Developing a natural gas trading hub in China

By

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ABSTRACT

Natural gas demand is expected to grow rapidly in China in the coming decade with the policy target of increasing the natural gas contribution to the energy supply from less than 6% in 2014 to 10% in 2020. Ensuing the 2013 national pricing reform, China started to launch more fundamental market reform in the natural gas industry and proposed to set up a gas hub in Shanghai. At the same time, there are also heated discussions for Asia to set up a benchmark gas hub with the growing needs for gas-to-gas pricing. This study discusses how China can successfully develop the Shanghai benchmark hub with deep analysis of both the unique features of the China's gas market and the development of the successful hubs in the US and Europe. By identifying the critical physical and market conditions of a successful hub such as sufficient infrastructures, the open access to the network and a more competitive market structure, the study summarizes the key takeaways of the international experiences that are most relevant to China's current situation. Then the author proposes the detailed pathway for the development of the Shanghai gas hub. The preliminary proposal argues that the reform should first start from LNG by distributing the costs of the large take-or-pay contracts which were signed at high prices. Then more substantial reform should be implemented with setting up an Independent System Operator (ISO) in charge of the operation and the investment of pipelines, LNG terminals and other infrastructures, yet still leaving the ownership of the assets to the three big oil companies. Such unbundling should start from the national level with the conditions that big consumers should be permitted direct connection to the trunk pipelines. Additionally, a new mechanism incentivized the ISO to efficiently expand and connect the network should be designed.

Thesis Supervisor: John Parsons
Title: Senior Lecturer/ MBA Program Finance Track Head
Acknowledgements

Working on this thesis is one of the most unforgettable and enjoyable experiences for me in MIT. During the process of writing this paper, I have received numerous help and advice from the thoughtful academic mentors, policy makers and industry experts across four countries in China, the US, the UK and Netherlands.

First, I want to thank my thesis advisor Prof. John Parsons for all the challenging questions he asked me. I still remember how frustrated I was when I came out of our first meeting after I arrived at MIT. I failed to answer almost all the questions and was then too nervous to ask any questions in my original question list. Certain experiences had often repeated afterwards. However, it was those questions, which seemed obvious at the first glance but were indeed fundamental to understanding the topics, that helped me to analyze the problems deeply. Actually, I later found this process of being challenged and then thinking critically is the most exciting moment for me in MIT. Another unforgettable quote from Prof. Parsons is that “don’t rely your writing on the literature because most literature is written on an average standard. However, I want you to become a good writer that is above the average.” I find I’m extremely fortunate to have the opportunity to be both challenged and encouraged by Prof. Parsons, which is the most valuable learning process during my studying at MIT.

Additionally, I want to thank Prof. Ignacio Perez-Arriaga from MIT and Prof. William Hogan from Harvard for teaching me the fundamental principles of the electricity market, which I then took reference a lot for working out the natural gas problems. I also appreciated both of the world experts’ help in introducing me to the policy makers and industry specialists in both the US and Europe.

During the past half year, I travelled extensively in the US and Europe, interviewing those who either personally experienced the liberalization of the natural gas market or who are currently running the gas market. The major institutions I visit include the independent gas regulators and the pipeline operators. Thanks for the help of all the interviewees, I’m very fortunate to have direct exposure to the insightful details of the liberalization process in the two continents dated back to 1990s.

Finally, I want to thank my colleagues in the SHPGX. They not only helped me to gain a deeper understanding of many unique features of the China’s gas market but also raised many interesting questions they encountered during the work, which help me to better evaluate the possible solutions that are more fit into China’s context.
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Introduction

The natural gas demand in China has been more than triple in the past decade. With China's even more severe environment pollution and the commitment to reduce the carbon emissions, natural gas is targeted to increase from less than 6% of the energy consumption in 2014 to 10% in 2020 in the Twelfth Five Year Plan. To reach the goal, the Chinese government has launched a national natural gas pricing reform program since 2011. A combination of the netback and oil indexation mechanism is adopted, and Shanghai city gate price is chosen as the benchmark price. To further increase the efficiency of the natural gas market and make gas competitive among the power mix, a more fundamental reform is in the progress. Many topics such as the open access to the network and setting up a natural gas hub in Shanghai are under heated discussion.

At the same time, Asia gas markets, which highly rely on LNG import, are facing increasing challenges of the current Japan Crude Cocktail (JCC) linked price mechanism. The soaring oil prices in the early 2010s coupled with the Fukushima nuclear accident in 2011 make the LNG buyers in great financial distress. As the Asian countries continuously moving away from oil, the oil-indexed pricing no longer consistently reflects the supply and demand of the natural gas market, and thus, there are growing interests in moving to gas-to-gas pricing mechanism. A natural gas benchmark hub in Asia is expected to greatly contribute to the development of the Asian gas market.

Aimed to prompt the market liberalization of the gas industry in China and set up the Asian natural gas benchmark hub, the Shanghai Petroleum and Natural Gas Exchange (SHPGX) was launched in July 2015 with a strategic alliance of National Development and Reform Commission (NDRC) and Xinhua News Agency in China.

While previous studies discussed the pros and cons of hub development in major Asian countries such as Singapore, Japan, Korea and China, the author thinks the Shanghai hub has certain physical and market advantages that other Asian hubs are incomparable with. However, the natural gas market in China is still at an early stage of development. Therefore, the goal of this paper is to propose a detailed pathway of how China can successfully develop the Shanghai benchmark hub with the recent natural gas market reform. The study first takes a thorough revision of the natural gas market in China. In particular, it reveals several unique features of China's gas market such as the domestic LNG market. Chapter 2 reasons the needs to move to gas-to-gas pricing both for China and Asia by reviewing the current pricing mechanism. Chapter 3 identifies China's strength and weakness in developing a benchmark gas hub in Asia based on the analysis of the critical physical and market conditions of a successful natural gas hub. Chapter 4 takes an in-depth analysis of the successful hubs (Henry Hub, National Balancing Point and Title Transfer Facility) in the US and Europe based on the interviews with the pipeline operators and the regulators that personally went through the liberalization process in these countries. Most importantly, the study summarizes the key takeaway that is most relevant to China's current situation. Based on all the previous discussion, Chapter 5 gives the preliminary proposal on the first stage of the development of Shanghai gas hub.

1 Though the SHPGX is called “Exchange”, its functions are very different from those of the traditional exchange. This will be discussed in more details in Chapter 5.
Chapter 1. China’s Natural Gas Market

1.1 Demand and Supply

1.1.1 Consumption

The consumption of natural gas in China rose substantially in the past decade. Compared to 51 billion cubic meters (bcm) in 2005, the consumption in 2014 rose to 188 bcm (BP 2015). While Japanese consumption represented the mainstay of Asian natural gas demand, China surpassed Japan as the largest natural gas consumer in Asia in 2010. An even larger gas demand is expected in the future as China seeks alternatives to coal with the severe environment pollution. In the Twelfth Five Year Energy Plan, natural gas was targeted to reach 10% of the total energy demand by 2020 (NDRC 2012). Nevertheless, natural gas only accounted for 6.3% of China’s overall energy consumption by the end of 2014.

Currently, industry accounted for the largest share of gas consumption. The consumption of natural gas in non-industrial sectors only became important until the 2000s. Followed by industry consumption (34%), residential and power generation respectively accounted for 20% and 18% of the gas consumption in 2012. Power generation is considered one of the most potential sectors for the future growth in natural gas consumption because it only accounted for 2.2% of national electricity generation in 2012. Transportation is another sector expected to have high growth in the future. As the leading country in the Compressed Natural Gas (CNG) vehicles, transportation accounted for 10% of natural gas consumption in 2012 (Li 2015).

Figure 1. Natural Gas Consumption by use between 2004 and 2012 (Li 2015)

1.1.2 Production

Though China more than tripled the domestic gas production since 2003, the production was still hard to keep up with the roaring demand (Figure 2). It produced 123.5 bcm natural gas in 2014 from four key regions (the Tarim Basin, the Sichuan Basin, the Ordos Basin, and the South China Sea Basin) which covered 90% of China’s total domestic gas production (EIA 2015).

Comparatively, the unconventional gas production was still limited (1.95% of gas production). Though EIA estimated that China had the largest shale gas reserves of 31.6 trillion cubic meters (tcm) in the world, the shale gas production in 2013 only accounted for 0.17% (0.2 bcm) of the China’s gas production. The slow growth forced the government to cut half of its original target (60 bcm) for the shale
gas production in 2020, which made the future development of shale gas more unclear (Renmin 2014).

**Figure 2.** China’s natural gas production and consumption, 2004-2014 (Source: BP)

200------
160--
140----
120-----
100---
80-----
60----
40-----
20-
0

- production  consumption

1.1.3 Imports

As China’s natural gas consumption outstripped domestic supply since 2007, there are rising imports of both liquefied natural gas (LNG) and pipeline gas. China’s total gas imports volume was 58.3 bcm (31% of the gas consumption) in 2014. Imports of pipeline gas (31.3 bcm) were a bit more than those of LNG (27 bcm).

Imports of pipeline gas didn’t start until 2010 when the first pipeline imports flowed to China from Turkmenistan through the first Central Asia Gas Pipeline (CAGP). Currently, other countries supply gas through CAGP including Uzbekistan and Kazakhstan. Additional to the first and second line of the CAGP, the third line, which started to operate by the end of 2015, and the fourth line, which is expected to complete construction by the end of 2020, will add up to the annual capacity of 85 bcm, almost triple the current gas imports (Sergey and Danwei 2015). The CAGP are connected to China’s West-East gas pipelines that pass through China from its western border all the way to Shanghai.

Additional to CAGP, there are two new sources of imports from Myanmar and Russia. In 2013, the Myanmar Gas Pipeline started to deliver 12 bcm gas to Guangxi and Yunnan regions. In 2014, China and Russia finalized a natural gas agreement that allowed China to purchase and transport gas from the Power of Siberia pipeline with up to 38 bcm annually of natural gas for 30 years starting in 2018 (Xinhua News Agency 2015). Another Russia’s Atai pipeline, which could deliver gas of 88 bcm annually, is also currently under negotiation (Paik 2015). If this agreement is reached, it will greatly crowd out the future LNG imports because the overall pipeline imports will add up to 223 bcm, more than the overall natural gas consumption in 2014.

China is also a major LNG importer. In 2012, China rose to become the third-largest LNG importer in the world, after Japan and South Korea. While Qatar is the biggest LNG exporting country to China (34%), the remaining LNG imports came from Australia (24%), Indonesia (16%) and Malaysia (13%). China currently has 11 LNG receiving terminal along the urban coastal, the capacity of which is 45 bcm annually. If the further 13 terminals in the planning stages are eventually built, it will take China’s LNG import capacity to 150 bcm annually (Russell 2014). However, due to China’s ever-growing LNG expansion and economic slowdown, the utilization factor of the receiving terminal is only about 50% (Paik 2015).
1.2 Pipeline gas market

This study divides China’s natural gas market into two markets, the pipeline gas and LNG markets, based on whether the natural gas is delivered to the end users through pipelines or LNG trucks. The reason of such division is the distinct market structures and players. While the pipeline gas market is dominated by monopolistic sellers and buyers, the LNG market is highly competitive with many private companies. Section 1.2 and 1.3 will analyze these two markets respectively from the upstream, midstream to downstream.

1.2.1 Upstream

The upstream of the pipeline gas market in China is controlled by the big three oil companies, China National Petroleum Corporation (CNPC), China Petroleum & Chemical Corporation (Sinopec) and China National Offshore Oil Corporation (CNOOC).

