supply and domestic demand began widening as LNG sales expanded. Australia's industries are the major consumers of natural gas, with a 32% market share in 2012, according to government data. The second-largest consumer is the power sector, accounting for 31%. The mining sector accounted for 19%, and the residential sector's share was 11%. Natural gas prices in the domestic market have been low compared to international rates.

However, rising LNG exports have created various supply-side cost pressures especially in the eastern states. As natural gas contracts expire, suppliers are raising prices to reflect the netback of global LNG markets. Rising gas prices could place downward pressure on consumption growth, especially from the power and manufacturing sectors, as some companies seek alternative fuel sources or cost reductions. Australia implemented a carbon tax in July 2012 that was expected to shift more electricity generation from the coal-fired to cleaner burning gas-fired facilities. However, Australia's new government, elected in September 2013, repealed the carbon tax and emissions trading scheme in July 2014 in attempts to lower electricity and natural gas prices for domestic consumers, particularly industries, as well as to reduce the financial burden on companies that are top emitters. This policy change could temper domestic natural gas demand growth, especially in the power sector, in favor of lower-cost baseload coal generation.

Australia has become a leading LNG exporter in the Asia-Pacific region in the past decade. Greater expected natural gas production and new LNG capacity in the next few years is likely to boost natural gas exports even more. As a result of its abundant gas resources and its geographic proximity to consumer markets, Australia has become a leader of LNG supply for the Pacific basin. Over the past decade, Australian LNG exports have increased nearly three times, and they are expected to rise substantially in the medium term as developers usher in new upstream and liquefaction capacity. Australia, the third-largest LNG exporter in the world behind Qatar and Malaysia, exported 1,070 Bcf of LNG in 2013, up from about 990 Bcf in 2012, according to IHS Energy. Australia exports natural gas almost exclusively to Asian markets, with Japan purchasing about 80% of Australia's exports in 2013, mostly through long-term contracts. Other key consumers include China, South Korea, and Taiwan. Japan's demand for LNG rose in 2011 when natural gas-fired generation was substituted for the lost nuclear capacity following the Fukushima power plant accident. Australia became the largest source of LNG for Japan by 2012. Chinese national oil companies (NOCs) have teamed with international oil companies (IOCs) on investments in several Australian liquefaction projects and signed gas purchase agreements to lock in supply for the growing market in China.

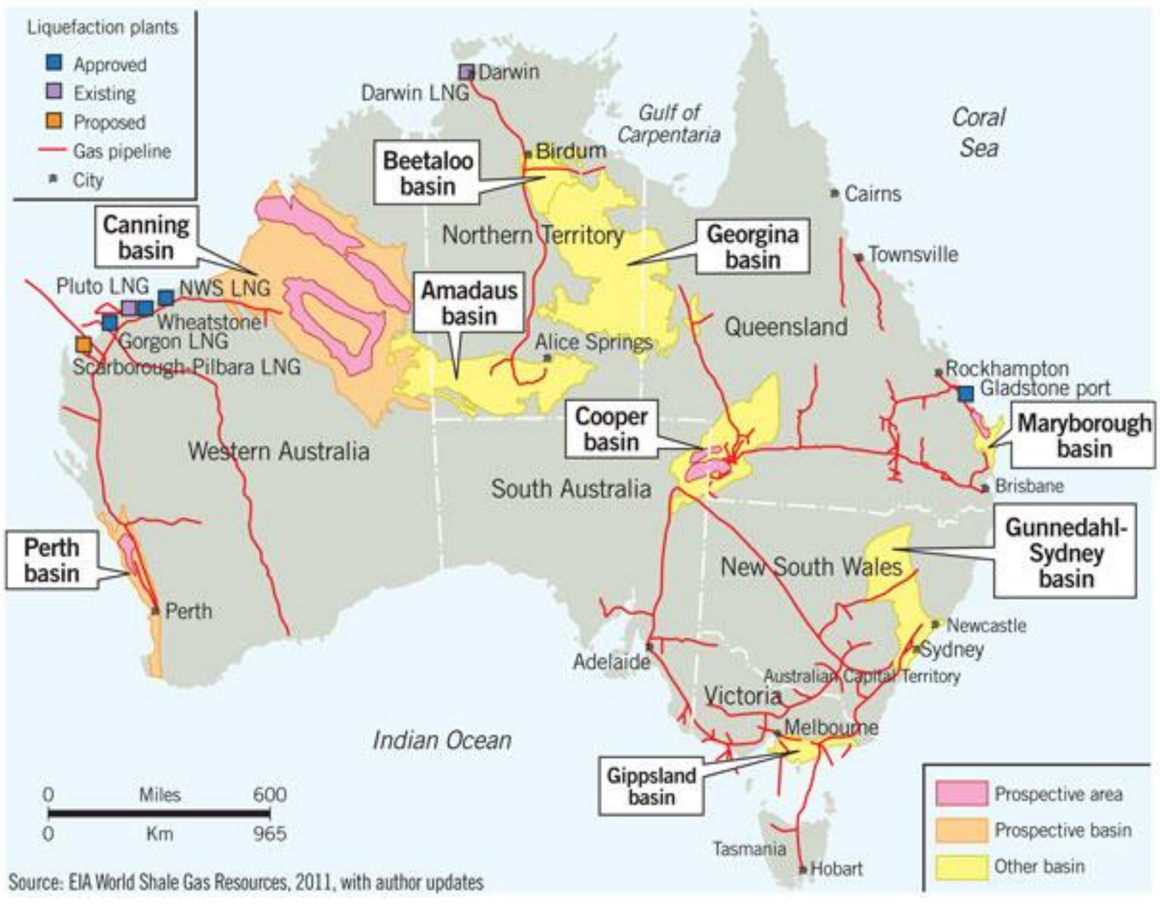
Australia has three LNG export facilities with a total capacity of almost 1.2 Tcf per year.As new LNG facilities and expansions of existing facilities come online within the next decade, Australia's LNG export capacity is set to expand substantially. Most of the liquefaction projects are located in the coastal or offshore northwestern Australia and in the northeastern Queensland region. Some projects such as Ichthys are designed to produce associated condensates and LPG. Currently, there are 7 projects under construction with a total capacity of 3 Tcf/y, 3 in Queensland and 4 in the basins of the northwest coast and offshore. These projects are scheduled to commence operations by 2017. Other projects are waiting on regulatory approval or final investment decisions, although these projects are facing competition and delays because of escalating costs and potential overcapacity for the amount of available natural gas supply. Australia currently has more than $190 billion worth of LNG projects under construction, and the country is on target to overtake Qatar as the world's largest LNG exporter by 2020, according to industry sources.

Natural gas that is used in Australia is transported from the often remote gas fields and processing facilities to areas of demand by long distance, high pressure, steel pipelines known as gas transmission pipelines. Once at a region of demand, which may be an industrial area or city, the gas is distributed to users through a low pressure pipeline system known as a gas distribution network.

Australia's domestic gas transmission pipeline network, covering 15,000 miles, is well developed and transports gas from the key production centers to main economic hubs in the east. Significant investments since 2000 have expanded the gas network. The pipeline system interconnects all states except Western Australia and the Northern Territory because of their remote locations. Some pipelines transport gas from the country's inland fields to Darwin, Sydney, and the southeastern coast. In Western Australia, there are three major pipelines that transport gas from northwestern gas fields to the southwestern region. Rising natural gas prices in Australia, particularly in the eastern region, and investments for new exploration and development of various basins around the country are compelling the country to further its gas pipeline integration. The APA Group (APA), Australia's largest pipeline operator, proposed an interconnector to link the Northern Territory to one of the major pipelines that serve demand in eastern Australia. A completely integrated system would optimize natural gas transit to meet domestic demand and LNG export obligations. The Australian Energy Regulator oversees the gas pipeline networks in all states with the exception of Western Australia, which is regulated by the Economic Regulation Authority. However, the transmission and distribution network is largely privately-owned and operated, and several major pipelines are only partly regulated or not regulated. APA operates 8,400 miles of pipeline and transports about half of the country's natural gas. In 2012, APA acquired Hastings Diversified Utilities Fund (owner of Epic Energy) making the operator the country's majority stakeholder of transmission capacity. Other key pipeline owners include Jemena, Prime Infrastructure, and Australian Gas Light.

AUSTRALIA GAS PIPELINES, LNG PLANTS, SHALE GAS BASINS

FIG. 3



2.2 Pipeline Regulation in Australia

2.2.1 Transmission Pipelines and Distribution Pipelines

Pipeline transport natural gas from processing or storage facilities over long distances to domestic markets. The pipelines typically have wide diameters and operate under high pressure to optimise shipping capacity. Considerable effort is devoted to ensuring gas transmission pipelines are safe, reliable and efficient; ensuring that supply is not disrupted. The industry-developed standard AS2885 is respected internationally and by other Australian industry sectors as a high-quality standard for the design, maintenance and operation of high pressure energy transmission pipelines.There is an interconnected pipeline network covering Queensland, New South Wales, Victoria, South Australia, Tasmania and ACT. Transmission pipelines in Northern Territory are not interconnected with other jurisdictions. There are currently over 25,000 km of gas transmission pipelines performing this task in Australia, some of them have been in operation for over 40 years.

A network of distribution pipelines delivers gas from points along transmission pipelines to industrial customers, and from gate stations to customers in cities and towns. A distribution network typically consists of high, medium and low pressure pipelines. The high and medium pressure mains provide a 'backbone' that services areas of high demand and transports gas between population concentrations within a distribution area. The low pressure pipes (typically at pressures lower than [1000kPa]) lead off the high pressure mains to end customers. There are currently over 80,000km of gas network pipelines in Australia. The gas retail sector then sells the delivered gas to end use customers.

The networks are regulated to manage the risk of monopoly pricing, where a business can charge higher prices or provide poorer services compared with the situation in a competitive market.

