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Executive Summary

Over the last decade, China has focused its policies simultaneously on moderating the rapid energy demand growth that has been driven by three decades of rapid economic growth and industrialization and on increasing its energy supply. In spite of these concerted efforts, however, China continues to face growing energy supply challenges, particularly with accelerating demand for oil and natural gas, both of which are now heavily dependent on imports. On the supply side, the recent 11th and 12th Five-Year Plans have emphasized accelerating conventional and nonconventional oil and gas exploration and development through pricing reforms, pipeline infrastructure expansions and 2015 production targets for shale gas and coal seam methane. This study will analyze China's new and nonconventional oil and gas resources base, possible development paths and outlook, and the potential role for these nonconventional resources in meeting oil and gas demand. The nonconventional resources currently being considered by China and included in this study include: shale gas, coal seam methane (coal mine methane and coal bed methane), tight gas, in-situ coal gasification, tight oil and oil shale, and gas hydrates.

In terms of the resource base, China's most abundant nonconventional gas resource is shale gas, with estimated technically recoverable resources of 15 to 25 trillion cubic meters, followed by coal seam methane with about 10 trillion cubic meters. Most of these resources are located in existing oil and gas basins in Northern China, Southwestern China and West China. Tight gas – which is considered conventional gas in China – also has abundant technically recoverable resources of 12 trillion cubic meters that accounts for 40% of China's natural gas resources-in-place. Because in-situ coal gasification can tap into otherwise unmineable coal, China's abundant coal resources also suggest abundant potential gas resources from in-situ gasification, but the recoverable resources are uncertain given that the process is still in the very early stages of demonstration and pilot testing and significant technological advancements

are needed to increase production. Similarly, vast amounts of potential gas hydrate resources exist in the northern South China Sea and permafrost zones but long-term research and development are needed, indicating that hydrates are unlikely to be a major supply prospect. For nonconventional oil resources, China has 1.3 billion tonnes of recoverable tight oil resources and 26 billion tonnes of technically proven reserves of oil shale (from which 1.5 billion tonnes of shale oil can be extracted). Both are not expected to contribute much to total petroleum output because of their limited scale of production and environmental concerns with extraction, particularly for oil shale, suggesting that petroleum imports will continue to rise in China.

Of the five nonconventional gas resources, China has most successfully developed and commercialized tight gas, with production accounting for 25% of the total gas supply in 2010. As the most viable alternative to conventional gas, tight gas will become an increasing proportion of China's domestic natural gas supply. Besides tight gas, both coal seam methane and shale gas have seen strong policy-driven push for increased resource evaluation, exploration and commercial development in recent years. However, both resources also face similar challenges in insufficient understanding of the resource base, technical, economic and institutional barriers to mass deployment of advanced drilling technologies to increase production. The shale gas industry, in particular, is still in nascent stage of development and faces additional environmental concerns about groundwater contamination and methane leakage, as well as water resource constraints.

From the demand side, the China Energy End-Use Model shows that China's energy demand will likely continue to increase from current levels at annual average growth rates of over 1% through 2030, driven by rapid growing demand from commercial building and the transport sector. In terms of fuel, the fastest growth in demand will be for primary electricity followed closely by natural gas and petroleum, which combined will make up about half of China's total primary energy demand in 2030. Petroleum demand will grow at annual average rates of 3% to reach a 25% share of total primary energy demand in 2030, driven by demand from growing stock of trucks, buses, and light-duty passenger vehicles as well as the petrochemical industry. Natural gas demand will grow even faster at annual average rates of 6% and across multiple end-use sectors, with rising shares of consumption from the power, transport and commercial buildings sector. Besides the power sector, which accounts for nearly a quarter of total consumption in 2030, other significant end-use consumers of natural gas in 2030 include urban residential space heating (15% share), residential urban water heating (7%), heavy-duty freight trucks (8%), hotel water heating (5%) and office space heating (5%). A comparison of the LBNL natural gas demand outlook with other recently published outlooks show similarly fast paces of growth through 2030, with 2030 annual consumption ranging from 210 to 285 billion cubic meters for final use (not including transformation input to the power sector).

As the most abundant nonconventional gas resource, shale gas could potentially play a large role in China's future gas supply. Using both U.S. and Chinese resource estimate and analogues to U.S. shale gas well productivity and decline rates, shale gas modeling shows that at maximum rates of successful exploitation, extraction rates peaks within a decade of commercialization, but that commercialization at the early stage is dependent on several key technology breakthroughs. The modeling results further illustrate that the maximum net shale gas supply in the worst and best resource scenario could displace as much as 85 to 357 million tonnes of raw coal in thermal equivalent terms. While this level of shale gas would account for 14% to 40% of China's 2030 net natural gas supply, it still represents only 2 to 9% of current coal consumption. The expectation that the exploitation of China's shale resources could provide a path to substantially offset coal consumption does not appear to be supported by the modeling results. The main impact of successful shale gas development, assuming all barriers can be overcome and all conditions can be met, is to ease the pressure off China's rising gas import dependency through the mid-2020s until peak production is reached. In the longer run towards 2030, the gap between domestic gas supply and continuously growing gas demand will widen. Without successful shale gas development or if shale gas resources are not as high as expected, then the gap between China's natural gas demand and domestic net gas supply would widen quickly, with demand outpacing supply by a factor of 2 in 2025 to a factor of 3 in 2030. Coal seam methane may provide a path to more quickly supplementing conventional gas supplies if breakthroughs in research and development are achieved, and although its ultimate annual production capacity is unclear, under analogue conditions with the US, it would still contribute to less than half of China's total gas supply depending on the success of shale gas production. Successful exploitation of China's nonconventional gas resources would provide an important and significant boost to cleaner energy development in the country and could help moderate China's gas import dependency in the near-term, but their longer-term role will remain limited given the expected scale and rapid rate of continued growth in China's demand for natural gas.

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1. Introduction

Over the last decade, China has focused its policies simultaneously on moderating the rapid energy demand growth that has been driven by three decades of rapid economic growth and industrialization and on increasing its energy supply. In 2006, for instance, China set for the first time a binding target for energy efficiency by requiring a 20% reduction in energy intensity per unit of GDP during the 11th Five-Year Plan (FYP) from 2005 to 2010. To help achieve this target, the central government introduced sector-specific energy efficiency policies and programs. At the same time, China also focused on expanding its energy supply through greater conventional and nonconventional oil and gas exploration and development, accelerated non-fossil power generation and emphasis on more efficient coal use. Specific to the oil and gas industries, China has also initiated some market reforms on oil and gas taxes, fees and pricing while undertaking pipeline infrastructure expansions.

In spite of these concerted efforts, however, China continues to face growing energy supply challenges, particularly with accelerating demand for oil and natural gas. In 2007, China became a net importer of natural gas for the first time and by 2011, more than one-fifth of domestic natural gas demand was met by imports. At the same time, petroleum imports also increased from 32% of total petroleum consumption in the early 2000s to more than half of total domestic petroleum consumption in 2011. The skyrocketing demand for increasingly expensive imported oil and gas has not only led to significant financial losses in the traditionally government price-controlled domestic industries, but the growing import dependency is also raising serious energy security concerns. The imbalanced growth in oil and natural gas supply and demand and the expected widening of the supply-demand gap has led China to turn its attention to the development of nonconventional oil and gas. The 12th FYP has not only laid out energy intensity and carbon intensity (per unit GDP) reduction targets, but also set production targets for nonconventional resources such as shale gas and coal seam methane. To achieve these production targets, the 12th FYP for Energy Development lays out specific scientific research and development activities to advance the technical foundation for nonconventional resources, and specific activities and policy directions to accelerate the development of nonconventional oil and gas industries.

Although China has had experience with the exploration, extraction and utilization of some nonconventional resources such as tight gas and tight oil, it has historically not focused much on the development of other nonconventional resources such as coal seam methane, shale gas, and in-situ coal gasification. Recent national resource assessments have indicated that China has relatively abundant nonconventional gas resources, but the extent to which China can rapidly extract and deploy these resources to assuage its mounting energy security concerns remain unknown.

This study will analyze China's new and nonconventional oil and gas resource base, possible development paths and outlook, and the potential role for these nonconventional resources in meeting oil and gas demand. The nonconventional resources that China is considering for future development and which will be covered in this study include shale gas, coal seam methane (coal mine methane and coal bed methane), tight gas, in-situ coal gasification, tight oil and oil shale, and gas hydrates. An assessment of each nonconventional resource's recent resource base, as well as a comprehensive review of its recent development in China and outlook for future development with emphasis on remaining barriers and challenges is conducted in this report.

This report begins with a review of energy-related developments under the 11^{th} and 12^{th} FYP, with emphasis on the oil and gas industries, as background and policy context for nonconventional resource development. The next section compares the resource classification schemes of China and the international community (i.e., Society of Petroleum Engineers) to highlight factors that could affect nonconventional resource assessments. Sections 4 through 9 then provides in-depth assessment of the resource base, recent development and current status and outlook for future development in China for each of the nonconventional resources mentioned above. Section 10 evaluates the prospects for China's future energy demand, including detailed outlook of oil and gas end-use consumption, and the implications for nonconventional resources. Finally, section 11 evaluates the future potential role for nonconventional oil and gas in China both qualitatively and quantitatively and presents a supply-demand gap analysis for natural gas. The report concludes with a summary of the key findings on the prospects for nonconventional oil and gas development in China.

2. Review of Energy-related Developments under 11th and 12th Five-Year Plan

After energy consumption surged from 2002 to 2005, China's 11th Five-Year Plan (FYP) for 2006 through 2010 incorporated a significant shift in the central government's energy policy focus, with the unprecedented setting of goal to reduce national energy consumption per unit of GDP by 20% in 2010 compared to 2005 levels. The national energy intensity reduction target was decomposed into provincial targets, which in turn affected industrial activity on the provincial level. The 11th FYP focused on both expanding energy supply, particularly non-fossil power generation and more efficient coal use, and curbing the growth in energy demand by launching a suite of efficiency programs. On the supply side, the 11th FYP focused on accelerating non-fossil energy development, the construction of oil and gas bases, developing China's coal bases in an orderly manner through increased centralization and optimizing the construction of efficient coal-fired power generation. On the demand side, in addition to the provincial energy intensity reduction targets, the 11th FYP also featured large-scale energy efficiency and conservation efforts including the Ten Key Projects, the Top 1000 Energy-Consuming Enterprises Program, building and equipment efficiency policies and initiatives, and closure of small and least efficient plants. China's achievements in energy production and efficiency during the 11th FYP are reviewed in the following section.

2.1. 11th FYP Achievements in Energy Supply and Production

In order to sustain the country's rapid economic development, as evidenced by average annual GDP growth rate of 11.2% from 2005 to 2010, China expanded its energy supply capacities and enhanced energy security by accelerating the extraction and production of its fossil and non-fossil energy resources. Table 1 summarizes the major achievements in total primary energy production and installed generation capacity during the 11th FYP period.

Table 1. 11th FYP Achievements in Energy Production

Target	2005	2010	AAGR
Total Primary Energy Production (Mtce)	2160	2970	6.6%
Coal (Mt)	2350	3240	6.6%
Oil (Mt)	180	200	2.1%
Natural Gas (bcm)	49.3	94.8	14.0%
Non-Fossil (Mtce)	160	280	11.8%
Total Installed Generation Capacity (GW)	520	970	13.3%

Hydropower	120	220	12.9%
Thermal	390	710	12.7%
Nuclear	6.85	10.82	9.6%
Wind	1.26	31	89.8%

Note: Mtce = million metric tons of coal equivalent = 29.27 million GJ; Mt = million metric tons; bcm = billion cubic meters

Source: National Energy Administration (NEA). 2013. "China's 12th Five Year Plan for Energy Development." http://www.nea.gov.cn/2013-01/28/c_132132808.htm

By 2010, primary energy production reached 2.97 billion metric tons of coal equivalent (Btce), driven by double-digit annual average growth in natural gas production and non-fossil fuel generation. In the power sector, new power generation capacity of 450 GW came online, nearly doubling total installed generation capacity from 520 GW to 970 GW over the five year period. At the same time, over 72GW of small, inefficient thermal power plants were decommissioned. During the 11th FYP period, China emerged as a world leader in total installed renewable and non-fossil generation capacity. China's 2010 hydropower installed capacity of 220 GW put it as the world leader in hydropower, and China also ranked first in terms of total covered area of solar water heating. The addition of 30 GW of grid-connected wind capacity over the 11th FYP period also put China second in the world. From 2005 to 2010, 15 nuclear generation units were put into operation and completion of the additional 26 units currently still under construction with designated capacity of 29.24 GW gives China a 40% share of global nuclear capacity under construction.

In 2011, China's primary energy production further increased to 3.1 Btce, making it the largest energy producer in the world. Primary energy production in 2011 included 3.52 billion tonnes of raw coal, 200 million tons of crude oil, 103.1 billion cubic meters (bcm) of natural gas and 849.2 TWh of primary electricity (hydro, wind, solar, biomass, and nuclear) production. An additional 8 GW of small, inefficient thermal power plants were eliminated, reducing coal consumption of thermal power supply by 37 grams of coal equivalent (gce) per kWh from 2006 levels, a decrease of 10% (State Council 2012). As a result of the improved thermal generation heat rate, total annual savings of more than 60 million tons of raw coal compared to 2006 levels were expected in 2011. Continued expansion of non-fossil fuels, including total installed generation capacity of 230 GW for hydropower, 47 GW for wind and 3 GW for solar photovoltatics enabled non-fossil energy to account for 8% of total primary energy consumption in 2011, resulting in over 600 million tons of CO_2 emissions reduction per year (State Council 2012).

2.2. 11th FYP Energy Efficiency Achievements

Over the 11th FYP period, public and private investment in energy efficiency, conservation and emissions reduction efforts totaled 2 to 3 trillion RMB, including 200 billion RMB of investment from the central government (CPI 2011). Two hallmark national programs to improve energy efficiency during the 11th FYP period were the Ten Key Energy Conservation Projects, which focused on providing economic incentives and technical strategies to improve efficiency in ten key areas, including lighting, coal-fired industrial boilers and motors, and the Top 1000 Energy Consuming Enterprises Program, which mandated energy conservation efforts for the largest 1000 firms in 9 key industrial sectors. In addition to these two programs, complementary policies to improve building energy efficiency and appliance and equipment efficiency were introduced and strengthened. Previous studies have evaluated the progress and interim achievements of efficiency programs and policies under the 11th FYP (Price et al. 2011), and news reports indicate that the Ten Key Projects increased energy conservation capacity by 340 Million tons of coal equivalent (Mtce) while the Top 1000 Enterprises program saved 150 Mtce (State Council 2012). On an economy-wide level, energy consumption per unit of GDP decreased by 19.1% from 2006 to 2010. In addition, all provinces with the exception of Xinjiang, met or exceeded their 11th FYP decomposed energy intensity reduction targets. Table 2 shows the provincial energy intensity reductions in 2005 and 2010, as well as the planned and actual reduction over the 11th FYP period.

Table 2. Provincial Energy Intensity and Intensity Reduction Target Achievements

Region	Year 2005		Year 2010	
	Energy Consumption per Unit of GDP (ton of SCE/10 000 yuan)	Reduction Target in the 11th FYP (%)	Energy Consumption per Unit of GDP (ton of SCE/10 000 yuan)	Reduction Compared with 2005 (%)
Beijing	0.792	-20.00	0.582	-26.59
Tianjin	1.046	-20.00	0.826	-21.00
Hebei	1.981	-20.00	1.583	-20.11
Shanxi	2.890	-22.00	2.235	-22.66
Inner Mongolia	2.475	-22.00	1.915	-22.62
Liaoning	1.726	-20.00	1.380	-20.01
Jilin	1.468	-22.00	1.145	-22.04
Heilongjiang	1.460	-20.00	1.156	-20.79
Shanghai	0.889	-20.00	0.712	-20.00
Jiangsu	0.920	-20.00	0.734	-20.45
Zhejiang	0.897	-20.00	0.717	-20.01

Anhui	1.216	-20.00	0.969	-20.36
Fujian	0.937	-16.00	0.783	-16.45
Jiangxi	1.057	-20.00	0.845	-20.04
Shandong	1.316	-22.00	1.025	-22.09
Henan	1.396	-20.00	1.115	-20.12
Hubei	1.510	-20.00	1.183	-21.67
Hunan	1.472	-20.00	1.170	-20.43
Guangdong	0.794	-16.00	0.664	-16.42
Guangxi	1.222	-15.00	1.036	-15.22
Hainan	0.920	-12.00	0.808	-12.14
Chongqing	1.425	-20.00	1.127	-20.95
Sichuan	1.600	-20.00	1.275	-20.31
Guizhou	2.813	-20.00	2.248	-20.06
Yunnan	1.740	-17.00	1.438	-17.41
Tibet	1.450	-12.00	1.276	-12.00
Shaanxi	1.416	-20.00	1.129	-20.25
Gansu	2.260	-20.00	1.801	-20.26
Qinghai	3.074	-17.00	2.550	-17.04
Ningxia	4.140	-20.00	3.308	-20.09
Xinjiang	Additional Examination			

Source: NBS, 2011. "Communique on the Achievements of Energy Conservation Targets by Region in "11th Five Year Plan Period."
http://www.stats.gov.cn/english/newsandcomingevents/t20110617_402732886.htm

As seen in Table 2, 28 regions achieved energy intensity reductions that exceeded their 11th FYP targets. Of these 28 regions, Beijing exceeded its energy intensity reduction targets by the largest amount, reducing its energy intensity by an additional one-third of its 20% reduction target. Xinjiang was the only region that required additional examination of its 2005 and 2010 energy intensities and final results are not available.

2.3. Oil and Gas Developments under the 11th FYP

The 11th FYP period also witnessed important developments in China's oil and gas industry, including infrastructure expansions, science and technology capacity enhancements and growth of the coal-seam methane industry. In terms of oil and gas infrastructure, the first and second East-West gas pipelines were completed during the 11th FYP period, providing 180 million residents with access to natural gas. By 2011, China's natural gas trunk lines exceeded 40,000 kilometers (State Council 2012). At the same time, China's petroleum pipeline network gained an additional 34,000 kilometers between 2005 and 2010, or an annual average growth rate of 10.3% in pipeline distance. As shown in Figure 1, the fast growth in pipeline construction during the 11th FYP period brought China's total pipeline network to 78,500 kilometers in 2010.

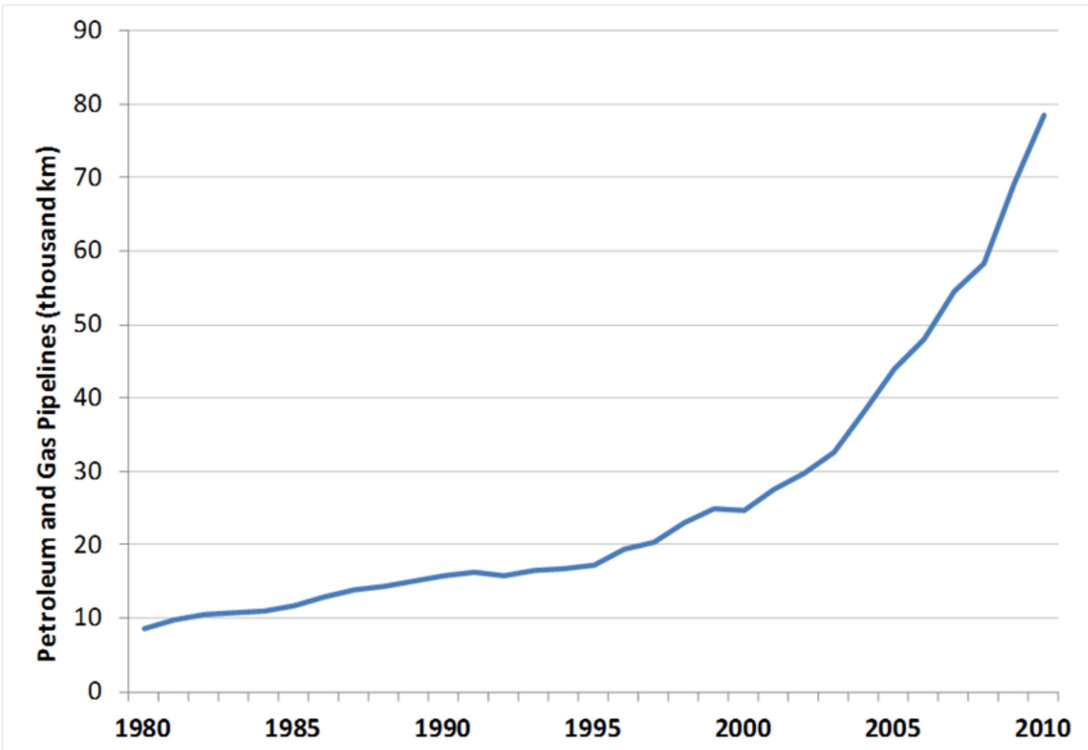

Figure 1. China's Petroleum and Gas Pipeline Distance, 1980 - 2010

In addition to physical infrastructure, science and technological capacity of the oil and gas industry also underwent significant improvements during the 11th FYP period. China succeeded in building oil rigs capable of operating at 3000 meters of water depth, and also independently designed and built oil refinery complexes with annual output capacity of 10 million tons (State Council 2012). Ethylene production plants with annual output of 1 million tons have also been designed and built domestically. In addition, China became the first country to adopt national emissions standards for coal seam methane, signaling its recognition of the importance of alternative gas resources.

However, despite the unprecedented growth in energy production and achievements in energy intensity reduction, China still lags behind in the available domestic supply of oil and gas to meet demand. As shown in Figure 2, the gap between domestic natural gas and oil production and consumption has grown significantly, particularly in the last three years. In 2007, China switched from being a net exporter of natural gas to Hong Kong to a net importer. Since 2007, China's natural gas imports have increased from 0% of domestic consumption in 2007 to 22% in 2011. For crude oil, China's import dependency has further exacerbated in the last five years as seen in Figure 3, with more than half of domestic oil consumption supplied by foreign imports. Energy security concerns over these rising shares of natural gas and oil imports have led to greater push for non-conventional oil and gas development under the 12th FYP.

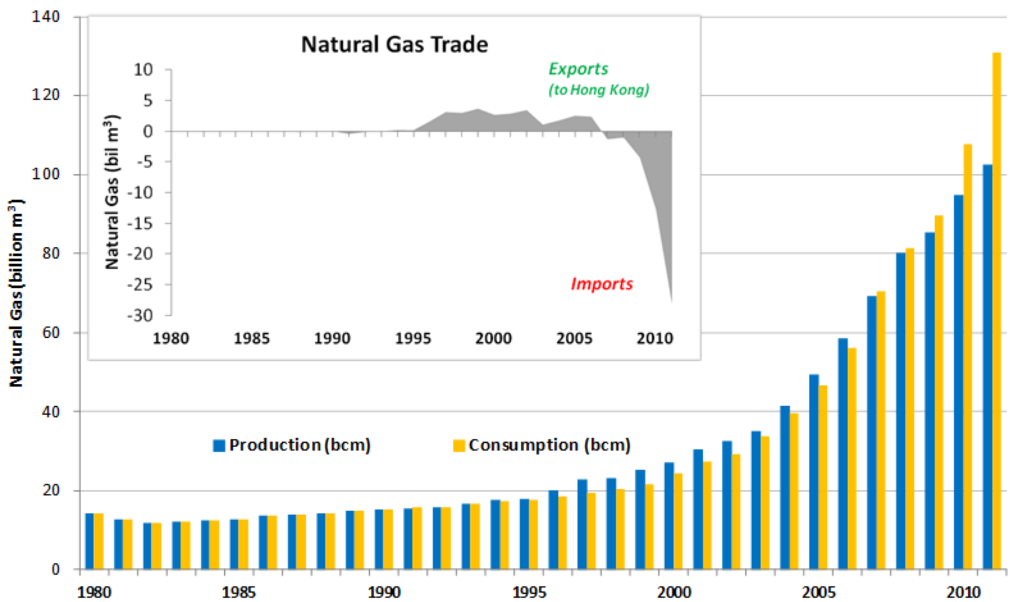

Figure 2. China's Natural Gas Production, Consumption and Trade, 1980- 2011

Source: BP 2012.

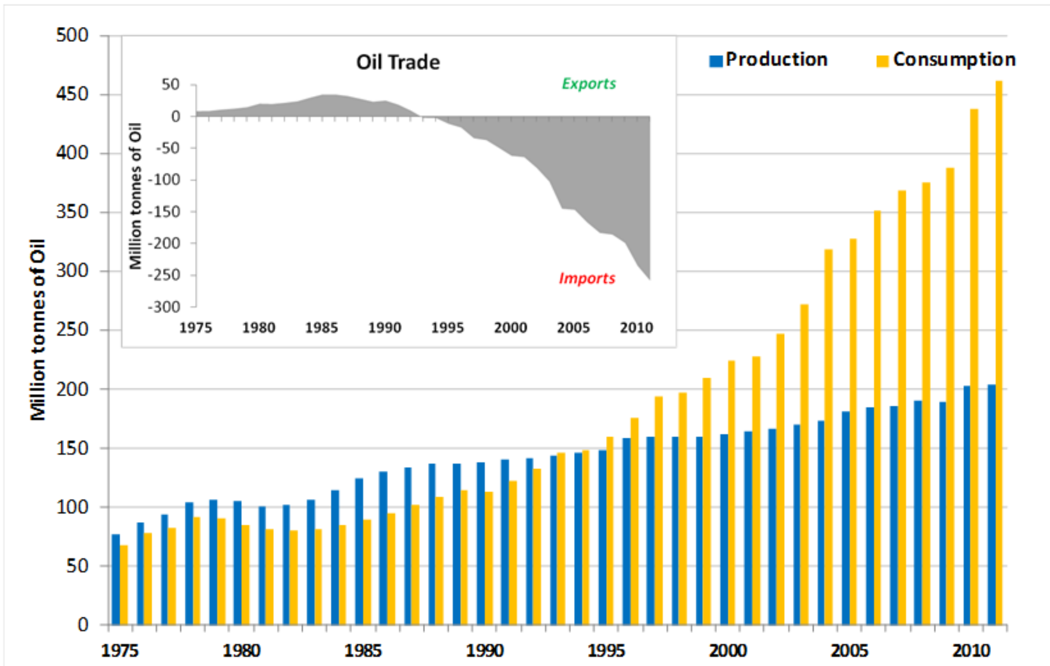

Figure 3. China's Oil Production, Consumption and Trade, 1975-2011

Source: BP 2012.

2.4. 12th FYP Objectives for Energy Demand

In continuing the momentum from the 11th FYP, China's 12th FYP continues to push forward the country's dual objectives of achieving an expanded energy supply and moderated energy demand growth. On the demand side, the plan sets several key binding and anticipated targets related to energy consumption as seen in Table 3. Total primary energy demand is anticipated to grow slower than during the 11th FYP period, at an annual average rate of 4.3% instead of the previous 6.6%. Of the total primary energy consumption in 2015, 11.4% must come from non-fossil fuels, including nuclear and hydropower when converted at the Chinese convention of using the power plant coal consumption calculation method[1] of converting primary electricity production to standard units. However, electricity demand is expected to grow at a faster annual average rate of 8%, further solidifying China's position as the world's largest electricity user.

[1] Following the power plant coal consumption method, China converts primary electricity (nuclear, hydropower and renewables) to standard primary energy coal equivalent units using the weighted average heat rate (kgce/kWh) of total power generation, rather than the IPCC convention of using the direct equivalent method of assuming 100% efficiency for all primary electricity.

Table 3. Key 12th FYP Energy Demand Targets

Target	Unit	2010	2015	AAGR
Total Primary Energy Demand	Mtce	3250	4000	4.3%
Non-Fossil Share	%	8.6%	11.4%	2.8*
Total Electricity Demand	TWh	4200	6150	8%
Energy intensity per unit GDP	tce/10,000 yuan	0.81	0.68	-16%*

Note: bolded target indicates binding target; * indicates change over 5 years, not AAGR.
Source: NEA 2013.

Another binding target under the 12th FYP is the 16% reduction in energy consumption per unit GDP goal for 2015, relative to 2010 levels. This is again decomposed into individual provincial energy intensity reduction targets. Table 4 compares the 11th FYP energy intensity reductions achieved with the 12th FYP provincial energy intensity reduction targets. All of the regions, with the exception of Xinjiang, have lower energy intensity reduction targets under the 12th FYP when compared with the reduction achieved under the 11th FYP. Cumulatively from 2006 to 2015, Beijing and Tianjin lead the other regions in having the two largest reductions in energy consumption per unit of GDP.

The 12th FYP also sets for the first time a national carbon intensity reduction goal of 17% for CO_2 emissions per unit GDP from 2010 to 2015 to help put China on the path to meeting its 2009 commitment to reduce CO_2 emissions per unit of GDP by 40-45% from 2005 levels by 2020. This target will apply only to CO_2 emissions from energy consumption and industrial activity. As with the energy intensity reduction target, the national CO_2 emission intensity reduction target of 17% has also been allocated to the provincial level as seen in Table 4.

Table 4. Provincial Energy and Carbon Intensity Reduction Targets for 11th FYP and 12th FYP

Region	Reduction in energy consumption per unit of GDP（%）			Reduction in CO_2 emissions per unit of GDP (%)
	11th FYP Period Actual	12th FYP Period Target	2006-2015 Cumulative Reduction	12th FYP Period
National	19.06	16	32.01	17
Beijing	26.59	17	39.07	18
Tianjin	21.00	18	35.22	19
Hebei	20.11	17	33.69	18

Shanxi	22.66	16	35.03	17
Inner Mongolia	22.62	15	34.23	16
Liaoning	20.01	17	33.61	18
Jilin	22.04	16	34.51	17
Heilongjiang	20.79	16	33.46	16
Shanghai	20.00	18	34.40	19
Jiangsu	20.45	18	34.77	19
Zhejiang	20.01	18	34.41	19
Anhui	20.36	16	33.10	17
Fujian	16.45	16	29.82	17.5
Jiangxi	20.04	16	32.83	17
Shandong	22.09	17	35.33	18
Henan	20.12	16	32.90	17
Hubei	21.67	16	34.20	17
Hunan	20.43	16	33.16	17
Guangdong	16.42	18	31.46	19.5
Guangxi	15.22	15	27.94	16
Hainan	12.14	10	20.93	11
Chongqing	20.95	16	33.60	17
Sichuan	20.31	16	33.06	17.5
Guizhou	20.06	15	32.05	16
Yunnan	17.41	15	29.80	16.5
Tibet	12.00	10	20.80	10
Shaanxi	20.25	16	33.01	17
Gansu	20.26	15	32.22	16
Qinghai	17.04	10	25.34	10
Ningxia	20.09	15	32.08	16
Xinjiang	8.91	10	18.02	10

Sources: Energy intensity reduction targets from State Council 2011a, carbon intensity reduction targets from State Council 2011b.