The three oil companies are the only legal direct importers of natural gas in China. For the production, CNPC was the first to produce natural gas in China in Changqing field in Shaanxi Province, though this field is depleting recently. CNPC is the largest gas producer in China (75% of the gas production) in 2014 with most of its production from the Tarim and the Sichuan basin. Sinopec constituted 16% of the overall gas production in 2014. Most of the production of Sinopec came from Puguang field in Sichuan basin, which was discovered in 2005 and estimated to have the reserves of 500-550 bcm (IEA 2014). Comparatively, CNOOC only produced a small amount of onshore natural gas. The majority of its natural gas business is LNG imports. Other small players such as Shaanxi Yanchang Petroleum (municipal), Xinjiang Guanghui (private), Henan CBM (private) are mainly producing unconventional natural gas.

Figure 3. Natural gas production in China (Source: Paik 2015)

1.2.2 Midstream: pipelines

With the production of CNPC in Changqing field, the 1st Shaanxi-Beijing gas pipeline was put into construction in 1996. This is also the start of the large-scale construction of natural gas pipelines for China (Gao 2013). In the following decade, China expanded its natural gas pipelines quickly, the total length of which was estimated to be nearly 85,000 km in 2014. CNPC is the largest owner of the trunk pipelines (75%) (IEA 2014). One of the most significant projects is the West-East Gas Pipelines owned by CNPC, which connect the consumption regions in the East Coast to the West. With two lines in operation, one line in construction and another two lines in plan, the project delivers natural gas from Western China and Central Asia to the major target consumer markets in Southeast China. Once the
The whole project is completed, it will have a total length of more than 20,000 km and an annual delivery capacity of 77 bcm (CNPC 2013). The detailed information of major natural gas pipelines is shown in Appendix 1 and 2.

In 2014, National Energy Administration (NEA) issued **Third-party Access to Oil and Gas Pipelines**. The guidelines permitted the third parties the access to the natural gas pipelines and related infrastructure (such as storage, liquefaction, LNG etc.) that have excess capacity on a non-discriminatory basis (NEA 2014). However, the guidelines didn’t have any practical impact on the operation due to the monopoly power of the three oil companies. The details the open access to pipelines will be analyzed in Chapter 3, 4 and 5.

**1.2.3 Downstream**

Different from the up and midstream, the natural gas distribution in China is crowded with more than 800 private and foreign companies in 2015. While no companies have the dominance, the largest distribution companies that have inter-regional business are Towngas (Hongkong company), ENN (private), China Gas holdings (private), China Resources Gas (State-owned), Kunlun Energy (owned by CNPC), Beijing Gas (municipal) and Shanghai Gas (Figure 4). It was not until 2008, CNPC’s gas distributors arms, Kunlun Energy, entered into the sector and tried to squeeze out non-state firms such as China Gas that had entered the business more than a decade ago (Zhu 2012).

However, the gas distribution in China is not a competitive market because once a gas distributor wins the bid for the franchise, it becomes a local monopoly. The gas distribution company makes profits by buying gas from the upstream at the city gate price and selling it to the end-users at the price set by the local government. Though the end-users price is based on the city gate price plus the distribution cost, there is flexibility in calculating the distribution cost considering the local monopoly power. Moreover, many gas distributors actually make profits through the installation fees rather than the distribution pipeline rate. The average installation fees of a new apartment are about 3000 RMB (460 USD), which is about twice of the original cost (Petroleum Online Newspapers 2014).

**Figure 4.** The sales of the major natural gas distribution companies (Source: Jing 2015)
1.2.4 Summarization of the pipeline gas market structure

<table>
<thead>
<tr>
<th>Upstream</th>
<th>Midstream</th>
<th>Downstream</th>
</tr>
</thead>
<tbody>
<tr>
<td>State-owned monopoly</td>
<td>State-owned monopoly</td>
<td>Local monopoly</td>
</tr>
<tr>
<td>• CNPC, Sinopec, CNOOC (pipeline imports and majority of gas production)</td>
<td>• CNPC, Sinopec, CNOOC</td>
<td>• 800 hundred local gas companies</td>
</tr>
<tr>
<td>• Small players (mainly unconventional): Yanchang, Xinjiang Guanghui, Henan CBM</td>
<td></td>
<td>• Top companies: Towngas, ENN, China Gas, China Resources Gas, Kunlun Energy, Beijing Gas and Shanghai Gas</td>
</tr>
</tbody>
</table>

1.3 The LNG market

The LNG market is a market very peculiar to China. The upstream of the LNG market is either LNG imports or the liquefaction plants that liquefied pipeline gas. About two-thirds of the LNG in the LNG market comes from liquefaction plants from January to October in 2015 (Figure 6). The LNG is then delivered through LNG trucks to the end-users. While the end-users used to be either industry or residential sector in the remote areas that were inaccessible to pipelines, because of the expansion of pipelines the primary end-users are now shifting to LNG fueling stations for heavy vehicles as an alternative to diesel. The supply chain of the LNG market in China is shown in Figure 5.

Figure 5. The LNG market in China

![Figure 5](image)

Figure 6. The supply of the LNG market in China (Source: SCI 2015)

![Figure 6](image)
1.3.1 Upstream

1. Liquefaction plants
Most of the liquefaction plants are owned by private companies (the list of top LNG Liquefaction
companies is shown in Appendix 4). The first liquefaction plant was set up in Henan Province in 2001
with a capacity of 0.3 mcm/day (million cubic meters/day). The industry grew rapidly since 2008 (Figure
6) and reached the capacity of 64 mcm/day in 2014. Different from the liquefaction plant for LNG exports
in other countries, the average capacity of an LNG liquefaction plant in China is about 1 mcm/day (ICIS
2015a).

2. LNG Terminals
The three oil companies are currently the only owners of LNG receiving Terminals, with CNOOC as the
first mover in the LNG business and the largest owners of LNG receiving terminals. China’s first LNG
receiving terminal, Dapeng LNG terminal in Guangdong Province owned by CNOOC, was put into
operation in 2004. Among the eleven LNG terminals in operation, CNOOC owns seven operational LNG
receiving terminals with a total capacity of 24.9 mt/yr (million tons/year). CNPC owns the three
operational LNG receiving terminals in Dalian, Rudong and Tangshan, with a combined capacity of 10
mt/yr. Sinopec is the last to start its LNG business. Its first terminal in Qingdao began operations in 2014.
The sole control of the three oil companies in LNG terminals didn’t change until 2015 when the NDRC
approved the first privately owned LNG receiving terminal project in Zhoushan by ENN. However, the
construction was postponed until January 2016 (AsiaChem 2016). The detailed information of LNG
Terminal projects is shown in Appendix 3.

There are two requirements for directly importing LNG to China. 1) The permission from the Ministry of
Commerce. Different from oil, as long as a gas company has the business license in China, it can
automatically gain the approval. 2) The access to harbors and receiving terminals, which needs to be
approved by NDRC. In 2014 Third-party Access to Oil and Gas Pipelines issued by NEA also
permitted the third-party access to LNG terminals (Qu 2013). In August 2014, CNPC’s LNG terminal in
Jiangsu opened to Shenergy Group (owned by the provincial government) as the first third-party access of
LNG terminals practice in China. Later in 2014 and 2015, the terminal was opened to ENN (private) and
Pacific Gas Company (Foreign). Though theoretically there are no policy obstacles for companies other
than the big three oil companies to directly importing the LNG to China, there are still many challenges in
practice. This will be discussed in more details in Chapter 5.

1.3.2 Midstream: LNG trucks
The LNG trucks are mainly owned by private companies (the list of top companies owning LNG trucks is
shown in Appendix 4). On average, an LNG truck is able to deliver about 30,000 cubic meters of LNG
per trip. While transporting LNG via trucks used to be a lucrative business with long delivery distance,
the penetration of LNG imports and the sharp growth in the number of LNG trucks greatly depressed this
logistic market (Figure 8) (ICIS 2015b).
1.3.3 Downstream

The major end-users of the LNG market are LNG fueling stations for heavy-duty trucks powered by LNG. Such trucks mainly transport cargoes, which are different from the LNG logistic trucks for transporting LNG. The LNG fueling stations are owned by multiple players (The list of top companies owning LNG fueling stations is shown in Appendix 4).

China is currently the leading country for natural gas vehicles in the world. CNG, accounting for 97 percent of vehicles running on natural gas, is the major competitor with LNG vehicles. However, compared with CNG that has lower energy density, LNG is better for heavy-duty vehicles that are in constant operation and need to be refilled quickly (Bloomberg 2016). The location of LNG fueling station is also more flexible than that of CNG since CNG is usually delivered through pipelines. More than 100,000 LNG powered vehicles were running on the road in 2014 (GE Reports 2015). More growth is expected because the gas price at fueling stations in China is far lower than the diesel price and there are more than 330,000 of heavy-duty trucks on the road (Jones 2015). Though the number of LNG fueling stations was more than triple from 2012 to 2014, the lack of fueling infrastructure is the largest constraint (Figure 9).

Figure 9. Number of LNG fueling stations in China (Source: SCI 2015)
1.3.4 Summarization of the LNG market structure

**Table 2. Market structure of the LNG market**

<table>
<thead>
<tr>
<th>Comapetiveness</th>
<th>Upstream</th>
<th>Midstream</th>
<th>Downstream</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Liquefaction plants: highly competitive</td>
<td>LNG logistics trucks: highly competitive</td>
<td>LNG fueling stations: competitive</td>
</tr>
<tr>
<td></td>
<td>LNG imports: monopoly</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Major Players</td>
<td>Liquefaction plants: mainly private companies</td>
<td>Many private companies</td>
<td>CNPC, CNOOC, ENN, Guanghui</td>
</tr>
<tr>
<td></td>
<td>LNG receiving terminals: CNOOC, CNPC and Sinopec</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Chapter 2. Move to gas-to-gas pricing

While historically the majority of natural gas pricing is either oil-indexed or government regulated in Asian countries, there is an increasing interest in gas-to-gas competitive pricing to increase the efficiency. This section will separately review the natural gas pricing system across Asian countries and specifically in China to argue the rationale for both to move to the gas-to-gas pricing.

2.1 Basic pricing formation mechanisms for natural gas

There are generally two formation mechanisms for a natural gas price, market-based or regulation-based. Under the market-based mechanism, gas price is determined by the supply and demand in a market, which can also trade commodities other than natural gas. In comparison, the regulated gas price is decided by the government directly (IEA 2013). The International Gas Union (IGU) has identified four major market-based pricing mechanisms and four major government-regulated pricing mechanisms (IGU 2015).

<table>
<thead>
<tr>
<th>Table 3. Market-based Natural Gas Pricing (IGU 2015)</th>
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<tbody>
<tr>
<td><strong>Oil Price Escalation (OPE)</strong></td>
</tr>
<tr>
<td><strong>Gas-on-gas Competition (GOG)</strong></td>
</tr>
<tr>
<td><strong>Bilateral Monopoly (BIM)</strong></td>
</tr>
<tr>
<td><strong>Netback from Final Product (NET)</strong></td>
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</table>

<table>
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<tr>
<th>Table 8. Regulation-based Natural Gas Pricing (IGU 2015)</th>
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<tbody>
<tr>
<td><strong>Cost of Service (RCS)</strong></td>
</tr>
<tr>
<td><strong>Below Cost (RBC)</strong></td>
</tr>
<tr>
<td><strong>Social and political (RSP)</strong></td>
</tr>
<tr>
<td><strong>No Price (NP)</strong></td>
</tr>
</tbody>
</table>
Figure 10 shows the pricing formation of natural gas in different parts of the world. In Asia, oil indexation and regulation are the dominant price mechanism. The US and the UK are the two most competitive markets with the majority of the gas based on gas-to-gas pricing since the liberalization of the natural gas market in the 1990s. Comparatively, the liberalization process in the continental Europe still leaves a large portion of its gas indexed to oil. In the Middle East, the Former Soviet Union and Africa, gas prices are highly regulated (IGU 2015).