2.2.2 Regulatory Framework

Gas pipelines are critical infrastructure for Australia, and important for the energy industry. Australia's domestic gas distribution network is served by a number of private and Government-owned transmission pipelines running from the onshore processing facilities to major demand centres. Since 1 July 2008, the Australian Energy Regulator (AER) has been the economic regulator for covered natural gas transmission and distribution pipelines in all States and Territories (except Western Australia as the Economic Regulation Authority (ERA) regulates the electricity, gas, water and rail freight industries in that State).

2.2.2.1 Economic Regulation of the Gas Transmission Market

Gas transmission pipelines are capital intensive and incur declining marginal costs as output increases. This gives rise to what is often technically described as a 'natural monopoly' industry structure, where the most economic means of increasing gas supply to a region is to expand existing infrastructure rather than build new pipelines.

Third party access policies require owners of natural monopoly infrastructure facilities, in this case gas transmission pipelines, to grant third parties access to the facilities. Such access to pipeline capacity is considered desirable and particularly important where, due to the high capital cost of assets, competition does not exist. In terms of Australia's gas transmission infrastructure, APIA notes: The major demand hubs in Eastern Australia are supplied by competing pipelines; Nationally, only 11 gas transmission pipelines (out of 64 major pipelines) are subject to economic regulation.

Energy policy works best in the long term interests of the consumer when it is focused on increasing investment and competition in the market. As investment and competition increase, gas users will have more options for gas supply and for transportation. This, then, enables greater use of commercial negotiations to set gas prices and associated charges, which is a more effective and efficient outcome than a process of regulators endeavouring to determine a theoretically efficient price.

Since privatisation commenced in the early 1990s, the length and capacity of the gas transmission network in Australia has trebled. Today, there are more than 25,000km of high pressure, steel pipelines in Australia dedicated to transporting natural gas. Around $5 billion has been invested in new transmission pipelines and expansions since 2000, and, at the same time, a reduction in the number of regulated pipelines.

2.2.2.2 The National Gas Law and Rules

The National Gas Law (NGL) and the National Gas Rules (NGR) provide the overarching regulatory framework for the gas transmission sector and came into effect on 1 July 2008, replacing the National Gas Code which provided the regulatory framework from 1997. The NGL and NGR set the criteria for determining whether a pipeline should be subject to economic regulation and the approach to be used for determining appropriate tariffs.

Under the National Gas Law the main regulatory bodies are the Australian Energy Market Commission (AEMC), the AER and the Australian Energy Market Operator (AEMO). These bodies have been established to manage regulated electricity and gas infrastructure under the National Gas Law and National Electricity Law.

Covered Pipelines: Pipelines that are deemed to require economic regulation are termed ‘covered pipelines’. A covered pipeline is required to submit an access arrangement to the Australian Energy Regulator. An access arrangement sets out the terms and conditions under which third parties can access the capacity of a pipeline and must specify at least one reference service that most customers seek and a reference tariff for that service. In setting a reference tariff, the AER seeks to establish the efficient cost of providing the service. Covered pipelines are required to publish their approved access arrangements, detailing reference tariffs and terms and conditions of access.

Non - covered Pipelines: Pipelines that are not covered are subject only to the general anti-competitive provisions of the Trade Practices Act 1974. Access to non-covered pipelines is a matter for the pipeline owner and customer to negotiate without regulatory intervention. Non-covered pipelines are not required to publish tariffs or terms and conditions of access. The majority of Australia’s pipelines are not regulated.

■ Australia has developed a competitive independent pipeline industry in response to privatisation and energy policy reforms.

■ Transmission costs comprise around 5 per cent of the retail cost of gas for consumers and around 15 per cent of the cost for major users.

■ Commercial negotiations are the most effective approach to achieving flexible and efficient market outcomes.

■ The focus of energy policy should be on increasing investment and competition and minimising the need for regulatory intervention.

■ Where pipelines are covered, regulated returns and costs of capital should be consistent with the need to attract capital from equity investors.

■ The customers of gas transmission pipelines are major users of gas, including power stations, minerals processors, and energy retailers. These companies are typically larger than the gas transmission companies, a situation which is unlike the relationship between energy retailers and consumers. Therefore, the customers of gas transmission pipelines do not need regulatory intervention to assist them in their negotiations.

2.2.3 Regulation Forms

There are two forms of access regulation under the National Gas Law (NGL). These are "full" regulation and "light" regulation: Full regulation requires a pipeline provider to periodically submit an access arrangement to the AER for approval. An access arrangement sets out the terms and conditions under which third parties can use a pipeline. It must specify at least one reference service likely to be sought by a significant part of the market, and a reference tariff for that service. The AER assesses the revenues needed to cover efficient costs and provide a commercial return on capital, then derives reference tariffs for the pipeline. Under light regulation, the pipeline provider determines its own tariffs. The provider must then publish relevant access prices and other terms and conditions on its website. In the event of a dispute, a party seeking access to the pipeline may ask the AER to arbitrate. Some pipelines are 'uncovered', meaning that they are not subject to economic regulation.

Both forms of regulation are based on a "negotiate/arbitrate" model of regulation. The key differences between "full" regulation and "light" regulation are as follows:

- "Light" regulation: covers non-discriminatory access, price- monitoring and the publication of an "access arrangement", but does not involve economic regulation of pricing. This is usually applied where the costs of "full regulation" would be disproportionate to the benefits, and is increasingly common in Australia.

- "Full" regulation: covers situations where an operator will be required to periodically submit a "full access arrangement" to the AER for consideration and approval. This will include minimum third-party access principles and the terms and conditions (including prices) for haulage services (which may include firm, interruptible and back-haul) offered to third parties.

2.2.4 Additional Explanations about Pipeline Regulations

Governmental authorisations are required to construct and operate natural gas pipelines and associated infrastructure. A separate pipeline licence or permit is typically required, together with consents to construct. In the offshore Commonwealth area, a pipeline licence is granted under the OPGGSA. Within State or Territory areas, each jurisdiction generally has its own pipeline or transport infrastructure legislation. The legislative procedures for land access, easement acquisitions and approval for construction and operation of pipelines also vary across the different States and Territories. However, the State and Territory regulatory regimes generally require that a pipeline licence is obtained to construct and operate a gas pipeline and land access rights or tenure are obtained for the pipeline. Any pipeline specific environmental approvals are complemented by the general environmental approval regimes under State or Territory legislation and the EPBC Act.

In general, Government authorities have powers of compulsory acquisition to facilitate land access. Offshore pipelines or infrastructure generally do not require separate land access rights. A pipeline or infrastructure licence, which are titles under offshore legislation is generally all that is required.

Onshore pipelines and associated infrastructure generally require land access rights or tenure. To secure the necessary land rights often requires approval or consent from other parties with an interest in the relevant land. Access to private land for the purpose of constructing and operating a pipeline will typically require the private land owner to grant, generally for a negotiated fee, an "easement" or other suitable right over the pipeline route. Subject to payment of proper compensation and to restrictions on proximity to improvements, private landowners can be compelled under the pipelines legislation to grant pipeline easements. Where the pipeline traverses

Government land, a Government authority, licence, permit or form of tenure such as an easement under the applicable land legislation would generally need to be obtained. Consents may need to be obtained from other interested parties, including native title parties, heritage stakeholders, local Government, pastoral lessees, and mining titleholders.

Access by third parties to any transmission and distribution pipelines may be covered by a statutory third-party access regime. Pipelines and associated infrastructure in relation to the upstream production of natural gas are typically constructed and treated as property owned by the applicable developer (often a joint venture). Access to such infrastructure is generally a matter for commercial negotiations. The principal regime for third-party access in relation to natural gas (and, in Western Australia, liquefied petroleum gas) transportation is set out in the NGL and the National Gas Rules (NGR). Under the NGL, the service provider of regulated pipelines (being the owners, operators or controllers) are obliged to comply with a range of obligations intended to facilitate third-party access.

The NGL contains the principal access regime for natural gas (and, in Western Australia, liquefied petroleum gas) pipelines. Where any pipeline falls outside of this regime, the applicable pipeline licence may contain access conditions and in the absence of any such conditions, any access will be a matter for commercial negotiation. In most cases, third-party access will only be regulated where the relevant pipeline has the potential to affect competition in the relevant market. The NGL provides for "light regulation" or "full access arrangement regulation". As with transmission pipelines, natural gas distribution networks may also be subject to the national access regime.

Where expansion of the pipeline capacity is considered, the NGR provides that the AER may not order the operator of a "light" regulated pipeline to expand capacity unless the third party seeking access pays for such expansion.Where a pipeline falls under "full" access regulation, the operator may not be required to extend the geographical range of the pipeline. In addition, the operator may not be required to pay for an expansion of capacity, unless the access arrangement approved by the AER provides for the operator to do so. In Western Australia, the AER's role is performed by the ERA.The model under the National Access Regime operates as follows:

- a person may apply to the NCC for a service provided by means of a facility to be "declared". The NCC will then make a recommendation to a specified Minister, who must then decide whether or not to declare the service;

- once a service is declared, the service provider and any access seeker must negotiate the terms of access to the service;

- if the negotiations are unsuccessful, then the access seeker may apply for the access dispute to be arbitrated by the Australian Competition and Consumer Commission (**ACCC**). The ACCC also has the power to require a service provider to "extend" a facility. While this has not been tested, this power has been viewed as both the power to require a service provider to geographically extend, as well as expand the capacity, of a facility.

However, if a service is already subject to a regime certified under the CCA or voluntary access undertaking approved by the ACCC, the service cannot be "declared".

At the time of publication, none of the States or Territories have applied for the NGL to be certified under the CCA. However, if the NGL does apply to a particular pipeline, then that is a matter that is likely to be taken into account before a service provided by means of that pipeline is "declared".

Domestic gas transportation is effectively split into two geographical areas: the eastern side of Australia; and the western side of Australia. There is no interconnection of these two systems. Co-operation within each system is generally commercially negotiated between the respective owners of each part of each system.