2.5. 12th FYP Energy Production Targets and Policy Objectives

On the supply side, the plan lays out specific targets for fossil and non-fossil energy production and power sector capacity additions as well as infrastructure and non-conventional oil and gas development goals. Table 5 shows the overall energy production targets for the 12th FYP. Energy production capacity, with the exception of oil production, is expected to continue increasing significantly during the 12th FYP period. The production of cleaner fuels such as natural gas and other non-fossil fuels are expected to grow at faster paces of over 10% per year on average. Under the NEA's 12th FYP for Energy Development shown in Table 5, the natural gas production target of 156.5 bcm includes over 130 bcm of conventional natural gas, 6.5 bcm of shale gas and 20 bcm of coal seam gas. However, under the NDRC's 12th FYP for Natural Gas Development, the total production target for natural gas is higher at 176 bcm. The scope of this target is also slightly different, and includes 138.5 bcm of conventional natural gas, 15-18 bcm of syngas and 16 bcm of surface coal-bed methane. The specific targets and policy directions for conventional and non-conventional oil and gas development under the 12th FYP are discussed in more detail in the next two sections.

Table 5. 12th FYP Targets for Energy Production

Target	Unit	2010	2015	AAGR
Energy Production Capacity	Mtce	2970	3660	4.3%
Coal	Mt	3240	4100	4.8%
Oil	Mt	200	200	0%
Natural Gas	bcm	94.8	156.5	10.5%
Conventional Natural Gas	bcm		130+	
Shale Gas	bcm		6.5	
Coal Seam Gas	bcm		20	
Non-Fossil	Mtce	280	470	10.9%

Source: NEA 2013.

For the power sector, the 12th FYP also set specific installed capacity targets and efficiency improvements as shown in Table 6 as well as policy objectives for ramping up non-fossil power generation development.

Table 6.12th FYP Targets for the Power Sector

Target	Unit	2010	2015	AAGR
Total Installed Capacity	GW	970	1490	9%
Coal	GW	660	960	7.8%
Hydro	GW	220	290	5.7%
Nuclear	GW	10.82	40	29.9%
Natural Gas	GW	26.42	56	16.2%
Wind	GW	31	100	26.4%
Solar	GW	0.86	21	89.5%
Thermal intensity per kWh	Kgce/kW	333	323	-0.6%
Power Grid Line Losses	%	6.5%	6.3%	0.2%*

Note: *percentage point change over 5 years.
Source: NEA 2013.

For hydropower, the total installed capacity of 290 GW target for 2015 will be driven largely by speeding up the construction of large hydropower stations on key rivers in southwest China as well as developing medium- and small-sized hydropower stations based on local conditions. Construction is also expected for pumped storage hydro. For wind, the 70 GW of additional capacity to be deployed during the 12th FYP period is expected to come from the completion of 6 onshore and 2 coastal and off-shore large wind power bases. Both centralized and distributed exploitation of wind resources will be focused on northwestern, northeastern and north China, as well as offshore areas, which is expected to contribute 5 GW of additional installed capacity by 2015. The 20 GW of solar installed capacity additions during the 12th FYP period will include large on-grid PV stations and projects in Qinghai, Gansu, Xinjiang and Inner Mongolia. Building-integrated distributed PV systems will also be encouraged in the favorable central and eastern regions, along with solar water heaters, solar central hot-water supply systems, solar thermal heating and other industrial solar applications.

2.5.1. Conventional Oil & Gas Development Objectives

China's 12th FYP policy goals of simultaneously developing conventional oil and gas can be summarized as stabilization in the east, accelerated development in the west, new development in the south and exploitation in offshore areas. In particular, the plan calls for creating five large-scale oil and gas production bases in key resource- abundant basins, including the Tarim and Junngar Basins, Songliao Basin, Ordos Basin, Bohai Bay Basin and

Sichuan Basin. In these five basins, efforts will be focused on increasing crude oil output, especially from the Tarim and Ordos Basins, and increasing the recovery ratio of old oilfields. Similarly, the plan also calls for accelerating the exploration and development of offshore and deep-water oil and gas fields. Major refining cluster areas are expected to be established in Bohai Rim, the Yangtze, and the Pearl River Deltas. For natural gas, the 12th FYP calls for enhancing the productivity and output of natural gas in major gas fields in the central and western regions while concurrently pushing forward the development of offshore oil and gas fields. As a result of these planned efforts, the plan aims to increase proven geological reserves of oil and conventional natural gas by 6.5 billion tons and 3.5 trillion cubic meters, respectively, by 2015.

In addition to increasing conventional oil and gas production, the 12th FYP also aims to strengthen and expand the supporting infrastructure for the oil and gas industry. One key focus area will be to continue expanding China's growing network of oil and gas pipelines in order to deliver oil and gas supply to where it is needed. Specifically, the plan emphasizes undertaking greater efforts to expedite the construction of existing and new networks of crude oil, product oil and natural gas pipelines and accelerating the construction of strategic imported oil and gas transmission lines for northwestern, northeastern and southwestern China. New pipeline networks that are expected to be completed by the end of 2015 include the China-Kazakhstan crude oil pipeline, the Central Asia natural gas pipeline and the East-West transmission lines 3 and 4. As a result of these new pipeline projects, China's oil and gas pipeline network is expected to reach a total length of 150,000 kilometers by 2015. The proportion of oil and gas transported by pipelines will also be increased under the plan. Regional networks of pipelines along with natural gas supply networks in cities will be improved, and unified planning of natural gas import pipelines, LNG receiving stations, and cross-regional trunk gas transmission and distribution networks will be undertaken as part of the 12th FYP efforts. Figure 4 shows the locations of existing and planned natural gas pipelines and LNG terminals in China.

Figure 4. China's Natural Gas Infrastructure

Source: Corbeau et al. 2012.

Moreover, the plan also calls for greater efforts to balance resource reserves and improve the reserve system for crude oil, oil products, natural gas and coal, while enhancing the abilities to use natural gas and coal to help in providing peak-shaving generation during peak electricity demand periods. For natural gas, a balanced gas supply layout for natural gas, coal-bed methane and syngas will also be created. From these strategies, it is apparent that while China will continue to aggressively pursue non-fossil development, it also seeks to maximize conventional oil and gas production by improving their transport, storage, and utilization.

2.5.2. Non-conventional Oil & Gas Development Objectives

Another important overarching goal of the 12th FYP for energy development is to enhance China's energy security from a supply perspective by actively promoting the development and utilization of non-conventional oil and gas resources. This includes advancing resource exploration efforts to increase proven geological reserves for key non-conventional resources, such as shale gas and coal-bed methane, while simultaneously establishing industrial bases in key basins for resource development and extraction. More specifically, the plan sets goals of increasing proven geological reserves by 600 bcm for shale gas by 2015 and 1 trillion cubic meters (tcm) for coal seam methane by 2015. For production, the plan targets annual production of 6.5 bilion cubic meters (bcm) for shale gas and 20 bcm for coal-bed methane by 2015. To meet these goals, shale gas development under the 12th FYP period will involve selecting a group of prospective areas and favorable exploration target areas, intensifying efforts to improve key technologies, and setting up new development mechanisms and incentive policies. Similarly for the coal seam methane industry, efforts will focus on speeding up exploration and exploitation and creating a mechanism to balance the development of coal and coal-bed gas. At the same time, China will continue to explore the development of other forms of non-conventional gas, including continuing a drilling and coring program for gas hydrates and pilot gasification and demonstration projects for in-situ coal gasification. For non-conventional oil resources, 12th FYP efforts will be primarily focused on expanding the pilot commercial production of tight oil[2] and increasing the extraction and retorting of oil shale.

In support of non-conventional oil and gas development, the government will initiate efforts to advance technology and research and development during the 12th FYP period. This includes the continued financial and policy support for a national high-tech program for large oil-gas field and coal-bed gas development and the launch of major technology demonstration projects in the development and utilization of coal-bed methane and exploration and development of shale gas. The government will also provide support to large enterprises and research institutes to conduct research and development related to coal-bed methane, shale gas, coal-based liquid fuels and coal-based co-production. At the same time, an evaluation and reward mechanism for technological development and incentive mechanisms for innovations will be developed to encourage technological breakthroughs.

2.6. Oil and Gas Prices and Fees

In addition to production and infrastructure policy changes during the 11th and 12th FYP period, there have also been important developments in the taxation, fees and pricing structure for oil and gas in China. These changes in turn influence the domestic oil and gas market and both reflect and contribute to changes in domestic Chinese oil and gas production, demand and international trade.

[2] In China's resource classification scheme, there is no distinction between tight oil and conventional oil but for the purpose of this study, tight oil will be referred to as a non-conventional oil resource.

2.6.1. Oil and Gas Taxes and Fees

Alongside China's economic reform over the past 30 years, regulations on oil and gas taxes and fees have evolved and gone through three different stages of development. Prior to 1984, there were no specific regulations on oil and gas taxation and fees. As domestic demand for oil – and natural gas to a lesser extent – began increasing with the country's growing economic reforms, a basic resource tax was introduced for crude oil, natural gas and coal through three sets of resource tax regulations. These included the 1984 draft Resource Tax Ordinance of the People's Republic of China, the 1984 Resource Tax Provisions and the 1986 Mineral Resources Law. At the same time, progressive tax rates on sales revenues were introduced with the intent to help adjust differential incomes in resource exploitation and to promote rational resource extraction. The concept of royalties on crude oil and natural gas production was introduced in subsequent regulations, with the promulgation of the provisions for royalties on offshore petroleum resources in 1989 and for royalties on onshore petroleum resources in 1990.

The third stage of tax and fee regulations from 1994 to present involves comprehensive taxation reform in line with other market reforms that took place in China during the same time period. In 1994, for instance, the basic resource tax was extended from the original 3 types of resources to cover a total of 7 types of resources, with the addition of resource taxes for the exploitation of other raw non-metal mineral ore, raw ferrous metal mineral ore, nonferrous metal mineral ore and salt. The specific amount of payable resource tax was determined by multiplying a producer-specific tax rate by the total volume of output. The 1994 resource tax rates for crude oil, natural gas and coal, for instance, ranged from 8 to 30 RMB per ton of crude oil, 2 to 15 RMB per 1000 cubic meters of natural gas and 0.3 to 5 RMB per ton of coal, respectively. In 2005, the oil resource tax rate was raised to 14 to 30 RMB per ton of crude oil while the tax rate for coking coal increased more significantly to 8 to 20 RMB per ton of coal.

Since 2005, the central government has been evaluating reforming the resource tax to be proportional to total sales rather than a flat, volume-based rate. In order to test the resource tax reform, the Ministry of Finance and State Administration of Taxation launched a pilot resource tax scheme based on total sales in Xinjiang province. The new pilot resource tax was set at 5% of the total sales amount of crude oil and natural gas extraction in Xinjiang. For natural gas, this reform translates into a much higher effective tax rate as the resource tax based on sales is 4.5 times higher than that based on the volume of output. The success of the pilot was followed quickly by a nationwide expansion of the tax reform, with 2011 revised regulations introducing a 5-10% resource tax on crude oil and natural gas sales, with the specific resource tax amount to be set by the ad valorem method.

In addition to the resource tax, three other kinds of taxes are also applied to crude oil and natural gas production in China. The income tax rate for oil and gas enterprises was set in 2006 at 25% but western regions were given a preferential rate of only 15%. In 2006, China also introduced a windfall tax on crude oil sales in the form of a special upstream profit charge. The windfall tax is set at five different levels based on crude oil prices, ranging from a low of 20% to a high of 40%. Originally, the windfall tax exemption threshold was set at $40 per barrel but this was raised by the Ministry of Finance to $55 per barrel in November 2011. Lastly, value-added tax was introduced in 2008, with the rate set at 17% for crude oil and 13% for natural gas. However, offshore crude oil production received a lower preferential value-added tax rate of only 5%.

A summary of the current taxes related to oil and natural gas production is shown in Table 7.

Table 7. Summary of Taxes on Oil and Gas Production

Tax Category	Current Tax Rate	Effective Date
Enterprise Income Tax	Income tax rate of 25% Income tax rate of 15% preferential rate for western regions	2007 2011
Value-added Tax	Crude Oil: 17% Natural Gas: 13% Offshore Crude Oil: 5%	2008
Resource Tax	5-10% of oil and gas sales	2011
Special Oil Upstream Profit Tax (i.e., windfall tax)	$55-60 per barrel: 20% $60-65 per barrel: 25% $65-70 per barrel: 30% $70-75 per barrel: 35% >$75 per barrel: 40%	2011

For fees related to oil and gas production, a mineral resource compensation fee of 1% of total sales was first introduced in 1994 for oil and gas with the promulgation of the Mineral Resources Compensation Levy Regulations on February 27, 1994. This regulation included two resource exceptions to the compensation fee, with 0% fee collected for coal-bed methane and 50-100% exemption for offshore oil production. However, in 1995, the revised royalty regulations for crude oil and natural gas production supplemented the mineral resource compensation fee and resource tax since enterprises paying royalties were not subjected to resource taxes or the compensation fee. The current royalties on crude oil could be as high as 12.5%, depending on the location and cumulative amount of production. Royalties on natural gas range from 0 to 3%, depending on the production location and cumulative production.

As domestic demand and production increased and resource exploration efforts intensified, China introduced two new fees for the acquisition and purchase of resource exploration and mining rights. The exploration and mining rights acquisition fee were first introduced in 1986 and revised in 1996 through 1998, and includes escalating exploration fees over time and a flat mining rights acquisition fee. More specifically, the exploration fee was set at 100 RMB per square kilometer per year for the first three years, rising by 100 RMB per square kilometer per year from the fourth year onwards to a maximum of 500 RMB per square kilometer per year. The mining rights acquisition fee was set at a flat rate of 1000 RMB per square kilometer per year. More recently in 2006, prices for purchasing resource exploration and mining rights were established with specific prices set by the geology and mineral resources authorities of the State Council. The purchase prices guaranteed exploration rights for up to 2 years and mining rights of up to 10 years, and can be paid either in lump sum or in installments. A summary of the current fee schedule and effective dates is shown in Table 8.

Table 8. Summary of Oil and Gas Resource and Production Fees

Fee Category	Specific Fee Schedule	Current Fee Effective Date
Mineral Resource Compensation Fee	1% of sales	1997
Royalties	Crude Oil: 0 - 12.5%, depending on location and cumulative production Natural Gas: 0 - 3%, depending on location and cumulative production *Enterprises paying royalties not subjected to resource tax or mineral resource compensation fee	1995
Exploration and Mining Rights Acquisition Fee	Exploration fee: Year 1 – 3: 100 RMB/km^2/year Year 4 onwards: increase by 100 RMB/km^2/year, up to 500 RMB/km^2/year Mining rights acquisition fee: 1000 RMB/km^2/year	1999

Exploration and Mining Rights Purchase Price	Price set by geology and mineral resources authorities of the State Council May be paid in lump sum or in installments Exploration rights period of up to 2 years Mining rights period of up to 10 years	2006

2.6.2. Oil Pricing and Reform

As with the evolution of the oil and gas resource tax and fee structures, oil prices in China have also gone through different phases of regulation, de-regulation and slow market-based reform. In the early years of the 1980s, China set a three-tiered price system for oil prices. Under this system, oil companies can sell their surplus production at market prices only after they have fulfilled centrally mandated quotas of 100 million tons. As a result of this requirement, there were essentially three different prices for crude oil: a low price of 300-500 RMB per ton of oil, depending on quality, a high price for production used to meet the quota, and the market price for production in excess of the quota (Chen 2006). For petroleum products, there were only in-quota low prices designated for serving the military, agriculture and some large oil-consuming state-owned enterprises and the market price for production in excess of the quota.

This strictly controlled and mandated low prices for in-quota production resulted in severe financial losses for the petroleum industry, which forced the central government to not only raise the quota prices but led eventually to pricing de-regulation over the late 1980s and early 1990s. By removing the low price quota level, petroleum pricing became a two-track system of subsidized prices and deregulated market prices with increasing proportions of both crude oil and refined petroleum products being sold at deregulated prices. In 1993, for instance, two-thirds of both crude oil and petroleum products were sold at deregulated prices close to international prices (Chen 2006).

By 1994, however, the period of decentralization and rapid economic growth caused rampant inflation and skyrocketing of both consumer prices and production costs. To rein in inflation and high prices, the central government regained control of crude oil and refined product prices with more heavily regulated pricing that virtually abolished the market. The central government was not only responsible for setting the differences between wholesale and retail prices, but also dictated the crude oil and oil product prices in each city and province (Chen 2006). This strict price control continued throughout much of the 1990s and it was not until 1998 that efforts were initiated to gradually introduce market-oriented pricing reform to the petroleum industry.

The first step towards integrating domestic oil prices with international prices was taken in June 1998, when the central government pegged Chinese oil prices to the average price of the previous month in the Singapore market. But because this over-transparent pricing scheme soon led to over-speculation in the domestic market, changes were made to increase the opaqueness of the domestic pricing scheme in late 2001. Rather than changing oil prices every month according to the Singapore market average, domestic prices were set to be changed only when international refined oil prices fluctuated beyond an 8% range. The domestic prices were also pegged to weighted-average market prices in the Singapore, Rotterdam and New York markets instead of only Singapore's market, and at unspecified timeframes (Chen 2006). Nevertheless, these changes were only able to achieve partial alignment to international prices and remaining problems included a delay in capturing international oil price fluctuations and inability to account for domestic production costs and accurately reflect supply-demand relations. To further integrate domestic prices with the international market, the oil price setting mechanism was changed again in May 2009. Domestic prices for refined oil were now adjusted only when average prices for Brent, Cinta and Dubai crude oil moved by 4% or more within 22 consecutive working days (Xinhua News 2013). But in 2011, this pricing mechanism failed to adjust prices upward when record inflation hit, resulting in significant financial losses for refiners and subsequent curbing of production. To further increase the responsiveness of domestic oil prices to international price fluctuations, the price adjustment time threshold was shortened from 22 to 10 consecutive working days and the 4% price change range was abolished in March 2013 (Xinhua News 2013). Beyond these two changes, however, little details are given to this latest set of efforts to reform the government-set oil prices.

2.6.3. Natural Gas Pricing and Reform

As China becomes increasingly dependent on natural gas imports, the pricing structure for domestic natural gas and calls for reform are beginning to attract greater regulatory attention. In particular, the gap between domestic gas prices and imported gas prices is widening as a result of difficulties in passing the rapidly increasing procurement costs of imported gas and onto final end-users. More specifically, China's natural gas pricing structure is currently based on a cost plus regulated approach consisting of three main elements: the wellhead price, the pipeline transportation tariff and the end-user price.

The wellhead price is proposed by the project developer but adjusted by the central government, and is based in principle on the production cost plus an appropriate margin for the producer. The wellhead price (which includes the gas processing fee) is intended to serves as a common baseline price for all domestic fields, although producers and buyers can negotiate up to 10% above the wellhead price.

The pipeline transportation tariff is set directly by the central government and has evolved from a flat tariff prior to 1984 to its current form of being based on pipeline cost plus a margin based on achieving an internal rate of return (IRR) of 12%, with adjustments for transport distance from each gas source to each city gate. The guaranteed IRR is set at a relatively high level of 12% in order to help offset losses at the production, imports and sales side that result from a capped wellhead price, but may in turn result in high pipeline tariffs and fluctuating transportation costs (Corbeau et al. 2012).

The end-user price serves to differentiate the prices that different end-users have to pay, and result from both differentiated wellhead prices and transport tariffs for different users. Residential end-user gas prices are set by the government at lower levels out of affordability concerns and to avoid triggering high inflation rates, and are typically the lowest compared to industry, commercial, power and transport sectors. Substantially lower residential prices may encourage inefficient use of gas by residential consumers while limiting industry or power generators' access to gas (given the limited supply) and cause significant losses for the government or producers. In fact, as the import share of China's natural gas demand rose to nearly 16% in 2010 and continues to rise with growing imports, the gas industry will likely incur more and more losses from the imbalance of state-controlled end-user gas prices and rising import costs. For example, CNPC is already believed to be losing 1 RMB/m^3, or an estimated total of 15.5 billion RMB for 2011 (Corbeau et al. 2012). This growing concern over the gap between domestic and imported gas prices has led the central government to take different measures in attempts to mitigate the widening gap.

In mid-2010, NDRC raised onshore wellhead prices by 25% and also increased the natural gas end-user prices for industrial and power sectors in some cities (EIA 2013a). In 2011, the central government also began granting tax rebates for import prices exceeding wholesale gas prices through 2020. Lastly, pilot pricing reforms based on a netback approach rather than a cost plus regulated approach were initiated in the two regions of Guangdong and Guangxi in December 2011. Under this pilot approach, city-gate prices would be linked to two natural gas substitutes, fuel oil and LPG, and there would only be one maximum single price at the city gate that is independent from the gas source. City-gate prices would be linked 60% to fuel oil and 40% to LPG, with Shanghai prices as the benchmark (Corbeau et al. 2012). This formula is intended to take into consideration the competition for gas in the industry and household sectors. Price reference points will be assigned to provinces, with an initial annual increase in city-gate prices and plans to move towards quarterly changes in pricing. In July 2012, plans were announced to extend the pilot gas pricing reforms to Sichuan as well as Chongqing. The first natural gas spot trading market opened in the Shanghai Petroleum Exchange to trade natural gas to power gas-fired peaker plants for summer peak electricity demand.

Despite these initial pricing reforms, some important pricing issues still remain. Under the netback approach, seasonality and the cost of storage are not addressed and may cause some local distribution companies to face losses when forced to purchase more expensive gas but still unable to pass through the cost increase. Likewise, the netback approach covers the cost of producing and bringing gas on the market, but does not define a specific price for transportation for third parties. In addition, the market substitute formula now in pilot use excludes coal as a competitive fuel in power generation. Ultimately, these issues will be need to be addressed as China's natural gas industry moves towards increasingly liberalized and market-based, rather than government regulated, prices.

3. Comparison of Chinese and International Resource and Reserves Classification Schemes

3.1. Overview of Chinese Classification Frameworks

China's oil and gas reserves classifications and definitions are defined by the Ministry of Land and Resources (MLR) based on previous national standards, specifically GB269-88: Oil Reserves Regulation and GB270-88: Gas Reserves Regulation. Under this initial classification system based largely on the petroleum classification system of the former Soviet Union, economic viability was not emphasized or lacked clarity. The classification of the reserve classes of inferred, indicated and measured reserves were based on the phase of exploration or development and the amount of available information. Specifically, the three reserve classes included:

- Inferred reserves: early exploration and discovery
- Indicated reserves: exploration well test with industrial flows, as defined by criteria for well test production rates at a given reservoir depth
- Measured reserves: end of exploration to development

China's current reserves classification system was approved in 2004 and went into effect in 2005. This new classification scheme is more closely aligned to existing international classification systems, including the Society of Petroleum Engineers' (SPE) classification system, because it follows the general McKelvey classification approach introduced in the early 1970s. This approach is shown in Figure 5, with the horizontal axis representing the scale of geological certainty and the vertical axis representing the scale of economic feasibility.

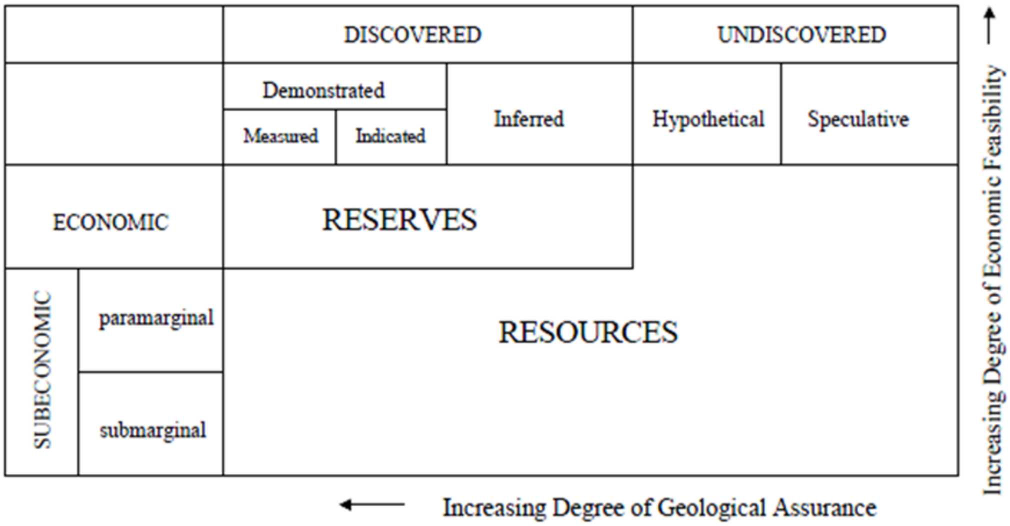

Figure 5. Diagram of McKelvey Reserve and Resource Classification

The current Chinese classification scheme is shown in Figure 6 below.

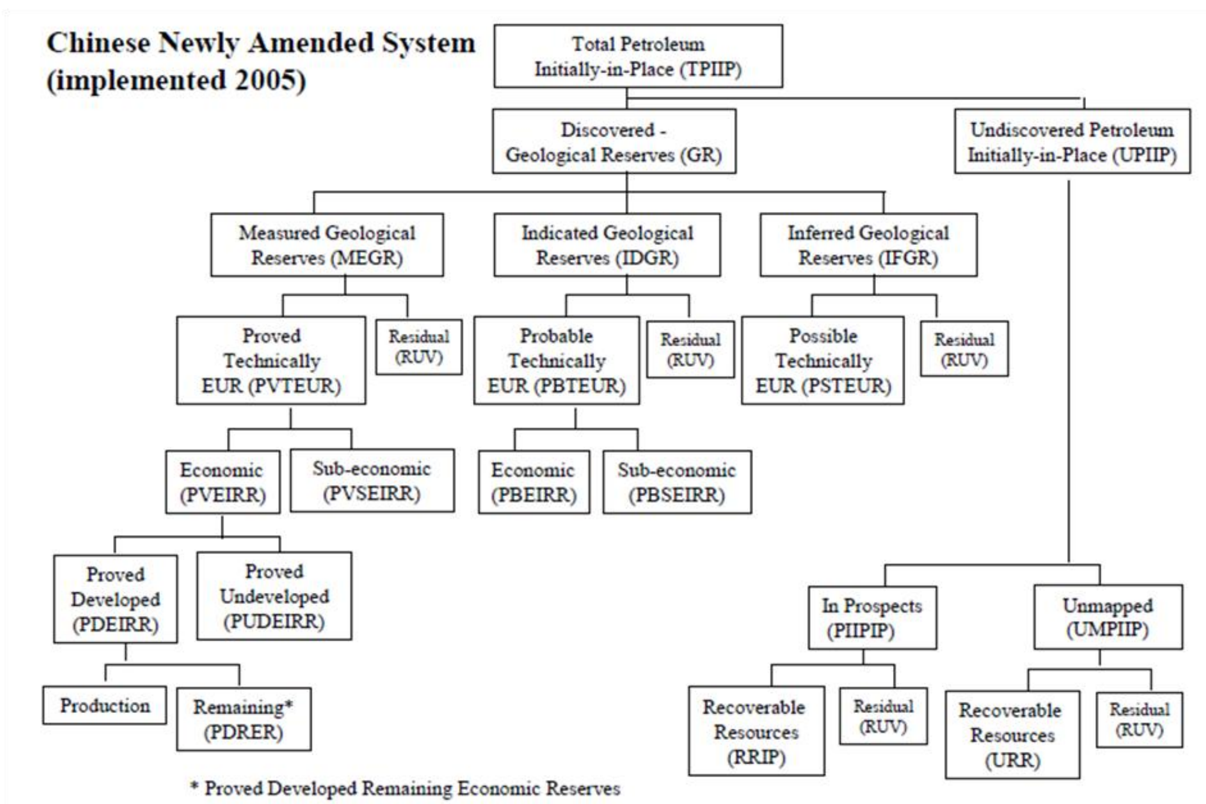

Figure 6. Chinese 2005 Reserves Classification Scheme

Source: Etherington et al. 2005.

Beginning at the top and in line with the McKelvey diagram, discovered in-place volumes are classified as measured, indicated or inferred reserves based on the phase of exploration and development. The key difference in the Chinese approach is that the term "reserves" is used to describe discovered in-place volumes as well as technically and economically recoverable volumes. In contrast, "reserves" under the SPE classification is only based on recoverable reserves. Geological reserves that are estimated with a high level of confidence after appraisal drilling has proven that the reservoirs are economically recoverable are considered measured geological reserves.

At the next level down, technically estimated ultimate recoveries (TEUR) refers to reserves that are estimated to be theoretically recoverable given technological conditions, including the presence of primary technologies and/or improvements in recovery technologies and development plans that are currently in place or expected in the near future. TEURs are then further classified as Proved, Probable and Possible based on specific degrees of geological confidence. Specifically, in the Chinese classification framework, proved reserves are defined by a probability of greater than or equal to 80% that the quantities actually recovered in the future will equal or exceed the initially estimated TEUR, probable reserves are defined by a probability of greater than or equal to 50% and possible reserves are defined by a probability of greater than or equal to 10%. In reality, however, the reserve assessments are usually based on deterministic scenarios and probabilistic analyses may not necessarily be used directly in the classification (Etherington et al. 2005).