**Figure 10.** The price formation of natural gas consumption in 2014² (Source: IGU 2015)

![Figure 10: Price formation of natural gas consumption in 2014](image)

**The increase of efficiency with gas-to-gas pricing**

Because the production and the network of natural gas need huge upfront investments, long-term forward contracts are a typical element of financing for sellers to gain the following two advantages: 1) they gain the information on demand that is revealed in a market price, and 2) they are likely to negotiate a higher sale price for their products since they can avoid the ex-post bargaining problem (Parsons 1989). However, the long-term contracts currently cause much inefficiency. Due to the lack of a gas market in the most part of the world, the price for the long-term contract is usually fixed or indexed to an alternative fuel such as oil. Such price doesn’t match the supply and demand of natural gas at all time. The rigidity of the long-term contract creates the risk that makes the buyers less willing to pay a higher price or contract a higher volume. Therefore, there is inefficiency in the market when many trades that could happen don’t take place.

Moving to gas-to-gas pricing makes everyone better off because the long-term contract indexed to the gas price indices increases the flexibility of the trading. By delivering the right price signals to the sellers and the buyers, it matches the current supply and demand with larger contract volumes at a higher price on average.

2.2 Natural gas pricing in Asia

2.2.1 Current natural gas pricing in Asia

Compared to the world average, the natural gas trade in Asia has a higher percentage of oil-indexed pricing (Figure 10). The major countries consuming natural gas in Asia are China, Japan, Korea, and

² Asia here refers to both Asia and Asian Pacific regions in IGU 2015 report.
Taiwan. However, all these countries except China do not have significant domestic gas resources and access to international pipelines, and thus have to rely heavily on LNG imports.

In 1969, LNG was first imported into Japan, and through the early 1970s, the price was fixed. This ensured the suppliers to recover their huge initial investments with certainty. However, after the oil shock in the 1970s, the price of LNG was gradually raised in line with the price of the Japanese Crude Cocktail (JCC). In the 1990s, the low oil prices caused LNG suppliers to suffer from deteriorating project economics and the new pricing mechanism, S-curve, was introduced (Figure 11). S-curve reduces the slope at the upper and lower pivot points and thus has the effect of protecting the buyer from high oil prices and the seller from low oil prices.

\[
P_{LNG}($/MMBtu) = A \cdot P_{JCC}($/bbl) + B ($/MMBtu)
\]

Figure 11. The notional S-curve of LNG contract (Source: EY 2016)

2.2.2 The rationale for gas-to-gas pricing in Asia

Though the JCC mechanism worked well in the past, many problems arose recently with increasing demand after the Fukushima accident and the needs for natural gas to be competitive with fuel other than oil in the end-users market.

As the crude oil prices soaring above $100/bbl in the early 2010s, LNG prices in Asia also dramatically increased. The Fukushima nuclear accident in 2011 further placed Japanese LNG buyers in an even more difficult financial situation as they were forced to import increasing quantities of LNG at prices substantially higher than those of Europe and North America (Rogers and Stern 2014). The 2012 average natural gas price was roughly $16/MMBtu in Japan, $9/MMBtu in Europe but only $3/MMBtu in the US (Ritz 2014). Though LNG prices plunged 60 percent of the peak price in 2012 to $7/MMBtu in 2015 with the sharp drop in crude oil prices (Paton 2015), the great loss since 2010 let the Asian importers realized the inefficiency of the current pricing mechanism based on oil-indexation. Therefore, a lot of discussions over whether the JCC mechanism should be retained, or replaced with either the index to the Henry Hub price or more aggressively gas-to-gas pricing in Asia.

Moreover, because oil is no longer the dominant competing fuel with natural gas in Asia, the oil-indexed pricing doesn’t reveal the true value of natural gas and thus makes it at a disadvantage in competing in the power mix. For Japan, while oil constituted 91% of the total energy consumption in 1979, it dramatically decreased to 22% in 2014 with coal as a comparable competitor (28% of total energy consumption). In other Asian countries, there is even less rationale of the oil-indexed pricing because oil has never been a major competitor with natural gas in history and now. In China gas, which accounts for a small percentage of the energy balance, is competing with cheap coal that was blamed for the severe
environment issues. India is very similar to China where the economy is still heavily relying on coal considering its cost advantage. For Korea and Taiwan, though coal is not dominant in total energy consumption, it is highly competing with gas in the power generation (Source: BP 2015).

**Figure 12.** Consumption by fuel in 2014 (Source: BP 2015)

Additionally, with the initial investments of LNG infrastructure were gradually paid back in some country like Japan, long-term contracts are no longer needed for suppliers to recover their huge initial investments. Thus, there is an increasing trend of short-term or spot cargoes in Asia (Figure 14). However, the price for the spot-traded LNG in Asia is still highly related to the oil price and only slightly deviates from the oil-indexed level with the market conditions such as the relationship between a buyer and a seller and the availability of surplus gas in the LNG supply chain. Nevertheless, the increase in spot trade of LNG is still a good indication for the liquidity of LNG market in Asia.

**Figure 13.** LNG annual supply to Asia by contract category (bcm) (Source: Rogers and Stern 2014)
2.3 Natural gas pricing in China

2.3.1 Before the 2013 pricing reform

Before the natural gas pricing reform in 2013, China’s natural gas had long been priced on cost-plus approach. The end-users’ price is derived from adding up ex-plant prices, transmission tariffs and distribution fees. There are four categories of ex-plant prices (Fertilizer, Direct industry supply, City gas for industry and City gas for other uses) and six categories of end-users’ prices (Residential, Commercial, Industrial, Heating, Cooling, Electricity generation, Compression) (NDRC 2010, Jing 2015).

\[
End\ users'\ prices = \text{Explant prices} + \text{Transmission tariffs} + \text{Distribution fees}
\]

1) Ex-plant prices

The ex-plant price of the onshore natural gas production was regulated by the NDRC. While the NDRC set the basis and the range of the price based on the four categories, the exact price was based on the negotiation of the supply and demand sides. The ex-plant price of the offshore natural gas production (10% of the whole production) was directly decided by sellers and buyers. The import of pipeline gas or LNG that would inject into the pipelines followed the ex-plant price of the onshore natural gas production (NDRC 2010).

2) Transmission tariffs

For the pipelines that were invested by the government before 1984, the transmission tariff was set at a union price. The majority of such pipelines were located around the oil and gas field. For the pipelines that were invested by companies after 1984, the transmission tariff was calculated line by line and needed to be approved by NDRC. The majority of such pipelines were long distance, interprovincial pipelines (Jing 2015). The transmission tariff was usually calculated based on the following formula (Sergey and Danwei 2015).

\[
\text{Transmission tariff} = \left( \text{Construction cost} + \text{Operation cost} + \text{Appropriate margin} + \text{Cost Variation of distance} + \text{Taxes} \right)
\]

3) Distribution fee

The calculation of the distribution fee was very similar to the transmission tariff, except for that it was regulated by the local government.

The cost-plus approach worked well when the natural gas still developed at a preliminary stage in China. With the growing consumption outpacing the production, the old pricing mechanism faced with many challenges. Firstly, while natural gas imports were more expensive than the domestic production, they received the same price. Thus, the import companies are faced with great losses. Additionally, the cost-plus approach worked well when the gas was from a single origin and delivered by a single pipeline. As the increase of the inter-transportation between different pipelines that deliver gas from different origins, it was hard to figure out where the gas was from originally and what pipelines the gas went through. Finally, because ex-plant gas and end-users’ gas was divided into different categories, many disputes arose on which price the gas distribution companies should pay the upstream suppliers for a certain type of end-users’ gas.

2.3.2 The 2013 pricing reform

To solve the above problems, China launched a national natural gas pricing reform program since 2011. The reform was implemented nationwide in 2013. The new natural gas pricing is based on a combination of netback and oil-indexation mechanisms. Moreover, two types of natural gas volumes are proposed for the first time. An existing volume is defined as the amount of natural gas consumption in 2012, and an
incremental volume is defined as the amount of natural gas consumption beyond that in 2012 (NDRC 2013). With the price of the existing volume adjusted by steps from 2013 to 2015, a single natural gas price except for the residential end-users was formed in 2015.

Table 4. The timeline of the reform (NDRC 2011, NDRC 2013, NDRC 2014, NDRC 2015)

<table>
<thead>
<tr>
<th>Time</th>
<th>Reform</th>
</tr>
</thead>
<tbody>
<tr>
<td>2011</td>
<td>Tested in pilot provinces of Guangdong and Guangxi.</td>
</tr>
<tr>
<td>2013</td>
<td>The nationwide city gate prices for the incremental volumes of natural gases were formulated by the new pricing approach. The old categories of end-users’ prices were abandoned.</td>
</tr>
<tr>
<td>2014</td>
<td>The city gate prices for the existing volumes were increased, and those for the incremental volumes were adjusted by the new pricing approach.</td>
</tr>
<tr>
<td>2015</td>
<td>A new single natural gas price for the existing and incremental volumes was formulated except for the residential end-users’ price.</td>
</tr>
</tbody>
</table>

Under the new approach, NDRC regulated the city gate price, which is the wholesale price the local gas distributors pay to pipeline operators to purchase gas. The city gate price is in principle the sum of the ex-plant price and the transmission tariff. The ex-plant price and the end-users’ price is set as follows (Jing 2015).

Explant price = City Gate price – Transmission tariff  
Endusers’ price = City Gate price + Distribution fee

![Diagram of pricing mechanism](image)

Figure 14. The pricing mechanism in China after the 2013 reform

Moreover, the city gate price at Shanghai is chosen as the reference price for all the city gate prices because Shanghai is both a large natural gas consumer and an important energy trading center in China. Take the gas from Xinjiang to Beijing as an example. The city gate price in Beijing is calculated as follows.

\[ P_{Beijing} = P_{Shanghai} - \text{Transmission fee from Shanghai to Beijing} + \text{Transmission fee from Xinjiang to Beijing} \]

The primary principle for the new pricing is that the value of natural gas can be largely represented by the value of two substitutes, fuel oil (FO) used in the industrial sector and liquefied petroleum gas (LPG) used in the residential sector. Thus, the formula of the city gate price in Shanghai is defined as follows.

\[ P_{Shanghai} = K \times (\alpha \times P_{FO} \times \frac{H_{NG}}{H_{FO}} + \beta \times P_{LPG} \times \frac{H_{NG}}{H_{LPG}}) \times (1 + R) \]

Where,

K is the discount factor set by the NDRC to encourage the use of natural gas (currently 0.85); 
\( \alpha \) and \( \beta \) are the weights for fuel oil and LPG (currently 60% and 40%);
$P_{FO}$ and $P_{LPG}$ are the average imported fuel oil and LPG prices; 

$H_{NG}$, $H_{FO}$ and $H_{LPG}$ are the heating value of natural gas, fuel oil and LPG (8000, 10000, 120000 kcal/m$^3$);

$R$ is the value added tax (VAT) rate for natural gas (currently 13%)

(Source: Jing 2015)

After the 2013 reform, the price of the existing volume stayed at a lower level than that of the incremental volume until 2015. With the plunge in the oil prices since 2014, there was also fall in the price of the incremental gas.

Figure 15. The change of the city gate price of natural gas in China (source: Sergey and Danwei 2015)

2.3.4 The rationale for gas-to-gas pricing in China

Though the 2013 reform improved the natural gas pricing system in China, there are still many problems with the current pricing mechanism and thus gas-to-gas pricing is proposed.