The operation of pipeline requires compliance with the licensing regime of the relevant jurisdiction, including obtaining all applicable authorisations. The general environmental approval regimes under State or Territory legislation and the EPBC Act will apply to a gas transmission or distribution network.

If a distribution pipeline is regulated under the NGL, then the AER can require a distributor to grant access to a specific user(s), in relation to an access dispute which has been referred to it under the NGL. However, this power is constrained by a number of NGL conditions including:

- an existing user's contractual rights must not be removed (e.g. an existing user's contractual right to reserved capacity in the pipeline must not be reduced);
- expansion can only be ordered if the third party seeking access pays for the expansion, the expansion is technically and economically feasible and is consistent with safe and reliable pipeline operation; and
- the AER cannot require a distributor to extend the geographical range of the pipeline.

If a service provided by a distribution network is declared under the national access regime, in determining an access dispute, the ACCC has the power to require a service provider to "extend" a network. While this has not been tested, this power has been viewed as both the power to require a service provider to geographically extend, as well as expand the capacity, of a network.

Where a distribution network is subject to "full access regulation" under the NGL, then the NGL provides for the service provider to offer to provide principal haulage services (together with, potentially, ancillary services) on regulated terms. The regulated fees and charges are, in broad terms, at a level which enables a service provider to earn a "total allowable revenue" based on a return on and of capital commensurate with the investment risk and economic life, plus efficient operating and overhead costs, using a building block approach. The fees and charges are periodically reviewed (commonly every three to five years), and the service provider's actual revenue is reconciled against its forecast revenue, which affects the regulated fees and charges for the next period. Network connection charges may also be specifically regulated or subject to certain rules, which require the charge to be set on a cost- reflective basis.

While the NGL requires service providers under “full access regulation” to offer regulated fees and charges, a service provider and access seeker are free to agree on different prices and terms and conditions. A service provider under “light access regulation” is not subject to price regulation, but must comply with pricing nondiscrimination rules. Otherwise, fees and charges for distribution services are set by each service provider. If the national access regime applies, then the price will be determined by the ACCC in an access arbitration if the parties cannot otherwise agree.

Regulatory approval will generally be required for the transfer of a licence to operate a distribution or transmission pipeline. In terms of acquiring an interest in the distribution assets, no specific restrictions apply, save for Victoria where limits on the control or level of interest that a person may hold in more than one relevant entity across the production, transmission, distribution and retail sectors are imposed.

2.3 Relevant Gas Pricing

Retail gas prices vary substantially between states. These variations result from a range of factors, including distance from sources and usage patterns. For example, an average residential user in Victoria annually consumes more than three times the gas consumed by an average Queensland residential user, while an average residential user in Perth is over 1500km away from the main sources of gas in that State. As a result, prices vary from around \$15.50/GJ in Melbourne to almost \$28/GJ in Brisbane1. Nevertheless, the components of the final retail price are relatively similar across States, with the four components of price relating to the separate sectors of the gas supply industry:

1. Production: The price component to produce the gas, which must cover the costs of exploration, development gathering and processing and accounts for 11-21% of the final retail price.

2. Transmission: The price component to transport the gas through high pressure transmission pipelines from the source to the market accounts for 2-7% of the fi nal residential price.

3. Distribution: The price component to distribute the gas to consumers through low pressure distribution pipelines is significant, as a large infrastructure network is

required to service each consumer. As a result, this component accounts for 38-58% of the final retail price.

4. Retailing: The price component to retail the gas, including marketing, customer service and revenue collection accounts for around 30% of the final retail price.

5.Manufacturing & Power Generation Price：The electricity, manufacturing and mining sectors typically do not require the services of natural gas distributers or retailers and, with their substantial volumes, pay significantly lower prices per unit for natural gas than do residential customers. Larger users will typically negotiate directly with producers to purchase gas, and then negotiate with a transmission pipeline for delivery of the gas. As the unit prices are lower for large users, transmission charges account for a higher portion of the price.

The wholesale price of gas is subject to negotiation with the gas producers and may be different for each user. Wholesale gas price information is not made publicly available other than in Victoria with its unique infrastructure and 'market' carriage system.

2.4 Pipeline Regulation in WA

Since the pipeline system in WA is regulated by the ERA(all the other States and Territories are regulated by the AER) and not interconnected with other states, it's necessary to introduce pipeline regulation in WA for better understanding the pipeline regulation in Australia.

The ERA plays a role in ensuring equitable access to all gas pipeline users in Western Australia. The ERA – the independent economic regulator in Western Australia – is responsible for regulating monopoly infrastructure including gas pipelines, electricity transmission and distribution lines and rail services. There are currently three regulated pipelines in Western Australia: the Dampier to Bunbury Natural Gas Pipeline (DBNGP), the Goldfields Gas Pipeline (GGP) and the Mid-West and South-West Gas Distribution System (GDS). There is also one light regulation pipeline, the Kalgoorlie to Kambalda Pipeline.Among of them, the Dampier to Bunbury Natural Gas Pipeline (DBNGP) is the longest natural gas pipeline in Australia and runs

entirely underground. It was commissioned in 1984 following three years of planning and construction. The DBNGP is currently operated by DBNGP (WA) Transmission Pty Limited and trades as DBP. DBP's shareholders are the DUET Group and Alcoa.
The ERA as an independent statutory authority determines the terms and conditions under which third parties can access gas pipeline services. The aim is to encourage competition both in the upstream services and the downstream services. The regulated tariffs and terms and conditions operate as a backstop if the parties fail to reach a commercial agreement. The main method by which the ERA encourages this competition is through setting the price and conditions for using pipeline services and making sure that they represent efficient practice. Just as ERA Chairman Lyndon Rowe said, "We need to ensure that the owner of the pipeline has sufficient revenue to cover its costs, but we need to check to make sure that what they propose to spend is efficient."

Regulators across Australia adopt a standard approach, which involves the pipeline owner submitting an access arrangement. This submission outlines what the pipeline owner thinks the price, terms and conditions for using the pipeline should be for the next five years based on an estimated operational and capital expenditure. A fairly detailed public consultation process follows, which can take up to 12 months.

The ERA will release an issues paper listing the pipeline owners' proposed terms and invite public comment. Taking into account the pipeline owner's application and submissions and the public's response, the ERA will then issue a draft decision, giving the pipeline owner, in addition to the general public, a chance to respond. Eventually, the ERA will release a final decision, which will determine the regulated tariffs and terms and conditions for users over the next five years. The ERA's main challenges are how to determine what an efficient operating expenditure, capital expenditure and rate of return is. To do this, the ERA asks companies to submit a detailed analysis of their operating and capital expenditure for the next five years as part of their access arrangement. The ERA then seeks to ensure that what is proposed to be spent is consistent with a prudent and efficient operator.

The ERA also uses engineering and economic consultants to independently assess whether the companies' proposals are appropriate or not.This process can be lengthy because there is sometimes a disagreement between the parties involved. For example, one of our roles is to make an assessment of what the ERA think – given the risk in the industry – is an appropriate return on the investment by the pipeline owners. Often providers will have a view that they need a higher rate of return than what we might think they need. If the ERA does not agree with what the pipeline owner initially proposes, it will publish in the draft decision a series of amendments, which must be made in order for the access arrangement to be accepted. If these amendments are not accepted by the provider, the ERA will issue its own access arrangement, which is subject to appeal by any party.

This was not always the case. There was a review of the legislation two or three years ago. Under the old code, if the provider had put forward a complying access arrangement – that is, if it had accepted the recommendations of the regulator, or at least made satisfactory changes – then that was the end of the story. No one could appeal. However, under the new legislation, it's open to any party to appeal the decision. If a user thought the ERA were being too generous, they could appeal the ERA's decision too."

Another recent change in monopoly infrastructure regulation is the appeal body. In Western Australia, the appeal body used to be state-based, but now appeals are made through the Australian Competition Tribunal. There are a number of reasons for this, One is streamlining, the other is consistent decision-making given that regulators are ruled by the same legislation across Australia.

The recent multitude of gas discoveries within Western Australia has not affected state economic regulation. It is possible that if you had a situation where multiple gas sources led to more competing gas pipelines, you might eventually argue there is no need for economic regulation. But probably the ERA are far from that right now.

3 Natural Gas Pipeline and the Regulation in U.S.

3.1 Natural Gas Pipeline Overview

The U.S. natural gas pipeline network is a highly integrated transmission and distribution grid that can transport natural gas to and from nearly any location in the lower 48 States. The natural gas pipeline grid comprises:

- More than 210 natural gas pipeline systems.
- 305,000 miles of interstate and intrastate transmission pipelines.
- More than 1,400 compressor stations that maintain pressure on the natural gas pipeline network and assure continuous forward movement of supplies
- More than 11,000 delivery points, 5,000 receipt points, and 1,400 interconnection points that provide for the transfer of natural gas throughout the United States.
- 24 hubs or market centers that provide additional interconnections
- 400 underground natural gas storage facilities
- 49 locations where natural gas can be imported/exported via pipelines
- 8 LNG (liquefied natural gas) import facilities and 100 LNG peaking facilities

3.1.1 Interstate Natural Gas Pipeline Segment

Two-thirds of the lower 48 States are almost totally dependent upon the interstate pipeline system for their supplies of natural gas.

On the interstate pipeline grid, the long-distance, wide-diameter (20-42 inch), high capacity trunklines carry most of the natural gas that is transported throughout the nation. In many instances, natural gas must be routed through several interstate pipeline systems before it reaches final destination. The interstate portion of national natural gas pipeline network represents about 71 percent of all natural gas mainline transmission mileage installed in the United States. The 30 largest interstate pipeline companies own about 77 percent of all interstate natural gas pipeline mileage and about 72 percent of the total capacity (183 billion cubic feet) available within the interstate natural gas pipeline network.