Next, of the TEUR, economic initially recoverable reserves (EIRR) are the quantities that are anticipated to be economically recoverable under existing economic conditions and given current or planned technical operating conditions. Of the total EIRR, proved EIRR are determined based on many different factors, including unescalated prices and costs, availability of operational or demonstrated pilot technologies, development plans, and confirmed economic productivity and economic feasibility studies, in addition to the 80% probability threshold.

3.2. Comparison to SPE Classification Framework

Since both the Chinese and SPE classification frameworks followed the McKelvey approach, there are similarities in reserve definitions that enable the approximate mapping of SPE definitions onto the Chinese framework. The SPE equivalent of some reserve definitions in the Chinese framework are shown in Figure 7.

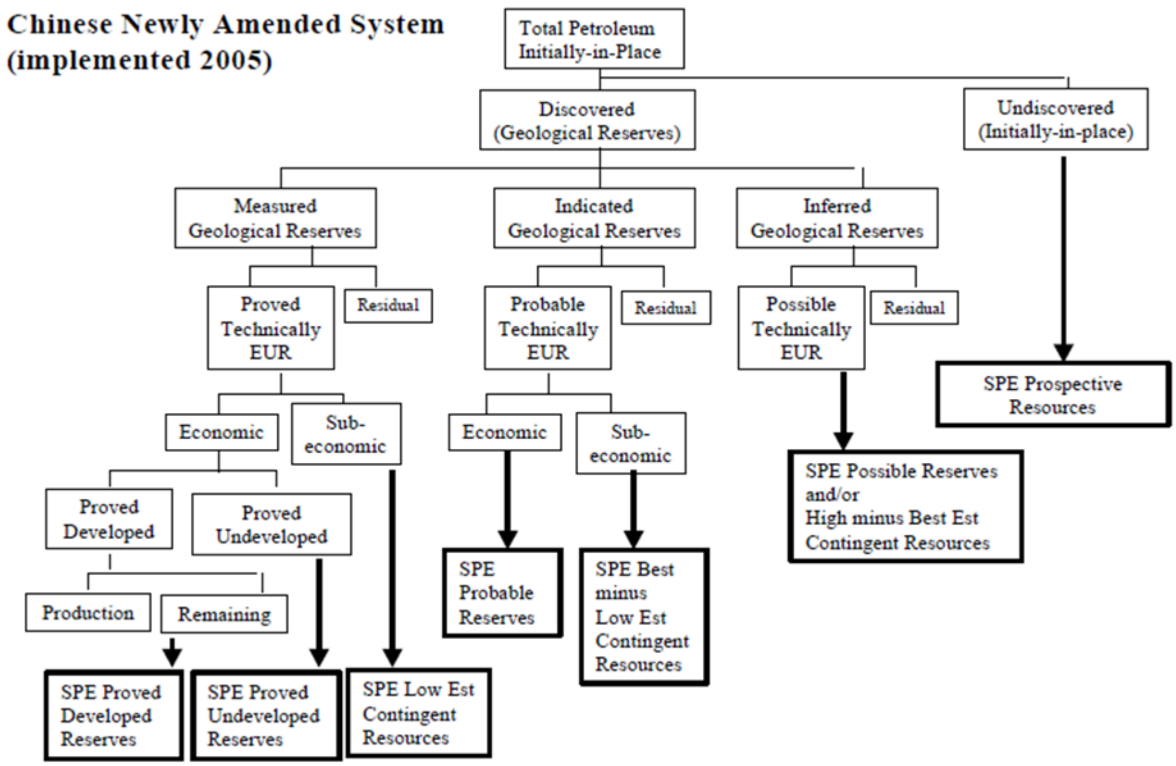

Figure 7. Chinese Reserve Classification Scheme with SPE Equivalent Definitions

Source: Etherington et al. 2005.

Outside of similarities in some reserve definitions, the two classification schemes differ in the underlying foundation for the classification approach as well as specific methods for defining proved, probable and possible reserves. As previously mentioned, one key difference between the Chinese classification scheme and the SPE classification scheme lies in the "reserve" definition. Whereas the Chinese bases their approach on geologic, in-place reserves, the SPE approach is based on recoverable reserves. Another key difference is that the SPE defines proved reserves as estimates with a probability of greater than or equal to 90%, rather than the 80% threshold used for the Chinese definition of proved reserves. For reserve definitions, the SPE also requires that the estimates be prepared using either deterministic or probabilistic methods. A deterministic estimate is based on a single best estimate made using known geological, engineering or economic data. A probabilistic estimate is based on using known geological, engineering or economic data to generate a range of estimates with associated probabilities. Under the SPE system, reserve numbers are typically defined within a range that is described either qualitatively by deterministic methods or quantitatively by probabilistic methods. In contrast, the Chinese reserve definitions are entirely based on deterministic methods. Finally, the Chinese reserve classification system reflects the needs of state ownership and management of energy and other resources, while the SPE system is oriented toward defining profitable extraction volumes. In general, China's reported reserve figures would be lower if classified according to SPE standards.

4. Shale Gas

As one of the main types of unconventional hydrocarbon, shale gas has proven to be viable alternative resource to conventional natural gas with its successful development in the U.S. In light of its limited domestic conventional natural gas resources, China has expressed recent interest in rapidly developing its shale gas resources in hopes of mitigating shortages in its natural gas market and subsequent energy security concerns with its natural gas import dependency. This section reviews China's shale gas resources according to the most recent assessments, recent shale gas resource development efforts and future targets, and barriers and challenges in the future outlook for shale gas development in China.

4.1. Resource Assessment

China's shale gas resources are deposited in three types of shale – Paleozoic marine shale, Paleozoic transitional shale and Meso-Cenozoic continental shale – located throughout the country as seen in Figure 8. Table 9 below lists the geographic location and corresponding land area coverage of the three types of shale formations.

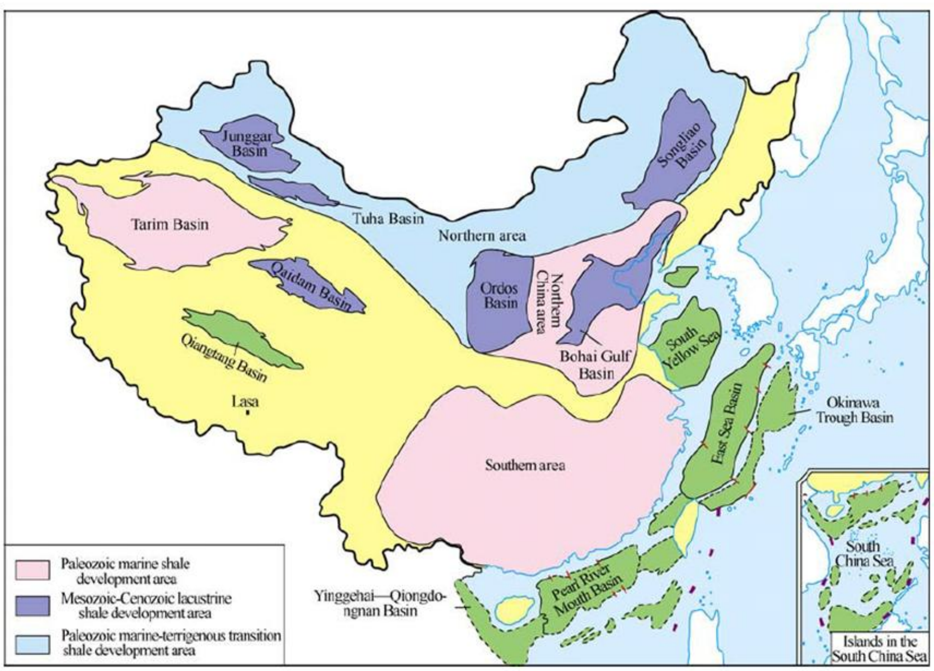

Figure 8. Geographic Distribution of Shale Formation Types in China

Source: Zou et al. 2010.

Table 9. Geographic Location and Land Area by Shale Resource Type

Type of Shale Gas	Location	Land Area
Paleozoic marine muddy shale	Southern area of China, Tarim Basin	600,000 – 900,000 km^2
Paleozoic transitional muddy shale	Northern China and Yangtze area	150,000 –200,000 km^2
Meso-Cenozoic lacustrine muddy shale	Songliao Basin, Bohai Bay Basin, Ordos Basin, Junggar Basin, Tuha Basin and Qaidam Basin	200,000 –250,000 km^2

Source: Jia et al. 2012.

Of the three types of shale, Paleozoic marine shale and Paleozoic transitional shale are considered the most geologically favorable type of shale gas resources given its abundant organic matter, stable regional distribution and large thickness. These two types of shale are also the most abundant in terms of land area, with marine shale covering 600 to 900 thousand square kilometers in Southern China and transitional shale covering 150 to 200 thousand square kilometers in Northern China. The Meso-Cenozoic continental shale formations hold better resource prospects due to its lower degree of thermal evolution and high heterogeneity, which requires more specialized technologies for development. The presence of continental shale formations is also a distinctive feature of Chinese shale gas compared to North American resources, which are all from marine shale formations. In terms of development prospects, the most promising area for shale gas development is the Paleozoic marine organic-rich shale resources in the Yangtze area which has favorable geologic conditions for hydrocarbon generation and shale gas accumulation. Specifically, shale resources favorable for commercial shale gas development generally has total organic carbon content of greater than 2%, brittle mineral content of over 40%, clay mineral content of less than 30%, maturity of over 1.1% and effective thickness of organic rich shale of over 30 to 50 meters (Zou et al. 2010). In China, shale gas formations in this region meet these geological characteristics and have been the focus of recent exploration and development efforts.

There have been two recent shale gas resources assessments for China; one conducted by the U.S. Energy Information Administration (EIA) as part of their global assessment of shale gas resources in April 2011 and another conducted domestically by the MLR in 2011. The initial resource assessments for the EIA assessment was carried out by a consulting firm, Advanced Resources International, and covered 48 major basins in 32 countries. For China, the EIA assessment focused only on two marine-deposited basins – Sichuan and Tarim Basin – and does not include non-marine shale resources in five other basins. On June 10, 2013, EIA released a revised global assessment of shale gas resources, including a revised estimate for China based on more basins and formations. The results of EIA's revised estimate is taken into consideration in a later section on shale gas supply forecasts, but the specific differences and changes in scope and methodologies in the revised EIA study is not included here due to limited time for conducting additional analysis. In contrast, the national resource assessment initiated by NDRC and carried out by MLR had a much larger resource assessment scope, covering marine, non-marine and transition formations in 8 major basins including Yangzi, North China, Tarim, Songliao, Bohai Bay, Ordos, Junnger and Tuha Basins.

The EIA assessment methodology included the following five steps (EIA 2011a):

1. Conduct preliminary geologic and reservoir character analysis of shale basins and formations
2. Establish the areal extent of the major shale gas formations
3. Define the prospective area for each shale gas formation
4. Estimate the risked shale gas in-place, which de-rates the estimated gas-in-place by factors that account for the current level of knowledge and technological capabilities based on the consulting expert's opinion
5. Calculate the technically recoverable shale gas resource

The Chinese assessment by MLR followed a similar volumetric method of analogy of abundance to gas ratio, but estimated technically recoverable shale gas resources based on the total estimated gas in-place, rather than risked gas in-place. Another difference between the EIA and Chinese shale gas resource assessment is the assumed recovery rate, with EIA assuming a higher recovery rate of 25% and China assuming a lower recovery rate of 15%. In addition, the Chinese assessment also found a wider range in the resource concentration of 0.74 to 1.52 x 10^8 cubic meters per square kilometer than the EIA assessment, which assumed a narrow range of only 0.62 to 0.87 x 10^8 cubic meters per square kilometer.

A summary of the major differences between the two shale gas resource assessments is shown in Table 10 .

Table 10. Overview of EIA's 2011 and China's Shale Gas Resource Assessment

	EIA 2011	China
Assessment Method	Analogy, volumetric method	Analogy of abundance/gas ratio, volumetric method
Resource Definition	Total Recoverable Resources based on the ***risked*** gas in-place	Total Recoverable Resources based on the gas in-place
Formations Assessed	4 Marine formations	Marine, non-marine and transition formations
Resource Concentration	0.87 – 0.62 x 10^8 m^3/km^2	0.74 – 1.52 x 10^8 m^3/km^2
Recovery Rate	25%	15%
Total Estimated Resources:	Shale gas in place: 708 tcm Risked shale gas in place: 144 tcm Risked technically recoverable shale gas resources: 36 tcm	Shale gas resources in place: 86 – 166 tcm Technically recoverable shale gas resources: 15 – 25 tcm

Source: U.S. EIA 2011a.

As a result of the differing scope of assessment as well as different assumptions, differences are observed in the assessment of the same formations by the two different studies as seen in Table 11. The Chinese assessment, which covered a larger land area, found a greater range in the formation thickness, organic carbon and thermal evolution degree. However, the EIA assessment results for total organic carbon and thermal evolution degree for the two formations are within the range of the Chinese values.

Table 11. Comparison of EIA's 2011 and Chinese Assessment Results for Two Shale Gas Formations

	Longmaxi		**Qiongzusi**	
	Yangzi Region		Yangzi Region	
	EIA	***China***	***EIA***	***China***
Thickness (m)				
Range	-	20-700	-	50-700
Average	177	100	119	120
Area (thousand km^2)	150	420	210	930
Total Organic Carbon (%)	3%	1.88 - 4.36%	3%	1.5 - 5.7%
Thermal Evolution Degree R_o (%)	2.3%	2.4 - 3.3%	2.5%	2.33 - 4.12 %

Source: EIA 2011a; Huang et al. 2012.

In terms of total estimated shale gas resources based on the two basins assessed, the EIA assessment found total shale gas in-place of 708 trillion cubic meters, with 144 trillion cubic meters of risked shale gas in-place and 36 trillion cubic meters of risked technically recoverable shale gas in-place. In contrast, the Chinese national assessment found 86 to 166 trillion cubic meters of geological shale gas in-place and 15 to 25 trillion cubic meters of technically recoverable shale gas in-place. The findings of the Chinese assessment are further broken down by the 8 major basins as shown in Figure 9. As seen in the figure, the majority of China's geological and technically recoverable shale gas resources are located in the Yangzi and North China regions.

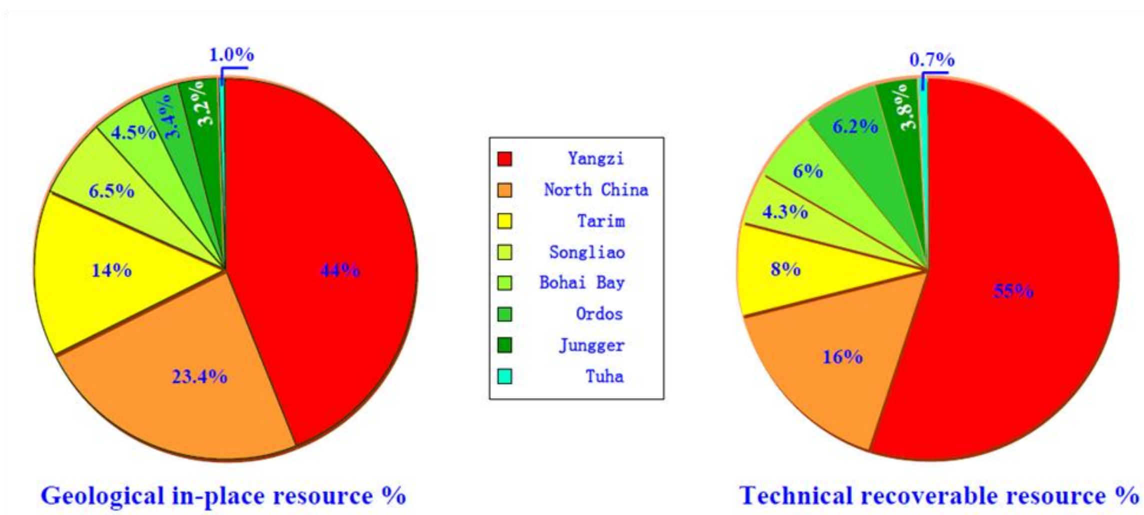

Figure 9. Chinese Shale Gas Resource Distribution by Basin

On the basis of the survey results, the MLR also identified 180 shale gas favorable areas. The geographic distribution of these favorable areas by region is shown in Figure 10 are consistent with the geographic resource distribution results, with the most favorable areas located in Yangzi and Northern China regions.

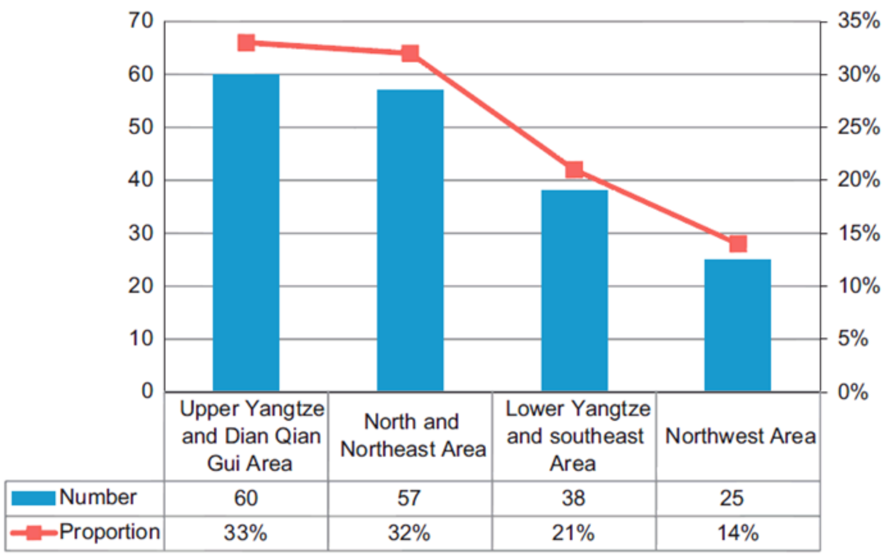

Figure 10. Geographic Distribution of Favorable Shale Gas Areas Selected by MLR

Source: Zhao et al. 2013.

4.2. Recent Shale Gas Development in China

4.2.1. Overview of Recent Developments

In contrast to the 80+ years of development in the U.S., shale gas development began only in 2009 in China and the industry is still in its early stages of development. Shale gas exploration in China began with the MLR's launch of the first shale gas resource exploration project in Qijiang County in Chongqing in October 2009. This was followed closely by the signing of a Memorandum of Understanding between China and the U.S. in November 2009. In 2010, more research, development and resource exploration efforts were initiated at both the government level and the state-owned enterprise level. In particular, the Shale Gas Research and Development Center of National Energy - China's first scientific research institution specializing in shale gas development - was established by the Institute of Petroleum Exploration and Development in August 2010. At the same time, the China National Petroleum Corporation (CNPC) began developing oil and gas fields with wellhead-testing and obtained industrial flow of 10,800 cubic meters per day while Sinopec began manufacturing fracking trucks and fracturing its first well in the Jianghan oilfield (Zhao et al. 2013).

2011 marked a key year for shale gas development in China, with important advancements in drilling as well as developmental milestones that included the first auction for shale gas drilling rights and its recognition as an independent mineral. On the technology side, CNPC successfully drilled its first domestic shale gas horizontal well in March 2011, followed by the exploration of China's first domestic continental shale gas well by the Shanxi Yanchang Petroleum Group in May (Zhao et al. 2013). The national assessment of shale gas resources was also completed in 2011, and identified 30 to 50 prospective shale gas resource exploration areas as well as 50 to 80 favorable target areas. To further encourage exploration activities in these target areas, the MLR held the first auction of shale gas drilling rights in June. In this first auction, six state-owned enterprises were invited to participate in the bidding of exploration rights for four shale gas blocks. The bidding process involved a preliminary review, followed by a detailed review of invested capital, equipment, personnel, and hydraulic fracturing technology (Sun 2013). The winners are selected based on the bidders who committed to drill the most wells with the largest capital investment, and are given an exploration permit valid for three years with the possibility for an extension. In exchange for the exploration permit, the winners have to invest capital expenditure of at least 20,000 RMB per square kilometer per year and drill at least two wells per thousand square kilometer over the three years. In the first auction, Sinopec and Henan Provincial Coal Seam Gas Development and Utilization Company won the drilling rights to two shale gas blocks, and drilling rights to the two remaining blocks were not issued because the minimum number of bids required by law was not met.

On December 31, 2011, the MLR officially recognized shale gas as the 172nd independent mining resource. This allows shale gas to be exempted from the restrictive legal regime that exists for conventional oil and gas exploration and production. Specifically, mining licenses for shale gas will no longer be restricted to the few large monopoly oil and gas enterprises and other investment parties, including small private companies, are now allowed and encouraged to enter the shale gas industry (Zhao et al. 2013). In the beginning of 2012, foreign investments in shale gas exploration and development was also added to the "encouraged" category of the Foreign Investment Industry Guidance Catalogue, thereby granted access to certain administrative and tax benefits (Sun 2013). In March 2012, the 12th Five Year Plan for Shale Gas Development was issued, formalizing the policy planning framework for shale gas development from 2011 to 2015. The specifics of this plan are discussed in the next section, but it is important to note that the plan set two shale gas production targets of 6.5 billion cubic meters by 2015 and 60 to 100 billion cubic meters by 2020. By May, a total of 63 trial shale gas wells had been completed, including 61 by oil companies and 2 by the MLR. Of these 63 wells, about half had achieved industrial-quality gas.

In October 2012, the second round of auctioning shale gas drilling rights was held and included 19 blocks covering 20,002 square kilometers. The auctioned blocks included: 5 blocks in Hunan, 5 blocks in Guizhou, 3 blocks in Chongqing, 2 blocks in Hubei, 2 blocks in Henan, and 1 block each in Jiangxi, Zhejiang and Anhui Provinces. Unlike the first auction which was by invitation only, this second auction was open to any Chinese enterprises with a registered capital of more than 300 million RMB and qualified in oil and gas exploration and a maximum of two blocks were allowed for each bid. As a result of the broader qualification criteria, a total of 83 enterprises including a third from the private sector participated in the second auction. The winners of the second auction were announced in December, and included 14 state-owned enterprises, mostly from the coal mining or the power industries, and two private Chinese firms (Sun 2013). The two private firms, Huaying Shanxi Energy Investment Co. Ltd. and Beijing Taitantongyuan Natural Gas Technology Co., won the rights to two blocks in Guizhou. Of the state-owned enterprises, Huadian Corporation had the highest number of winning bids, with its three subsidiaries being granted the exploration rights to four blocks. In contrast, none of the state-owned oil companies won the rights to any shale gas blocks. The winners have to establish an exploration company, evaluate its designated area and formulate an exploration proposal detailing geological conditions of the formation, selection of drilling sites and technologies, and fracturing design and completion methods.

Although they did not win the bidding rights to any shale gas exploration blocks, China's major state-owned oil companies are still undertaking exploratory efforts in anticipation of the commercial development of shale gas. At present, they have implemented massive hydraulic fracturing and micro-seismic monitoring and have achieved industrial gas flow with daily production of 3,000 to 20,000 m^3 in existing shale gas wells (Jia et al. 2012). Specifically, CNPC obtained industrial gas flows in five wells, including 3 horizontal wells, as part of joint efforts with Shell. CNPC is also in the process of establishing pilot testing areas for shale gas development in Sichuan and Chongqing with international cooperation with Newfield, Shell, Statoil, ConocoPhillips and Shell. Sinopec has drilled 5 appraisal wells in Guizhou, Sichuan and Anhui and obtained industrial gas flow in 2 wells with breakthroughs in Mesozoic continental shale drilling. Sinopec has also launched joint shale gas exploration and assessments with BP, Chevron, and ExxonMobil in the Sichuan Basin. In addition, PetroChina is focusing on the Paleozoic marine formations in the Upper Yangzi region while CNOOC is beginning commercial exploration and geological research in Sichuan, Chongqing, Guizhou and Anhui. Lastly, the power companies of Huaneng and Huadian and the oil-rig drilling equipment manufacturer Honghua have signed development agreements with Chongqing, Hunan and Sichuan. From these efforts, it can be seen that shale gas development is currently at the pre-phase of exploration and preparation and that despite achieving commercial gas flows in some pilot wells, commercial development remains on the horizon.

4.2.2. 12th Five-Year Development Plan for Shale Gas

Building on two-plus years of initial shale gas exploration efforts, the National Energy Administration and MLR jointly compiled and issued the 12th Five-Year Development Plan for Shale Gas in March 2012. This plan called for supporting shale gas development on the basis of its contribution to scientific and technological progress, economic growth, improving energy structure, alleviating energy security concerns and environmental protection. It also laid out a set of four specific development targets – two quantitative and two qualitative - for the 12th FYP Period from 2011 to 2015 as a solid foundation for continued development in the 13th FYP period from 2016 to 2020. The four main targets outlined in the 12th FYP include (NEA 2012):

1. Complete national shale gas resource survey and appraisal and selection of 30-50 shale gas prospective areas and 50-80 favorable target areas;
2. Reach proven geological reserves of 600 billion cubic meters, recoverable reserves of 200 billion cubic meters and 2015 production output of 6.5 billion cubic meters;
3. Develop suitable methods, technologies and equipment for China's shale gas resource survey, appraisal, exploration and production;
4. Establish technical standards, rules and policies regulating activities related to China's shale gas development, including resource survey, appraisal and certification, testing and analysis, exploration and production and environmental measurements.

Building on the efforts to expand shale gas development and production during the 12th FYP period, the Plan also outlines the strategic plan for continued industry development in the 13th FYP period. For the 13th FYP period, the Plan calls for increased investment and expanded production scale of 19 exploration blocks, provided that more clarity to the resource situation and exploration and development technology breakthroughs are achieved during the 12th FYP period. It also encourages the vigorous promotion of exploration and development of Dongting-Poyang Lake, Jiangsu, Zhejiang, Anhui, Ordos, Southern North China, Songliao, Junggar, Tuha, Tarim, and Bohai Bay Basins in order to strive for annual output of 60 to 100 billion cubic meters by 2020.

In order to meet these specific short-term and medium-term targets, the Plan outlines five key activities that should be pursued during the 12th FYP to advance shale gas development in China.

The first key activity is to increase government investment in shale gas resource survey and appraisal efforts. Designated funds will be set up to support three types of efforts: shale gas resource survey and appraisal, selection of shale gas exploration trial areas and exploration technology demonstration projects, and geological study of shale gas and international cooperation. Although this activity signals the central government's recognition of the need to invest more in improving the fundamental understanding of China's shale gas resources, the lack of specifics on the designated funding makes it difficult to gauge whether the proposed level of investment is sufficient.

The second activity outlined as a key step to achieving the 12th FYP targets is to advance the science and technology related to shale gas exploration and development. This includes increasing government support of shale gas technology innovation and improvement and classifying shale gas technology research and development as a key national project. It also calls for the establishment of a shale gas research and development center and support for international cooperation and exchanges.

The third activity focuses on establishing new mechanisms for shale gas exploration and development in China. As the first two auctions of shale gas drilling rights showed, China is still in the process of setting up regulatory process for managing shale gas exploration and development. The 12th FYP calls for the refinement of this management system by accelerating the permitting process for qualifying investors to widen participation in China's shale gas development and developing relevant qualification standards and tender regulations for future mineral rights auctions.

The fourth activity seeks to spur greater market interest in shale gas development by introducing incentive policies for the shale gas industry. Following the introduction of subsidy policies for coal-bed methane projects, the government will be offering different financial incentives to shale gas developers. This includes the November 2012 introduction of a production subsidy of 0.4 RMB per cubic meter of shale gas production from 2012 to 2015, as well as license fee reductions and waivers for shale gas drilling license holders. The import of shale gas exploration and drilling equipment that are not available or cannot be produced in China will also receive exemptions from custom taxes, and shale gas developers will be given priority in land use permit applications. In order to promote more market competition and incentives for new entrants to the industry, the Plan also seeks to liberalize shale gas well-head prices with the goal of having prices be determined by market conditions.

The fifth activity is to improve the supporting infrastructure for shale gas development and utilization. The type of improvement outlined in the plan varies by the location of the shale gas reserves. For reserves close to existing natural gas pipeline networks, the construction of transportation pipelines at shale gas production fields with connections to existing natural gas pipeline networks will be encouraged. For reserves located far from existing natural gas pipeline networks, the construction of small-scale LNG or CNG facilities will be promoted for capturing the gas produced and to avoid flaring.

Through these five sets of activities outlined in the 12th FYP, the government is following a multi-faceted approach to encourage greater and more diverse shale gas exploration and development while providing better regulatory and infrastructure frameworks to support rapid development.

4.3. Barriers and Challenges to Shale Gas Development

As a relatively nascent industry, the shale gas industry faces various barriers and challenges to achieving the rapid development needed to meet the ambitious 2015 and 2020 production targets. Institutional barriers to accelerating shale gas development in China include an immature industry with capacity shortages and regulatory barriers to extraction, while resource, technological and economic limitations to ramping up production also persists. In addition, the hydraulic fracturing needed to extract shale gas also poses serious environmental and water availability concerns for China.

4.3.1. Nascent industry and capacity shortages

Unlike the U.S. and its 80-plus years of shale gas exploration and production, the fact that China began pursuing shale gas exploration only within the last five years is indicative of the industry's infancy. With the national resource assessment completed only in 2011, there is still very limited understanding of the potential shale gas resources in China. Many of the fundamental resource evaluation activities were only recently initiated, and there is a lack of detailed geological information and thus high uncertainty surrounding many of the potential drilling sites. With very limited drilling thus far, most of the existing shale gas resource estimates are based on analogies to the major shale plays in the U.S. and thus highly uncertain (Gao 2012). The absence of actual drilling and exploration have also resulted in a lack of sufficient practical data and key parameters for identifying and characterizing favorable target areas ("sweet spots") and regional mineable resources, such as gas volumes (Zhao et al. 2013). These high uncertainties surrounding shale gas resource potential has in turn curbed investment interests. This was highlighted by the first auction of shale gas drilling rights, where the low interest in bidding on two of the four blocks likely resulted from a lack of data about resource potential in selected blocks. Without significant increases in exploration, evaluation and subsequent information on specific resource potential, investment interests will likely remain limited.