1. Oil not as a major competitor with natural gas

Just like the problem in other Asian countries, natural gas is competing with cheap coal rather than oil in China. With the even severe air pollution caused by coal, many local governments issued the directives that aimed to transfer the fuel of boilers from coal to gas after the central government issued the Plan on Preventing the Air Pollution in 2013 (The State Council 2013). While oil accounts for 6% of the energy consumption in China, it is mainly deployed as a transportation fuel. Because the Shanghai city gate price is linked to the price of fuel oil and LPG, the supply of natural gas might deviate a lot from the demand with the current pricing mechanism.

2. Bundled pricing impeding the production of unconventional gas

The current pricing scheme is still based on the vertically integrated market structure where the production is bundled with the pipeline transportation. Without separate prices for natural gas as a commodity and the pipeline tariff, independent producers will find it hard to enter the industry. This is especially troublesome to the production of unconventional gas, the advancement of which is mainly propelled by innovative and more risk-taking companies. The shale gas revolution in North America was
not led by Chevron or other large international oil companies, but instead by thousands of small and medium sized private companies. As mentioned in Chapter 1, though China is estimated to have a huge reserve of shale gas, the shale gas production in 2013 only accounted for 0.17% (0.2 bcm) of the China’s gas production due to the insufficient drilling technology and high costs. Therefore, gas-to-gas pricing is expected to provide the incentives for independent producers to invest and commercialize the current immature technology, and scale up the shale gas production.

3. The inefficiency of the distribution
Since the end-users’ price is still regulated by the local government based on the city gate price, there is usually an interval between the adjustments of the city gate price and the end-users’ price. Thus, the pricing signals are delayed to be delivered to the end-users. Additionally, as discussed in section 1.2.3, the collusion between the distribution company as a local monopoly and the local government further creates the institutional inefficiencies of the market.

4. Gas subsidy from industry to residential
Though the delivering cost of natural gas to the industry is lower than that to the residential sector, the residential gas price is set at a lower level by the government due to the political reasons. This greatly undermines the cost competitiveness of natural gas among the power mix for the industry and electricity generation. Therefore, gas-to-gas pricing can reveal the true value of gas to different end-users and contribute to the adoption of natural gas to a larger extent.
Chapter 3. The rationale of developing a natural gas hub in China

3.1 What is a natural gas hub

The natural gas hub, sometimes also regarded as the market center, is where physical flows of gas are connected through a network point (a physical hub) or a wider geographical area (a virtual hub). The key services provided by hubs include the receipt/delivery access to two or more pipeline systems and administrative services that facilitate the transfer of gas ownership.

Gas hubs bring together many buyers and sellers. By providing a reliable price signal in a liquid market, hubs help match supply and demand at low transaction costs. Thus, many hubs also provide new and innovative services such as access to internet-based natural gas trading platforms that expedite and improve the natural gas transportation process. Additionally, the price of the benchmark hub such as Henry Hub in the US also provides the price benchmark for the whole region.

3.2 Conditions for a successful hub

To develop a successful natural gas hub, there are several necessary physical and market conditions. Chapter 4 will use the international experiences to explain how different conditions play a role in the development of a gas hub.

3.2.1 Physical conditions

1. The geographic location of the hub is important because it determines the interconnectivity to other gas market areas.
2. There should be a diversified supply, such as domestic production, pipeline gas, and LNG.
3. Sufficient physical infrastructures ensure physical transactions. Thus, the availability of storage, LNG receiving terminals and the well-developed gas network is crucial.

3.2.2 Market conditions

A competitive market is the foundation of a liquid natural gas trading hub. To build a competitive natural gas market, the study identifies the following two conditions as the most important drivers:

1. Non-discriminatory access to pipelines and LNG facilities by suppliers
2. A competitive market structure with sufficiently large number of market participants

These two conditions are also the two biggest obstacles to the liberalization of the natural gas market according to the past international experiences. Without open-access, natural gas won't be able to reach the end-users. Without a competitive market structure, non-discriminatory access will only become an administrative rule.

Additional to the two market conditions, an independent regulator is usually needed to supervise the natural monopoly of the network and ensure the market competition. Furthermore, transparency of the information is also important to avoid the price manipulation.

3.3 The rationale for China and Asia to develop a natural gas benchmark hub

3.3.1 For China

With the commitment to reaching peak carbon emissions in 2030 and the severe air pollution, China is determined to replace more coal with other cleaner sources in the short term. Natural gas is one of the most promising alternatives. However, as discussed in Chapter 1, natural gas only accounts for 6.3% of China’s overall energy consumption by the end of 2014. Therefore, the author thinks one of the most
important motivations for China to develop a natural gas hub is to boost its natural gas consumption, in particular in the sector of industry and electricity generation.

A successful natural gas hub can bring together many buyers and sellers. With more players, the more competitive market will help direct gas to where it is most needed from whoever can supply it most cheaply. Transparent price signals and standardization of contracts will help to reduce the transaction cost and increase the market liquidity. Such price signals will also help the investors to make decisions of efficient investment. Additional to increase the efficiency of the market, a successful hub will help to ensure the energy security by diversifying sources of supply.

The current pricing system in China discussed in Section 2.3 fails to provide an efficient signal to the buyers and sellers. Thus, not sufficient investments are made in the upstream and by the end-users to fully bring out the value of natural gas in China. The expansion of the network and the connectivity between different pipelines and LNG terminals are slow due to the monopoly and the insufficient incentives from the downstream. This is a chicken and egg problem. Without a developed network, the end-users, in particular industrial consumers in China, find it expensive and inconvenient to consume natural gas. Without sufficient end-users, pipeline companies don’t have the incentives to invest in the infrastructures. Additionally, because China is continuously increasing its natural gas import, the hub can also help ensure the energy security with diversified supply to keep up with the increasing natural gas consumption.

3.3.2 For Asia

As the indexation to oil continuously creates problems in Asia, an Asian gas hub can help to form competitive prices that reveal the true value of natural gas and increase the cost competitiveness in Asian markets. While most of the Asian countries rely on natural gas imports, Asia encompasses various national gas markets in various stages of development. By analyzing four economies including China, Singapore, Japan, and Korea, the IEA report considered Singapore as the most potential candidate because of the push from its government for increasing competition both from the consumer and supplier side (IEA 2013).

However, the biggest obstacle for Singapore is its limited sources of supply (no domestic production and pipeline gas, LNG only) despite the push from the government in building LNG terminals and storage facilities. Though Singapore tries to repeat its success of a key trading hub for other commodities like oil, questions remain whether the single supply of LNG will be attractive to sellers and buyers in Asia when more than half of gas imports in China, the biggest consumer in Asia, are through pipelines.

China, on the other hand, is considered by IEA lacking hands-off government approach and dominated with vertically integrated energy companies. However, on the other hand, China is a high profile candidate to meet many physical conditions of a successful hub. With domestic natural gas production, LNG and the pipeline gas from Central Asia, Myanmar and Russian, China has a diversified supply. There are eleven LNG Terminals in operation along the east coast and five more terminals already in construction. Moreover, while pipeline gas is dominated by the vertically integrated companies, the domestic LNG market discussed in Chapter 1 is a highly competitive market with little government control. Therefore, the author will propose a detailed pathway of how China can meet the essential market conditions of developing a gas hub and thus tap the full potential of its physical advantages. However, the paper doesn’t argue that China will be the only country that develops an Asian benchmark hub. Asia might need more than one benchmark hubs to accommodate different national markets.
Chapter 4. International experiences of establishing successful natural gas hubs

To better understand how the physical and market conditions contribute to a successful hub, this Chapter analyzes these two aspects of the three most successful hubs in the world. They are Henry Hub in the US, National Balancing Point (NBP) in the UK, and the Title Transfer Facility (TTF) in Netherlands. Compared to the physical conditions, establishing a competitive natural gas market is a more complicated process, which will be discussed in more details in this study.

4.1 Henry Hub

Although the concept of natural gas hubs first evolved in the late 1980s, it was fast-tracked after the issuance of FERC Order 636, which promoted the concept of the market center. The Federal Energy Regulation Commission (FERC) suggested the centers could provide the services for pipeline shipper and customers so that the interchange of natural gas across pipeline systems can be greatly increased (EIA 2008).

The development of Henry Hub was more a market-driven process, though the FERC did strategically promote Henry Hub as the major market center even before the launch of NYMEX futures. Initially, the FERC also thought about the market centers in Texas, but it later abandoned the idea because Texas natural gas market was highly regulated and there were a lot of political issues (O’Neill 2016).

In 1990, Henry Hub was chosen as the physical delivery location for the Henry Hub Natural Gas Futures Contract at the New York Mercantile Exchange (NYMEX). The introduction of financial players further increased the liquidity of the hub.

4.1.1 Physical preconditions

As a benchmark hub in North America, Henry Hub has a diversified supply of domestic production in the US. Henry hub is located in the Gulf Coast’s producing area and connecting more than a dozen of major natural gas pipelines which deliver gas to the East Coast and Midwest consumption centers. The US also has an extensive network infrastructure of about 303,000 miles of high pressure inter- and intrastate pipelines, over 400 underground storage facilities and 9 LNG import facilities.

While Henry Hub used to hold the dominant role in the US, its liquidity is declining with the growth of trading volumes in the shale gas production areas such as Marcellus and Utica. This again shows how physical conditions can greatly influence the development of hubs.

4.1.2 Setting up the competitive gas market

The continuous failure of regulating the wellhead prices that matched the supply with the demand was the primary reason for the US to liberalize the gas market. Without dominant buyers or sellers, the US saved much trouble in dealing with the market structure problem. However, the major obstacle the US met with was ensuring open-access transportation services. The pipeline companies were resistant to the change because they were trapped in the huge take-or-pay contracts that were signed when the gas price was high. Therefore, the key to the success is solving the problem caused by the take-or-pay contracts and designing the capacity market to ensure the non-discriminatory access.

1. The motivation for liberalization

The regulated wellhead prices of natural gas continuously distorted the market with either shortage or surplus of the supply despite the various measures adopted by the FERC. Thus, the liberalization was aimed to let the market decide the most efficient pricing.
The Federal Power Commission (FPC), the predecessor of the FERC, started to regulate the wellhead prices, the rate at which producers sold natural gas into the interstate market since the Supreme Court's decision in *Phillips Petroleum Company v. Wisconsin* in 1954. This created an extreme administrative burden for the FPC considering a large number of natural gas production fields. Because the rates were not determined in time, for most of the areas, prices were essentially frozen at 1959 levels, much lower than that of the intrastate gas. To make life simpler, the FPC adopted national price ceilings of the interstate gas in 1974. Although the national prices already doubled the prices that had been set during the 60s, the new price caps were still below the market value because the oil prices surged in the 1970s following 1973 OPEC oil embargo and the high oil prices made natural gas an even more attractive fuel. The regulated low interstate gas prices and the unregulated high intrastate gas prices resulted in gas shortages in the consuming states yet abundant gas supply in the intrastate market. The Natural Gas Policy Act (NGPA) of 1978 was, therefore, Congress' attempt to integrate the interstate and intrastate market. While the price ceilings of the "new gas" were aimed to be enhanced in three stages, and be eventually fully lifted in 1985, the sharp drop in the oil prices in the early 1980s surprised the market again by dragging the gas prices even below the price ceilings. The market then faced with unexpected over-abundant natural gas supply. Figure 16 shows the shortage and surplus of gas supply with the changing oil prices.

The continuous failure of balancing the supply and demand through the regulated prices triggered the liberalization of the US natural gas market in hopes of creating efficient market prices for natural gas.

*Figure 16. The relationship between US gas market conditions and the oil price*

2. *The structural change*

There were hundreds of producers, pipeline companies and Local Distributed Companies (LDCs) even before the liberalization. Thus, no companies had monopoly or oligopoly power, which greatly saved the trouble of establishing the competitive wholesale market. By 2012, there were over 6,300 producers, 160 pipeline companies, and 260 marketing companies (NaturalGas.org 2016) in the US.