Some of the largest levels of pipeline capacity exist on those natural gas pipeline systems that link the natural gas production areas of the U.S. Southwest with the other regions of the country. Sixteen of the thirty largest U.S. natural gas pipeline systems originate in the Southwest Region, with four additional ones depending heavily upon supplies from the region.

Today, almost every major metropolitan area in the United States is supplied by, or is the final destination of, one or more of the major interstate pipeline companies or their affiliates.

3.1.2 Intrastate Natural Gas Pipeline Segment

Intrastate natural gas pipelines operate within State borders and link natural gas producers to local markets and to the interstate pipeline network. Approximately 29 percent of the total miles of natural gas pipeline in the U.S. are intrastate pipelines.

Although an intrastate pipeline system is defined as one that operates totally within a State, an intrastate pipeline company may have operations in more than one State. As long as these operations are separate, that is, they do not physically interconnect, they are considered intrastate, and are not jurisdictional to the Federal Energy Regulatory Commission (FERC). More than 90 intrastate natural gas pipelines operate in the lower-48 States.

For instance, Texas is the top ranked natural gas consuming State. Intrastate pipelines in Texas account for 45,000 of the 58,600 miles of natural gas pipelines in the State. The largest intrastate pipelines in Texas are Enterprise Texas Pipeline Company (8,750 miles) and the Energy Transfer Partners LP (8,800 miles).The intrastate network in Texas has experienced significant growth over the past several years as a result of increased demand for pipeline capacity caused by the rapid development and expansion of natural gas production in the Barnett Shale Formation. New pipelines have been built, and expansions to existing ones undertaken, to meet increased demand.

In some instances, an intrastate natural gas pipeline may also be classified as a "Hinshaw" pipeline. Although such pipelines receive all of their supplies from interstate pipeline sources, and therefore fall within FERC's regulatory purview, they have been exempted from its jurisdiction because the gas they deliver is consumed totally within the state in which they operate.

3.1.3 Major Natural Gas Transportation Corridors

The national natural gas delivery network is intricate and expansive, but most of the major transportation routes can be broadly categorized into 11 distinct corridors or flow patterns.

- 5 major routes extend from the producing areas of the Southwest

More than 20 of the major interstate pipelines originate in the Southwest Region. Some extend to the Southeast through Louisiana and Arkansas, others to the Central and Midwestern States through Texas, Oklahoma, and Arkansas, and to the Western States through New Mexico. This area of the country exports about 45 percent (6.1 trillion cubic feet in 2007) of its production, which is 47 percent of the total natural gas consumed elsewhere in the lower 48 States.

Pipelines exiting the region have the capacity to accommodate as much as 45.2 Bcf per day: 62 percent to the Southeast Region, 20 percent to the Central Region, 13 percent to the Western Region, and the rest to Mexico. Much of the pipeline capacity directed toward the Southeast traverses the region en route to Midwestern and Northeastern markets. To a lesser degree, this is also true for the pipeline capacity exiting to the midsection of the country, much of which is ultimately destined for the Midwestern States.

- 4 routes enter the United States from Canada
- 2 originate in the Rocky Mountain area.

In the Central Region, only two major interstate pipelines originating within the region provides transportation services directly to another region, Kern River Transmission Company and the Rockies Express Pipeline Company. All the others operate primarily within the Central Region itself or originate in other regions. Shippers using these interregional lines to move supplies outside the region take advantage of the interconnections these lines have with the interstate pipelines traversing the region, principally those coming out of the Southwest Region.

3.1.4 Natural Gas Import/Export Pipelines

As of the close of 2008 the United States has 58 locations where natural gas can be exported or imported.

- 24 locations are for imports only
- 18 locations are for exports only
- 13 locations are for both imports and exports
- 8 locations are liquefied natural gas (LNG) import facilities

Imported natural gas in 2007 represented almost 16 percent of the gas consumed in the United States annually, compared with 11 percent just 12 years ago.

Forty-eight natural gas pipelines, representing approximately 28 billion cubic feet (Bcf) per day of capacity, import and export natural gas between the United States and Canada or Mexico.

Between 1990 and 2008, import pipeline capacity from Canada increased by 181 percent (to 18.1 Bcf per day) and from Mexico by 147 percent (to 0.9 Bcf per day). During the same period, export capacity to Canada more than tripled (to 4.3 Bcf per day) while export capacity to Mexico quadrupled (to 3.6 Bcf per day).

In 2007, the United States received 99.8 percent of its pipeline- imported natural gas from Canada with the remainder from Mexico. Canada also accounted for 60 percent of pipeline natural gas exports, and Mexico, 40 percent.

In 2007, the top five import points accounted for about 70 percent of all natural gas brought into the United States via pipeline. They are:

- Port of Morgan, Montana (Northern Border Pipeline)
- Eastport, Idaho (Gas Transmission Northwest)
- Sherwood, North Dakota (Alliance Pipeline Company)

- Noyes, Minnesota (Great Lakes Gas Transmission Company)
- Noyes, Minnesota (Viking Gas Transmission Company)

Five relatively small border crossing points (four in Montana and one in North Dakota) were also installed during the past decade, primarily to facilitate the movement of local production gas to processing plants or to pipeline receipt points located on the opposite side of the border. The relatively small level of natural gas flowing through these points is not counted as imports to the respective receiving country.

U.S. natural gas import and export activities are regulated under Section 3 of the Natural Gas Act of 1938 by the U.S. Department of Energy and the Federal Energy Regulatory Commission (FERC). While FERC is responsible for review and approval of the actual siting, construction, and operation of natural gas import and export facilities, DOE is responsible for authorization of the contracts governing the importing and exporting of natural gas.

3.1.5 Natural Gas Pipeline Capacity & Utilization

Natural gas pipeline companies prefer to operate their systems as close to full capacity as possible to maximize their revenues. However, the average utilization rate (flow relative to design capacity) of a natural gas pipeline system seldom reaches 100%. Factors that contribute to outages include: scheduled or unscheduled maintenance; temporary decreases in market demand; weather-related limitations to operations. Most companies try to schedule maintenance in the summer months when demands on pipeline capacity tend to be lower, but an occasional unanticipated incident may occur that suspends transmission service.

Utilization rates below 100% do not necessarily imply that additional capacity is available for use. A pipeline company that primarily serves a seasonal market, for instance, may have a relatively low average utilization rate especially during the summer months. But that does not mean there is unreserved capacity on a long-term basis.

On the other hand, during periods of high demand for natural gas transportation services, usage on some portions of a pipeline system may exceed 100% of certificated capacity. Certificated capacity represents a minimum level of service that can be maintained over an extended period of time, and not the maximum throughput capability of a system or segment on any given day.

Integrating storage capacity into the natural gas pipeline network design can increase average-day utilization rates. This integration involves moving not only natural gas currently being produced but natural gas that has been produced earlier and kept in temporary storage facilities.

Storage is usually integrated into or available to the system at the production and/or consuming end as a means of balancing flow levels throughout the year. Trunklines serving markets with significant storage capacity have greater potential for achieving a high utilization rate because the load moving on these pipelines can be leveled. To the extent that these pipelines serve multiple markets, they also can achieve higher utilization rates because of the load diversity of the markets they serve.

3.1.6 Natural Gas Market Centers/Hubs

Natural gas market centers and hubs evolved, beginning in the late 1980s, as an outgrowth of natural gas market restructuring and the execution of a number of Federal Energy Regulatory Commission's (FERC) Orders culminating in Order 636 issued in 1992. Order 636 mandated that interstate natural gas pipeline companies transform themselves from buyers and sellers of natural gas to strictly natural gas transporters. Market centers and hubs were developed to provide new natural gas shippers with many of the physical capabilities and administrative support services formally handled by the interstate pipeline company as "bundled" sales services.

Two key services offered by market centers/hubs are transportation between and interconnections with other pipelines and the physical coverage of short-term receipt/delivery balancing needs. Many of these centers also provide unique services that help expedite and improve the natural gas transportation process overall, such as Internet-based access to natural gas trading platforms and capacity release programs. Most also provide title transfer services between parties that buy, sell, or move their natural gas through the center.

As of the end of 2008, there were a total of 33 operational market centers in the United States (24) and Canada (9).

3.1.7 Underground Natural Gas Storage

At the end of the mainline transmission system, and sometimes at its beginning and in between, underground natural gas storage and LNG (liquefied natural gas) facilities provide for inventory management, supply backup, and the access to natural gas to maintain the balance of the system. Underground natural gas storage provides pipelines, local distribution companies, producers, and pipeline shippers with an inventory management tool, seasonal supply backup, and access to natural gas needed to avoid imbalances between receipts and deliveries on a pipeline network.

There are three principal types of underground storage sites used in the United States today. They are:

·depleted natural gas or oil fields(326)

·aquifers(43)

·salt caverns(31)

In a few cases mine caverns have been used. Two of the most important characteristics of an underground storage reservoir are the capability to hold natural gas for future use, and the rate at which natural gas inventory can be injected and withdrawn (its deliverability rate).Most underground storage facilities, 82 percent at the beginning of 2008, were created from reservoirs located in depleted natural gas production fields that were relatively easy to convert to storage service, and that were often close to consumption centers and existing natural gas pipeline systems. In some areas, however, most notably the Midwestern United States, some natural aquifers have been converted to natural gas storage reservoirs.

At the close of 2007, 400 underground natural gas storage sites were operational in the United States. During the year, four new storage sites were added, one in Michigan, Mississippi, Pennsylvania, and West Virginia, while 18 existing storage fields underwent expansions, and two storage fields were abandoned (ceased operations). Consequently, working gas capacity in the U.S. increased by 32 Bcf, to 4,091 Bcf (4,059 Bcf in 2006) while deliverability rates rose to 88.2 Bcf/d (85.1 Bcf/d in 2006). The largest expansion of working gas capacity (9.3Bcf) occurred at the Midland natural gas storage site in Kentucky, a depleted-reservoir facility. The number, type, and profile of underground natural gas storage varies by region.