Similarly, because the shale gas industry in China is still immature and interest in development is so new, there is a shortage of the trained personnel needed to support the industry's planned rapid expansion. In particular, because there is limited expertise and experience in shale gas development to date, China lacks both the experienced managers needed to manage large and complex shale gas drilling and completion projects as well as the skilled labor capable of operating sophisticated drilling rigs and fracturing pumps (Gao 2012). Human resource shortages could therefore be a limiting factor to rapid increases in the scale and speed of intensive shale gas drilling and production over the next decade.

4.3.2. Insufficient infrastructure

As with conventional natural gas, most shale gas reserves also have to be connected to a network of pipelines in order for the extracted gas to be delivered to the major markets where it can be utilized. While China has increased its pipeline network with concerted development efforts in recent years, it still has an inadequate pipeline network with much lower pipeline density than the U.S. China's pipeline network density of 100,000 kilometers is only 5% of the U.S. pipeline network of 2 million kilometers (Zhao et al. 2013). This suggests that China still needs much more effort and time for the identification of new routes, construction of new pipelines and connection to existing networks.

4.3.3. Regulatory barriers to industry expansion

Besides uncertainties surrounding shale gas resource potential, regulatory barriers have also hampered the entry of many private investors into the industry and subsequent inflow of domestic investment. MLR has taken a cautious approach to auctioning off drilling rights by limiting participation in the first auction to only state-owned enterprises and private enterprises comprising of only one-third of participants in the second auction. The limited participation of private enterprises in shale gas exploration is slowing industry competition, which limits the industry's development by not being able to help reduce costs and drive technological advancements, as was the case in the U.S. At the same time, while multinational companies such as Shell, BP and Chevron have been able to enter into joint cooperative agreements on shale gas development with Chinese partners, the interests of other smaller and medium-sized independent U.S. companies in investing in Chinese shale gas development have been viewed with ambivalence. Although these companies hold U.S. expertise in shale gas exploration, they do not have the same level of strategic importance as larger multinationals to make them attractive as foreign investors. Without any existing footprint in China, it is extremely difficult for these smaller independent foreign companies to gain entry into the Chinese industry, despite the technological and operational experiences in the U.S. shale gas industry that they can bring (Gao 2012).

Another major regulatory barrier facing the expansion of the Chinese shale gas industry is the absence of clear legislation or administrative system for managing shale gas drilling rights and exploration. Besides the bidding criteria set in the first two auctions, there are no regulatory policies on shale gas mining rights bidding, evaluation of shale gas resources or supervision of exploration and development (Zhao et al. 2013). There are also still disputes over systems for managing shale gas drilling rights and block registration, as well as over designated regulatory environmental oversight (Xu and Wang 2012). As a result, the first two auctions for drilling rights were vastly different and represent an iterative, rather than a clearly laid out, approach to managing shale gas exploration. Without specific legislation or a management system governing shale gas exploration and drilling, investors will be hesitant to invest in the fundamental resource evaluation and appraisal needed to build up the industry.

4.3.4. Resource quality challenges

The recent resource evaluations conducted in China have indicated abundant shale gas resource potential, but have also identified resource quality challenges that will make rapid increases in extraction and production over a short period of time more difficult. China's shale gas resources include both marine and non-marine shale formations, with nearly one-fifth of the total land area composing of non-marine formations (Jia et al. 2012). Non-marine shale resources are more difficult to extract and commercialize, with lower thermal evolution degree and higher heterogeneity than marine formations (Zou et al. 2012). For marine shale gas formations with the higher thermal evolution degree needed for commercial development (typically ranging from at least 1.1% to 3%), these resources are located in areas with frequent tectonic movements and additional effort is needed to identify prospective resource areas away from fault damage zones (Zou et al. 2012).

Moreover, compared to shale gas resources in the U.S., China's shale gas resources are buried much deeper underground and often under mountainous terrain, which makes it more difficult and costly to extract. Whereas U.S. shale gas burial depth generally ranges from 180 to 3600 meters, Chinese shale gas resources are buried as deep as 5000 to 7000 meters. In the promising Qiongzhusi shale formation in Southern Sichuan Basin, for example, nearly 40% of the total estimated resources are located in depths of greater than 3600 meters. Extraction of these deeper resources may be problematic, especially in the short-term, given that the newest technologies adopted in the U.S. Delaware Basin are capable of reaching depths of only 4000 to 6000 meters (Huang et al. 2012).

4.3.5. Technological and economic challenges

Closely related to China's shale gas resource quality issues and the industry's relatively early stage of development are the looming technological and economic challenges to expanding shale gas production in China. Significant increases in shale gas production – particularly from resources located at greater depths – will require the rapid deployment of long-reach horizontal and multiple-stage fracturing capable of reaching unconventional reservoirs. However, despite having accumulated expertise in onshore and conventional oil and gas drilling, China still lacks access to and experience in utilizing multi-stage fracturing technologies. China has started to utilize horizontal drilling in its tight gas development, particularly through international cooperation, but the technology is still in the research and development phase of development and has not been mastered domestically yet. This has resulted in much higher costs for multi-stage fracturing, with CNPC's latest horizontal shale gas wells drilled and completed in the Sichuan Basin costing USD 11 million per well, as opposed to the average costs of only USD 4 to 6 million per well in the U.S. (Gao 2012). China also lacks systematic technologies needed for shale gas development and the experimental apparatus needed for measuring and testing key parameters during resource exploration and development.

Furthermore, China faces technological limitations to rapidly expanding the capacity of its supply chain to drill intensively to meet its ambitious shale gas production targets. Although China is an international producer and manufacturing supplier of oil and gas field equipment, most of its production is of relatively low-tech equipment used for conventional oil and gas development. China lacks the capabilities and expertise to produce the advanced equipment such as high-spec fit-for-purpose drilling rigs, pumps, fracturing trucks, fracturing additives and proppant needed to develop shale gas (Gao 2012). The advanced equipment for horizontal and multi-stage fracturing are still manufactured in North America, and dependency on imported technologies will not only raise production costs but can also create supply chain bottlenecks that limit the speed and scale at which the domestic shale gas industry can expand.

In light of these technological limitations, China faces higher drilling costs for both vertical and horizontal wells. In general, drilling costs are three to four times higher in China than in the U.S., with average costs of USD 20,000 and USD 30,000 per meter for vertical and horizontal wells, respectively (Zhao et al. 2013). Thus, it would cost at least 300 million RMB to drill a well located at depth of 3000 meters. On an industry scale, it is estimated that significant investments on the order of 400 to 600 billion RMB (US$64-97 billion) is needed over the next 10 years to reach the 2020 production target (Xu and Wang 2012).

4.3.6. Environmental risks and water supply concerns

Although shale gas has environmental advantages over dirtier fossil fuels such as coal, the extraction of shale gas resources also carries some severe environmental risks. Compared to conventional oil and gas, the extraction and production of shale gas poses more serious environmental risks with the use of toxic chemicals in hydraulic fracturing. The high pressure pumping of treatment fluids with additives and proppants into reservoirs to create fractures that enable gas to flow to the surface could result in underground and groundwater contamination if leakage occurs. Shale gas exploitation can also result in the leakage of methane, a potent greenhouse gas, into the atmosphere which would offset the lower carbon footprint of using shale gas. There is greater concern about these potential environmental risks in China because environmental protection standards and regulations related to shale gas drilling and extraction are not yet in place, and there is no clearly designated authority responsible for environmental oversight.

Besides the potential risks of chemical and methane leakages, the water resource requirements and treatment options are two other major environmental concerns linked to rapid shale gas development. The use of hydraulic fracturing requires the input of a large amount of freshwater, and the specific water input is closely linked to the shale gas formation's geological characteristics. In the U.S., typical water usage per well is 11,000 to 15,000 cubic meters (Gao 2012). A well in the Barnett Shale formation in the U.S., for instance, consumes 182 cubic meters of water for drilling and 13,650 cubic meters of water for hydraulic fracturing (Zhao et al. 2013). In China, the water requirements are expected to be even higher per well given that its shale gas wells are likely to be located at greater depths and with higher porosity. It could take as much as 23,000 cubic meters to drill and fracture a deep shale gas well, which poses water resource challenges for water-scarce China, which has the second lowest per capita water resources in the world (Gao 2012).

The significant water requirements for shale gas drilling and fracturing is particularly problematic because there is a geographic imbalance in the distribution of China's water resources and shale gas resources. On one hand, the majority of China's shale gas-bearing basins are located in water-scarce locations. As shown in Figure 11, the Tarim, Tuha and Junggar basins are located in the desert Northwestern areas that face the most critical water shortages. On the other hand, the other basins that are located in relatively water-rich areas such as Songliao and Sichuan Basins still face resource availability concerns because of competing demand from growing population and intensive economic activities. This is particularly true because these basins are located in areas of high population density, where residential and agricultural use of water is always prioritized ahead of industrial usage by the government for social and economic reasons. The location of gas-bearing basins in population dense areas also leads to greater restrictions on land access for exploration drilling due to concerns about health and security risks.

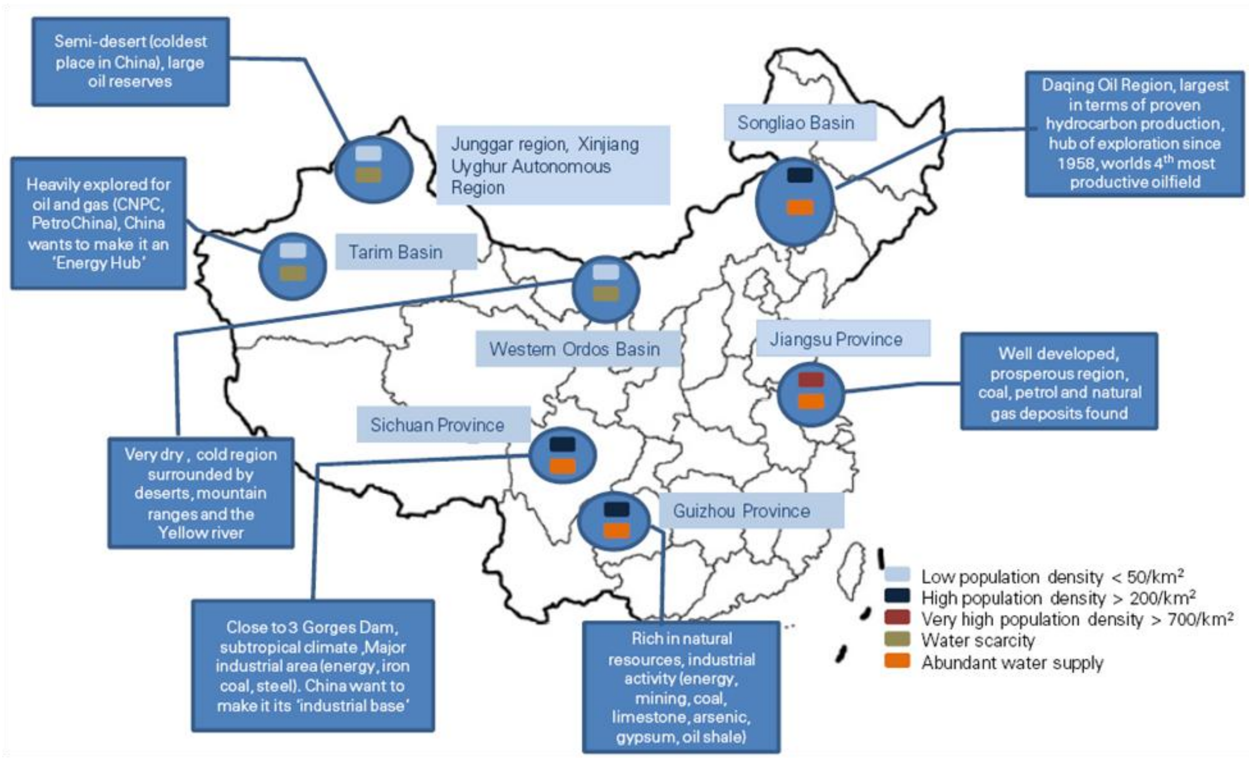

Figure 11. Water Resource Availability and Population Density of Major Shale Gas Basins

Source: Liu, 2012, 12th Annual U.S.-China Oil & Gas Industry Forum.

A potential solution to the water resource challenges of shale gas exploration and extraction is wastewater treatment, since treated fracturing water and groundwater from underground aquifers can be recycled and reused. China, however, has not developed adequate wastewater treatment systems and the recycle and reuse of waste water will not be able to play a significant role without a major technology breakthrough. Even then, the sheer volume of water needed to meet the large-scale shale gas drilling and fracturing needed to meet the 2020 target will still be the largest obstacle. For example, one estimate of the water needed to maintain production of 50 billion cubic meters of shale gas per year – assuming a 25% recycle and reuse rate – puts it at 154 million cubic meters per year, or the annual consumption of 2.6 million residents (Gao 2012). This clearly illustrates the severity of the water challenge facing the commercial development of China's shale gas industry.

5. Coal Seam Methane

Coal seam methane (CSM) serves as another supplement to conventional natural gas resources and includes two major categories of production defined by production process and methane quality. In China, the most prevalent type of CSM is Coal Mine Methane (CMM), which refers to methane drained from active mines (primarily for safety reasons) with methane concentrations of 25% to 60%. Less developed in China is Coal Bed Methane (CBM), which refers to methane extracted from a coal seam prior to mining, often from the surface, with methane concentrations above 90% (Wang 2010). In China, these two types are sometimes referred to as underground drainage and surface production; in some cases, however, the two are lumped together and considered more broadly as CSM (煤层气).

5.1. Resource Assessment

China has abundant CSM resources and holds the world's third largest reserves of CSM. At buried depths of less than 2000 meters, China is estimated to have 415,400 square kilometers of methane-bearing area with 45 coal-accumulating basins. At the same depth, China's total geological reserves have been estimated to total 36.8 tcm (Luo et al. 2011). The bulk of the geological reserves are located at depths of less than 1500 meters as shown in Figure 12. Of the 24.9 tcm of geological reserves buried in depths of less than 1500 meters, only 44% or 10.9 tcm are considered recoverable.

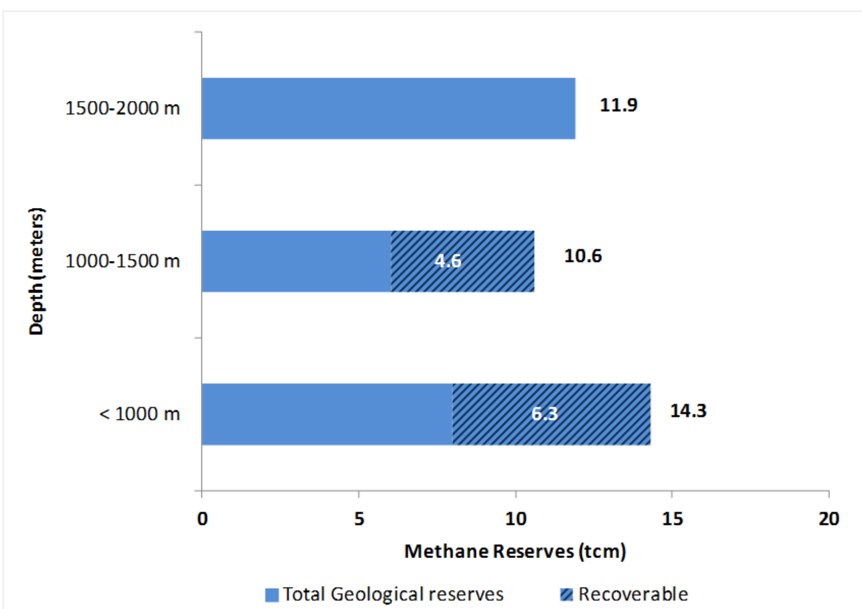

Figure 12. CSM Reserve Distribution by Depth

Source: Data from Luo et al. 2011

In terms of geographic distribution, the vast majority of China's CSM resources are located in large basins in Northern China, with 56% in North China, 28% in Northwest China and 1% in Northeast China (Equity Research 2011). Within Northern China, half of the CSM resources are concentrated across three large basins - Qinshui in Shanxi, Ordos in Inner Mongolia and Junggar in Xinjiang – and 40% of the resources in these three basins are recoverable at depths of less than 1,500 meters. The other half of China's CSM resources is distributed across 11 other basins as shown in Figure 13.

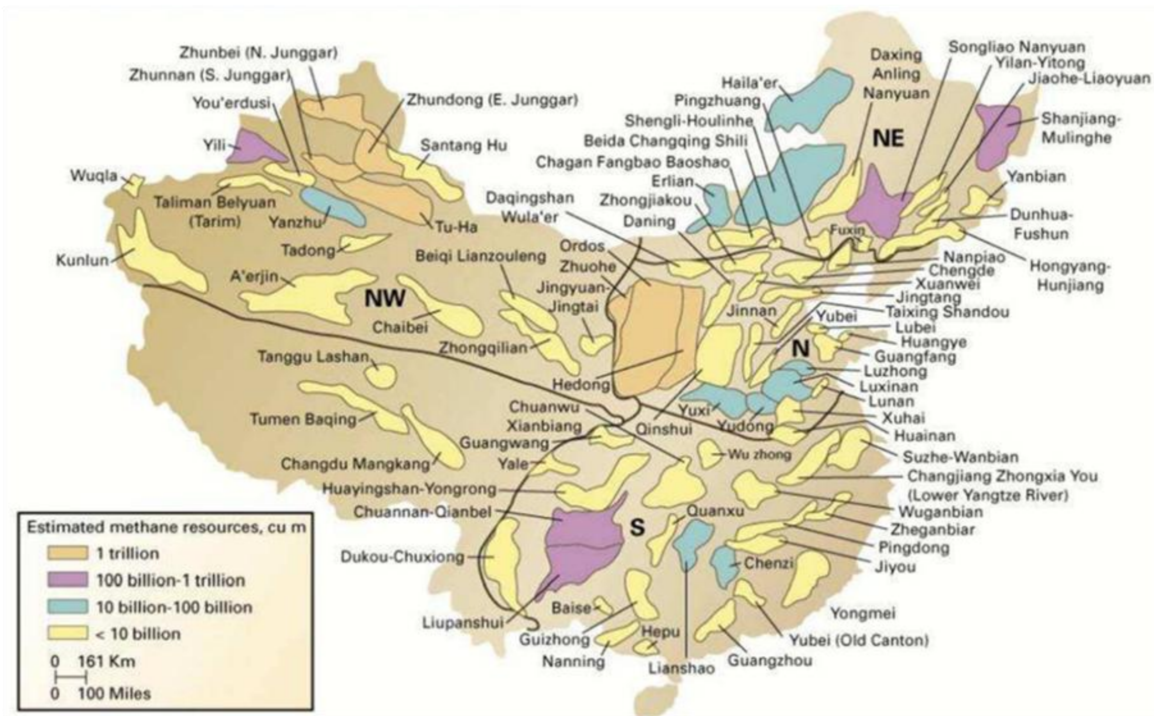

Figure 13: Distribution of China's CSM Resources by Basin
Source: Wang 2010.

Table 12 lists the total area assessed and the geological and recoverable CSM resources results from the 2010 MLR assessment of other major CSM basins. It is interesting to note that although Ordos Basin is by far the largest basin in terms of total area and available geological resources, Erlian Basin actually has the largest recoverable resources.

Table 12. CSM Resource Distribution by Major Basins

Basin (group)	Assessment area/10^4 km^2	Geological resources/10^{12} m^3	Recoverable resources/10^{12} m^3
Ordos	10.88	9.86	1.79
Qinshui	2.71	3.95	1.12
Junggar	3.46	3.83	0.81
Eastern Yunnan-Western Guizhou	1.61	3.47	1.29
Erlian	3.48	2.58	2.10
Tuha	0.94	2.12	0.41
Tarim	4.06	1.93	0.69
Tianshan	1.05	1.63	0.67
Hailaer	1.30	1.60	0.45

Source: Jia e tal. 2012.

5.2. Recent Development in China

CSM capture can occur through either pre-mining drainage (CBM) or post-mining drainage (CMM). Pre-mining drainage involves drilling vertical wells or horizontal boreholes into the coal seam before mining occurs in order to preemptively release methane and prevent explosions (World Coal Association 2012). Post-mining drainage focuses on recovering methane released during coal mining by capturing it, diluting it below the explosive range of 5-15% and removing it using large ventilation systems.

CSM recovery and utilization started in China in the early 1990s as a strategy to improve coal mining safety, diversify energy resources and take advantage of a fuel that was previously wasted (IEA 2009). Prior to the 1990s, most of the CSM captured was vented and only a small portion was used for on-site heating and cooking. In the early 1990s, collaboration and technical assistance from the U.S. Environmental Protection Agency and the World Bank's Global Environment Facility led to increased CSM recovery and use. In recent years, the Chinese government has recognized the environmental benefits of using CSM as a clean energy source and by 2007, 40 projects were in place with estimated 8.6 Mt CO_2e emissions avoided per year (IEA 2009). At the same time, the Chinese government has adopted a variety of policies that include financial subsidies, preferential tax policies, coal mining safety regulations and standards on low concentration CMM transportation and utilization to actively promote CSM recovery and utilization.

The central government has offered a financial subsidy of 0.2 RMB per m^3 of CBM gas produced in addition to local government subsidies that may have existed since the early 2000s. The government also provides a 3 to 5 year tax holiday period during CBM production phase. Other preferential tax breaks and fiscal policies for CSM projects are listed in Table 13.

Table 13. Early Preferential Fiscal Policies for CSM Projects in China

Category	Preferential Policy
Enterprise Income Tax	30% and 3% local tax, total income tax rate is 33% Tax rate is 0% from 1^{st} -2^{nd} year, 16.5% from 3^{rd} -5^{th} year Other local preferential policies Preferential policies on depreciation calculation
Value-added tax	5%
Resource tax	0
Royalty	0 to 3% varies with the location and gas production
Tariffs	0% except certain imported equipment listed in the State Council's not exempted category
Exploration right acquisition	100 RMB/km/yr, but can be exempt
Mining right	100 RMB/km/yr, but can be exempt
Other tax	<1% vehicle and ship license tax and urban real estate tax etc.

Source: CMBC 2004.

In addition to preferential fiscal policies, the State Council also issued "Opinions on Speeding Up CSM Extraction and Utilization" in 2006 to strengthen mine safety while promoting CSM extraction. This policy mandates that CMM must be drained prior to initiating coal mining; coal mines must implement CMM measurement and monitoring measures; coal mining activity must be suspended if significant problems are caused by CMM; and coal mine owners and operators are legally responsible for following safety standards (IEA 2009). In April 2008, an emission standard prohibiting CBM and CMM drainage systems from emitting gas with 30% or higher concentration of methane was adopted by the Ministry of Environmental Protection (Zhao 2011). This standard went into effect for new coal mines and surface drainage systems on July 1, 2008 and also applied to existing mines and systems as of January 1, 2010.

The 11^{th} FYP further ushered in a variety of policies and measures promoting the greater utilization of CBM and CMM in China. In April 2007, NDRC issued two notices on CSM price management and prioritization of electricity generation from CSM. For price management, NDRC specified that the price of methane gas can be determined through negotiations if it is not distributed via city pipelines. To promote CSM power generation, NDRC exempts CSM power plant owners from market price competition and responsibility for grid stability and also required that the power generated from CSM plants be given priority by grid operators (IEA

2009). For the 12th FYP period, CSM extraction and utilization is expected to grow rapidly with aggressive targets and policies set out for the 12th FYP. From 2011 to 2015, newly increased proven reserves of CSM are expected to increase to 1,000 bcm, with total production to reach 30 bcm by 2015. Of the 30 bcm of CSM production targeted for 2015, 16 bcm should come from surface drainage and extraction (CBM) while 14 bcm should come from underground drainage (CMM). The 12th FYP also sets targets of 60% utilization rate for CMM and total installed capacity of 2.85 GW for CSM power generation.

In China, low gas permeability, low gas pressure and relatively low concentrations of methane in recovered CMM have all influenced the drainage technologies and methods being applied. Most of the CMM drained and recovered have been located in Shanxi Province with a 44% share of the national total in 2007, with smaller shares of 4% in Shaanxi, Liaoning, Anhui, Henan, Guizhou and Chongqing. In addition, post-mining drainage has far exceeded CBM as shown in Figure 14, with CBM composing of only 18% of total CSM drainage in 2011.

Although China has extensive experience in the technologies used in CMM drainage, surface production of CBM using surface standard wells or surface gob wells[3] into collapsed mined-out parts of coal mines is still relatively new. Surface development is advantageous over underground drainage as it produces gas with higher concentrations of methane and the gas is easier to collect, transmit and utilize. However, there are still barriers to large-scale CBM commercial development including insufficient gas utilization and pipeline infrastructure and limited exploration in the majority of undeveloped fields (CMBC 2004). In addition, China's distinct reservoir conditions of low pressure and permeability have limited high CBM yield through surface development. Nevertheless, the Chinese government has promoted surface production of CBM since the 1990s and surface volumes have increased over the last decade. The high concentration level of methane in recovered CBM makes it a viable alternative for conventional natural gas. However, natural gas pipeline networks are needed to transport the gas to demand centers away from the coal mining sites. The next section will discuss in more detail the specific challenges facing CBM production in China, but it is clear from the figure that CBM production will have to ramp up very quickly over the next five years in order to meet the 12th FYP target of 16 billion cubic meters.

[3] Gob wells refer to a type of recovery well where methane is extracted from the gob areas of a mine after the mining has caved the overlying strata.

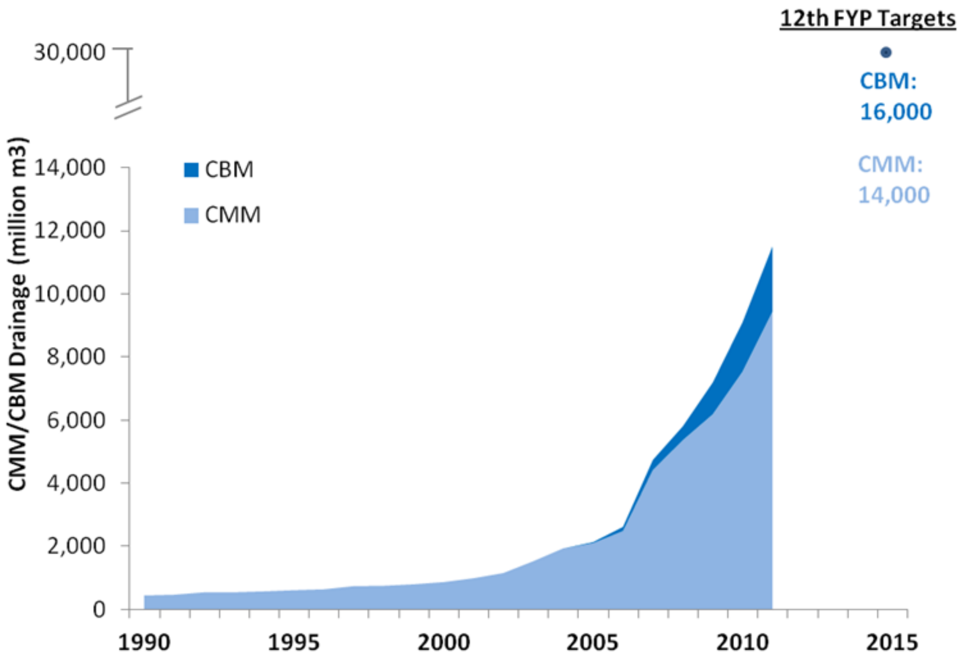

Figure 14. CMM and CBM Production and Targets

Source: Fu 2012.

Unlike CBM, which is utilized 100% due to its high methane concentration, CMM utilization is determined in large part by the methane concentration of the recovered CMM. China's CMM utilization is mostly medium concentration with methane content of 30% to 80% or low concentration with methane content of less than 30%. Low concentration methane is rarely utilized because methane is explosive with concentrations in the range of 5% to 15% and project developers and vendors have avoided projects that would require transporting, distributing and using low concentration methane. Lastly, ventilation air methane constitute the largest source of CMM emissions in China as the large volume of air with methane concentrations of less than 1% are emitted directly from mine ventilation shafts. In China, research into developing the technologies to capture and utilize ventilation air methane began only recently but ventilated air methane has been used to generate heat or electricity in the U.S., Australia and Canada (IEA 2009).

Medium-concentration CMM with methane content of at least 40% can be used as a household fuel, industrial fuel or for power generation. As a household fuel, CMM is used directly as a gas for residential and commercial energy demand within coal mining districts in Liaoning and Shanxi provinces. Underground drained CMM has the same heat value as coke gas and as an industrial fuel; it can replace coal gas, natural gas, LPG or coal as fuel input to industrial boilers in Shanxi and Anhui provinces (CMBC 2004, IEA 2009). Because significant investment and time are needed to construct the infrastructure needed to transport and distribute CMM from the mines to point of use, its application as a household or industrial fuel is relatively limited to sites close to coal mines. Lastly, CMM with methane content of at least 30% can be used to power gas combustion turbines with 30% efficiency and gas combustion engines with 40% efficiency to generate electricity. CMM utilization for power generation has increased rapidly over the last few years, with installed capacity growing from 200 MW in 2005 to 920 MW with a total of 1,400 generators by the end of 2008 (Zhao 2011).

The influence of government policy and pace of technological development on CMM drainage and utilization over time can be seen in Figure 15. In the 1990s as China began to develop the technologies and methods for CMM drainage, total drainage began to rise steadily but at a relatively slow rate, growing only from 536 million cubic meters in 1993 to 858 million cubic meters in 2000. After 2000 with the commercialization of CMM drainage and increased government attention on CMM as a clean energy resource under the 10th FYP, the drainage amount increased rapidly from 1,146 million cubic meters in 2001 to 2,614 million cubic meters in 2006. During the last five years with greater policy emphasis under the 11th FYP, CMM drainage has accelerated and tripled between 2007 and 2011, from 4,735 to 11,500 million cubic meters. At the same time, the setting of utilization targets and policy focus on comprehensive resource utilization under the 11th FYP has greatly increased CMM utilization rates from 21% in 2006 to 40% in 2010.