While the wholesale market is fully competitive, many LDCs are still vertically integrated because they are not in the supervision of the FERC. LDCs operations in 2006 accounted for approximately 60 percent of the natural gas delivered to the end-users, with the remaining 40 percent delivered directly via trunk pipelines. However, the FERC's legislation seems to have influenced LDCs' operations as well. In 2006, on average, about 46 percent of the gas delivered by LDCs was on nondiscriminatory basis while ten years ago the percentage was less than 10 percent (EIA 2008).
3. Open-access transportation services

1) Take-and-pay contracts

One of the biggest resistances of the restructuring came from the pipeline companies because they had committed to the long-term take-or-pay contracts well above the market prices. Most of these contracts were signed during the gas shortage in the late 1970s when the gas price was high, but the 1980s oil glut greatly dragged the gas price down. Thus, many customers tried to reduce purchases or switch to alternative fuels.

With the continuous pressure from the customers, FERC Order 436 issued in 1985 gave the pipeline companies two options of accepting open-access status or declining open-access status and at the same time excluding all independently owned gas from its line. However, this voluntary open-access status only led to the partial restructuring because of the unsolved problem of large take-or-pay contracts. To handle the problem, FERC Order 500 issued in 1987 distributed the take-or-pay costs between the pipeline companies and the end-users and LDCs. The pipeline companies ultimately absorbed about 35 percent of these costs (Figure 17). Additionally, the FERC also encouraged the renegotiation of the contracts. This also met with the producers’ interest as they felt the enforcement of the contracts would drive the pipeline companies into bankruptcy considering the relative value of the take-or-pay contracts and their book value3 (the right and left chart in Figure 17). These two measures greatly contributed to the success of the implementation of the open-access status for the interstate pipelines.

Figure 17. Gas restructuring imposed transition costs (Source: Hogan 2015)

![Graph showing transition costs](image)

2) Capacity released market

The capacity released market is one of the most genius creations by Order 636 to ensure the full nondiscriminatory transportation services. Shippers are allowed to sell excess pipeline transportation capacity to those who desired to use the extra capacity on both short-term (less than one year) and long-term basis in the capacity released market. Usually, such capacity is sold through auctioning. However, Order 636 prohibited direct capacity transfer between shippers, instead requiring that capacity release had to be conducted through pipeline companies. Thus, the pipeline companies were responsible for publishing the availability of the capacity to the shippers. In 2000 Order 637 removed the price cap for

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3 This is very special to the US. According to Chapter 11 of the Bankruptcy Code, the company can reject all the contracts after it declares bankruptcy.
short-term capacity release to eliminate existing disadvantages for released capacity relative to pipeline-controlled capacity.

3) Tariff design
In Order 636, the FERC adopted the straight fixed-variable (SFV) tariffs as its standard method of cost classification. Each customer is charged the same amount for fixed costs but the different amount for variable costs depending on how much the customer consumes. Because the fixed costs account for the major part of the tariffs, the SFV tariffs, as opposed to the volumetric tariff beforehand, make the cost less variant to how much gas passed through.

Additionally, the majority of tariffs are charged on a point-to-point basis where the price of transportation varied by the location of the receipt and delivery points. Some tariffs are under postage stamp rates where shippers paid the same rate for transportation regardless of how far the gas is moved (FERC 2015).

Another tariff issue the FERC struggled with was whether the pipeline companies could draw upon the inherent value in existing pipelines to subsidize new pipelines. The initial roll-in tariffs proved to be problematic because of continuous complaints from the existing customers. They also caused damaging effects on the entry of new pipeline companies since the projects of the incumbent pipeline companies with the lowest-historic-cost existing capacity were heavily favored. The roll-in tariffs were replaced with the incremental tariffs in 2000 that allowed the prospective shippers to decide whether an incremental project is financially viable on its own merits (O’Neill 2016, Makholm 2012).

4.2 The NBP
The NBP was initially a virtual point created by the Network Code 1996 to promote the balancing mechanism, but it rapidly evolved as a trading point. The gas traded in the NBP is confined to that bought and sold within the transmission pipelines managed by the Transmission System Operator. The physical trade on NBP is based on a standardized contract known as the “Short Term Flat NBP Trading Terms & Conditions” – or the NBP ’97. In 1997 International Petroleum Exchange (IPE) introduced Natural Gas NBP contract as the first gas futures contract in Europe. The financial trading volumes increased quickly and accounted for nearly half of the total trading volumes in 2010.

The NBP became the most important hub in Europe not only because the British gas market liberalized first, but also because it had the greatest transparency on network and storage information in Europe. However, the relatively few interconnections to other European countries is one of the major reasons why the physical trading volumes in the NBP growing at a slower pace compared to those in the TTF. Nevertheless, the NBP is still leading in the financial trading. The overall physical and financial trading volumes of the NBP are 36% higher than those of the TTF.

4.2.1 Physical conditions
The NBP enjoys a diversified gas supply. Indigenous natural gas production accounted for 47% of the UK total natural gas supply in 2016, though it is continuously declining over the past decade. There are four LNG reception terminals, four pipelines bringing in Norwegian gas and two pipelines connecting the UK to the continental markets (one connecting Belgium and the other connecting Netherlands). The significant surplus of physical import infrastructures (less than 30% of import capacity utilization) helps to manage significant variations in the mix of gas import sources without the need for large amounts of storage (Lewis et al. 2015).

4.2.2 Setting up the competitive gas market
The main takeaway from the UK experience is that open-access rules will only take effect in practice after unbundling the vertically integrated BGC and introducing new players to the market. As the first country that liberalized the natural gas market in Europe, the UK was widely taken as reference for other countries in the continental Europe. Compared to the US that has the majority of gas produced domestically, the
UK, as well as other European countries, needs to rely largely on gas imports from Russia, Norway etc. Such differences in geographic resources create entirely distinct paths for Europe to establish the competitive natural gas markets. Among all the challenges, the market structure of a few or even a single vertically integrated monopoly before the reform created the biggest obstacles. The UK is a key example because the direct privatization of the British Gas Corporation (BGC) instead of unbundling it first made the competition only an administrative term for a long time.

Even nowadays some people still argue that the European gas markets are in general not competitive enough due to the high concentration of the market. However, this study argues that the success of the liberalization of the natural gas market doesn’t solely depend on the competitiveness of the market. By setting up the market, countries can achieve other important benefits such as energy security and higher adoption of natural gas in the energy mix. This point will be discussed in more details with the experiences of Netherlands in Section 4.3.

1. The motivation for liberalization

The strong political will from the Thatcher’s government was one of the biggest push among many factors that motivated the liberalization. As the UK economy was in a weakened state in the late 1970s, the Thatcher’s government hoped the liberalization would raise money for the government finances and let the private companies self-fund future investments. At the same time, as a free market proponent, Thatcher deeply believed the economic efficiency gains with a more hands-off approach of the government. Another reason for the reform was the discovery of the large oil fields in the North Sea. Though there were large estimated gas reserves, the exploration of gas fields was slow due to the monopoly power of BGC. The liberalization was expected to tap the full potential of the North Sea fields.

2. The structural change

In the late 1940s, the UK nationalized more than one thousand privately owned and municipal gas companies to form twelve area gas boards. The gas industry was again restructured in the early 1970s by merging all the area boards into the BGC. Before the liberalization, the BGC controlled the whole natural gas supply chain from the full rights of buying all gas produced and providing it to end-users.

The failure to introduce the structural changes at the beginning of the reform had cost the UK great losses before the real progress was made in establishing competition in both the wholesale and retail markets. While the Gas Act (1986) privatized the BGC to British Gas (BG), introduced obligatory third-party access and opened the market for large consumers (consuming more than 25,000 therms per annum), the competition was developing very slowly at first. This is because the developers of gas fields still only sold gas to BG when the newcomers did not have a big enough market to buy a whole field. To solve the problem, the Competition Commission introduced the 90:10 rule in 1989, whereby BG was limited to buying at most 90% of a new field, and the remaining 10% had to be sold to its competitors (Juris 1998).

While the 90:10 rule gave a kick-start to the market by enabling more sellers in the market, there were still no other buyers since BG is also dominant in the downstream. Thus, BG was forced to release about 3 percent of its total gas supply to independent suppliers in 1990. At the same time, it created two divisions, British Gas Energy, and British Gas TransCo. TransCo was separated two years later as a subsidiary of BG responsible for transport and storage. During the process, BG lost a significant proportion of its market share to independent suppliers (Table 5). The Gas Act (1995) further enforced the permanent structure change by paving the way for competition in the residential market. BG demerged into BG plc, which took overall gas production and transportation business, and Centrica, which took over all downstream supply business, in 1996. The new BG later separated its pipelines and storage business and was sold to the National Grid in the early 2000s (Heather 2010).
By 1994, there were around 15-20 companies using a very simple standard contract to trade physical natural gas. The number of market participants rose to around 50-60 companies within two years following the 1995 Gas Act. As a rapid growth in indigenous gas production put downward suppressed gas prices around the same period, new entrants gained the advantage over the established suppliers whose long-term contracts were signed at high prices (Lewis et al. 2015).

Nowadays, the UK gas market is dominated by the so-called Big Six (Centrica, EDF, E.ON, Scottish Power, SSE and RWE). They hold large stakes in both gas production and retail markets. Additionally, many large independent oil and gas companies are acting as independent suppliers (Lewis et al. 2015).

3. Open-access transportation: the Network Code

Once the competition was introduced, the open-access status was more easily to enforce because the whole network business was demerged from British Gas. Therefore, the key issue then became how to operate the network under the new market structure. The Network Code, first introduced in 1996, drew up the framework of the entry-exit system of gas operation and tariff design.

National Grid Gas, used to be British Gas, is the Transmission System Operator (TSO) that runs the British high-pressure transmission pipeline network based on the Network Code. All companies that want to trade, and use the transmission system, must become a signatory to the Network Code and acquire the approval from the Ofgem, the UK gas regulator. They need to nominate the expected supply or consumption to the TSO. While before the liberalization, physical balancing of supply and demand was done on a monthly basis and took up to 15 days to settle, the Network Code enabled the transition to a daily balancing. It was replaced with the Uniform Network Code (UNC) in 2005.

1) The Flexibility Mechanism

If the shippers do not maintain their balance, the TSO must inject or withdraw natural gas to restore the balance in the pipeline system. To facilitate the pricing of this part of the transaction, the Flexibility Mechanism was introduced. If the shipper is unable to balance by itself, it will be forced to trade on a specific balancing market, the On-the-day Commodity Market (OCM) which is operated by ICE Endex exchange. If after trading through the OCM a shipper still is not balanced, it will be balanced by the TSO at the cash-out price. While if the TSO has to buy gas from the shipper in question, the cash-out price will be lower than the OCM’s system average price, if the TSO has to sell gas to the counterparty, the gas will be more expensive (Lewis et al. 2015).

2) The Entry-Exit Tariff

The initial distance-based rates based on the US model was replaced with the Entry-Exit tariffs in 1994 because it is hard to calculate the exact path of the gas. As TSO directed gas flows subject to system

By 1994, there were around 15-20 companies using a very simple standard contract to trade physical natural gas. The number of market participants rose to around 50-60 companies within two years following the 1995 Gas Act. As a rapid growth in indigenous gas production put downward suppressed gas prices around the same period, new entrants gained the advantage over the established suppliers whose long-term contracts were signed at high prices (Lewis et al. 2015).

Nowadays, the UK gas market is dominated by the so-called Big Six (Centrica, EDF, E.ON, Scottish Power, SSE and RWE). They hold large stakes in both gas production and retail markets. Additionally, many large independent oil and gas companies are acting as independent suppliers (Lewis et al. 2015).