3.2 U.S. Natural Gas Regulatory Authorities

3.2.1 Beginning of Industry Restructuring

In April 1992, the Federal Energy Regulatory Commission (FERC) issued its Order 636 and transformed the interstate natural gas transportation segment of the industry forever. Under it, interstate natural gas pipeline companies were required to restructure their operations by November 1993 and split-off any non-regulated merchant (sales) functions from their regulated transportation functions.

This new requirement meant that interstate natural gas pipeline companies were allowed to only transport natural gas for their customers. The restructuring process and subsequent operations have been supervised closely by FERC and have led to extensive changes throughout the interstate natural gas transportation segment which have impacted other segments of the industry as well.

3.2.2 Regulations Today

Most natural gas pipelines in the United States, including many in the intrastate segment as well, now only transport natural gas and no longer buy and sell it. Although interstate natural gas pipelines are no longer subject to as much regulation as before Order 636, many aspects of their operations and business practices, are still subject to regulatory oversight.

For example, FERC determines the rate-setting methods for interstate pipeline companies, sets rules for business practices, and has the sole responsibility for authorizing the siting, construction, and operations of interstate pipelines, natural gas storage fields, and liquefied natural gas (LNG) facilities.

Regulatory bodies have the authority to suspend some rules and regulations under specific circumstances, especially in response to emergency and disaster situations, placing needed projects on a regulatory fast-track.

3.2.3 Coordinating with other Regulatory Agencies

Almost all applications to FERC for interstate natural gas pipeline projects require some level of coordination with one or more other Federal agencies. For example, the Environmental Protection Agency assists FERC and/or State authorities in determining if the environmental aspects of a pipeline development project meet acceptable guidelines. FERC is also required to take the lead on the environmental reviews under the National Environmental Policy Act, the Endangered Species Act, the National Historic Preservation Act, and the Magnuson-Stevens Act. With respect to Natural Gas projects, FERC safeguards the environment by: disclosing, analyzing and minimizing impacts where it is feasible and reasonable to do so; encourage applicants to communicate with relevant federal and state natural resources agencies, Indian tribes, and state water quality agencies, prior to submitting an application; ensuring that all applicants perform the necessary studies to make an informed decision on the project; issuing environmental assessments (EA) or draft and final environmental impact statement (EIS) for comment on most projects; including requirements with any certificate issued to reduce environmental impacts; and visiting proposed project areas to determine the range of environmental issues requiring analysis and holding scoping meetings as appropriate.

Once Natural Gas pipeline projects become operational, safety is regulated, monitored and enforced by the U.S. Department of Transportation's Office of Pipeline Safety (OPS). Governing the safety standards, procedures, and actual development and expansion of any pipeline system is the job of the OPS. A pipeline may not begin operations until a line, or line segment, has been certified safe by the OPS. The OPS retains jurisdiction for safety over the lifetime of the pipeline.

3.3 Regulations of U.S. Natural Gas Pipeline

3.3.1 Regulation of Mergers and Acquisitions

To help ensure fairness and to preserve open markets, agencies at the Federal, State, and sometimes local levels examine mergers and acquisitions. Among those most actively involved in examining mergers and acquisitions at the Federal level are FERC, the Department of Justice, the Federal Trade Commission, the Internal Revenue Service, and the Nuclear Regulatory Commission. State public utility commissions, or their equivalent, also have responsibility for oversight in mergers and acquisitions of pipeline companies.

Each of the various agencies has the power to impose conditions that must be met to get approval for a merger or acquisition. If these conditions are not satisfied, the agencies can prevent the corporate combination from taking place. For example, analysis of mergers or acquisitions for potential harm to the consumer is under the shared jurisdiction of the Federal Trade Commission and the Department of Justice, where the concept of market power plays a central role in the antitrust review process.

3.3.2 Regulation of Interstate/Intrastate Transportation and Gas Tariff

FERC requires that any intrastrate, or local distribution pipelines engaged in the transportation of natural gas for any interstate pipeline, or local distribution company Served by an interstate pipeline must have an approved tariff on file with the Commission. 18 Code of federal regulations (CFR) Part 284 provides the tariff filing requirements and procedures for these pipelines to file rate changes and Statements of Operating Conditions (SOC) with the Commission. There are two separate regulatory provisions depending on the statutory authority a pipeline is subject to: the Natural Gas Policy Act (NGPA), section 311 or the Natural Gas Act (NGA), section 1(c) (Hinshaw).

The Commission follows similar processes in managing intrastate and Hinshaw pipeline tariff filings, though there are some differences due to the different underlying statutory authorities. The Commission will often refer to such tariff filings as Part 284 or section 311 filings regardless of the statutory status of the pipeline.

Intrastate Pipelines transporting natural gas, or local distribution pipelines served by an interstate pipeline are subject to section 311(a)(1) of the Natural Gas Policy Act. These intrastate pipelines must file with the Commission: Rates and Charges, and A

Statement of Operating Conditions (SOC) (tariff) pursuant to the Commission's regulations. NGA Hinshaw Pipelines are local distribution pipelines served by interstate pipelines that are not subject to Commission jurisdiction by reason of section 1(c) of the Natural Gas Act.

Hinshaw pipelines that receive a Blanket Certificate to transport natural gas on behalf of: any interstate pipeline or any local distribution company served by an interstate pipeline must file with the Commission rates, charges and a Statement of Operating Conditions (SOC) (tariff) pursuant to the Commission's regulations. In general, any transaction authorized under a blanket certificate is subject to the same: rates and charges, terms and conditions, and reporting requirements that apply to a transaction authorized for an intrastate pipeline.

As of September 30, 2010, all gas pipeline tariff filings must be made using the eTariff filing system. Current gas pipeline tariffs are available on the eTariff Viewer. The Commission requires that all tariffs, tariff revisions and rate change applications be filed electronically in the manner prescribed by Order No. 714.

3.3.3 Regulation of natural gas storage

The underground storage of natural gas has historically been critical in assuring that overall demands and use specific requirements of natural gas customers are met.

The Energy Policy Act of 2005 added a new § 4(f) to the Natural Gas Act, stating that the Commission may authorize natural gas companies to provide storage and storage-related services at market-based rates for new storage capacity (placed into service after the date of enactment of the Act), even though the company can't demonstrate it lacks market power.

To make this authorization, the Commission must determine that market-based rates are in the public interest and needed to encourage the construction of the capacity and that customers are adequately protected. The Commission shall ensure that reasonable terms and conditions are in place to protect consumers and must periodically review the market-based rates authorized to ensure they remain just, reasonable and not unduly discriminatory or preferential.

3.3.4 Regulation of Natural Gas Pipeline Development and Expansion

Under section 7 of the Natural Gas Act, the Commission reviews applications for the construction and operation of natural gas pipelines. In its application review, the Commission ensures that the applicant has certified that it will comply with Department of Transportation safety standards. The Commission has no jurisdiction over pipeline safety or security, but actively works with other agencies with safety and security responsibilities. To meet the growing demand for natural gas, the Commission must continue to respond quickly when companies propose to expand and construct needed pipelines and related facilities. The Commission has expedited the certification of natural gas pipelines by having Commission staff actively participate in projects that were using the pre-filing process to engage stakeholders in the identification and resolution of stakeholder concerns prior to the filing of a certificate application with the Commission. The staff's participation and initiative in these efforts will allow for the filing of better certificate applications enabling more efficient and expeditious licensing actions by the Commission.

An interstate natural gas pipeline construction or expansion project takes an average of about three years from the time it is first announced until the new pipe is placed in service. The project can take longer if it encounters major environmental obstacles or public opposition.

A pipeline development or expansion project involves several steps: Determining demand/market interest; Publicly announcing the project; Obtaining regulatory approval; Construction and testing.

To gauge the level of market interest, an open season is held for 1-2 months, giving potential customers an opportunity to enter into a nonbinding agreement to sign up for a portion of the capacity rights that will be available. If enough interest is shown during the open season, the sponsors will develop a preliminary project design and move forward. If not enough interest is evident, the project will most likely be dropped or placed on indefinite hold.

Developing the final project design and obtaining first financial commitments from potential customers may take from three to six months. Then, the project specifications are filed with the appropriate regulatory agency. If the proposed project involves an interstate pipeline, that is, it falls under the jurisdiction of the FERC, the project sponsor has the option of either requesting that a National Environmental Policy Act (NEPA) pre-filing review be initiated during the early states of project design, or waiting until later and filing with FERC under the traditional application review process.

The pre-filing process is designed to facilitate and expedite the review of natural gas pipeline projects that would normally require FERC to prepare an environmental assessment, an environmental impact statement, or a historic preservation review as part of the traditional review process. The project sponsor must notify and request that the various regulatory agencies be involved in evaluating the project if a pre-filing review from NEPA is filed. In this case, FERC staff will take the lead in scheduling and coordinating the approval steps.

A FERC review of an interstate pipeline project takes from 5-18 months, with an average time of 15 months. No data are available on the average time for obtaining approval from an individual State agency. Usually, approval by the regulating authority is conditional, but most often the conditions do not constitute a significant impediment. The project sponsor must then either accept or reject the conditions or reapply with an alternative plan.

4 Natural Gas Pipeline and the Regulation in China

4.1 China Energy Overview

Rapidly increasing energy demand, especially for petroleum and other liquids, has made China influential in world energy markets. Despite consumption and production growth slowing from recent historical averages, China still dominates world energy, remaining the world's largest energy consumer, producer and net importer. China had nearly 35,498 miles of main natural gas pipelines at the end of 2013. China intends to increase its natural gas pipeline network to 74,564 miles by 2020.