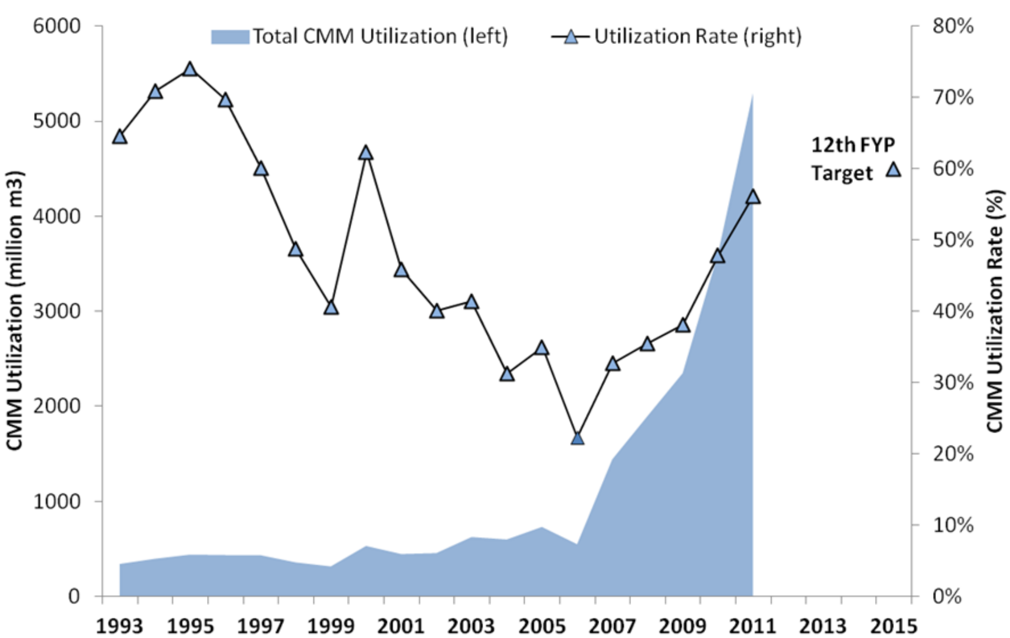

Figure 15. CMM Utilization and Utilization Rates

Source: China Coal Statistical Yearbook, various years.

5.3. Barriers and Challenges

The 12th FYP and supporting policies present an optimistic future for the CSM industry in China, but there are several major barriers and challenges that could continue to hamper or slow CBM development and greater CMM utilization in the near future.

5.3.1. Policy Limitations

While the government launched different sets of policies to promote CMM and CBM development, particularly during the 11th FYP period, most of these policies failed to focus on the initial stage of resource exploration and appraisal. Rather, most of the policies have focused on supporting the development phase after commercial production, but as seen in the case of CBM, commercial development may not have been realized yet. In the early stages of the CSM industry's development, only 3 to 4.6 million USD per year were invested in CBM resource exploitation and evaluation (Gao 2012). This lack of direct government financial support resulted in the industry having to invest in exploration and development as well as production and transportation of the gas to market (Gao 2012).

Furthermore, similar to renewable generation, there have been problems in implementing subsidies for CSM power generation and enforcing the priority grid access policies passed in April 2007. For example, many mine operators are not aware of the subsidy for CSM generated power and for those who are aware and interested, there are still hurdles to connecting to the grid (IEA 2009). At the same time, there are also conflicting interests and overlapping rights between coal and oil companies for CBM development. For a specific region, the coal mining rights were often held by coal groups but the CBM mining rights were held by major national oil companies. CPNC, for instance, holds the CBM mining rights to over 75% of total CBM acreage registered under the MLR, but a large proportion of this acreage – 137,000 out of a total of 161,000 square kilometers, is overlapping area within oil and gas license blocks (Gao 2012).

5.3.2. Technical limitations

Technical limitations exist for both CMM and CBM production in China. For CMM, there is limited technical knowledge on how to mitigate or recover ventilation air methane with very low concentrations given the relatively nascent stage of technologies worldwide. Likewise, knowledge and technical capacity gaps about methane recovery and utilization and CMM power generation still persist in smaller mines. For CBM, despite recent increase in surface drainage, existing technological limitations with surface development still result in high extraction costs and limited yield. Technologies for surface development of CBM are still not well developed, and many of the CBM projects are still in the trial phases with limited production. During the 11th FYP period, research focused on developing technologies using cluster-well drilling and completion technique and staged stimulation technique in horizontal wells (Jia et al. 2012). By the end of 2010, China had set up 48 CBM exploration areas but only six of the exploration areas had trial production of 3 billion cubic meters. Commercial production has only been achieved in Qinshui and Ordos basin, and more trial development efforts are needed in other prospective areas in Southwestern and Northwestern China. Additionally, China also needs domestic technological improvements and breakthroughs in development of CBM in deeper coal seams with depths of 1000 to 1500 meters (Fu 2012). This is particularly important because single well production in China is lower compared to other countries due to the geological conditions of Chinese coal seams, which lowers the effectiveness of foreign drilling technologies and requires local adjustments to be made to optimize production. Both CMM and CBM thus require greater technological research and development and possibly technology transfer and information exchange.

5.3.3. Institutional barriers

One of the main institutional barriers facing CSM development is the limited local demand for CSM gas utilization in China, which limits the amount of CMM and CBM able to be utilized for household and industrial fuels and power generation. On one hand, because most of China's coal mines are located in isolated rural areas with sparse population, there is very limited local demand for methane gas. In some cases, it is not even feasible for large mine operators to supply methane to households beyond the immediate border of the mine (IEA 2009). On the other hand, it is not financially viable to transmit methane via long-distance pipelines to large coastal cities that have unmet demand for methane gas. This geographic imbalance between CSM extraction and utilization thus caps the CSM gas use opportunities in China.

Similarly, the insufficient pipeline infrastructure also poses as a major barrier to CSM production growth in China. On one hand, as discussed in the case of shale gas, China's network of pipeline infrastructure is still relatively limited and has much more room to grow. On the other hand, in areas where CBM production can access existing pipeline networks, there is competing demand for limited pipeline capacity from conventional gas. With the soaring demand for natural gas, most of the existing pipelines are operating at full capacity with little space for natural gas produced from unconventional reservoirs. In the event that spare capacity is available, conventional gas is often prioritized by the pipeline operator – oil and gas companies in most cases - over CBM production because it is produced in larger volumes and has stable rather than variable wellhead pressure. Additionally, because the quality of gas from

CBM wells is often poorer and produced at lower pressure than conventional gas wells, CBM faces additional processing and compression costs before it can be accepted into the pipeline networks, thereby further reducing an already narrow profit margin for CBM production (Gao 2012). For all of these reasons, it has been very difficult to increase CBM production.

The Chinese government has started to address some of these challenges and barriers with the launch of new supporting policies for CSM – and particularly CBM - extraction and utilization in the 12th FYP. For example, the CSM industry is expected to receive total investment of 120 billion RMB to help increase CMM and CBM production during the 12th FYP period. This investment will be used to build 36 large-scale gas extraction mining areas with capacity exceeding 0.1 bcm per year. In addition, 13 CSM transmission pipelines with total length of 2,054 kilometers and transport capacity of 12 bcm will be constructed across the Qinshui basin, eastern Ordos basin and northern Henan province. The rapid growth and possibly commercialization of surface drainage technologies will also be supported by 58.1 billion RMB of investment in advancing CBM surface drainage in two demonstration basins - Qinshui in Shanxi Province and Ordos in Inner Mongolia - which are expected to produce 10.4 bcm and 5 bcm, respectively, by 2015 (NDRC 2012). Additional financial support will be provided to increase CSM utilization, with a doubling from current levels of 0.2 RMB per m^3 to 0.4 RMB per m^3 and increased payment for CSM power generation from 0.25 RMB per kWh to 0.35 RMB per kWh. The degree to which these new policies can mitigate existing barriers to CMM and CBM development remains to be seen.

6. Tight Gas

Tight gas is commonly used to refer to dry natural gas that is difficult to access in low permeability sandstone, siltstone and carbonate reservoirs. However, there is not a formal definition for tight gas and usage of the term varies considerably between countries. In the U.S., tight gas has been defined as gas extracted from reservoirs with an expected value of permeability to gas flow of less than 0.1×10^{-3} μm^2, but the permeability threshold differs in other countries such as 1×10^{-3} μm^2 in the United Kingdom and 0.6×10^{-3} μm^2 in Germany. In China, tight gas is classified as part of conventional gas and is generally from reservoirs with low porosity of less than 10%, low permeability of less than 0.1×10^{-3} μm^2 and low gas saturation of less than 60% (Jia et al. 2012).

There are two main types of tight gas reservoirs in China based on different characteristics, reserves and structural positions. The first type is the continuous-type of tight gas reservoirs, which are mainly located at low structural positions with indistinct trap boundaries, inconsistent gas-water boundaries, reversal of gas and water distribution, large reserves and source rocks that are the same as or close to reservoirs (Dai et al. 2012). The second type of tight gas reservoirs is trap-type reservoirs, which differs in that they are mainly located at high positions with normal gas-water correlation and relatively low reserves. Although tight gas reservoirs typically have low natural productivity below the lower limit of commercial gas production, it is feasible to commercially develop tight gas after specific treatment and under certain economic and technical conditions.

6.1. Resource Assessment

In China, tight gas is widely distributed with a total favorable exploration area of 320,000 square kilometers. China's relatively abundant technically recoverable resources have been validated through three national resource assessments. The latest assessment estimated total on-shore recoverable resources of 12 trillion cubic meters for tight gas, accounting for 40% of total natural gas resources-in-place. Other studies have estimated geological resources of 17.4 to 25.1 trillion cubic meters, and recoverable resources of 8.8 to 12.1 trillion cubic meters using analog methods (Jia et al. 2012). Most of the recoverable resources are distributed across seven key basins, including the Ordos, Sichuan, Songliao, Tarim, Tuha, Bohai Bay and Junggar Basins. The distribution of estimated geological and recoverable resources of tight gas by basin is shown in Table 14.

Table 14. Tight Gas Distribution and Resource Estimates by Basin

Basin	Basin area (10^4 km^2)	Exploration layers	Geological resources (10^{12} m^3)	Recoverable resources (10^{12} m^3)
Ordos	25.0	C–P	6–8	3–4
Sichuan	18.0	T_3x	3–4	1.5–2
Songliao	26.0	K_1	2–2.5	1–1.2
Tarim	3.5	J+K	4–7	2–3
Tuha	5.5	J	0.6–0.9	0.4–0.5
Bohai Bay	8.9	Es_{3-4}	1–1.5	0.5–0.8
Junggar	13.4	J_{1-2}, P_1j	0.8–1.2	0.4–0.6

Note: P_1j—Lower Permian Jiamuhe Formation

Source: Jia et al. 2012.

Of the 45 large gas fields - defined as a field with geological resources of at least 30 billion cubic meters - discovered by the end of 2010, there were 15 tight gas fields that accounted for 45% of the proven reserves of all large gas fields (Dai et al. 2012). Figure 16 shows the geographic distribution of the 7 favorable basins and 15 discovered large gas fields for tight gas (see Figure 8 for the location of the Tuha Basin).

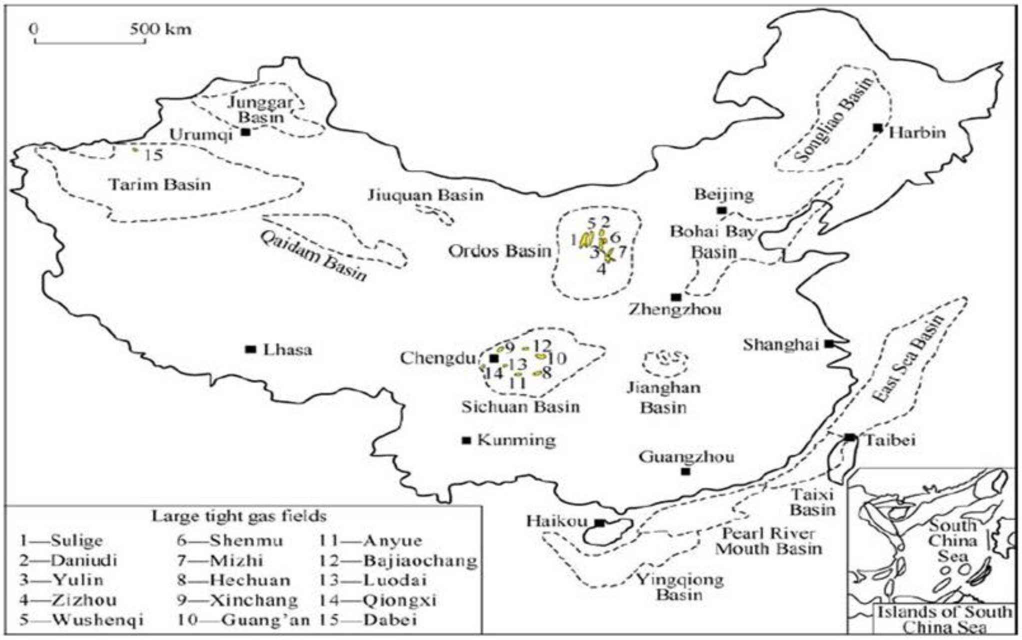

Figure 16. Geographic Distribution of Key Tight Gas Basins and Large Gas Fields

Source: Dai et al. 2012

As shown by the geographic clustering of large tight gas fields, the two realistic large exploration areas for tight gas in China are located in the Ordos Basin and the Sichuan Basin. The largest gas field in terms of both geological resources and annual production output is Sulige field in Ordos Basin, which produced 13.5 billion cubic meters in 2011 alone (Liu 2012). Table 15 shows some key geological characteristics as well as estimates of geological resources and annual output of tight gas in the 15 large tight gas fields.

Table 15. Key Characteristics of 15 Large Tight Gas Fields

Basin	Field	Main pay bed	Reservoir type	Geological reserves*/10^8 m^3	Annual output*/10^8 m^3	Mean porosity/%	Permeability/10^{-3} μm^2		Reference
							Range	Mean value	
Ordos	Sulige	P_2sh, P_2x, P_1s_1	Continuous	11 008.2	104.75	7.163(1 434)	0.001–101.099	1.284(1 434)	This study
	Daniudi	P, C		3 926.8	22.36	6.628(4 068)	0.001–61.000	0.532(4 068)	
	Yulin	P_1s_2		1 807.5	53.3	5.630(1 200)	0.003–486.000	4.744(1 200)	
	Zizhou	P_1s, P_2x		1 152.0	5.87	5.281(1 028)	0.004–232.884	3.498(1 028)	
	Wushenqi	P_2sh, P_2x, O_1		1 012.1	1.55	7.820(689)	0.001–97.401	0.985(687)	
	Shenmu	P_1t, P_1s, P_2x		935	0	4.712(187)	0.004–3.145	0.353(187)	
	Mizhi	P_1s_1, P_2x, P_2sh		358.5	0.19	6.180(1 179)	0.003–30.450	0.655(1 179)	
Sichuan	Hechuan	T_3x	Continuous	2 299.4	7.46	8.45		0.313	[21]
	Xinchang	J_3, T_3x	Dominated by trap	2 045.2	16.29	12.31(>1 300)		2.560(>1 300)	[22]
	Guang'an	T_3x	Continuous	1 355.6	2.79	4.2		0.35	[23]
	Anyue	T_3x		1 171.2	0.74	8.7		0.048	[21]
	Bajiaochang	J, T_3x	Dominated by trap	351.1	1.54	7.93(Mean value of T_3x_4)		0.58	[24]
	Luodai	J_3	Trap	323.8	2.83	11.8(926)		0.732(814)	[25]
	Qiongxi	J, T_3x	Dominated by trap	323.3	2.65	3.29(Mean value of T_3x_2)		0.063 6	[24]
Tarim	Dabei	K	Trap	587	0.22	2.62(5)		0.036(5)	This study

Note: *data for the year of 2010: data in the brackets refers to the number of samples.

Source: Dai et al. 2012, Table 2.

6.2. Recent Development in China

Tight gas production began as early as the 1990 in China with production steadily growing over the past three decades. This increase in tight gas production has resulted in tight gas becoming an increasingly larger share of China's total conventional gas production, as seen in Figure 17.

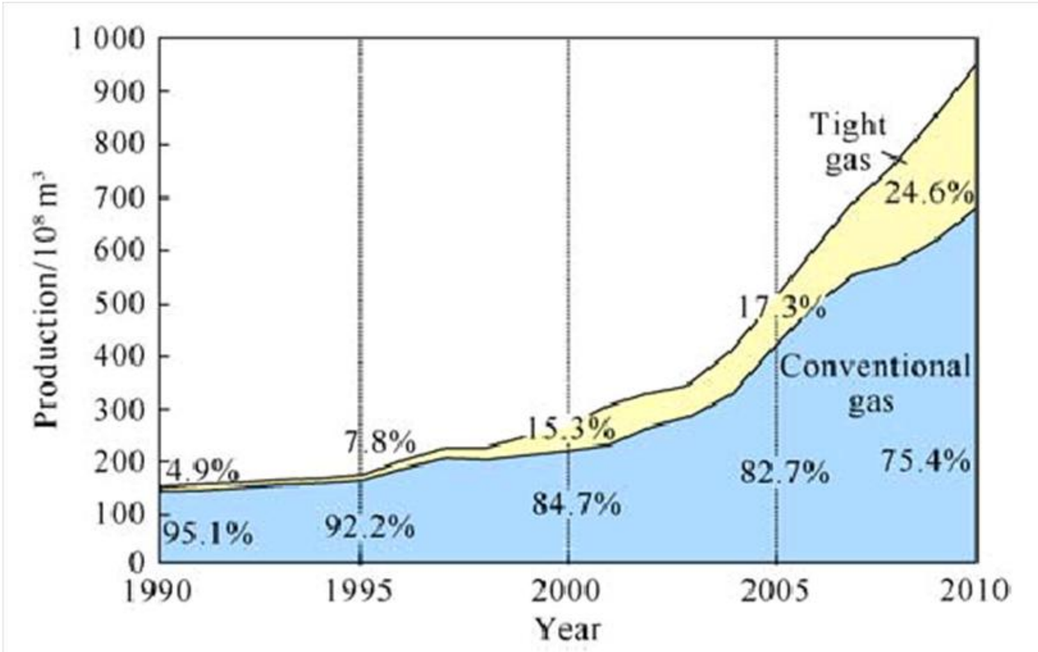

Figure 17. Tight Gas and Conventional Gas Production in China, 1990-2010

Source: Dai et al. 2012, Figure 7.

In 1990, only 0.75 billion cubic meters of tight gas was produced – all from Sichuan Basin – and accounted for 4.9% of total conventional gas output. By 2000, tight gas comprised of 15.3% of gas output and included total production output of 4.07 billion cubic meters from both Sichuan and Ordos Basin (Dai et al. 2012). Specifically, 2.05 billion cubic meters of tight gas came from Sichuan Basin while 2.02 billion cubic meters came from Ordos Basin. Over the last decade, tight gas has undergone large-scale commercial development and utilization in China with corresponding rapid growth in total production output. By 2010, tight gas output from the 15 large tight gas fields totaled 22.3 billion cubic meters, with an additional 1.05 billion cubic meters of output produced from other small and medium tight gas fields. This total production of 23.35 billion cubic meters equaled nearly one-quarter of China's total gas output in 2010.

This rapid increase in tight gas production in China has taken place despite relatively poor physical properties of tight gas reservoirs in the largest tight gas fields such as Sulige. As a result of low porosity of 4% to 10% and low permeability of 0.1×10^{-3} to 3.5×10^{-3} μm^2 in tight gas reservoirs in Ordos Basin and equally low porosity of 6% to 10% and low permeability of 0.1×10^{-3} to 5×10^{-3} μm^2 in Sichuan Basin, single-well production for tight gas is low and productivity declines quickly (Jia et al. 2012). To improve resource exploration and increase subsequent production, techniques that have been utilized include full-digital seismic exploration techniques to more accurately predict thin gas layers, six different identification techniques to improve gas reservoir identification abilities and separated layer fracturing to improve reservoir production capacity (Jia et al. 2012). Although the majority of drilling is done using vertical drilling, horizontal drilling in combination with separated layer fracturing for horizontal wells have been undertaken in the Sichuan Basin to increase single well productivity from reservoirs that have lower reserves than the Ordos Basin. These techniques have contributed to the rapid increase in total tight gas production by enabling daily production of up to 240,000 m^3 of tight gas per well in the Sichuan Basin.

6.3. Outlook for Future Development

As highlighted by the recent acceleration of tight gas development and its increasing share of total gas production output, tight gas is emerging as the most feasible nonconventional gas in China compared to shale gas and coal seam methane. As with coal seam methane, tight gas development has had a long history of development in China tracing back to the 1990s. But compared to coal seam methane, tight gas resources have been better quantified and studied and recovery and extraction of these resources have proven to be more feasible. Moreover, unlike the significant challenges still facing coal bed methane extraction, technological advances in tight gas exploration and production have been achieved and have sustained tight gas production growth. As a result of these promising prospects for tight gas production, companies such as PetroChina have announced their intentions to focus more on tight gas rather than shale gas (Platts 2013). In addition, Chinese joint ventures with multinational companies such as Shell have also emerged in the tight gas industry. Industry experts predict that annual output of tight gas could reach 30 to 40 billion cubic meters by 2015, and 50 to 60 billion cubic meters by 2020 (Jia et al. 2012). This underscores that the current trend of tight gas being an important component of China's natural gas supply will continue.

7. In-situ coal gasification

In-situ or underground coal gasification is the process in which coal is converted into a gaseous product through in-situ heating and chemical reactions. The process of in-situ coal gasification involves several steps, as shown in Figure 18.

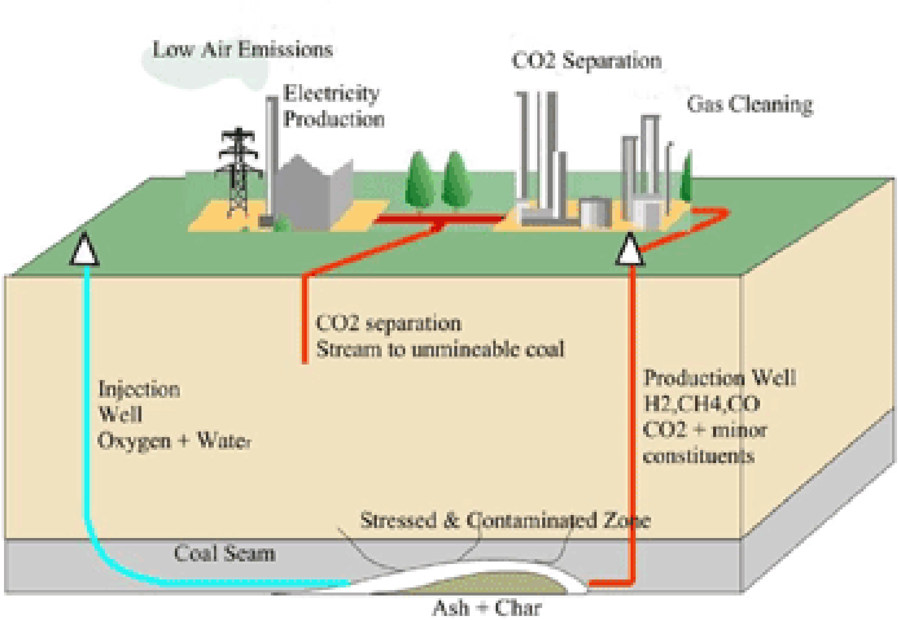

Figure 18. In-situ gasification process diagram

First, injection and production wells are drilled into the coal seams via vertical or horizontal directional drilling. Pressured oxidant, generally air or a mixture of oxygen and steam, is fed into the coal seam through the injection wells. The production wells are then used to recover syngas, also known as synthesis gas, a product gas composed of hydrogen, carbon monoxide, methane and carbon dioxide with generally low heat values. The syngas is then processed to be used as useful fuels for power generation, liquid fuels, hydrogen, fertilizers and chemical feedstock.

7.1. Resource Assessment

Of the abundant coal reserves distributed worldwide, 85% cannot be mined using surface mining techniques because the reserves are located too deep or too remote, or are deemed uneconomical or of poor quality for extraction. These unmineable reserves, however, can be utilized through in-situ gasification and potential gas reserves of more than 140 trillion cubic meters from in-situ gasification have been estimated worldwide. Of the countries with the greatest potential for in-situ gasification development, China is ranked fourth in terms of available coal reserves for in-situ gasification behind the U.S., Europe and Russia as shown in Figure 19. The World Energy Council's 2007 Survey of World Energy Resources estimated that China has 51.8 billion tonnes of available coal reserves suitable for in-situ gasification, which could provide potential gas reserves of 19.2 trillion cubic meters (WEC 2007). If able to fully utilized, in-situ gasification could significantly increase natural gas supply in China, as its estimated potential gas resources is more than five times higher than its most recently estimated natural gas resources of 3.5 trillion cubic meters.

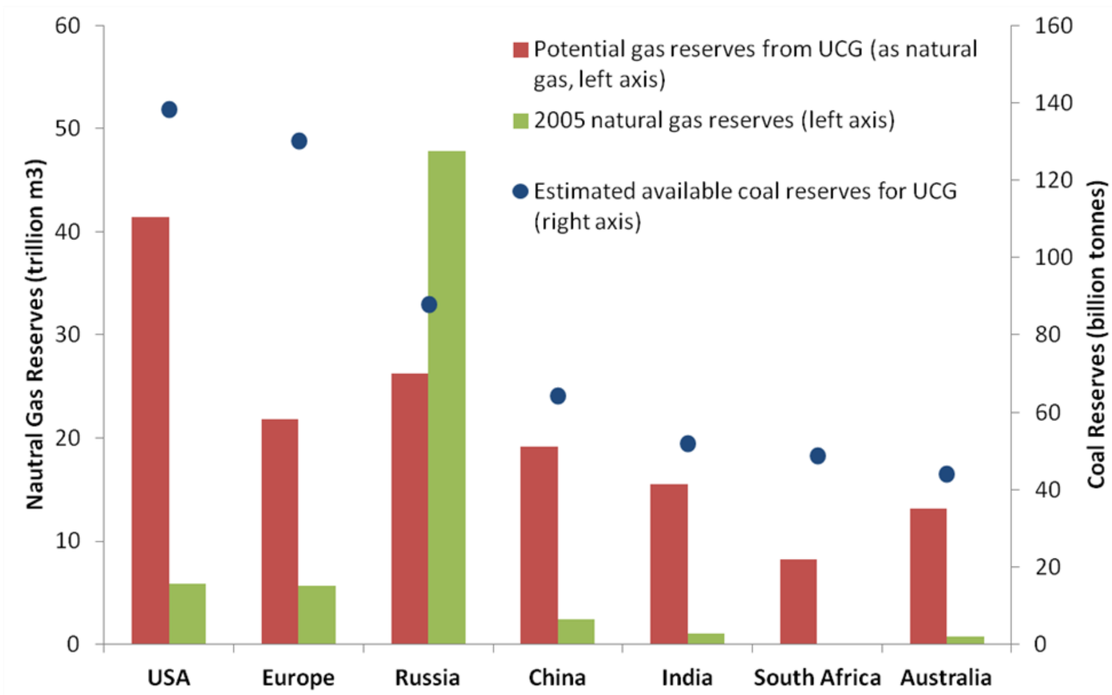

Figure 19. Comparison of China's Coal, Natural Gas and In-situ Gasification Potential Gas Reserves

Source: WEC 2007.

7.2. Recent Development in China

International interest in in-situ gasification has increased over time, beginning with the first experimental testing conducted in Russia in the 1930s. Since then, more tests and pilot projects have been launched in the U.S., Europe and Australia with a total of 50 tests or pilot projects carried out worldwide. Most notably, in-situ gasification was commercialized in Angren, Uzbekistan with the successful completion of a commercial-scale gasification plant that still powers a 400 MW power station today.

China began exploring the potential for in-situ gasification in the late 1950s with the launch of initial trials in several provinces including Heilongjiang, Liaoning, Jilin, Shanxi and Anhui provinces, but the trials were quickly ended due to technological and economic limitations. It was not until 1984 that more experimental tests were conducted in coal mines in Jiangsu province to evaluate a two-stage in-situ gasification process. The tests confirmed the feasibility of using in-situ gasification for large-scale hydrogen production. In 1984, the Underground Coal Gasification Research Center was created at the China University of Mining and Technology in Beijing to formalize in-situ gasification research and development. China continued to conduct trials throughout the late 1980s, using vertical wells in abandoned galleries of used coal mines to test in-situ gasification processes. Throughout the 1990s, larger-scale trials were conducted at shallow depths of less than 300 meters in Jiangsu, Hebei, Heilongjiang, and Henan provinces and achieved daily production of 12,000 to 36,000 m^3 of air and water syngas with average heat values of 2.52 to 5.7 MJ/m^3. Some specific examples of successful trials included:

- March 1994: Semi-industrial in-situ gasification trial in Xuzhou of Jiangsu province gasified 1,152 tons of coal with a total output of 3.45 million cubic meters of syngas. This included daily production of 36,000 cubic meters of syngas with heat value of 5 MJ per cubic meter for 96 continuous days.
- May 1996: a two-stage gasification trial conducted in Tangshan of Hebei Province produced air and water syngas, with daily production of 80,000 to 120,000 cubic meters and 50,000 cubic meters, respectively. The heat values of the air and water syngas were 4.2 to 5.7 MJ per cubic meter and 15 MJ per cubic meter, respectively.
- 1998: in-situ gasification trial conducted for 70 days, gasifying 3,470 tonnes of coal to produce syngas with heat value of 5 MJ per cubic meter.

Figure 20 shows the locations of in-situ gasification test trials and pilot projects in China.