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optimization, the gas withdrawn from the network by the buying shipper was often different from the gas injected by the selling shipper.

The calculation of the entry-exit tariffs is based on the long-run marginal cost (LMRC) at each entry and exit point. There is a 50/50 split of tariffs between fixed and variable charges. Ofgas is targeting to achieve a 90/10 split because the 50/50 split doesn’t reflect the true ratio between the fixed and variable costs of the network, and thus suppresses the consumption of transportation services, especially of interruptible transportation. Overall, the costing, pricing, and capacity allocation system are highly complex for the entry-exit system, requiring ongoing seminars and training sessions for even sophisticated industry participants to understand (Makholm 2012).

3) The Capacity market
The UK Capacity market model partially took the reference of that in the US. The shipper can purchase pipeline capacity from the capacity booking by signing a 12-month firm transportation contract or interruptible contract with the TSO at an entry or exit point. The shippers can also sell spare capacity in the secondary market through auctioning or bilateral trading between two shippers, though this market experiences little activity because of the abundance of capacity in the primary market in the UK (Juris 1999).

4.3 The TTF and Europe’s gas roundabout
As a very young hub, the TTF was first introduced in 2002. The major operation and trading model of the TTF took reference of the NBP. While trading volumes on TTF were small at the beginning, they have risen rapidly by over 62% per year in the past few years, and the OTC trading volumes first overtook those in the NBP in 2013.

The uptake of the TTF was considered part of Netherlands’ strategy to develop Europe’s ‘gas roundabout’. The gas roundabout consists of a connected junction of gas infrastructure elements for production, transport, storage, transit, trade and knowledge development. Despite the continuously decreasing domestic production of the Groningen field, the gas roundabout ensures Netherlands’ energy security and its leading role in the natural gas industry in Europe.

The biggest gas supplier GasTerra played a very crucial role in this process. Encouraged by the regulator, the company first traded on the TTF in mid-2005 and acted as an initial market maker. The large trading volumes boost by GasTerra then attracted more players to the hub. However, the role GasTerra plays is a double edged sword because the monopoly power GasTerra might exert on the market (Hakvoort 2016, Jong, Hoven, and Sloet 2016).

4.3.1 Physical conditions
Netherlands is the first country in Europe to export the abundant domestic gas production to other European countries in the 1970s. This provides Netherlands with strong interconnections with other continental European countries, which is considered one of the key advantages the TTF gains over the NBP. The large interconnection capacity reduces the risk when there is a gas shortage or imbalance. Moreover, the overall network of the TTF is well developed. Its average utilization factor is only about 50%. The sufficient storage of many depleted gas fields also offers the system much flexibility. Last but not least, the supply for the TTF is diverse. Despite the recent decline in the domestic production, the Groningen field and other small fields are still producing more than 70% of the gas traded on the TTF. Pipeline gas imports from Russia and Norway and the LNG imports via the Gate Terminal are continuously increasing in the recent years.

4.3.2 Setting up the competitive market
The motivation for setting up the market is very different between Netherlands and the UK, though the liberalization of the gas market in Netherlands took many references of the NBP model. There are many
similarities between the two systems, in particular the operation of the network based on the entry-exit framework. Therefore, this section will put emphasis on discussing how Netherlands dealt with the structural issues beyond its network operation.

1. The motivation for liberalization

The liberalization of the natural gas market in Netherlands was among the big trends of energy market liberalization in the EU. In order to achieve a single European market which ensures the security of energy supply at the lowest possible price among all its member states, the EU decided to open the energy markets to competition in the 1990s with the first liberalization directives adopted in 1996 for electricity and 1998 for gas. While the First and Second Energy Package regulated only the general principles, it wasn't until the Third Directive that the ownership unbundling of the suppliers and network operators became mandatory.

2. Structure Change

The Groningen field in Netherlands was the world's largest gas fields ever known when it was found in 1959. The Groningen field was owned by Maatschap. Two international oil companies, Shell and Exxon, each owned 25% of the company. The state-owned coal mining company DSM owned 40% shares and the state directly owned the rest of 10%. The pipelines and the supplies of natural gas were totally under Gasunie with the same shareholders as those of Maatschap. Additional to the dominant Groningen field, small gas fields owned by other independent production companies also produced gas.

The restructure of Gasunie was the biggest challenge to the liberalization. In 2002, third-party access required by the government forced Gasunie to make its first move to the partition of its activities into two entities, one taking care of transport services and the other undertaking trade and supply. Initially, the two entities were still two separate departments of Gasunie working in separate buildings to ensure the closed-door practice. It was not until July 2005 that Gasunie officially divided into two companies GTS and GasTerra. GTS took over all the network assets and was totally controlled by the state. It was required to produce open-access transportation services to all parties based on the network code. All other business of Gasunie, which relates to trading natural gas as a commodity, was practiced under GasTerra, whose shareholders are the same as the old Gasunie.

Though this structural change introduces new players both to the natural gas imports and domestic production, GasTerra is still the dominant gas supplier. GasTerra is the single owner of the Groningen field, and, together with its other small gas fields, accounts for around 40 to 50 percent of the total natural gas supply. The other main suppliers in the Dutch gas market include Russian gas (5%), Norwegian gas (10%), LNG imports (5%), and a variety of small field gas producers (30-40%).

The dominance of GasTerra is further reinforced by the flexibility service it provides. Because demand for gas is strongly tied to seasonal patterns, particularly for domestic households, one of the major functions of the Groningen field is to satisfy peak demand and provide backup capacity in case of supply failures. The sole ownership of Groningen gives GasTerra market power because most of the shippers need to contract with GasTerra to maintain the balance level required by the Network Code.

4.4 The US versus European gas hubs

The physical conditions of the three hubs are all qualified for successful hubs, but the market conditions are very different in the US and Europe. While there are thousands of sellers and buyers in the US gas market, a limited number of companies dominate in the European gas market. The gas prices in the NBP and the TTF also seem to have a strong correlation with the oil prices due to a large number of long-term contracts. Therefore, many doubts remain on how competitive the UK and Dutch gas market is. However, the author argues that even in an imaginary world where the few big companies could be demerged into hundreds of small business as the US, there would be market inefficiency due to the monopoly power of importers. Currently, Russia is the major gas importer to Europe. Gazprom's monopoly power would...
leave small buyers in Europe in great disadvantage during the negotiations.

However, the failure to reach the first optimal economic efficiency because of the import monopoly doesn’t wipe out the benefits a regional hub can bring. The NBP and the TTF improve the efficiency by enabling companies to trade the residual volumes from long-term contracts on the spot markets. The future development of the spot and financial markets will further help the company to move away from the rigid long-term contract by indexing to the spot market prices. Additionally, there are benefits of a regional hub other than increasing the efficiency of the market. Netherlands is an excellent example that strategically developing the hub ensures the energy security and helps the country maintain the leading role in the gas market.
Chapter 5. Preliminary proposal for the hub development in China

Many papers have already discussed the milestones China needs to hit in order to develop a successful hub. For example, IEA depicts the sequence of steps required to create a competitive wholesale gas market in the 2013 report (IEA 2013). However, few literature discussed the detailed pathway of how to achieve each milestone such as the expansion of network, the non-discriminatory access, and a more competitive market structure.

This study identifies two stages of the development (Figure 18). By the end of the first stage, a natural gas wholesale market will be set up. Such a wholesale market is still at an early stage because the major players are still physical parties. The second stage will not only introduce more players to reinforce the competitive market structure but also let financial parties to further increase the market liquidity and generate the long-term price signals. This paper will mainly discuss the three pillars of the first stage. Much future work on the involvement of the financial players can be done based on the current discussions.

Figure 18. The preliminary proposal of developing the hub

<table>
<thead>
<tr>
<th>First Stage</th>
<th>Second Stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Open access to LNG Terminal</td>
<td>More production players</td>
</tr>
<tr>
<td>International LNG players</td>
<td>Unbundling distribution network</td>
</tr>
<tr>
<td>Asian spot price index</td>
<td>Link with financials</td>
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<tr>
<td>Unbundling national network + ISO</td>
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<tr>
<td>New mechanisms for network investments</td>
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5.1 Icebreaking from LNG

There are a few reasons why the paper thinks LNG is a good place to start the reform.

1. The domestic LNG market, as discussed in Chapter 1, is a highly competitive market along the whole supply chain.
2. The three oil companies have less control over the LNG supply, which is a global market with many huge international oil and gas companies.
3. Theoretically, the current policy has lifted all the barriers for the foreign companies to directly importing LNG to China.
4. Asia is in a rush need for a benchmark gas price due to the multiple reasons mentioned in Chapter 2. As most of the Asian countries are LNG importers, starting from the LNG will help to develop the benchmark price in the short term.

5.1.1 Open-access LNG terminals

Based on the discussion in Chapter 1, theoretically companies other than the three oil companies can directly import LNG into China once they have both the import permission from the Ministry of Commerce and the approval of third-party access to LNG terminals from the NDRC. Practically, there are
still many obstacles to third-party access to LNG receiving terminals. To remove the barriers, the study proposes the following two solutions.

1. Distributing the costs of the expensive take-or-pay contracts

The three oil companies are presently burdened with the huge take-or-pay contracts that were signed when the natural gas price was high. CNPC reported the loss of 8.5 billion RMB (1.3 billion USD) by selling 5.7 bcm LNG imports in 2015. The average LNG import price was 1.49 RMB (0.23 USD) more expensive than the selling price. Sinopec is the last among the three oil companies to start the LNG business. It signed 13.8 bcm of LNG long-term contracts from 2009 to 2014 when the LNG price was at the peak in Asia. Though CNOOC benefited from its early cheap contracts with Australia, the new expensive contracts will start to deliver 3 to 4 bcm annually in the following years (Huang 2016). To make things worse, recently the natural gas demand is stagnant due to the slowdown of China’s economy. Therefore, the oil companies become more reluctant to open their receiving terminals to other cheaper LNG gas.

Such scenario is very similar to that in the US back to the early 1980s when many pipeline companies were resistant to the reform due to the expensive take-or-pay contract. However, the renegotiation of the contracts is much more difficult in the China case because of the international trades. Therefore, this study proposes distributing the costs of the take-or-pay contracts to among the three oil companies, the end-users, and the government. Such distribution can, on the one hand, provide some compensation to the oil companies so that they will have the incentives to obey the open-access rule. On the other hand, the cost burden taken by the government can increase the cost competitiveness of the LNG among the power mix. Additionally, the State-owned Assets Supervision and Administration Commission of the State Council (SASAC) should proportionally lower the profit target for the three oil companies by taking into considerations the costs that would incur.

2. Ensuring the distribution companies can and are willing to buy gas from the newcomers

Additional to third-party access to the receiving terminals, it is crucial to ensure non-discriminatory access to the pipelines that is directly connected to the terminal so that gas can be delivered to the distribution companies. The pipelines are usually under the same ownership of the terminals. Moreover, the regulation should ensure that the distribution companies are not forced to stay away from the small newcomers due to the monopoly power of the oil company.

5.1.2 Introducing International LNG players

There are two main reasons why it is important to invite more international players to trade LNG directly in China.

1. To develop a benchmark price for the regional market in Asia, the participation of other international players in Asia markets is essential.

2. The three state-owned oil companies are the dominant gas sellers in China. In the short-term, it is hard for small players to compete with them even if the policy barriers are removed. The big international oil companies, however, have the competency to compete because LNG is a global commodity.