New leadership emerged in China in March 2013 when Xi Jinping became President and Li Keqiang assumed premiership. The new administration is keen to initiate economic and financial reform in China in the interest of greater long-term and sustainable growth. In November 2013, at the Third Plenum, a major policy meeting held every five years, the Chinese government outlined broad principles for economic reform in China. The government is pursuing incremental policy and economic reforms to create more balanced economic growth and to shift away from an economy driven primarily by excessive investments and exports to an economy characterized by greater domestic consumption. In the energy sector, the government is moving toward more market-based pricing schemes, energy efficiency and pollution-controlling measures, and competition among energy firms, as well as making greater investments in more technically challenging upstream hydrocarbon areas and renewable energy projects. China has been seeking ways to attract more private investment in the energy sector by streamlining the project approval processes, implementing policies to foster more energy transmission infrastructure to link supply and demand centers, and relaxing some price controls.

Chinese gas industry is characterised by an oligopolistic structure dominated by three companies. In most parts of the gas value chain, other players have limited roles. The gas industry needs a clear regulatory framework; this can be compromised by overlapping powers from different agencies and from the central and local governments. Some of the issues faced by China regarding gas are not new, but as

Chinese gas demand reached over 130 billion cubic meters (bcm) in 2011 (CNPC Research Institute, 2012), making it the fourth

largest gas market in the world, they have become more acute and could represent obstacles to further demand growth. The 12th FYP aims at doubling the share of gas in the primary energy demand, which means almost doubling gas demand by 2015 from the 2011 consumption level. This requires sufficient import infrastructure to be built in an efficient manner in co-ordination with building new domestic transmission, distribution and storage infrastructure. This also implies the need to attract sufficient supply, potentially in a higher price environment. Stakeholders' opinions on the potential demand levels by 2015 differs widely depending on their views on how much could be imported and produced domestically, with an average consensus at around 230 bcm.

China accounted for 23% of global energy consumption and 61% of net energy consumption growth. China remained the world's largest energy producer, accounting for 19.1% of global energy supply. Among the fossil fuels, consumption growth was led by natural gas (+8.6%), followed by oil (+3.3%) and then coal (+0.1%). All significantly below their ten- year averages. China's energy mix continues to evolve. While coal remains the dominant fuel, accounting for 66% of China's energy consumption, this was the lowest share on record and down from recent highs of 74% in the mid-2000s.

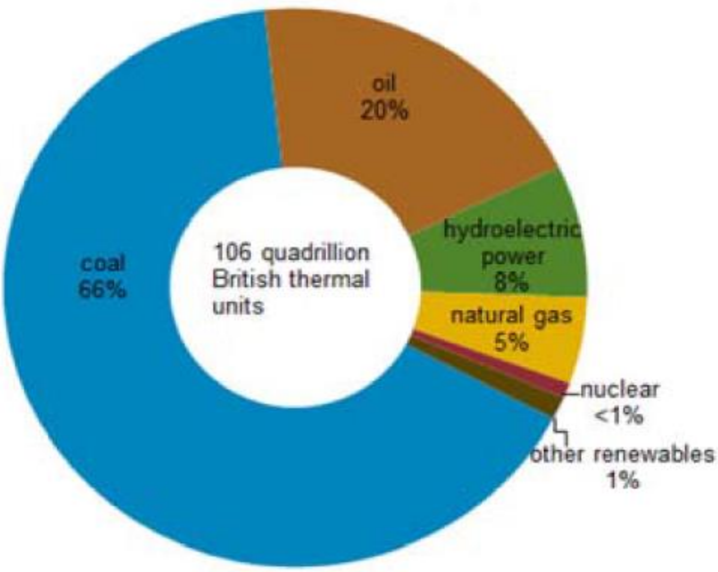


Table 4-1 Total Primary Energy Consumption In China by fuel type, 2012

4.2 Natural Gas Demand

In its current 12th Five-Year Plan (2011 to 2015), the Chinese government plans to double the share of natural gas in the primary energy consumption and reach consumption levels up to 260 billion cubic meters (bcm) by 2015, twice the level of gas consumed in 2011. Such a target is ambitious and implies that the country be able to attract sufficient supplies from all possible sources, not only from domestic gas production but also from imports of liquefied natural gas (LNG) and pipeline gas. This requires that all these supply sources deliver at the targeted level, whereby import levels depend crucially on the supply sources linked to long-term contracts to deliver supply in a timely manner at contracted level. Natural gas use in China has also increased rapidly over the past decade, and China has sought to raise natural gas imports via pipeline and as liquefied natural gas (LNG).

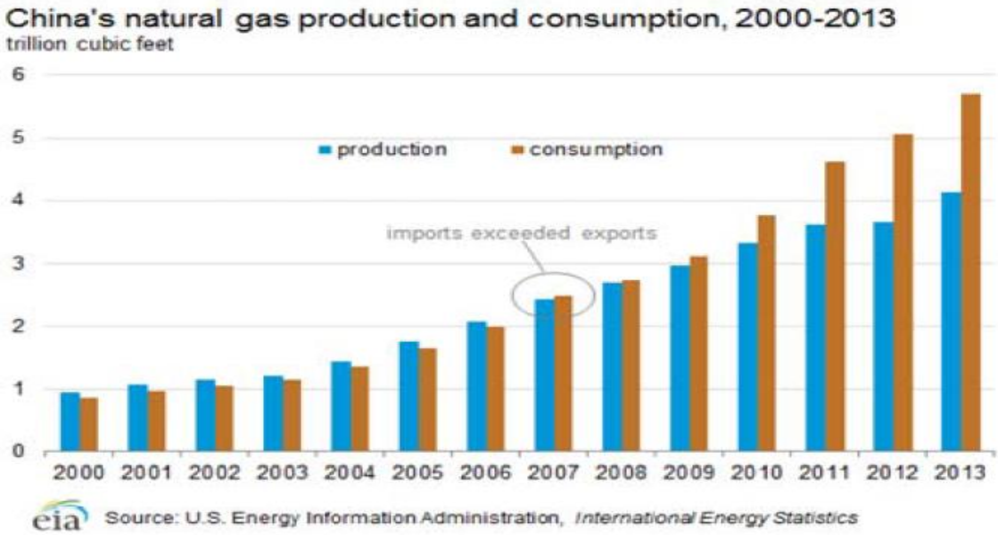


Table 4-2 China Natural Gas Product and Consumption, 2000 – 2013

Such targets of rapidly increasing gas consumption are not new, neither are the challenges associated with them. But these issues, mentioned above, have become more acute as Chinese gas consumption in 2011 has already increased fourfold from 2000 levels. While China's gas demand would double over 2011-15, the volumes implied are significant as China is already the fourth largest gas user in the world, consuming 130 bcm in 2011. China consumes more than any OECD country but the United States, and its gas consumption is foreseen to be one of the world's fastest growing. In 2002, China was already looking at doubling the share of gas in the primary energy mix within ten years. In 2011, it planned to do the same but within five years, potentially reaching an annual consumption level of 350 bcm by 2020, according to CNPC's forecasts. When the International Energy Agency (IEA) published a study with China in 2002, Developing China's Natural Gas Market (IEA, 2002), China was a self-sufficient country, and planning both longdistance pipelines to bring gas to coastal areas from far Western China (Tarim basin) and new terminals to import LNG. Since then, China has become a significant gas importer, with pipeline and LNG imports covering one quarter of its demand, and with increasing quantities of domestic gas production from areas far from demand centres. This trend is forecasted to accelerate, making China one of the world's largest gas importers.

China's gas demand growth slowed down to single digits in 2014, a substantial slowdown from the 14% averaged during the prior five years. Considering the massive slowdown in primary energy consumption that is taking place in the country, this growth rate is still impressive. Profound changes are unfolding in China in relation to both the structure of the economy and the way energy is deployed. However, the net effect of these transformations is less clear for gas than it is for other energy components. On the one hand, slower economic growth and the sharp slowdown in primary energy consumption growth are strong headwinds for gas. On the other hand, the ongoing intensification of China's environmental policy should be broadly beneficial for gas. In this respect, lower import prices have the potential to turn gas into an increasingly attractive option from an environment viewpoint. While the fuel remains uncompetitive when compared with coal, the price spread between the two has narrowed appreciably and has the potential to move the balance between the economic cost of using gas and its perceived environmental benefits. Overall, this outlook forecasts a moderate re-acceleration of gas consumption growth from the lows of 2014, and an average annual increase of 10% throughout the rest of the decade is projected.

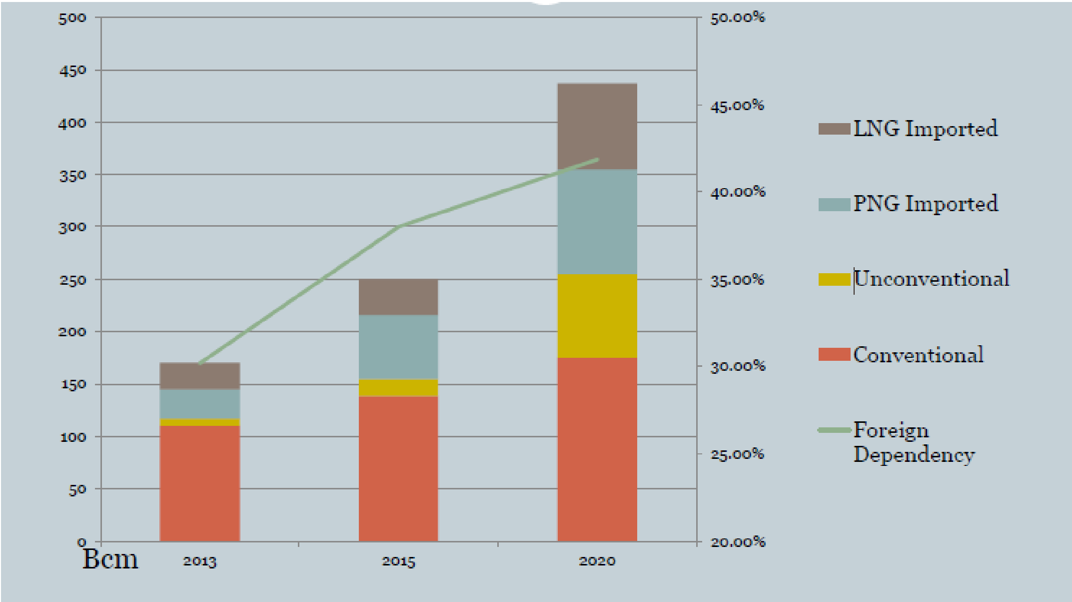


Table 4-3 China Natural Gas Consumption Forecast ， 2013 To 2020

4.3 Pipeline Scale and Construction in China

4.3.1 Pipeline Network Scale

China continues to invest in natural gas pipeline infrastructure to link production areas in the western and northern regions of the country with demand centers along the coast and to accommodate greater imports from Central Asia and Southeast Asia. At of the end of 2014, China has built natural gas pipeline of 85,000 kilometers, formed with the Shanjing pipeline, second Shanjing, third Shanjing line, west east gas transmission line, west east gas pipeline, Sichuan gas to east sent to other main trunk, Ji Ning line, line Huai Wu, blue and silver and noble line for the contact line of national backbone network, trunk pipeline network always lose gas capacity of more than 2000 billion cubic meters / year. In recent ten years, China's natural gas pipeline length with an average annual growth rate of about 0.5 million km.