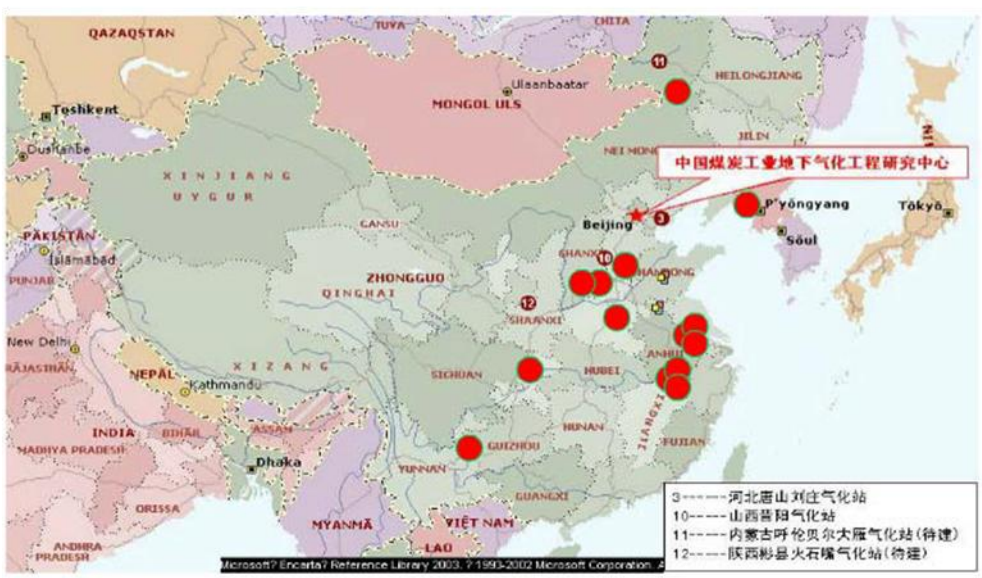

Figure 20. Map of In-situ Gasification Test Trials and Pilot Projects in China

As seen in Figure 21, China is a relatively latecomer in in-situ gasification research and development compared to other countries involved in in-situ gasification research and development. Compared to Europe, China's pilots and test projects have also been conducted at shallower depths of less than 300 meters.

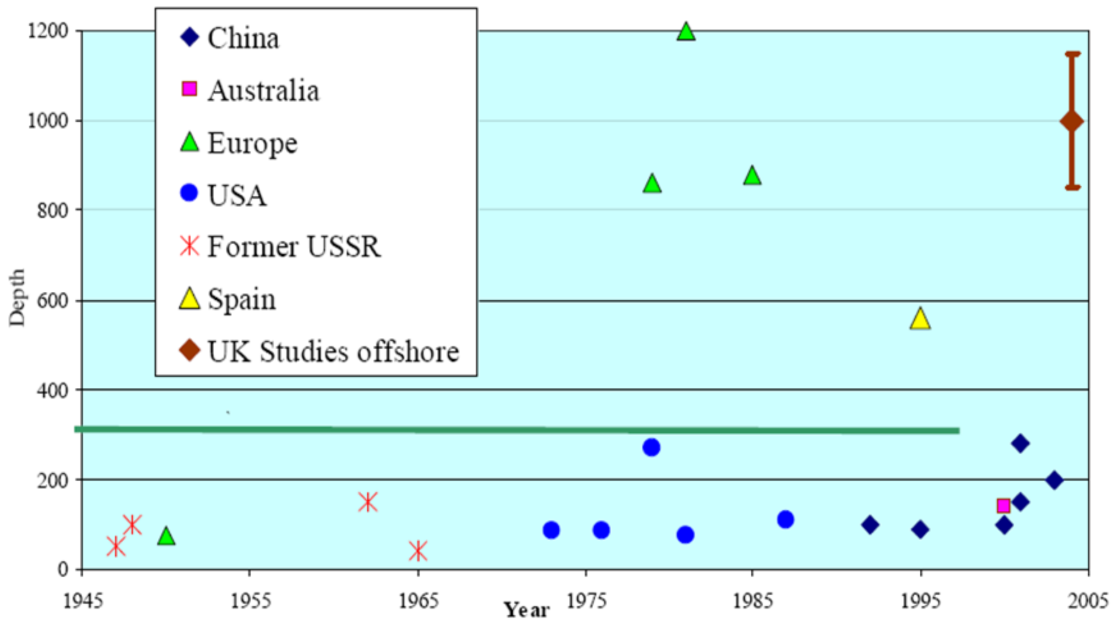

Figure 21. Timeline of Worldwide In-situ Gasification Tests and Pilot Projects

Source: Bowen, 2008

Over the last decade, however, China has made further strides in advancing the development of in-situ gasification through policy support and larger-scale research and development efforts. In 2000, the Xinwen Mining Group in Shandong province successfully carried out a two-stage in-situ gasification trial that produced syngas with a much higher average heat value of 10.54 MJ per cubic meter. In 2005, the Xinwen Mining Group built a pit in-situ gasification test base with daily production of over 50,000 cubic meters of syngas with heat value of greater than 8.36 MJ per cubic meter. This gasification station is still operational today and provides syngas for electricity generation, boiler combustion and industrial furnace use. The Xinwen Mining Group also operates six underground gasifiers, which produces gas for civilian power generation, in the largest existing underground gasification industrial base in China.

Another recent achievement in the development of in-situ gasification in China include the launch of a US$112 million joint venture project between China University of Mining and Technology and ENN Group in 2006, which resulted in a demonstration pilot industrial plant with daily production capacity of 15 million cubic meters for power generation. Most recently in 2012, a technical cooperation agreement was signed with the Australian Carbon Energy company to develop in-situ gasification in Shanxi province, with plans for developing an initial plant with minimum annual production of 30 PJ of syngas.

7.3. Outlook for Development

As illustrated by the growing international interest in in-situ gasification and the strong government support for its research and development in China, in-situ gasification and its development will be driven by its advantages as an alternative energy source. Its greatest advantage is that it enables the utilization of coal reserves with unfavorable characteristics for surface mining and would otherwise be deemed unusable. At the same time, compared to surface gasification, in-situ gasification also benefits from higher thermal efficiency, particularly if it is operated at high pressure to increase the reaction intensity. It also uses less water and can utilize water within the coal seam itself, rather than high quality surface water, when compared to surface gasification processes. By eliminating the need for specialized coal processing and gasification reactors, in-situ gasification can lower the capital investment costs and reduce operating costs (Bhutto et al. 2013). In-situ gasification can also help improve work safety by eliminating coal mining safety concerns, and has additional environmental benefits compared to conventional coal mining. These include minimal surface disturbance and land degradation, no discharge of tailings, SOx or NOx air pollutants as well as reduced sulfur emissions and discharge of ash, mercury and tar (Bhutto et al. 2013). Depending on the location and geological characteristics of the in-situ gasification site, the well infrastructure may also be applicable to geological CO_2 sequestration in the future. For China, some prospective areas for geological CO_2 storage have been identified along the eastern coast as shown in Figure 22.

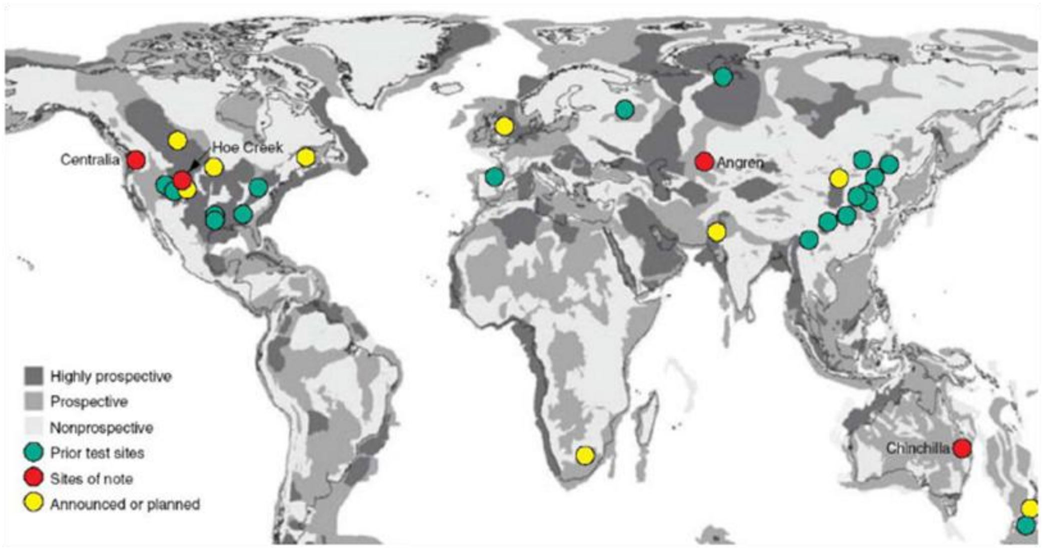

Figure 22. Current Global Status of In-situ Gasification Development

Note: The circles represent planned and prior in-situ gasification test and pilot sites and current activities overlaying CO2 storage potential areas. Gray areas show potential areas for geological carbon storage.
Source: Bhutto et al. 2013, Figure 2.

As a process still in the early stages of demonstration and pilot applications, in-situ gasification still faces many technical challenges as well as environmental and health concerns that need to be resolved before it can be fully commercialized. In terms of technical challenges, site selection is crucial because there are limited applications of in-situ gasification for shallow seams, which would result in higher heat losses, lower thermal efficiency and product gas quality. Thus, in order to identify a suitable site, costly exploratory drilling and seismic surveys are needed to comprehensively evaluate and understand the many geological, geotechnical and hydrogeological factors of the potential site. While deeper seams are more favorable for in-situ gasification and can avoid problems such as groundwater contamination and rock subsidence, they require more expensive guided drilling technologies and higher injection and operating pressure (Bhutto et al. 2013). This cost trade-off for increased productivity with deeper seams suggests that more technological advances are needed before in-situ gasification can become technically feasible and economically competitive on a commercial scale.

In spite of the environmental benefits of in-situ gasification compared to conventional coal mining, there are still environmental concerns with the process. One concern, particularly with respect to climate change mitigation, is the release of CO_2 emissions produced in the in-situ gasification process when it is separated from the product gas. The CO_2 emissions produced need to be captured and stored or utilized to avoid venting into the atmosphere. Surface subsidence is another concern, as the coal seam's surface morphology will be altered by the high temperature of gasification and could cause stress and displacement among rocks. There is also environmental health risks associated with in-situ gasification, particularly given the toxic chemicals used in the gasification process. Groundwater contamination is a major concern because the diffusion and penetration of contaminants generated by in-situ gasification processes – including potentially carcinogenic, mutagenic and toxic chemicals – can result in possible leaching into the natural groundwater flow. The potential dangers of groundwater contamination has been highlighted in Australia, where its Cougar Energy project was suspended in 2011 after ruptured in-situ gasification well released benzene and toluene into groundwater aquifers.

Taking these attractive benefits and remaining challenges of in-situ gasification into consideration, China has recognized the strategic value of in-situ coal gasification by actively pursuing research and development activities while providing policy support. Since the 1990s, in-situ gasification research and development efforts have included state-sponsored tests and have recently achieved industrial-scale pilot demonstration projects. A total of seven policies related to in-situ gasification, ranging from medium- to long-term science and technology development plans to clean coal industry development plans, has been implemented since 2001. Most recently, in-situ coal gasification was recognized as one of the emerging industries in the 12th FYP. Despite these achievements, however, China still faces several specific technical challenges to achieving commercial development of in-situ coal gasification. Unlike other countries pursuing in-situ gasification, China has yet to conduct any tests in active coal fields and lacks experience in constructing underground gasifiers and horizontal directional drilling. Pilot and demonstration projects have also underscored remaining difficulties in controlling gas yield and calorific value with in-situ gasification. Finally, given China's 2015 and 2020 commitments to reducing carbon intensity per unit GDP, the unresolved issue of possibly venting CO_2 emissions remains a major concern.

8. Tight Oil

Tight oil, the light crude oil trapped in tight sandstone and carbonate rock, is typically characterized by very low porosity and permeability and located in or adjacent to source rocks. Tight oil reservoirs have relatively poor physical properties, such as greater depth and low thermal evolution, which are similar to unconventional formations and make it more difficult to extract hydrocarbons. However, these tight oil reservoirs have good oil-bearing capacity and large reserves because of the source rocks' proximity to the reservoirs. And because tight oil is essentially conventional oil trapped in unconventional formations, China does not make any distinctions between tight oil and conventional oil in its resource classification.

8.1. Resource Assessment

In China, tight oil consists of primarily continental deposits with strong heterogeneity and smaller distribution, as well as lower porosity and permeability. There are three main types of tight oil reservoirs in China located across different basins: continental light sandstone reservoirs located in the Ordos Basin, lacustrine carbonate reservoirs located in the Bohai Bay Basin and central Sichuan Basin, and the muddy limestone fractured reservoirs located in the Bohai Bay and Jiuquan Basins. Figure 23 shows the geographic distribution of tight oil in China's major basins.

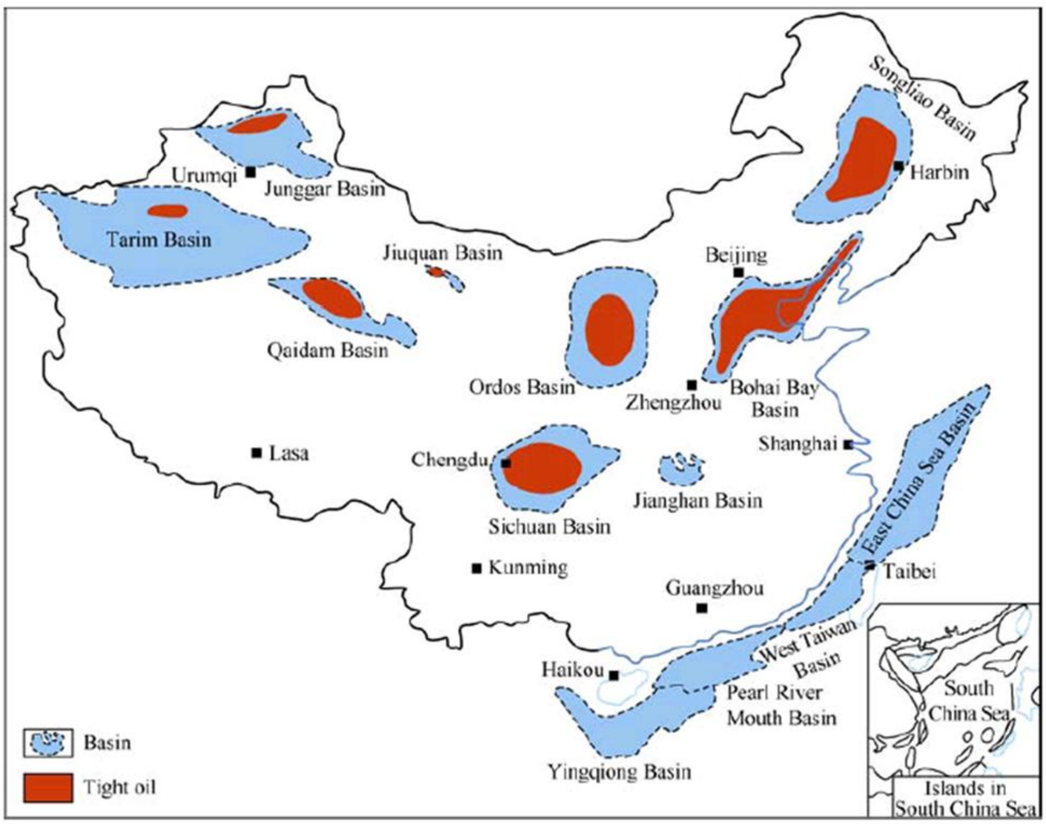

Figure 23. Tight Oil Distribution in Major Basins of China

Source: Jia et al. 2012, Figure 2.

Preliminary resource estimates using aerial oil ratio method have found total favorable exploration area of 180,000 square kilometers for tight oil. The tight oil resource base in China includes 7.4 to 8 billion tonnes of geological, in-place resources and 1.3 to 1.4 billion tonnes of recoverable resources (Jia et al. 2012). The favorable exploration areas and geological resources are mainly distributed across seven major basins, as shown in Table 16. Ordos, Songliao, Sichuan and Bohai Bay basins, in particular, have greater potential for tight oil extraction given the thicker, organic-rich shale and mudstone formations located in those basins.

Table 16. Tight Oil Distribution Areas and Resource Estimates for China

Basin	Exploration layers	Exploration area/10^4 km^2	Geological resources/10^8 t
Ordos	Ty_7	10.00	19–25
Sichuan	J_1dn	1.50	10
Songliao	K_1	1.50	16
Qaidam	E, N	1.00	4
Bohai Bay	Es	2.00	11
Junggar	P_1	0.30	12
Jiuquan	K_1g	0.03	2

Source: Jia et al. 2012, Table 4.

8.2. Recent Development and Outlook in China

China's tight oil resources were discovered in the seven basins in the 1960s, beginning with the discovery of the first tight oil well in Songliao Basin which produced 2.66 tonnes of tight oil per day from the mudstone formation. Since then, there have been more than 320 wells with oil and gas shows and more than 30 wells with oil and gas flow in the Bohai Bay Basin alone, with maximum well yield of 110 tonnes per day achieved. In the Jiuquan Basin, good oil and gas shows have also been obtained with lower yielding wells. In addition to Bohai Bay, tight oil has also been commercially produced in technological pilot projects in Ordos, Junggar, Sichuan, and Songliao Basins (Jia et al. 2012). More recently, six tight oil fields were discovered in central Sichuan Basin, with proven reserves of 81 million tonnes, probable reserves of 23.5 million tonnes and possible reserves of 56.5 million tonnes (Jia et al. 2012). As a result, tight oil production from the central Sichuan Basin reached 89,800 tonnes in 2010. There have also been recent technological improvements in tight oil exploration and extraction. On the exploration side, improved forecasting techniques have been utilized to predict tight oil layers with coincidence rates of up to 85%. On the extraction side, breakthroughs were achieved in the application of multi-stage fracturing in four horizontal test wells to extract from reservoirs with extremely low permeability (Jia et al. 2012). The discovery of the new tight oil fields and the recent technological advancements suggest that tight oil will continue to contribute to China's conventional oil production, though its low recoverable resource base will not likely result in tight oil extraction reversing China's long term decline in oil production.

9. Oil Shale

Oil shale is a fine-grained, low permeability, kerogen-rich sedimentary rock that yields crude oil or gas when heated at high temperatures. The oil that is released when oil shale is heated, or distilled, is known as shale oil. Globally, commercial oil shale mining has been undertaken for over a century. Total mined oil shale peaked in the 1980s, but has recently started to rise again.

9.1. Resource Assessment

China has abundant and widespread oil shale resources and is ranked second globally in terms of its potential resources. The first national oil shale evaluation was conducted between 2004 and 2006, and found total geologic, in-place oil shale resources of 719.937 billion tons. This includes proved reserves of 50.05 billion tonnes and technically proved reserves of 25.9 billion tonnes (Fang et al. 2008). From the oil shale resources, the evaluation estimated total shale oil resources of 47.6 billion tonnes, with proved reserves of 2.74 billion tonnes and technically proved reserves of 1.46 billion tonnes. China's oil shale resources are distributed across 20 provinces, 47 basins and 80 deposits. More than 70% of the oil shale resources are located in eastern and middle China, with the remaining 30% concentrated primarily in Qinghai-Tibet area and Western China. The quality of China's oil shale resources can be considered moderate or better.

9.2. Recent Development in China

The oil shale industry was established in Fushun of Liaoning Province in the 1920s, when oil shale retorting to produce shale oil first began. By the end of the 1950s, a total of 266 retorts were in operation with daily production capacity of 100 to 200 tonnes of oil shale. By 1959, the two Fushun refineries produced a total of 780,000 tons of shale oil (Qian et al. 2003). The shale oil in turn was processed to produce gasoline, kerosene, diesel oil, wax and lubricating oils. In the 1960s, additional heating retort refineries opened in Jilin and Guangdong provinces (Qian et al. 2003). The current oil shale retorting centers are located in Liaoning, Jilin, Shandong and Heilongjiang provinces (Guangdong's retorts in Maoming were closed in 1990s), as shown in Table 17. Of these four centers, Huadian in Jilin and Longkou in Shandong have the deposits with the highest energy potential for shale oil in terms of having the highest Fischer Assay oil yield ratio. In 2007, PetroChina began evaluating the potential application of in-situ conversion processes, which have lower environmental impacts in terms of surface disturbance, water input requirements and waste management. By 2008, PetroChina completed the design for a model of electric heating in-situ conversion of oil shale.

Table 17. Oil Shale Retorting Centers in China

	Oil shale				
	Fushun	Huadian	Longkow	Yilan	Songyasan
Province	Liaoning	Jilin	Shandong	Heilongjiang	
Age	Tertiary				
Burial condition	Coexists with coal, open pit mining	Oil shale, underground mining	Coexists with coal underground mining	open pit mining	
Recoverable reserves, million tons	2,000	200	40	10	20

Source: Qian et al. 2003, Table 1.

Following the commercial development of oil shale mining and retorting in the 1920s, China has produced a sizeable share of the global total of mined shale as seen in Figure 24. China's oil shale mining peaked in the 1980, but then declined though 1999 due to growing competition from declining oil prices. This trend was reflected in the total global oil shale mining, which also peaked around 1980 before beginning to decrease significantly. Since 1999, the total mined oil shale in China has started increasing again, with corresponding increases in shale oil production. China's shale oil production grew by 24% from 330,000 tonnes in 2007 to 755,000 tonnes in 2011, or 51% of the world total shale oil production (Li et al. 2012).

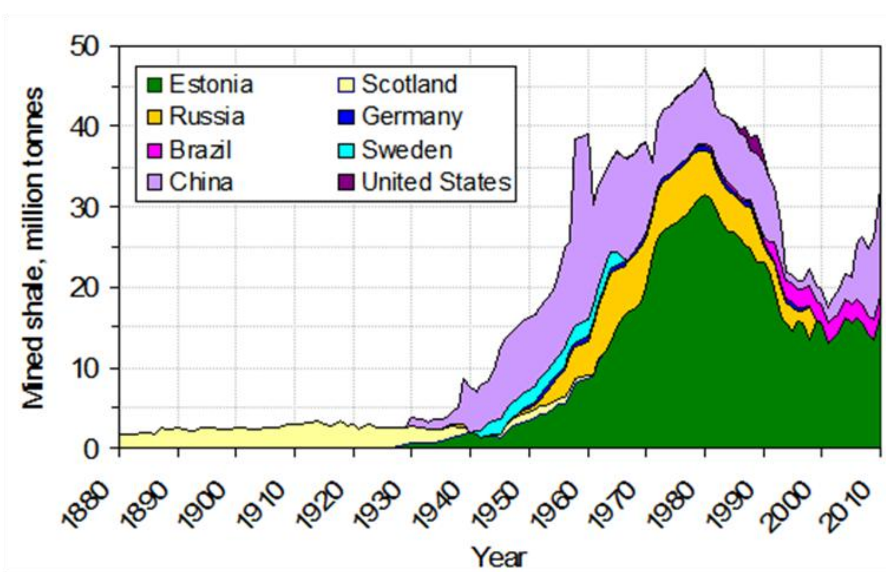

Figure 24. World Oil Shale Mined by Country

Source: Li et al. 2012.

9.3. Outlook for Development

The outlook for oil shale in China will be largely determined by developments in the two possible utilization of mined oil shale: power generation or extraction of shale oil. In its utilization for power generation, oil shale is burned in pulverized coal-fired boilers or fluidized bed combustion. Although the application of oil shale for power generation has higher commercial value, it has not reached commercial development due to technical limitations with both pulverized coal-fired boilers and fluidized bed combustion. For pulverized coal-fired boilers, the main challenges with using oil shale include metal corrosion of the radiant heating surface, ash clogging resulting from ineffective heat transfer, explosions and the fuel injection needed to support combustion with the lower calorific value of oil shale (Fang et al. 2008). The utilization of oil shale to power fluidized bed combustion also faces problems with low combustion intensity, large space needs, difficulty of control, low heat efficiency and environmental pollution (Fang et al. 2008). The extraction of shale oil by mining, crushing and retorting oil shale, on the other hand, has reached large-scale production with relatively mature but simple technology and techniques. However, oil shale mining and shale oil extraction are linked to environmental problems such as land, ecosystem and water quality degradation, and ash pollution. At the same time, mining deep oil shale deposits increases to economic costs of shale oil extraction and also has very low net energy return. In light of these remaining challenges, China's newest efforts in oil shale development have focused on developing in-situ conversion, where the oil shale rock is heated underground using electric, fluid or radiation heating in order to generate oil and gas from producer wells. These different in-situ conversion processes are still largely under development, with only a few technologies having moved forward to testing, and bring with it other disadvantages that will need to be addressed before oil shale can take on a more important role in China's resource supply.

10. Gas Hydrates

Gas hydrates are ice-like crystalline forms of water and gas, such as methane, which occur naturally in marine sediments and within or beneath permafrost. Gas hydrate resources typically occur at low temperatures of 0 to 10°C, at high pressures of greater than 10 megapasacals, and water depths of greater than 300 meters with burial depths of up to 1100 meters. In China, gas hydrates are characterized by high density, wide distribution and shallow burial depths (Ma 2009). Because the amount of methane potentially trapped in natural methane hydrate deposits may be significant, with possible yields of 164 cubic meters of gas per cubic meter of gas hydrate, there has been growing international interest in gas hydrates as a potential energy resource since the first gas hydrate samples were discovered in the Black Sea in the late 1960s.

10.1. Resource Assessment

In 2006, the China Geological Survey Bureau estimated 60 to 70 trillion cubic meters of total gas hydrates resources in the northern South China Sea. This included 11 gas hydrate prospective distribution areas, both on-shore and off-shore, with total area of 126,000 kilometers (Ma 2009). The offshore prospective areas include the South China Sea and East China Sea, while the on-shore prospective areas include the permafrost zones of Qinghai-Tibet and Northeastern China.

10.2. Recent Development in China

China initiated basic research related to gas hydrates in the early 1990s, including the development of the first laboratory gas hydrates in Lanzhou in 1990. The next milestone in gas hydrate research and development was in 2004, when the Guangzhou Center for Gas Hydrate Research was established to expand laboratories studies and to conduct the first offshore resource assessments to evaluate the energy resource potential of offshore gas hydrates. On May 1, 2007, a deep-water gas hydrate drilling and coring expedition was successfully completed on the north slope of the South China Sea through efforts sponsored by the Guangzhou Marine Geological Survey, China Geological Survey and Ministry of Land and Resources (NETL 2012). This expedition successfully recovered marine gas hydrates from three of five sites cored in the Shenhu area of the northern South China Sea, and marked the first time that China recovered marine hydrate samples. At the same time, China also became the fourth country in the world to collect gas hydrate samples through national research and development program. From 2008 to 2009, a permafrost drilling and coring program sponsored by the Chinese Academy of Geological Sciences and China Geological Survey was initiated in Qinghai province. As part of this program, gas hydrate samples were recovered from three of the four holes drilled in Qilian Mountain permafrost in Qinghai province (NETL 2012). There are now a total of twenty research groups in China involved in gas hydrate research and future research and drilling expeditions to both the Shenhu area and other regions of the northern South China Sea are being considered.

10.3. Outlook for Development

The potential of gas hydrates to serve as a new energy resource for China lies in its advantages as a denser source of hydrocarbons than conventional energy sources. As an abundant potential source of natural gas, gas hydrates would also be a cleaner fuel source than coal, oil or oil shale. However, as exemplified by its limited and late development in China as well as the absence of any international production yet, gas hydrates are still very far from reaching the stage of commercial production. After over fifty years of research and drilling expeditions, only basic research has been initiated in evaluating gas hydrates' potential as an energy source with no prospects for utilization in sight yet. In China, additional research needs to be carried out to evaluate and better understand various characteristics of gas hydrates, including their sources of gas, the types of deposits formed, their mode of occurrence, controls on the formation and enrichment of deposits and their dynamic behavior over time (NETL 2012). More research, development and demonstration are needed concurrently to improve technologies for gas hydrate characterization, extraction and utilization.

Moreover, there are also practical challenges with utilizing gas hydrates as energy resources. Although it could be considered a cleaner fuel source, the release of hydrocarbons as a gas with the decomposition of hydrates when removed at low temperatures and high pressure could increase greenhouse gas emissions. This is especially true considering that methane has a more potent global warming potential of 21 times that of CO_2 emissions. The extraction and transport of gas from gas hydrates would also be economically challenging, given the high costs of constructing long pipelines across unstable continental slopes to where the gas hydrates are located. Pipelines located in water at greater depths and low temperatures are also more likely to become plugged with hydrates during gas transport, and could also damage sensitive chemosynthetic marine communities. These environmental and logistical barriers to commercial utilization of gas hydrates, as well as the significant amount research and development needs that remain, make it unlikely that gas hydrates will contribute to China's energy supply in the near future.

11. China's Energy Outlook to 2030

In order to understand China's potential energy demand through 2030, particularly for oil and natural gas, and the subsequent role for nonconventional oil and gas resources, a bottom-up, end-use model is used to characterize future energy demand and its drivers under a reference scenario in which China continues the current pace of energy efficiency and energy-related technological improvements (e.g., technological upgrades). This model, the China Energy End-Use Model, is based on an accounting framework of China's energy and economic structure using the LEAP (Long-Range Energy Alternatives Planning) software platform. Using LEAP, the China Energy End-Use Model captures diffusion of end-use technologies and macroeconomic and sector-specific drivers of energy demand as well as the energy required to extract fossil fuels and produce energy and a power sector with distinct generation dispatch algorithms. This model enables detailed consideration of technological development—industrial production, equipment efficiency, residential appliance usage, vehicle ownership, power sector efficiency, lighting and heating usage—as a way to evaluate China's energy development path below the level of its macro-relationship to economic development.

11.1. Modeling Methodology

The China Energy End-Use Model consists of energy demand and transformation (i.e., supply) modules. Within the energy demand module, the model is able to address sectoral patterns of energy consumption in terms of end-use, technology and fuel shares including trends in saturation and usage of energy-using equipment, technological change including efficiency improvements and complex linkages between economic growth, urban development and energy demand. From the supply side, the energy transformation module in the model represents energy production subsectors such as oil refining, oil extraction, coking, coal mining, natural gas extraction and power generation. The energy production subsectors account for energy input to extracting different types of energy output, and is linked to the demand module. Supply curves for coal, natural gas and oil were developed and incorporated into the model. Similarly, following specified power sector module parameters, the model uses algorithms to calculate the amount and type of capacity required to be dispatched to meet the final electricity demand from the economic sectors. Specifically, the model uses an environmental dispatch order for generation, which favors non-fossil generation and reflects dispatch priority policies that are being considered in China.