As discussed in Section 5.1.1, the main obstacle for the international companies to LNG imports is third-party access to LNG terminals. Another primary concern is the unknown credit conditions of the local Chinese companies. This issue can be solved with a credit guaranteed institution, such as the SHPGX in Section 5.4, acts as an intermediary to bear the risk. The third major problem is the currency and other logistic issues related to imports. A good start will be Shanghai Free-Trade Zone, China Pilot Free-Trade Zone established in Shanghai in 2013. Commodities entering the zone are not subject to duty and customs clearance as would otherwise be the case. However, such benefits have only been adopted to the consumer goods. Policies concerning oil and gas commodities are still under discussion.
5.1.3 Developing Asian price index

With the accomplishment of the previous two steps, the domestic LNG market will become a competitive marketplace with both domestic and international players. The size of such market is expected to account for 10-20% of the natural gas consumption in China. Considering the trading volumes and the competitiveness of the LNG market, the Shanghai city gate price can then be linked to the price index of this market to better reveal the supply and demand of the natural gas in China. Consequently, the Shanghai city gate price will have the potential to be taken as major reference price by other Asian players because of China’s big natural gas market and their LNG business in China’s market.

5.2 Unbundling natural gas suppliers from the network operator

The restructuring of the LNG market is not a long-term solution. Firstly, the buyers of LNG imports are only confined to the local distribution companies due to the lack of connectivity with other infrastructures. Secondly, the LNG market size is shrinking because of the expansion of pipelines. Therefore, third-party access to the whole network should be the second step.

As discussed in Chapter 4, the liberalization in the UK is a good example of the failure of a pure open-access obligation without first making any fundamental changes to the gas market structure. The key takeaway is that without unbundling of the network operation from the natural gas supply, the pipeline companies will always be discriminatory to the gas from other sources.

Among different options of unbundling, the following three alternatives are under discussion in China.

1. Set up the pipeline companies as subsidiaries of the oil companies;
2. Set up an independent company to both operate the network and own the network assets;
3. Set up an independent company to operate the network, but the network assets still belong to the oil companies or in the future to other investors.

The author is in favor of the third option. This section argues that the third option not only ensures nondiscriminatory services but also is more likely to be implemented in China. Furthermore, the study argues that the unbundling should start from the central trunk pipelines with the conditions of allowing the big consumers be directly connected to the trunk pipelines. After the preliminary wholesale market is formed, the unbundling could be expanded to the distribution companies.

5.2.1 The model of Independent System Operator (ISO)

The main reason for the unbundling is to avoid the pipeline company allocating the natural gas capacity in favor of certain suppliers. Therefore, the one that makes the decisions on the capacity allocation should be different from the one who owns the gas. If the pipeline company is still a subsidiary of the gas supplier, the past experiences in Europe shows that no matter how government supervised the activity, the pipeline company always had the tendency to favor the affiliated gas supplier. Moreover, since the three oil companies separately owned natural gas infrastructures, adopting the first option means setting up a subsidiary of each company. The problem of lack of connectivity among different infrastructures will still not be solved.

Therefore, an independent company operating the national gas infrastructures should be set up. The only difference between option 2 and 3 is the ownership of the assets. The pipeline companies in the US and Europe are both the system operators and the owners of infrastructures. However, if we have a look at the electricity transmission, the US model is the Independent System Operator (ISO) without the ownership of the transmission lines. Since the operation of electricity is more complicated than that of natural gas, as long as the ISO for natural gas has the control of operation, both option 2 and 3 can work.

However, practically option 2 will meet more resistance, in particular from the three oil companies, because they will directly loose the stable cash flow generated by the existing network. By adopting option 3, the three oil companies will still maintain a constant stream of profits, though the operation and
investment decisions will be made by the ISO, which is a non-profit organization. The mechanism should be designed to incentivize the ISO to make the right decisions that maximize the economic return to the whole society. Though there will be conflicts between the asset owners and the ISO, this study considers the difficulty in the reconciliation of the conflicts is acceptable in practice.

5.2.2 The national versus the distributed network

After the model of the ISO is decided, further questions arise on whether the unbundling should start from the national or regional level. The author supports directly setting up the ISO that operates the national network.

Almost all the national gas infrastructures in China are owned by the three oil companies. The distributed pipelines are owned by the local distribution companies, many of which are municipal companies. This structure creates two layers of monopoly. Firstly, the three oil companies exert monopoly power when selling gas to the distribution company at the city gate. Secondly, the distribution company exercises monopoly power to the end-users that even the three oil companies have no control of. Such tension creates the problems to big consumers. Even if the big industrial companies are located just near the trunk pipelines, they still need to pay extra fees to have their gas delivered by the distribution company. For example, such distribution fees amounted to more than 1360 million RMB (210 million USD) in 2015 in Foshan, a third-tier city in the South of China (Xiaotian 2016).

While the three oil companies are state-owned, many distribution companies are owned by provincial governments. Thus, the key of the problem lies in the conflict of interests between the central and local government. There are two proposals regarding this problem. One is taking the reference of the US point-to-point model and starting the reform from the central level; the other is adopting the European Entry-Exit model at the provincial level and then integrating all the provinces afterward. This study is very skeptical with the second approach. Although the size of each province in China is comparable to a European country, there are following three reasons the author thinks the European model doesn’t apply to China.

1. After successfully adopting the Entry-Exit system in each European country, Europe has started to integrate the whole system recently. However, the integration of the electricity market in Europe shows that it is easy for Power Exchanges to integrate, but underlying network compatibility only becomes worse. Therefore, the second approach will be challenging for the integration of national gas market in the future.

2. Even if we assume that unified rules were applied to different provinces since we’ve already foreseen the future integration, two problems that make China very different from Europe. First, while each European country has the direct access to the upstream gas production or imports, the municipal distribution company can only buy gas from the three oil companies. Thus, the mere reform at the provincial level without unbundling trunk pipelines will leave the distribution companies in an awkward situation.

3. The second problem is that starting the reform from the provincial level will still leave the trunk pipelines and LNG terminals, which were owned by different oil companies, unconnected with each other (see more detailed discussions in section 5.3). This, however, is the major problem that impedes the natural gas adoption in China.

The US was faced with similar challenges with China regarding the conflict interests of the federal and the states. The FERC open-access rules only apply to the interstate pipelines, though more intrastate pipelines are required by the state to provide nondiscriminatory services. Therefore, although US natural gas market is regarded as the most competitive gas market in the world, such competitiveness is only at the wholesale level. The retail markets in many regions are still served by the vertically integrated distribution companies. However, as discussed in Section 4.1, because 55% of the industry end-users and 98% of the natural gas generation are directly connected to the interstate pipelines, the distribution companies in the US are mainly serving the commercial and residential end users.
Therefore, this study suggests the third-party access should first be directly implemented to the national network, which the central government also has more direct control. At the same time, large consumers over a certain threshold should be allowed to connect directly to the trunk pipelines. The exemption of the distribution fees and the competition in the wholesale market will not only make natural gas more cost competitive with coal but also provide more efficient signals for the investment of the trunk pipelines (see more detailed discussions in section 5.3).

Once the unbundling of the national network is accomplished, and the wholesale market is set up, the non-discriminatory services should be expanded to distribution. While the author thinks the point-to-point framework should be applied to the national level, the Entry-Exit approach might be better for some distribution network.

5.3 New mechanisms for the network investment

One of the main differences between China and other countries that went through the liberalization of the natural gas market are that the network in China is still developing at an early stage. Though the natural gas pipelines in China quickly expanded to 85,000 km in 2014, comparing to 303,000 miles (487,000 km) of pipelines in the US, China still needs to invest heavily in the network. Additional to the insufficient overall network capacity, the infrastructures owned by the three oil companies are not well connected with each other. The LNG receiving terminals belonging to CNOOC can only be used by the local communities which the pipelines invested by CNOOC can reach. This is also one of the main reasons why the utilization factor of LNG receiving terminals remain low in China (55% in 2014) (Li 2015).

It is a common concern that the liberalization of the gas market in China will lead to insufficient network investments because the market participants will lack the incentives to commit to the huge upfront cost. Therefore, designing the mechanism that still provides sufficient incentives for network investments in a competitive market is crucial.

The study proposes that the investment decisions should be first proposed by the ISO and then needs to be approved by the independent regulator. Without an established regulator, the proposal needs to be approved by the government. The ownership and the construction of the pipelines can be assigned by competitive bidding. However, the incentive mechanism such as RPI-X should be designed to avoid over investments by the ISO because the ISO has the tendency to put the energy security to the priority without sophisticated considerations on the economic viability. Contrary to the common argument, the author thinks with a good design of the mechanism for network investment, the expansion of the network can be expedited because of the following three reasons.

1. Precise signals provided by the large consumers
   Chapter 1 identifies industry and electricity generation as the two most potential sectors for the future growth of natural gas demand. Therefore, allowing the big users to connect directly to the trunk pipelines can provide direct signals for the ISO to invest in new pipelines. What's more, the big consumers can also become the owners of the new pipelines to increase the investment further.

2. Tapping the potential of LNG imports with the national operation
   Currently, the LNG received at the terminals can only be consumed locally except for that transported by LNG trucks to other regions, because different LNG receiving terminals are not connected with each other or with the trunk pipelines. This is because the trunk pipelines and LNG terminals are under the control of three different companies. While CNPC dominates in pipelines (75% of the trunk pipelines), CNOOC is the major owner of LNG receiving terminals (7 of the 13 terminals). The three oil companies each protect its gas infrastructures from transporting gas from the other companies. This is very detrimental to LNG imports because the gas can only be delivered to a limited number of consumers that are connected to the pipelines built by the LNG terminal owners. Therefore, the ISO, which operates the national gas infrastructures, should invest in the pipelines that connecting different LNG receiving
terminals and the trunk pipelines. This can greatly help the delivery of LNG gas to other inner lands that are short of gas.

3. Leaving the space for the development of unconventional gas

The unconventional gas still accounts for the very small amount of total gas production (1.95%). While China is estimated to have the largest shale gas reserves in the world, the development of shale gas is slow. The uptake of shale gas in the US is largely contributed by thousands of small and medium drilling companies. Therefore, if more players participate in the shale gas production in China in the future, the new ISO model will help the investment of pipelines transporting unconventional gas. Since it is hard for a small player to commit to the large investment, the ISO can coordinate with the small producers and make sufficient investments that are beneficial to all.

5.4 Acceleration of the reform with the Shanghai Petroleum and Natural Gas Exchange (SHPGX)

To boost the natural gas market reform in China, the Shanghai benchmark gas hub was proposed to be established. Registered in the Shanghai Free-Trade Zone with the initial capital of 1 billion RMB (159.7 million USD), the Shanghai Petroleum and Natural Gas Exchange (SHPGX) was launched in July 2015 as an accelerator for the development of the Shanghai gas hub (Reuters 2015). Because many preconditions of a successful gas hub, which is discussed in Chapter 3, are not met, the SHPGX is faced with many challenges. Therefore, though the SHPGX is called “Exchange”, its functions are very different from those of the traditional exchange. Additional to its main business of a trading place, the SHPGX is helping the central government to work out the barriers to the formation of the competitive market such as the discriminatory services and the monopoly market structure. As the first natural gas spot market in China, the SHPGX also plans to develop financial natural gas products in the future.

5.4.1 Shareholders and market participants

The SHPGX is initiated under a strategic alliance between the Xinhua News Agency and the National Development and Reform Commission (NDRC). It involves ten enterprises along the value chain as its shareholders. Acting as a neutral third-party, Xinhua News Agency, holds the largest shares of 33%. The big three oil companies, CNPC, Sinopec and CNOOC, each holds 10% of shares. The downstream gas companies, Shenergy Group, Beijing Gas Group, ENN Group, Hong Kong and China Gas each holds 7% of shares. Huaneng Group, the biggest utility in China, holds 2% of shares (SHPGX 2016).