CNPC is the key operator of the main gas pipelines, including the West-East pipelines, and holds nearly 80% of the gas transmission in China. CNPC moved into the downstream gas sector recently through investments in gas retail projects as well as investments in several pipeline projects to facilitate transportation for its growing gas supply. CNPC developed three parallel pipelines, called the Shan-Jing pipelines, linking the major Ordos basin in the North with Beijing and surrounding areas. The third Shan-Jing pipeline began operations in 2011. The NOC completed in 2013 its Zhongwei to Guiyang Gas pipeline, which delivers gas from the West-East pipeline network in the north-central part of the country to the gas markets in southwestern China. Sinopec is also a major player in the downstream transmission sector, operating long-haul pipelines from the Sichuan province to Shanghai and the north central region to Shandong along the northeastern coast. CNOOC operates pipelines mainly along the coastal areas of China.

China is expanding not only its pipeline capacity but also its LNG regasification capacity. The country started importing LNG in 2006 and has ten LNG terminals in operation with a total regasification capacity of some 46 bcm3. Eight LNG terminals are reported to be under construction or being expanded. This would increase China's total LNG regasification capacity to around 70 bcm3 in the coming years.

4.3.2 Pipeline Building

In 2015, natural gas pipeline industry remained the momentum of rapid development. There are four major natural gas pipeline projects to be completed in 2015 as follow:

1．In January 2015, ShanJing gas pipeline project across the board completed and put into production. The project has a total length of 1066 kilometers, design input capacity of 30 billIon m3 / year.

2．In February 2015, the forth ShanJing gas pipeline had been completed and put into production, which is 1274.5 km long. It's capacity is about 25 billion m3 / year.

3．In March 2015, Ordos - Anping - Cangzhou pipeline projectis has been built, which is 2422km. It's capacity is about 30 billion m3/ year.

4． In April 25, 2015, the west-east pipeline has been completed, which is 7378 km, It's capacity is about 300 billion m3/ year.

In the future, China will focus on the construction of the third, forth and fifth west-east gas pipelines, Russian-China gas pipeline, Xinjiang coal gas pipeline etc. When these projects fully completed, the national network system will have been basically formed.

4.3.3 Lack of Development of Pipelines

The United States counts around 500 000 km of pipelines, 70% of which are interstate pipelines, which can be compared to China’s long distance pipelines (China and the United States have roughly the same surface (including Alaska), while the United States consumes close to 700 bcm. By any account, China seems to have a long way to go before reaching the same developed network infrastructure as Germany or the United States. Even if CNPC meets its target of building another 40 000 km over the next five years, China would still have less pipeline than Germany with a demand level about 2.5 times higher.

In particular, long distance Coal Bedded Methane (CBM) transport infrastructure needs to be developed, and the same requirement will apply to shale gas, for this supply to reach coastal areas. Additionally, new areas of gas production might emerge with a push towards more market-based approaches on exploration and production, and will have to be connected to the demand centers.

4.4 Regulation in China

4.4.1 Pipeline Regulation

After Xi Jinping chaired a meeting of the central financial leadership, research on China's energy security strategy and stressed that in the face of new energy supply and demand pattern, the new trend of international energy development, to protect national energy security, China must promote energy production and consumption revolution. Natural gas as an important part of China's energy strategy, the oil sales network assets, and Russia signed gas purchase contract and other events in the background, in fact, the national relevant departments in 2014 2-4 months of intensive development of a series of policies and regulations, specifically as follows:

These documents are involved in the field of natural gas pipeline network open, supply and marketing contracts, infrastructure, the price mechanism and other aspects, is to build a new situation of natural gas regulatory system of important policy documents, will be a long time in the future development of natural gas industry has an important impact.

In order to break the monopoly of oil and gas pipeline network state, in February 13th, the National Energy Administration issued the Measures for the Supervision and Administration of Fair Opening of Oil and Gas Pipelines Network Facilities (for Trial Implementation). Requirements for oil and gas pipeline facilities companies, to open the use of oil and gas pipeline network facilities.

Through policy officially clear network facilities open to oil and gas pipelines and branches and related facilities, the introduction of oil and gas pipeline facilities to promote fair and open, improve the use efficiency of pipe network facilities, security and stability to protect oil and gas safety and stability, the current oil and gas industry in the current system, to solve the problem of opening up the main demand for the regulatory level.

The NEA shall be responsible for the work relevant to the supervision and administration of opening of oil and gas pipelines network facilities, The contents subject to supervision and administration shall include the planning of oil and gas pipelines network facilities, the implementation of plans and major oil and gas projects, fair opening of oil and gas pipelines network facilities, the capacity and efficiency of transportation (storage, gasification, liquefaction and compression), prices and costs, application for and access and acceptance, contract signing and implementation, information disclosure and submission, and other matters relevant to the fair opening of oil and gas pipelines network facilities.

4.4.2 Price of pipeline gas

4.4.2.1 Price reform

The ultimate goal of the reform of natural gas price is to release the price of natural gas, which is formed by market competition, and the government only manages the transportation price of natural gas pipeline with natural monopoly nature.

China's natural gas prices, similar to retail oil prices, are regulated by the NDRC and have been kept below international market rates. China's nascent natural gas market has flourished in the past few years and has become more complex as relatively expensive gas imports began to compete with domestic production. In order to bolster investment in the natural gas sector, to create more transparency in the pricing system and responsiveness to market fluctuations, and to make domestic natural gas competitive with other fuels and imported gas, the NDRC implemented a new system linking gas prices more closely to higher international oil prices.

China launched a pilot program for natural gas price reform in the southern provinces of Guangdong and Guangxi at the end of 2011. Following this pilot phase, China rolled out the reforms on a nationwide basis for all customers, apart from the residential and fertilizer sectors, in July 2013 as a three-phase reform process. The new system links the natural gas prices at the citygate (delivery point from a gas transmission pipeline to a local distribution utility) to the price of imported fuel oil and liquefied petroleum gas. The linked natural gas price is discounted to some degree to encourage use of natural gas rather than coal. The pricing scheme covers natural gas from imported pipeline gas, most domestic onshore sources, and LNG imports sent through pipelines. Prices for shale gas, coalbed methane, and coal-to-gas, and LNG imports sold at the terminal for local distribution can be negotiated between the producer and the wholesale buyer and are not subject to regulation. The reform created two categories of prices, one for existing demand based on 2012 consumption (Tier 1) and incremental natural gas demand above 2012 levels (Tier 2). The NDRC raised the average price for all Tier 1 customers by about 15% for non residential consumers. Average city gate ceiling prices for the second tier were set about \$3.7/MMBtu higher than the first-tier volumes.61

In September 2014, China ushered in the second phase of the reforms by increasing the prices for existing demand by around 20%, while keeping the price caps for the incremental demand the same.62 At this time, China created market-based prices for all imported LNG, shale gas, coalbed methane, and coal-to-gas even for volumes transported through the long-distance pipeline network. This policy allows sellers to market the gas directly to buyers through independent sales agreements.

In the third phase, which took effect April 1, 2015, the government combined the prices of the two tiers into one price by lowering the price for incremental demand and raising the price for the existing customer base. This last phase effectively lowered the price of Tier 2 customers by about $1.90/MMBtu and slightly raised the price for Tier 1 customers by $0.17/MMBtu, resulting in a weighted average price of 2.51 yuan/cubic meter ($10.62/MMBtu). Overall, average regulated city gate prices increased by more than 36% between the time prior to the reforms in 2013 and the third phase in 2015, according to IHS Energy. The NDRC plans to adjust this price ceiling every six months in line with the LPG and fuel oil prices. China also intends to create more market-based rates for residential customers by the end of 2015, but this directive has not been clearly defined yet.

4.4.2.2 Price Mechanism

Firstly, the current cost plus pricing method to become the main method of market net back value method pricing. Select the basis points and alternative energy sources, the establishment of natural gas and alternative energy price linked mechanism.
Secondly, natural gas price based on the basis of the price of the benchmark price, taking into account the natural gas market resources, the main flow and pipe transport costs, determine the price of the provinces (autonomous regions and municipalities) natural gas valve station. Comprehensive consideration of China's natural gas market resources, consumption and distribution of the status quo, the selection of the Shanghai market (central market) as the basis for valuation.

Third, the natural gas valve station price adjustment mechanism, according to the alternative energy price changes in a year, and gradually transition to every half year or quarterly adjustment. To establish the market price and alternative energy prices, the market price of natural gas valve is determined by the principle that the price of fuel oil and liquefied petroleum gas (LPG) can be replaced by fuel oil and liquefied petroleum gas (LPG), and the price of natural gas and natural gas is 90%: The formula for calculating the price of the central market is:

P NG -central mark et door station price (including tax), yuan / cubic meter;
K - discount factor, tentative 0.9;

α、â—The weights of alpha, beta, fuel oil and liquefied petroleum gas are 60% and 40% respectively;

P fuel oil, PLPG - the price of fuel oil and liquefied petroleum gas by the Customs Statistics in the period of the valuation, yuan / kg;

HFO, HLPG,HNG, - fuel oil, liquefied petroleum gas and natural gas net calorific value (low calorific value), respectively, 10000000 cards / kg, 12000000 cards / kg and 8000000 cards / cubic meters.