Within the China Energy End-Use Model, both macroeconomic and sector specific drivers and technology trends with important linkages to future energy demand are modeled. Key macroeconomic drivers include GDP growth, which directly affects industrial production and trade as well as household income which in turn drive household energy usage, consumption patterns and transport demand. In the model, fast economic growth is expected to continue from 2010 to 2020 at annual average growth rate of 7.7% before slowing down to 5.9% between 2020 and 2030. Given China's significant population size, population growth and urbanization is the other major force shaping China's development and energy pathways. Using United Nation's World Population Prospects and published Chinese urbanization outlook, 360 million new residents are expected to be added through 2030. China already reached an urbanization rate of 50% in 2011 with 70% of the population expected to be living in cities by 2030. The influx of new urban residents will add new mega-cities and second-tier cities that require new infrastructure and buildings. In addition to the indirect energy use for producing building materials such as cement and steel to support infrastructure development, new cities will also drive commercial and residential demand for energy services and spur inter- and intra-city transport activity.

For the specific end-use sectors of residential and commercial buildings, industry and transport, different sectoral drivers are used to evaluate China's future energy demand outlook. For the residential building sector, urbanization and growth in household incomes drive energy consumption as urban households generally consume more commercial energy than rural households and rising household incomes correspond to increases in size of housing units (and thus heating, cooling and lighting loads) and appliance ownership. Similarly, commercial building energy demand is driven by two key factors: building area (floor space) and end use intensities such as heating, cooling and lighting (MJ per square meter). For the industrial sector, analysis was conducted for seven energy-intensive industrial sub-sectors (cement, iron and steel, aluminum, glass, ammonia, ethylene and paper) based on physical drivers for each industrial product and recent and expected efficiency and technological trends. For cement, steel and aluminum production, for example, the scenarios were based on major physical driver relationships to built environment requirements for growing urban population, with floor space construction area as a proxy. Ammonia production, in contrast, was modeled as a function of sown area and fertilizer intensity while ethylene production was based on population and per capita demand for plastics. For each industrial sub-sector, projections of process efficiency requirements and technology shift for materials production were developed and the energy return on energy investment for primary energy producing sectors was examined. Transport sector activity is driven by demand for freight transport and for passenger transport. Freight transport is calculated as a function of economic activity measured by value-added GDP while passenger transport is based on average vehicle-kilometers traveled by mode (e.g., bus, train, car) of moving people. For passenger transport, growing vehicle-kilometers traveled in different modes is driven by population growth and growing demand for personal transport with rising income levels. The largest mode of passenger transport is in road transport, which is driven primarily by the burgeoning ownership of private cars that follows rising per capita income.

The energy supply and demand outlook is based on a reference scenario developed to represent a pathway in which the Chinese economy continues a moderate pace of "market-based" improvement in all sectors and adopts all announced policies and goals related to efficiency improvement. For end-uses that use natural gas, for instance, assumed improvements include continuing the recent pace of appliance standard revisions for natural gas water heaters and stoves, continued fuel economy improvements in freight trucks, and meeting energy intensity reduction targets for iron and steel, aluminum and ammonia industries. For the power sector, China is assumed to reach the 12th FYP target of 56 GW of natural gas installed capacity by 2015, growing to 100 GW by 2030 with a constant capacity factor set at the 2010 level and improved process efficiency from 45% in 2010 to 55% in 2030. Unlike a frozen scenario, which is unrealistic given China's recent commitments to energy and carbon intensity reductions, the reference scenario reflects what is likely to happen. More specific details on the key assumptions, drivers and parameters for modeling each end-use sector can be found in Fridley et al. 2012.

11.2. Total Energy Demand Outlook to 2030

As seen in Figure 25, China's energy demand will continue to increase from current levels through 2030, driven by rapid growing demand from commercial building and transport sectors. Total primary energy demand will grow by an average of 2.2% per year through 2020, then slow down to average growth of 1% per year, to a total of 4560 Mtce in 2030. Primary energy demand for the transport sector, on the other hand, will grow at a faster annual average rate of 4.7% while commercial buildings also grow at a fast annual average rate of 3.8% per year from 2010 to 2030. The industry sector, while continue to hold the largest share of total primary energy demand, will grow at a much slower rate of only 0.6% per year through 2030. By 2030, the residential, commercial, transport and industry sectors will account for 13%, 12%, 20% and 54% of China's total primary energy demand.

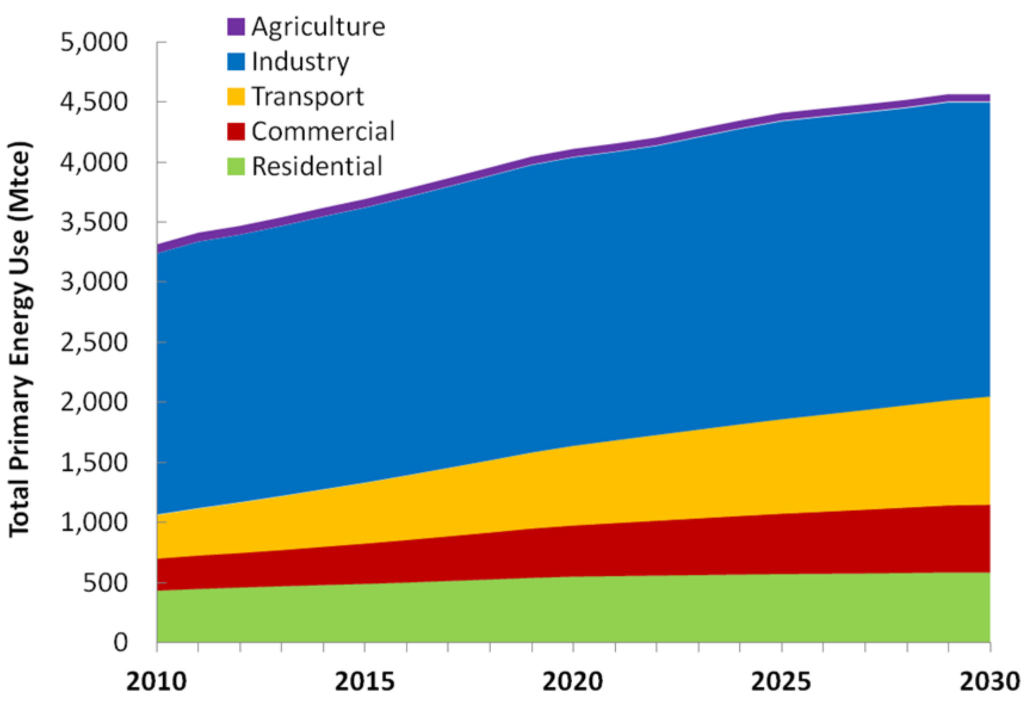

Figure 25. China's Primary Energy Demand Outlook by Sector to 2030

Figure 26 shows China's primary energy demand to 2030 in terms the fuel breakdown. Rapid growth is expected in the demand for primary electricity (i.e., hydropower, nuclear and renewable generation), natural gas and petroleum and the three fuel types combined will make up about half of China's total primary energy demand in 2030. Natural gas demand will grow at annual average rate of nearly 6% through 2030 to make up 11% of total primary energy demand in 2030. Petroleum demand will also grow at an average of 3% per year through 2030 to reach a 25% share of total primary energy demand in 20230. The primary energy demand for coal will peak around 2020, and then decline slightly through 2030. In terms of its share of total primary energy consumption, coal's share will decrease significantly from 73% in 2010 to only 51% in 2030.

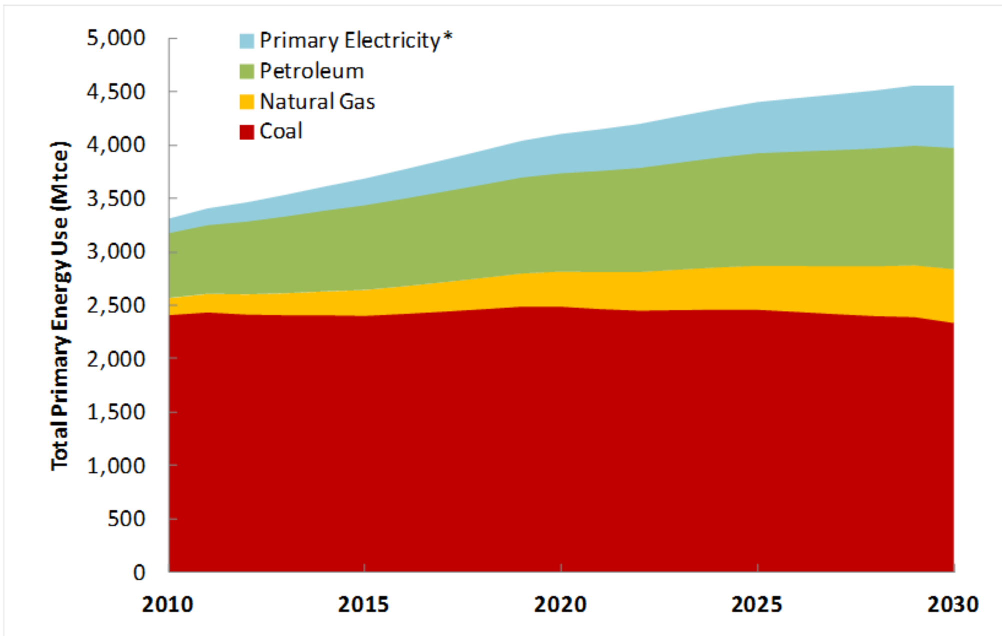

Figure 26. China's Primary Energy Demand Outlook by Fuel to 2030

Note: primary electricity includes nuclear, hydropower and other renewables.

11.3. Oil Demand Outlook

The rising share of petroleum in total primary energy demand is linked to the increased crude oil demand driven by a burgeoning transport sector that is increasing its share of total oil use, as seen in Figure 27. While the other end-use sectors all have flat or declining shares of total oil final demand, the transport sector's share will grow from 53% in 2010 to 58% in 2030. In absolute terms, the transport sector's demand for oil will more than double from 208 Million tonnes of oil equivalent (Mtoe) in 2010 to 458 Mtoe in 2030, growing at an annual average growth rate of 4%. Within the transport sector, most of the demand for oil will be from trucks, particularly heavy and light-duty trucks, buses, light-duty passenger vehicles with smaller shares from water freight transport. In the industry sector, the demand for oil is predominantly from the petrochemical industry.

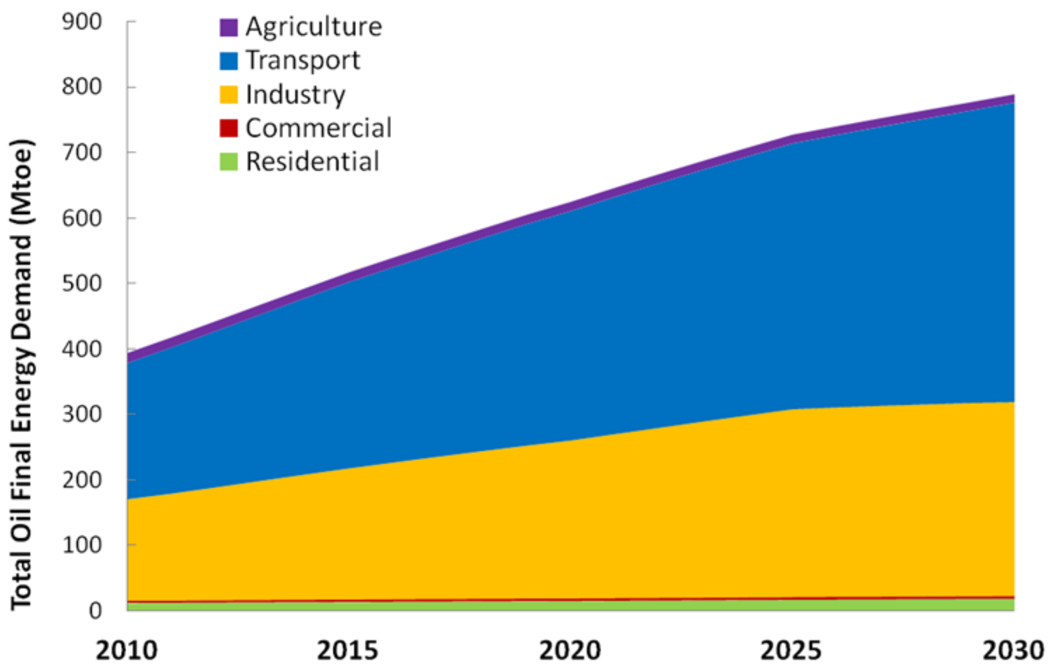

Figure 27. China's Oil Demand Outlook by Sector to 2030

11.4. Natural Gas Demand Outlook

The recent growth in demand for natural gas shown previously in Figure 2 has been driven largely by natural gas's appeal as a cleaner alternative to coal in the buildings and power sector and as a cleaner alternative to oil in the transport sector. Unlike oil, the demand for natural gas is concurrently growing across multiple end-use sectors. Figure 28 shows China's natural gas consumption by end-use sector in 2011. Nearly half of the total natural gas consumption of 128 billion cubic meters was by industry, with a quarter from residential and commercial buildings, one-fifth from the energy transformation sectors of power generation and heat supply and the remainder from transport. Over the next two decades, natural gas demand will likely rise in all sectors except industry.

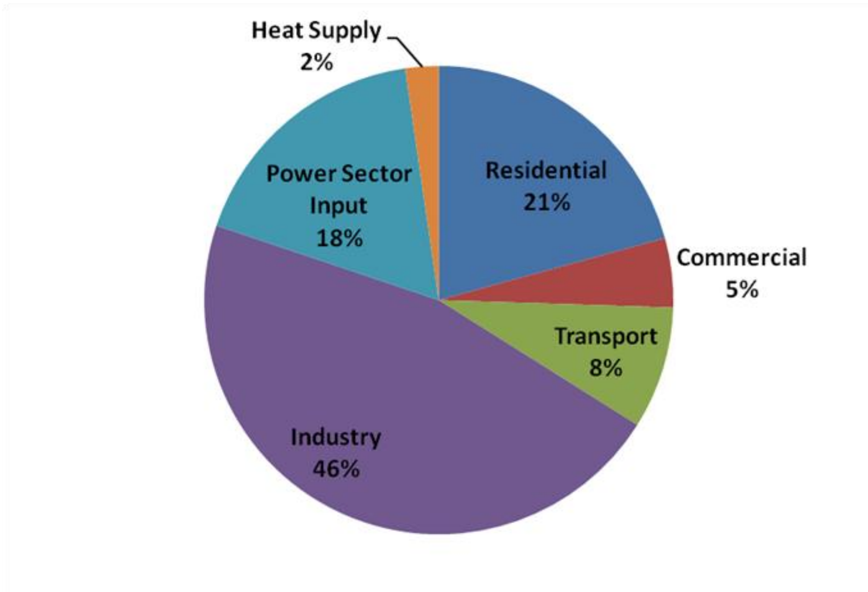

Figure 28. China's 2011 Natural Gas Consumption by End-use Sector

Source: Data from NBS, 2012.

In the power sector, natural gas will become an increasingly important alternative to coal-fired generation as China seeks to decarbonize its power sector. The larger role expected for natural gas in power generation is already reflected in recent policies, with the 12th FYP's setting of a 56 GW installed capacity target for 2015. The 2012 Natural Gas Utilization Policy also, for the first time, moved natural gas utilization for power generation from the restricted to the permissible utilization category. For the other demand sectors of residential, commercial and transport, continued growth in natural gas consumption is likely given that all three of these sectors are prioritized under the 2012 Natural Gas Utilization Policy. Under the policy, natural gas use for residential and commercial space heating and water heating, especially in large cities, are prioritized under the preferential category of utilization. Similarly, natural gas use in the transport sector is also listed in the preferential category, and the use of compressed natural gas vehicles for taxis, buses and trucks are promoted. Industry, on the other hand, will likely see a declining share of total natural gas consumption because natural gas input to fertilizer and ammonia production has been listed in the restricted utilization category.

Figure 29 shows China's natural gas demand outlook to 2030 broken down by the demand sector and power sector input. In absolute final energy terms, annual natural gas consumption is expected to increase nearly three-fold from 2012 to 310 billion cubic meters by 2030. Natural gas consumption in the power sector, residential, commercial and transport sectors are also expected to grow with annual average growth rates of 7%, 6%, 8% and 12%, respectively. The growth in the transport sector is particularly fast because of its very low starting point in China, with transport sector only consuming 10 billion cubic meters of natural gas in 2011. In relative terms, industry's share of total natural gas consumption will dramatically decrease from nearly half of total consumption in 2011 to less than a fifth in 2030. The decrease in industry's share is offset by increases in the shares of the power sector, transport and commercial sectors in total natural gas consumption. Residential sector's share of total natural gas consumption remains relatively constant.

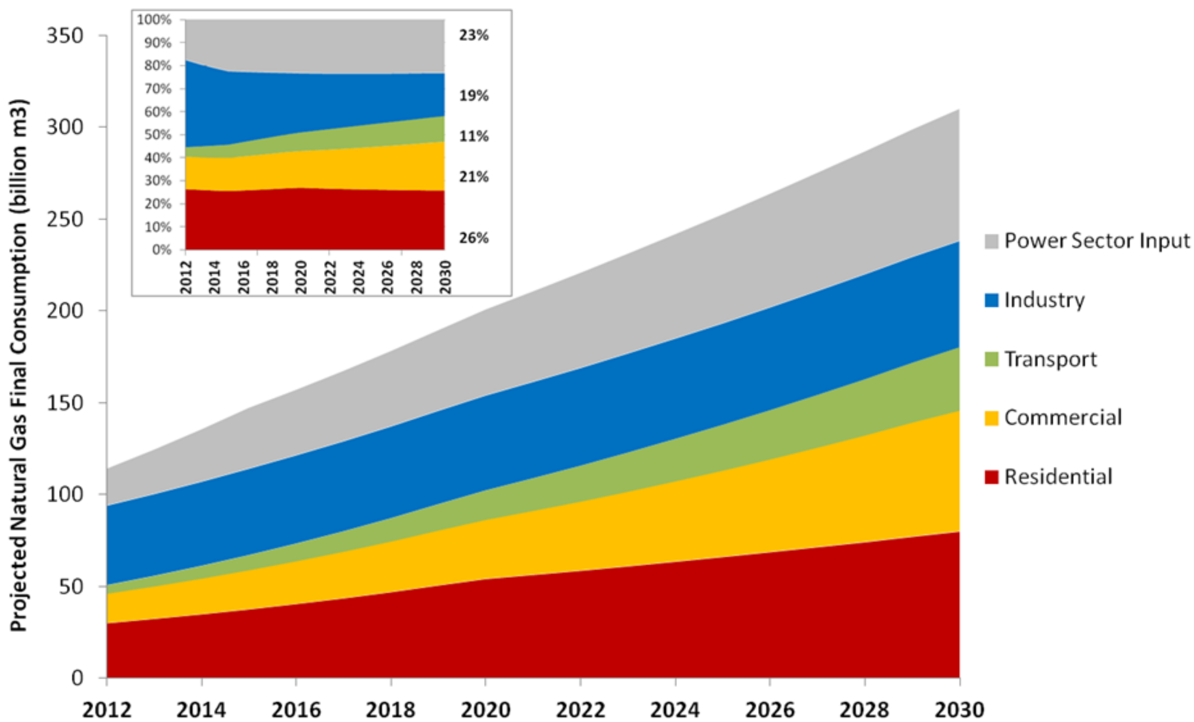

Figure 29. China's Natural Gas Demand Outlook by Sector, 2012-2030

At below the demand sector level, the total natural gas consumed by different end-uses vary significantly. As seen in Figure 30, annual natural gas consumption by end-use ranges from a high of 71 billion cubic meters by the power sector to lows of less than 1 billion cubic meter for building cooling applications in the commercial sector in 2030. Besides the power sector, other significant end-use consumers of natural gas include urban residential space heating (15% share in 2030), residential urban water heating (7%), heavy-duty freight trucks (8%), hotel water heating (5%) and office space heating (5%). The other industry subsector is also a large natural gas consumer, but its natural gas demand outlook is less certain given the heterogeneity of the subsector and its multiple demand drivers.

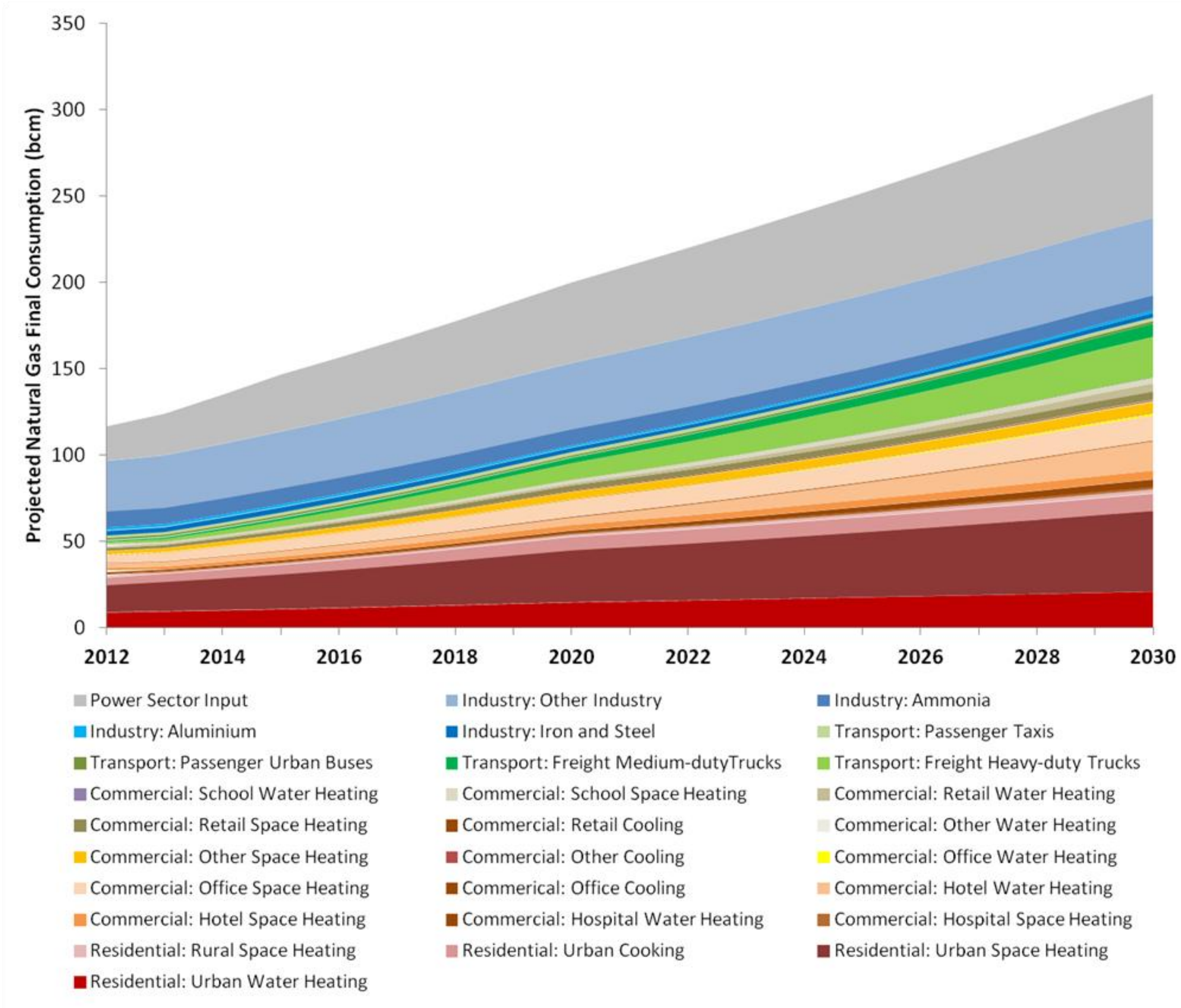

Figure 30. China's Natural Gas Consumption Outlook by End-Use, 2012-2030

The multiplicity of end-uses – and growth in the demand of many of these end-uses – underscore the strong drivers for natural gas demand and the increasing need for China to increase its natural supply both from domestic production and from imports. In fact, several different international studies have underscored the expected rapid growth in China's natural gas demand, as illustrated in Figure 31. A comparison of these outlooks show that 2030 annual consumption ranges from 210 to 285 billion cubic meters for final end-use only; these numbers exclude natural gas input into the energy transformation (e.g., power) sector. Our demand outlook as discussed above is relatively conservative in comparison, slightly higher than the demand outlook the China's Energy Research Institute within the National Development and Reform Commission (NDRC 2009) but below the outlooks by IEA in its 2011 World Energy Outlook (WEO) and EIA's 2011 International Energy Outlook (IEO). If the additional natural gas input to the transformation sector is considered, our natural gas demand would be higher with an additional 70 billion cubic meters of natural gas consumed in 2030. In the absence of data from the other outlooks on the natural gas input to the power sector, our total natural gas consumption scenario cannot be directly compared with the other outlooks. However, this increase in future natural gas demand once input to the transformation sector is taken into consideration will likely occur for the other outlooks as well, although the magnitude of the increase will vary. Natural gas-fired power generation is expected to hold 3.5%, 5% and 6.8% share of 2030 total generation under IEO 2011, NDRC 2009 and WEO 2011 outlooks, respectively, compared to the 6% share in our demand outlook.

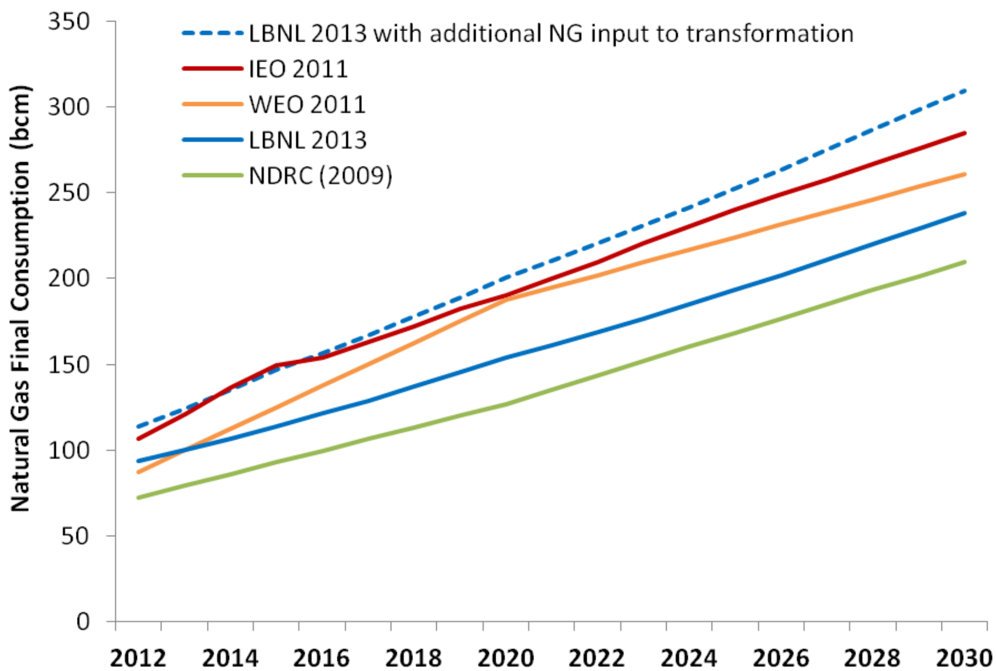

Figure 31. Comparison of China's Natural Gas Demand Outlooks to 2030

Sources: EIA 2011, IEA 2011, NDRC 2009.

12. The Role for Nonconventional Resources in China's Oil and Gas Outlook

To evaluate the potential role of nonconventional oil and gas resources in China's future supply, both conventional and nonconventional supply curves were developed for gas and compared to the demand outlook from the China Energy End-Use Model. For oil, only conventional oil supply was considered because tight oil is considered part of the conventional oil resources in China. The nonconventional resources of oil shale will likely have limited impact on expanding domestic supply given the technical, economic and environmental challenges it faces.

12.1. Oil Supply Outlook:

The outlook on China's oil supply is based on the use of modified logistics curve for two scenarios of ultimate recoverable resources (URR), a low scenario based on a URR of 68 billion barrels and a high scenario based on a URR of 114 billion barrels from a study published by scholars from the China University of Petroleum (Feng et al. 2008). Derivative logistics curve calculations were used to constrain the extraction profile to accord with two estimated total volume of reserves available for extraction, with maximum extraction levels occurring at about half-way in the depletion of the reserves. The resulting supply curves shown in Figure 32 are fitted to historical extraction figures from 1949. As seen in Figure 32, China's oil supply, even under a more optimistic URR of 114 billion barrels, will be far outpaced by its rapidly growing oil demand. By 2020, China's oil demand could exceed its supply by over 300% under the scenario of lower URR of 68 billion barrels and still by as much as 270% under the scenario of higher URR. By 2030, the gap between China's annual oil demand increases to 620% and 380%, or 12.4 and 10.8 million barrels per day, for the low and high URR scenarios, respectively. These results suggest that China petroleum import dependency will continue to rise as the gap between its domestic production and demand widens, especially given that nonconventional resources are not expected to be able to play any notable role in increasing supply in the near to medium-term; indeed, further exploitation of China's tight oil resources—already considered in the URRs modeled here—may serve mainly to prolong a production plateau or moderate production declines.