The participants trading on the SHPGX need to register as members. There are more than 200 members, including all the major gas companies in China, are registered on the SHPGX.

**Figure 19.** Shareholders of SHPGX (Source: The SHPGX website)
5.4.2 The trading activities

Currently, there are two products, the PNG and the LNG, are traded on the platform. The separate trading of the two natural gas products corresponds to the different features of the pipeline and LNG markets discussed in Chapter 1. While the delivery points of the pipeline gas are located in many provinces near Shanghai, Ningbo Terminal is the only delivery point of LNG.

Most of the current trading, in particular, the PNG, is still based on bilateral contracts. To prompt the natural gas reforms, the NDRC urged industrial players to sell and purchase non-residential natural gas via the SHPGX. Though the SHPGX is now only displaying the transactions, the gas pricing transparency has been significantly increased because the SHPGX is the first platform where the information of the trades of the three oil giants is revealed to the public on a daily basis, which, to some extent, depresses the market manipulation.

The trading of the PNG was active in the last quarter of 2015, stopped during the first quarter in 2016 because of Chinese New Year and has been inactive since then. The trading of LNG also peaked at the end of 2015, slowed down during the same break period, but became very active recently (Figure 20). The trading volumes are estimated by the SHPGX to range from 5 to 6 bcm in 2015 and double in 2016 (Xinhua Finance Agency 2015).

Figure 20. The trading volumes on the SHPGX till April 19th 2016 (Source: the SHPGX website)
While the price of the PNG gas is generally lower than that of the LNG because of the liquefaction and the higher costs of transportation, both prices descended with the lower oil prices (Figure 21). The big fall of the price of the PNG during the second half of November was mainly due to the announcement by the NDRC to cut the benchmark city-gate prices by 0.7 RMB ($0.11) per cubic meter for industry and commercial users on November 20th. The price bounced back in mid-December.

To set up a successful gas hub, the SHPGX alone is not enough. Other institutions such as the ISO and the independent regulator should be established to prompt the natural gas development in China in the future.

**Figure 21.** The trading prices on the SHPGX till April 19th, 2016 (Source: the SHPGX website)
Conclusions

Developing the Shanghai natural gas trading hub is aligned with the development of the natural gas markets both in China and Asia. While many previous studies have already discussed the critical conditions China needs in creating a successful hub, this study proposes the detailed pathway of how to achieve each condition, and thus pave the way to develop the Shanghai benchmark hub.

LNG is considered a good place to start the reform. The key issue to be solved is non-discriminatory access to the LNG terminals. By redistributing the costs of the take-or-pay contracts signed at the high prices, the current administrative third-party access will be practically implemented. The second step is reaching non-discriminatory access of the whole network by unbundling natural gas suppliers from the network operator from the national level. By comparing different models of the pipeline companies, the study proposes setting up an Independent System Operator (ISO) to operate and make investment decisions of the pipelines and LNG facilities, though the ownership of the assets will still be left to the three oil companies. Moreover, a national level approach starting from the trunk pipelines is more preferred with the condition that large consumers above the certain threshold should be allowed to directly connect to the trunk pipelines. Another major argument this study makes is that the liberalization of the natural gas market doesn’t necessarily lead to insufficient investments in the network. In contrary, the ISO can help to expand current network more efficiently because it will integrate the infrastructures separately owned by the three oil companies.

While the preliminary proposal outlined here focuses more on forming the physical market in the Shanghai hub, bunches of questions left unanswered regarding how financial trading should play a role and further increase the liquidity of the market. Additionally, the future uncertainty of the shale gas development in China might greatly change the natural gas market structure. Thus, further analysis on how more production players should be introduced to encourage the development of shale gas needs to be conducted.


SHPGX. 2016. “About the SHPGX.” April 19.


### Appendix 1. Major natural gas pipelines in China (Source: Paik 2015, CNPC 2015)

<table>
<thead>
<tr>
<th>Pipeline name</th>
<th>Supply Sources</th>
<th>Ownership</th>
<th>Supply Capacity (bcm/y)</th>
<th>Development stage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shaanxi-Beijing I</td>
<td>Domestic gas</td>
<td>CNPC</td>
<td>3.3</td>
<td>In operation in 1997</td>
</tr>
<tr>
<td>Shaanxi-Beijing II</td>
<td>Domestic gas</td>
<td>CNPC</td>
<td>12</td>
<td>In operation in 2005</td>
</tr>
<tr>
<td>Shaanxi-Beijing III</td>
<td>Domestic gas</td>
<td>CNPC</td>
<td>30</td>
<td>In operation in 2015</td>
</tr>
<tr>
<td>Shaanxi-Beijing IV</td>
<td>Domestic gas</td>
<td>CNPC</td>
<td>25</td>
<td>Started construction in 2014</td>
</tr>
<tr>
<td>Sichuan-East</td>
<td>Domestic Puguang gas</td>
<td>Sinopec</td>
<td>12</td>
<td>In operation in 2012</td>
</tr>
<tr>
<td>SeNingLan</td>
<td>Domestic gas</td>
<td>CNPC</td>
<td>6.8</td>
<td>In operation in 2011</td>
</tr>
<tr>
<td>West-East I</td>
<td>Domestic gas</td>
<td>CNPC</td>
<td>17</td>
<td>In operation in 2008</td>
</tr>
<tr>
<td>West-East II</td>
<td>Central Asian gas</td>
<td>CNPC</td>
<td>30</td>
<td>In operation in 2012</td>
</tr>
<tr>
<td>West-East III</td>
<td>Central Asian gas</td>
<td>CNPC</td>
<td>30</td>
<td>Completed construction in 2015, in operation by 2016</td>
</tr>
<tr>
<td>West-East IV</td>
<td>Domestic gas</td>
<td>CNPC</td>
<td>25</td>
<td>Not yet</td>
</tr>
<tr>
<td>West-East V</td>
<td>Central Asian gas</td>
<td>CNPC</td>
<td>25-30 or 45</td>
<td>Not yet</td>
</tr>
<tr>
<td>Erdos-Hebei</td>
<td>Domestic gas</td>
<td>CNPC</td>
<td>30</td>
<td>Not yet</td>
</tr>
<tr>
<td>ENN Xinjiang-Guangdong</td>
<td>Domestic gas</td>
<td>CNPC</td>
<td>30</td>
<td>Approved by NDRC</td>
</tr>
<tr>
<td>Russia-China (Heihe – Changling)</td>
<td>Russian gas</td>
<td>CNPC</td>
<td>38</td>
<td>In discussion</td>
</tr>
</tbody>
</table>
Appendix 2. Map of natural gas pipelines in China (Paik 2015)

**Natural Gas Pipelines In China**

**WE II Pipeline:**
- Runs from Horgos to Guangzhou
- Covers 14 provinces
- Total length = 8,700km (inc. 8 branch lines)
- Design pressure: 12MPa for west section, and 10MPa for east section
- Line pipe grade: X80
- Annual throughput: 30 billion m³
- Construction duration: 2008—2011

The dotted line in blue is WE II.
Appendix 4. Top LNG Liquefaction, LNG trucks, LNG fueling stations companies

Top LNG Liquefaction companies (Source: ICIS 2015a)

<table>
<thead>
<tr>
<th>Ranks</th>
<th>Company</th>
<th>Capacity (mcm/day)</th>
<th>Location</th>
<th>Public/Private</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Hanas</td>
<td>3</td>
<td>Ningxia</td>
<td>Public</td>
</tr>
<tr>
<td>2</td>
<td>Guanghui</td>
<td>3</td>
<td>Xinjiang</td>
<td>Public</td>
</tr>
<tr>
<td>3</td>
<td>Yanchang</td>
<td>1.5</td>
<td>Shanxi</td>
<td>Private</td>
</tr>
<tr>
<td>4</td>
<td>Zhongyuan</td>
<td>3</td>
<td>Shanxi</td>
<td>Private</td>
</tr>
<tr>
<td>5</td>
<td>Xinsheng</td>
<td>2.75</td>
<td>Inner Mongolia</td>
<td>Private</td>
</tr>
<tr>
<td>6</td>
<td>Ansai</td>
<td>2</td>
<td>Shanxi</td>
<td>Public (CNPC)</td>
</tr>
<tr>
<td>7</td>
<td>Lvyuanzizhou</td>
<td>1</td>
<td>Shanxi</td>
<td>Private</td>
</tr>
<tr>
<td>8</td>
<td>Xinxin Energy</td>
<td>1</td>
<td>Inner Mongolia</td>
<td>Private</td>
</tr>
<tr>
<td>9</td>
<td>Yigao</td>
<td>0.9</td>
<td>Shanxi</td>
<td>Foreign</td>
</tr>
</tbody>
</table>

Top five companies owning LNG trucks in China (Source: SCI 2015)

<table>
<thead>
<tr>
<th>Rank</th>
<th>Company</th>
<th>Province</th>
<th>Private/Public</th>
<th>Number of LNG Trucks</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ENN</td>
<td>Hebei</td>
<td>Private</td>
<td>635</td>
</tr>
<tr>
<td>2</td>
<td>Guanghui</td>
<td>Xinjiang</td>
<td>Private</td>
<td>190</td>
</tr>
<tr>
<td>3</td>
<td>Lihua</td>
<td>Hebei</td>
<td>Private</td>
<td>173</td>
</tr>
<tr>
<td>4</td>
<td>Shengtong Energy</td>
<td>Shandong</td>
<td>Private</td>
<td>160</td>
</tr>
<tr>
<td>5</td>
<td>Hengtong Transportation</td>
<td>Shandong</td>
<td>Private</td>
<td>150</td>
</tr>
<tr>
<td></td>
<td>CNPC Huangdong</td>
<td>Jiangsu</td>
<td>Public (CNPC)</td>
<td>150</td>
</tr>
</tbody>
</table>

Top Companies owning LNG fueling stations (Source: SCI 2015)

<table>
<thead>
<tr>
<th>Rank</th>
<th>Company</th>
<th>Number of fueling stations</th>
<th>Private/Public</th>
<th>Percentage of the overall fueling stations (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Kunlun Energy</td>
<td>762</td>
<td>Public (CNPC)</td>
<td>33.91</td>
</tr>
<tr>
<td>2</td>
<td>Natural Gas and Electric Corporation</td>
<td>315</td>
<td>Public (CNOOC)</td>
<td>14.02</td>
</tr>
<tr>
<td>3</td>
<td>ENN</td>
<td>473</td>
<td>Private</td>
<td>21.05</td>
</tr>
<tr>
<td>4</td>
<td>Guanghui</td>
<td>223</td>
<td>Private</td>
<td>9.92</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td>1773</td>
<td></td>
<td>78.90</td>
</tr>
</tbody>
</table>
Interviewee Lists

United States
1. Richard O’Neill, Chief Economic Advisor, FERC
2. Thomas Pinkston, Branch Chief, Division of Analytics and Surveillance, FERC
3. Gary Mahrenholz, Market Oversight Branch, Economist, FERC
4. Jeff Makholm, Senior Vice President, NERA Economic Consulting
5. Bradford Leach, former vice president of research at NYMEX

United Kingdom
1. Malcolm Keay, Former Deputy Director General of Ofgas (late 1980s)
2. Eileen Marshall, Former Deputy Director General of Ofgas
4. David Ford, Former Head of Marketing and Training at ICE London

Netherlands
2. Rudi Hakvoort, Former Head of Unit DTe (1998-2005)
3. Aad Correlje, Researcher at Clingendael Institute and Professor at Delft University
4. Sybren de Jong, Manger Strategic Market Modeling, GTS
5. Bert Hoven, Senior Advisor Market Research, GTS
6. Gert Sloet, Project Manager, GTS
7. E.W.L. Westdijk, Business Developer, GTS, formerly at GasTerra