R - natural gas VAT rate, currently 13%.

The last issue is the release of shale gas, coal-bed methane, coal gas and other unconventional natural gas prices, the implementation of market regulation.

4.4.2.3 Price regulation

The central government on the city gate prices and long-distance pipeline price regulation, Local government sales price and urban Gas Co transmission and distribution costs, The central government regulation of natural gas prices for most domestic onshore natural gas and pipeline, domestic offshore natural gas, imported LNG, Unconventional gas (such as shale gas, coal-bed methane, coal-bed methane, coal gas), government regulation is gradually relaxed, the future direction is only natural monopoly nature of natural gas valve station price, well head price gradually liberalized control.

4.4.3 Regulation of Network

As regulation is one of the two key issues faced by the Chinese gas market, greater clarity is needed regarding agencies’ responsibilities. For instance, regulation of the network infrastructure, the part of the gas value chain the most vulnerable to monopolistic behaviour, is a patchwork with many open spots. A major issue is the lack of or limited access for smaller or foreign parties to gas infrastructure, be it transmission pipelines or LNG import facilities. Lack of access to the transmission infrastructure is probably the biggest hurdle, as it de facto prevents or limits any upstream competition as well as entry of new suppliers delivering LNG or pipeline gas to end-users or to gas distribution companies.

4.4.3.1 Regulatory Entities

There is no independent regulator for natural gas; authority is split between different ministries and agencies, while both the central and the local governments also have distinct powers. One possible solution would be to pass a natural gas law that would inter alia define the powers of a regulator and a regulatory framework for access to infrastructure. Such a law could establish a gas market structure that would provide a reliable level playing field for all participants, and would thus ensure private investors' confidence. It could also help to avoid progressive structural consolidation throughout the gas value-chain, and thereby ensure highest cost-efficiency through market competition while strengthening security of supply. The sooner these structural changes were imposed, the lower the level of market monopolisation – and its associated welfare losses, created by monopolistic prices and sub-optimal system architecture – would be, and the easier it would be for the government to be successful with such a reform.

The above approach is not the only possibility, of course. Were policy makers to decide that supply development were the most urgent task, an alternative would be a step-wise approach that focuses first on upstream liberalisation (including pricing), to foster development of new supplies, and that takes up the issue of network access at a later stage, on the condition that producing companies can develop pipelines to transport the gas to demand centres. This alternative would, however, potentially conflict with other policy goals, such as encouragement of investment in the energy sector by a broader set of participants to develop as wide an array of sources as possible, and to encourage the competition necessary to drive efficiency and to bring down costs.

An independent regulator with strong powers would not only enable fair and cost-efficient access to pipelines, it would overcome the present variety of entrenched stakes held by government agencies and the NOCs. This does not automatically require that the regulator be responsible for both upstream and midstream regulation;

there could be different entities responsible for upstream oil and gas activities and for power and gas markets. Additionally, there are some cases of missing regulation, notably in the cases of granting authorisation to build new pipelines, and granting access to existing pipeline networks, LNG infrastructure and storage facilities. Many industry observers doubt that a powerful enough regulator could be formed, and that ministries will not give up key parts of their current powers. There is also the question of the hierarchy in the government; where, for instance, would such an entity fit? At what level would it have to be placed to exert the authority necessary to carry out its functions?

In the decade prior to the start of the West-East Pipeline, China's natural gas consumption grew steadily by an average annual rate of 7%, then it jumped up and rapidly increased by above 20% per year from 2005 to 2007. However, natural gas is still a relatively minor fuel in China's energy mix and only detained a 3.5% share of total primary energy consumption (TPEC) in 2007, whereas the share of coal is 69.5%. The Chinese government has been promoting natural gas use in order to improve energy diversification and energy efficiency, and as a solution to environmental problems.

4.4.4 Emergency Policy

Since China was not a net importer until 2007 and its consumption of natural gas was quite limited compared to other fossil fuels, an emergency policy for natural gas disruption was not highly prioritised. However, in addition to the gradually increasing demand for natural gas and after a gas shortage in the winter of 2009, in 2010 the NDRC and the NEA started to ormulate a response plan in co-operation with oil and gas companies. The key elements of this plan are to further promote domestic natural gas production, to construct gas storage facilities and to accelerate construction of LNG terminals and interregional gas pipelines in order to strengthen the supply of gas imports. Since this plan is not public, detailed information is not available. However, the government is considering enhancing its readiness and preparedness for gas supply disruptions as natural gas becomes an important energy source. In November 2013, the NOCs are reported to have started to cut natural gas supplies to industrial consumers, and the chemical sector in particular, to ensure natural gas supply for the residential and transport sectors.

5 Comparisons and Implications

5.1 Comparisons

Through above analysis, competitive gas markets have been built in Australia and America. They have a common point that natural gas pipeline pricing has realized third party access ensured by laws and regulations. But some differences of pricing between them have embodied three aspects.

5.1.1 Difference among rate structure

The pipeline pricing includes proper incentives and pipeline transportation rate mostly uses the “ingress/egress” in Australia. But the pipeline pricing use two-part method and transportation rate uses the structure of point-to-point or area to area in North America. The reason is that the natural gas supply is dependent on a large part of import in Australia and self-sufficient in America.

5.1.2 Difference among pricing method

The pipeline transportation pricing method mainly adopts service-cost method in North America and cap pricing mechanism in Australia. The price can be free to determine only if the company's capital returns rate not exceeds the control under service-cost method. The supervision of returns rate exists a costing mechanism that means capital spending and operating expense of investments are easy to the price of product or service unrelated to the regulated rate whose establishment is estimated by moderators after considering diverse factors comprehensively sometimes existing regulators, companies game process.

Under cap pricing mechanism, the regulators set acceptable price upper limit and companies sell goods and services at any price among the limit to retain their profits. In ideal conditions, price upper limit directly refers to industry input prices and production rate so it allows price to change for a while in order to give space for market competition. The regulators permit companies to adjust price during some times by pre-determined coefficient.

5.1.3 Difference among government supervision

The gas long-distance transportation and distribution execute all the time tighter government supervision in North America. The market competition should not be opposed to government supervision and combined well with only except the differences among ranges and ways due to the different development degree of natural gas industry. But in Australia government adopts various incentive mechanisms to encourage company reinvestment except pipeline transportation price control.

5.2 Implications

Through above analysis, China gas market structure is very similar to the America's on small importation. So we can learn more lessons from it on the natural gas pipeline.

5.2.1 A timely imposing third party pipeline access

According to experiences of Australia and America, the third party pipeline access is one of the major measures for promoting gas industry competition. Now our pipeline building grows fast and has formed some regional pipeline networks. Along with the nationwide network's gradual formation, different main pipes may be connected. Meanwhile, gas suppliers possible need use different main pipeline capacity to make effective use of gas pipeline networks in order to avoid duplicate constructions. So our need carry out the third party pipeline access to set up competitive gas market. The third party access requires the separation between transportation and selling. Due to the marketing operation in gas industry now, the two businesses are still in a company but use financial independence of accounting. Thus the third party access basically can reserve property structure of our gas pipeline companies.

5.2.2 Gradually using the two-part pipeline price

Now our gas pipeline pricing method belongs to one-part range and treats all users equally. One-part pricing method recovers fixed pipeline transportation costs and variable costs by the actual used capacity. Its advantage is simple operation in theory and in actual operation. But it doesn't meet the feature of pipeline transport service. On the condition of facing users having different requirements, it causes unreasonable user burden, not fully utilized pipeline and other problems.

By contrast, the two-part pricing method can better apply to markets or customers requirement which can give expression to the equity of rights and obligations between pipeline companies and users. That transportation cost can be fair burden among users takes full advantage of pipeline transporting capacity and the best use reduces the level of average price in turn. These promote pipeline companies to recover investment timely and gain justifiable return.So the pipeline pricing should gradually adopt two-part method based on annual total service costs.

Specifically, the pipeline capacity fees should be collected by following requirements on peak-use in order to recover the fixed costs. After reserving capacity in contract, users must pay whether actual volume reaches the reserved or not. The pipeline company should compensate relative loss to users because it did not transport enough gas in time as contract, the pipeline using fee should be collected by following the actual spending in order to recover the variable costs. The rate is related to the variable costs and relevance expenses in gas pipelining. The pricing mechanism is helpful for promoting consumers to keep balance in using gas as they could in different seasons, increasing pipeline system loading, taking full using of capacity, reducing per unit costs and recovering investment, gaining justifiable return for pipeline investors.

5.2.3 Improving legal laws and regulations

Legal laws and regulations are the law guarantee for gas industry healthy stability development. There are definite provisions of accounting policy, transportation rate and rules, selling related to gas pricing management through the legislation in Australia and America. But now the legislation is vacant in our gas industry which used to standardize operations in natural monopoly area, a few laws involved oil and gas have narrow surface, short pot life and little authority. Therefore our country should accelerate research and work out relevant laws and regulations as gradually relaxing gas transportation pricing controls. And meanwhile the need for effective regulation is nevertheless undeniable.

5.2.4 Adopting discriminatory policy on the situation

The third party access should be used and regional regulator should be built in our eastern parts because the gas source and market competition pattern had or will have been built. The parts whose base installation has implemented certain scale and gas supply market has less competitiveness should aim at increasing working efficiency and furthering gas exploit. To the parts only running on initial development period, we should encourage infrastructure investment and regulate the pricing of gas product and service more vigilantly through preferential policies and a long-term institutional arrangement.

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