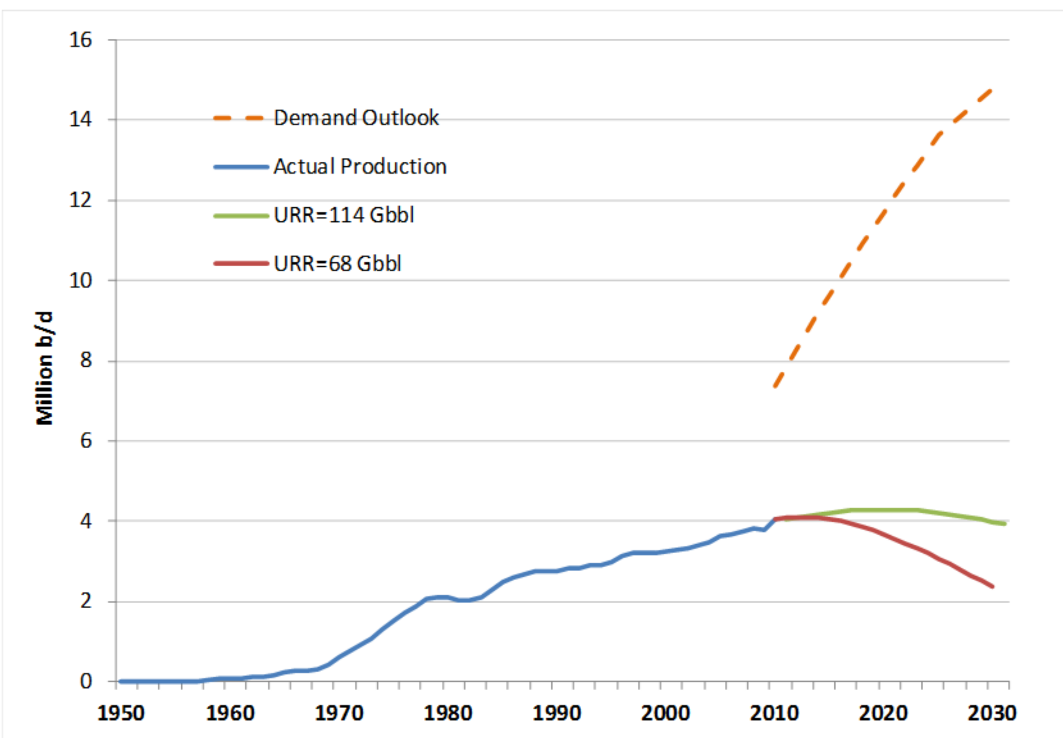

Figure 32. China's Oil Demand and Supply Outlook by Scenario

12.2. Gas Supply Outlook: conventional gas supply outlook, CSM and shale gas outlook

For China's gas supply outlook, the prospects for domestic extraction and production of conventional gas, including tight gas, as well as nonconventional gas of coal seam methane and shale gas were evaluated. Because of their major technical and environmental challenges as well as limited progress in commercialization and development to date, the other nonconventional gas resources from in-situ coal gasification and gas hydrates are not expected to materially contribute to China's gas supply before 2030, although in-situ gasification may play a limited role in production of syngas for chemicals.

12.2.1. Conventional Gas Supply Outlook

The outlook on China's conventional gas is also based on modified logistics curve and two scenarios – a high and a low estimate - of conventional natural gas resources. The high estimate of 6.8 trillion cubic meters of ultimate recoverable resources is taken from an estimate by the French petroleum engineer Jean Laherrere in 2008 based on creaming curve analysis (i.e. estimating reserves from plotting cumulative discoveries against exploration activity) (Laherrere 2008). The low estimate of 3.20 trillion cubic meters of technically recoverable reserves is based on the publicly released results of the latest 2010 MLR national resources survey (MLR 2011). As with the oil supply curves, derivative logistics curve calculations were also used to constrain the extraction profile to accord with two estimated total volume of reserves available for extraction, with maximum extraction levels occurring at about half-way in the depletion of the reserves. Both curves were also fitted to the actual production time series dating back to 1949. The two conventional gas supply curves are shown in Figure 33.

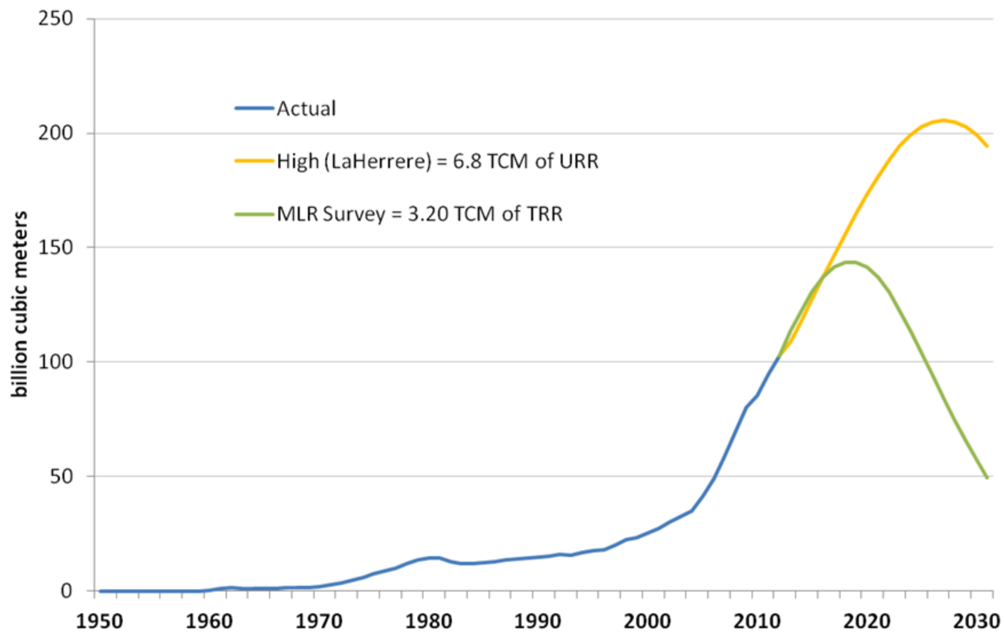

Figure 33. China's Conventional Gas Supply Outlook by Scenario

For China's conventional gas outlook, it is also assumed that tight gas will hold an increasingly large share of the gas supply. Specifically, it is assumed that tight gas will grow linearly from its current shares of 25% to 40% share of conventional gas supply by 2030, reaching the same proportion of conventional gas resources as its resource base.

12.2.2. Shale Gas Supply Outlook

To evaluate the potential shale gas supply outlook for China, an in-depth analysis and modeling of several key production scenarios was conducted using China-specific targets and parameters as wells as parameters derived using analogue to U.S. shale plays. Figure 34 shows the modeling approach undertaken and the key input parameters and processes for forecasting future shale gas production potential.

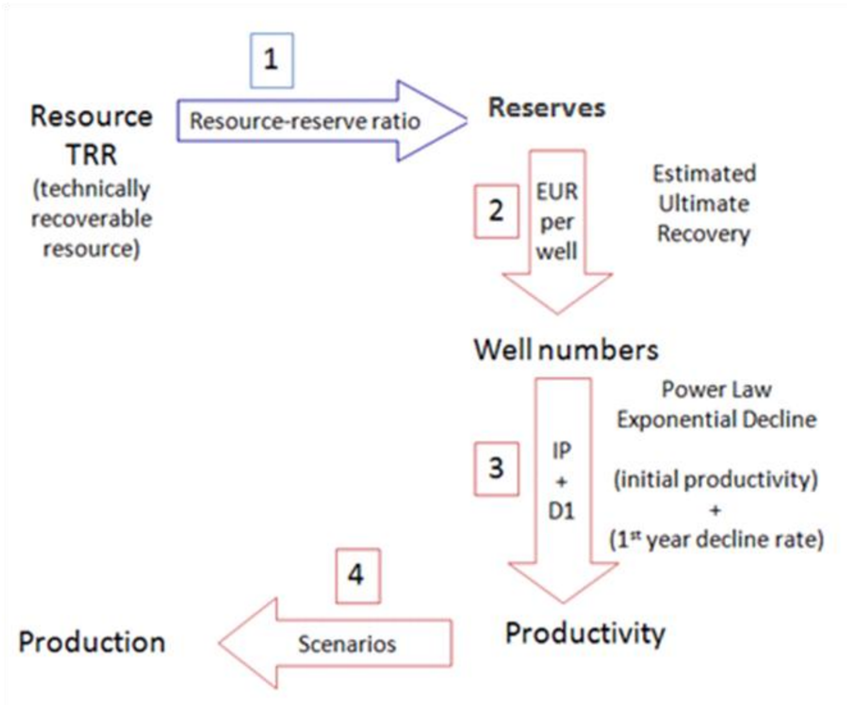

Figure 34. Flow Diagram of Shale Gas Production Modeling

For the first parameter of China's technically recoverable resources of shale gas, the resource estimates from China's national shale gas resource assessment and from EIA's revised resource estimate released on June 10, 2013 were used. Specifically, the four resource estimates evaluated include: China's low estimate of 15 trillion cubic meters, China's average estimate of 20 trillion cubic meters, China's high estimate of 25 trillion cubic meters and EIA's 2013 revised estimate of 32 trillion cubic meters.

For each of the four resource estimates, a resource to reserve ratio of 10% as well as ratios of 20% and 30% as sensitivities were applied to estimate the possible proportion of the shale gas resources that could be proved up into reserves available for drilling and extraction (step 1). Resource to reserve ratios of 10% to 30% have been observed in numerous natural gas basins in both the US and China and in the implied resource-to-reserves ratios based on estimated gas technically recoverable reserves reported in Engelder 2009 and EIA's 2011 Annual Energy Outlook (Engelder 2009, EIA 2011b). The resource to reserve ratio of 10% is considered a reasonable estimate for China's nonconventional gas resources, when taking into consideration the geological characteristics of China's shale formations that limit the volume that will become technically and economically recoverable. The higher resource to reserve ratios of 20% and 30% are also included in the scenario analysis to highlight the sensitivity of this ratio under conditions that would more closely approximate conventional resources.

Once the reserves have been estimated for the different sets of scenarios, China's 2012 actual number of wells drilled along with the 12th FYP targets for the total number of shale gas wells to be drilled by 2015 were used to project the annual number of wells drilled through 2015. Specifically, it is assumed that the annual number of wells drilled in 2013 is 105, followed by increases to 500 wells in 2014 and 535 wells in 2015. The implicit assumption underlying this projected growth in the annual number of wells drilled from 2012 to 2015 is that horizontal drilling will be commercialized by 2012, with production from horizontal drilling to start by January 2013. For the 13th and 14th FYP, the annual number of wells drilled is assumed to double each year until it reaches a peak number of wells determined either by its available reserves or an upper limit bound set at the U.S. peak level of annual gas wells drilled. The total number of wells is limited by the estimated ultimately recovery (EUR) per well, which estimates the total volume of oil or gas that is expected to be extracted from a single well (step 2). In the absence of any Chinese data on EUR from shale gas wells, a U.S. analogue of the average of EIA-reported mean EUR for all U.S. shale gas wells of 1.17 billion cubic feet (35.5 million cubic meters) per well was used (Hughes 2013).The EUR and estimated reserves determines the maximum number of shale gas wells that can be drilled, with the assumed constraint that the highest number of annual wells that can be drilled cannot exceed the peak U.S. level of 32,000 total natural gas wells per year as reported by EIA (Hughes 2013). A summary table of the annual and cumulative wells drilled under each scenario is shown in Table 18.

Table 18. Annual and Cumulative Shale Gas Wells Drilled by Resource-Reserve Scenario

TRR	**32 TCM**			**25 TCM**			**20 TCM**			**15 TCM**		
Resource-Reserve Ratio	**10%**	**20%**	**30%**	**10%**	**20%**	**30%**	**10%**	**20%**	**30%**	**10%**	**20%**	**30%**
2013	105	105	105	105	105	105	105	105	105	105	105	105
2014	500	500	500	500	500	500	500	500	500	500	500	500
2015	535	535	535	535	535	535	535	535	535	535	535	535
2016	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
2017	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000
2018	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000	4,000
2019	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
2020	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000	16,000
2021	32,000	32,000	32,000	32,000	32,000	32,000	28,466	32,000	32,000	13,315	32,000	32,000
2022	31,527	32,000	32,000	11,618	32,000	32,000		32,000	32,000		26,769	32,000
2023		32,000	32,000		32,000	32,000		25,072	32,000			32,000
2024		32,000	32,000		23,375	32,000			32,000			8,224
2025		31,193	32,000			32,000			21,678			
2026			32,000			32,000						
2027			32,000			3,133						
2028			30,860									
2029												
2030												
Cumulative	*95,667*	*191,333*	*287,000*	*75,758*	*151,515*	*227,273*	*60,606*	*121,212*	*181,818*	*45,455*	*90,909*	*136,364*

In addition to the projected annual well numbers, a number of simplifying assumptions were also made about drilling and well operations. Each formation is assumed to be drilled and developed individually, with 100% drilling success and 75% operating rate for a field. The 75% operating rate implies that one out of every four wells will not have yet been completed, is under maintenance, or awaits reworking. Successfully drilled wells are expected to operate 330 days out of a year. It is also assumed that are no constraints on drilling (e.g., rigs, personnel, etc.) or transport. For transport, China's available pipeline capacity is expected to double following targets set by the 12th FYP, from the current capacity of 150 billion cubic meters per year to 300 billion cubic meters per year.

The next step (step 3) in the shale gas production modeling is to evaluate the productivity of the shale gas wells, taking into consideration that shale gas wells have much steeper productivity decline curves than conventional gas wells. To find the best-fitting model for modeling shale gas well productivity decline, several common models were evaluated using

U.S. shale gas well data reported in Hughes 2013. The exponential decline model was not used because it does not reflect the faster productivity decline of shale gas production over time, and the Weng Model developed in China could not be used because no historic data on shale gas productivity exists for China. The hyperbolic decline curve, a common decline curve used in modeling oil and some gas production where the rate of decline is not constant, was evaluated but the estimated production levels using U.S. historic data were too low and did not fit actual production trends well. Ultimately, the power law exponential decline model was determined to be the best-fit model for shale gas production in the U.S., with good fits for data from the Barnett, Haynesville and Marcellus formations.

The power law exponential decline curve equation is:

$$q = \hat{q}_i \exp[-D_\infty t - \hat{D}_i t^n],$$

Where:

$\hat{q}_i$ = Rate "intercept" defined by Eq. 6 [*i.e.*, $q(t=0)$].

D_1 = Decline constant "intercept" at 1 time unit defined by Eq. 3 [*i.e.*, $D(t=1$ day$)$].

D_∞ = Decline constant at "infinite time" defined by Eq. 3 [*i.e.*, $D(t=\infty)$].

$\hat{D}_i$ = Decline constant defined by Eq. 6 [*i.e.*, $\hat{D}_i = D_1/n$].

n = Time "exponent" defined by Eq. 3.

Source: Mattar et al. 2008

A more detailed discussion on the origins and the mathematical theory underlying the Power Law Exponential Decline Curve can be found in Mattar et al. 2008, but the general definition of the key parameters and the assumed values in this study are summarized below.

$\hat{q}_i$ is the initial productivity of the well. In this study, the initial productivity is assumed to be 40,900 cubic meters per day based on the calculated average value of reported initial productivity for the 18 largest U.S. shale gas fields in terms of production, as reported in Hughes 2013.

D_1 is the first year well productivity decline rate. In this study, the first year well decline rate is also assumed to be 58% based on the calculated average value of decline rates of the 18 largest U.S. shale gas fields as reported in Hughes 2013.

D∞ is the decline rate over infinite time. In this study, a D∞ of 0.000046 is used, based on the calculated average of 5 mature shale gas wells in the Barnett formation where production has already started declining.

n is a time exponent. In this study n is set to 0.216, which is also based on the calculated average of 5 mature shale gas wells in the Barnett formation referenced for D∞.

Using these assumed parameters and the power law exponential decline curve, production forecasts were developed for the 4 sets of technically recoverable resource scenarios, with 3 subsets of scenarios each for the three different resource-reserve ratio in step 4. The production results with peak production levels are shown in Figure 35, Figure 36, Figure 37, Figure 38 and summarized in Table 19.

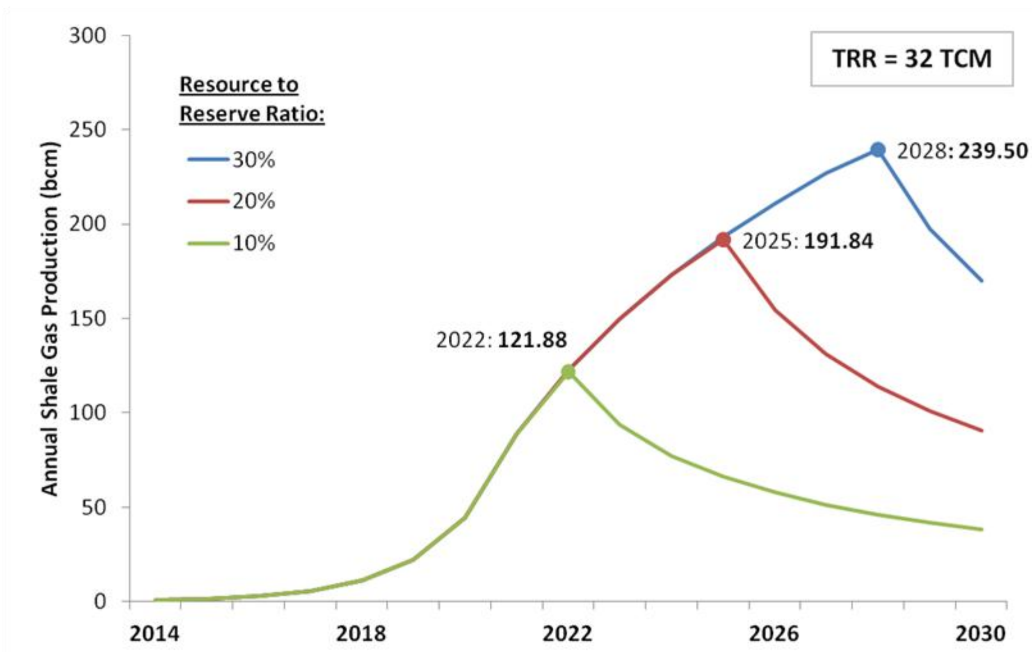

Figure 35. Shale Gas Production Outlook by Resource to Reserve Ratio for TRR of 32 TCM

Under the revised EIA estimate of 32 trillion cubic meters of technically recoverable shale gas resources for China shown in Figure 35, shale gas production will peak in the 2020s for the three different sets of assumed resource to reserve ratios. The highest peak production under the most favorable 30% resource to reserve ratio would occur in 2028 with annual production of 239.5 billion cubic meters.

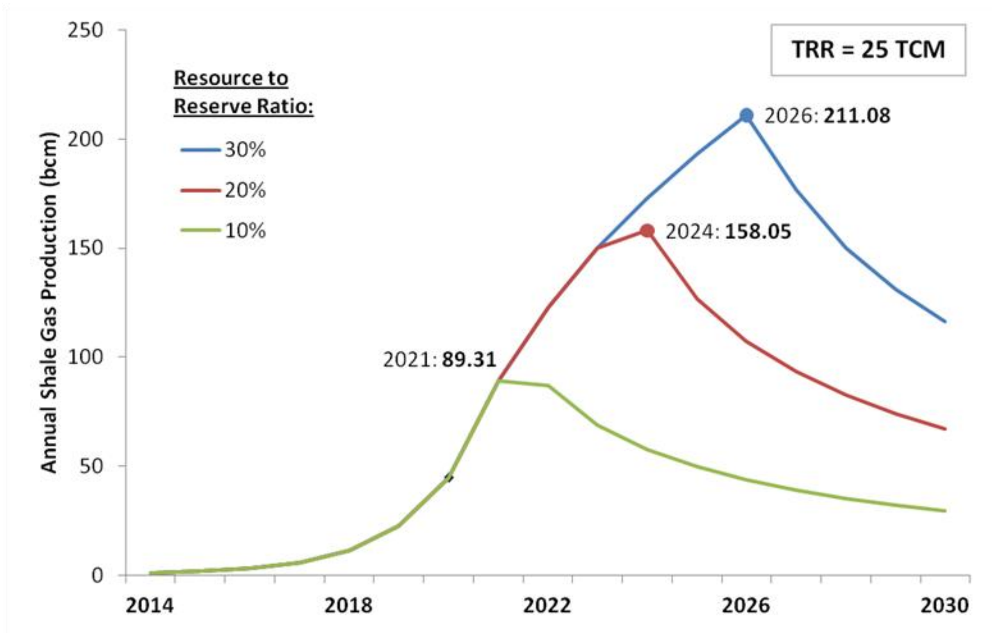

Figure 36. Shale Gas Production Outlook by Resource to Reserve Ratio for TRR of 25 TCM

Under the shale gas production scenario for China's high estimate of 25 trillion cubic meters of technically recoverable shale gas resources shown in Figure 36, the peak production levels would occur slightly earlier and at lower production levels as a result of the lowered estimated resource. This trend is also reflected in Figure 37, with an even lower estimated resource base of 20 trillion cubic meters.

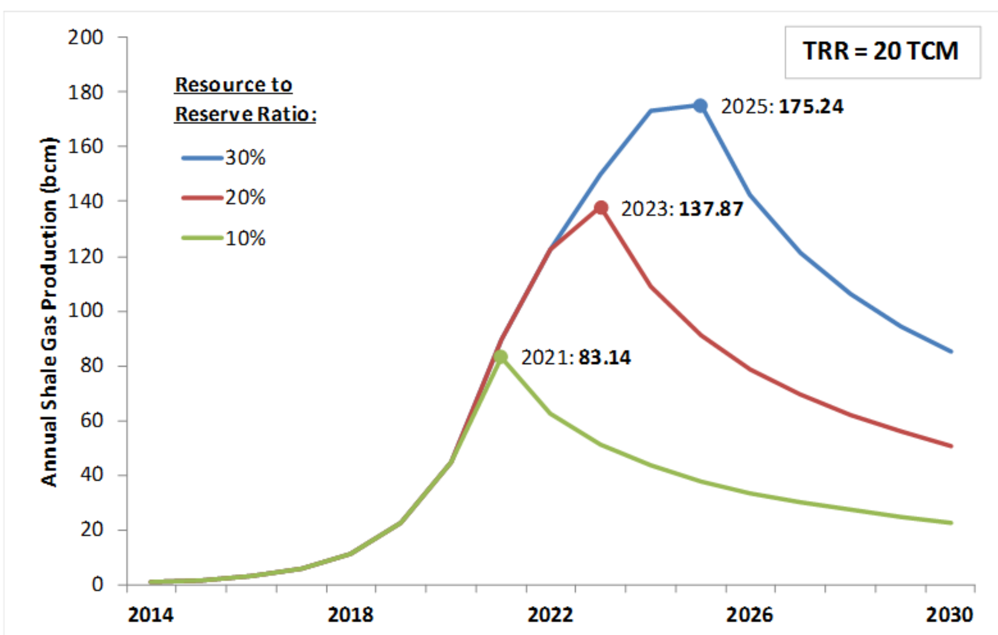

Figure 37. Shale Gas Production Outlook by Resource to Reserve Ratio for TRR of 20 TCM

For the low end of the Chinese estimate of technically recoverable shale gas resources of 15 trillion cubic meters, the production outlook shown in Figure 38 shows that peak shale gas production, under drilling and other conditions outlined earlier, could occur as early as 2021 through 2023, depending on the assumed resource-to-reserve ratio. Likewise, the annual peak production level would reach only about 150 billion cubic meters under the most favorable 30% resource to reserve ratio.

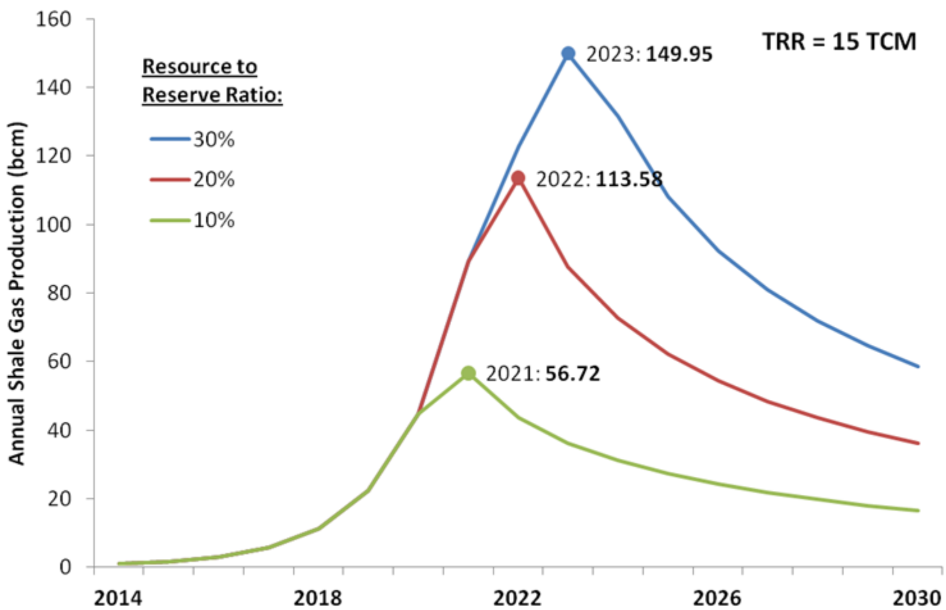

Figure 38. Shale Gas Production Outlook by Resource to Reserve Ratio for TRR of 15 TCM

As seen in Table 19, shale gas production in the short-term for 2015 and 2020 are the same under all of the scenarios despite different levels of technically recoverable resources and a range of resource-to-reserve ratios because the number of wells drilled is fixed. The 2015 production forecast of 1.66 billion cubic meters is much lower than the 12th FYP target of 6.5 billion cubic meters, while the 2020 production forecast of 44.71 billion cubic meters also falls short of the 60 to 100 billion cubic meters target. This suggests that both the 2015 and 2020 targets will be very difficult to meet, and that the 2015 target will be extremely difficult, if not impossible, given the size of the shortfall, even with the favorable US-analogue parameters assumed in the modeling.

Table 19. Summary of Shale Gas Production by Scenario

Production: Billion cubic meters	32 TCM			25 TCM			20 TCM			15 TCM		
	10%	**20%**	**30%**	**10%**	**20%**	**30%**	**10%**	**20%**	**30%**	**10%**	**20%**	**30%**
2015	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.66
2020	44.71	44.71	44.71	44.71	44.71	44.71	44.71	44.71	44.71	44.71	44.71	44.71
2025	66.13	191.84	193.24	49.86	126.77	193.24	37.88	91.09	175.24	27.24	62.24	108.04
2030	38.2	90.85	170.21	29.33	66.93	116.38	22.72	50.74	84.99	16.56	36.08	58.64
Cumulative	773.41	1407.96	1863.32	622.52	1160.55	1603.2	506.24	955.86	1349.97	385.24	737.35	1059.91

In addition to these sets of scenarios based on different resource estimates and resource to reserve ratios, a sensitivity analysis was also performed to evaluate which parameters in the power law exponential decline equation the production outlook is the most sensitive to. Figure 39 and Figure 40 show the sensitivity analysis results for 2015 and 2020, with the annual production for 2015 and 2020, respectively, shown on the y-axis and the percent change in the parameter tested shown on the x-axis.

Figure 39. Sensitivity Analysis of Power Law Exponential Decline Parameters for 2015 Production

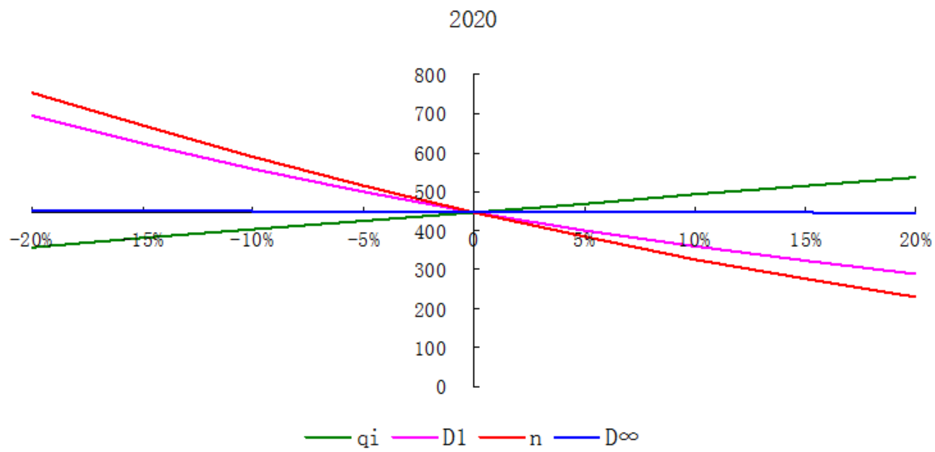

Figure 40. Sensitivity Analysis of Power Law Exponential Decline Parameters for 2020 Production

As seen in both figures, the most sensitive parameters are the time constant, n, followed by the first year decline rate. Changes in both of these parameters can result in significant changes to the projected production levels for 2015 and 2020. The initial productivity value is somewhat sensitive, with smaller changes in production as a result of changes in the parameter. The D∞ value is the least sensitive parameter, with essentially no change in the annual production level despite ±20% change in the parameter.

Related to the sensitivity analysis, a back-calculation was also conducted to evaluate what values would be needed for the three sensitive parameters in order to reach the 2015 production target of 6.5 billion cubic meters and the 2020 production target of 60 to 100 billion cubic meters. Since the 2020 production target is set with a wide range, four representative values of 60, 65, 80 and 100 billion cubic meters were used. The results of this analysis are shown in Table 20.

Table 20. Productivity Parameters Needed to Meet 2015 and 2020 Production Targets

Production Targets ($10^9 m^3$)	**2015**	**2020**			
	6.5	**60**	**65**	**80**	**100**
Initial Productivity ($10^3 m^3$)	161	54.9	55	73.2	91.5
First Year Decline Rate D1 (%)	21.88	50.27	48.18	42.74	36.93
Time Constant, n	0.0588	0.1930	0.1862	0.1672	0.1440

The results of this analysis underscore once again the high level of difficulty associated with meeting the 2015 target and the upper range of the 2020 target. The parameters needed to meet the 2015 target, including initial productivity of 161,000 cubic meters per day, a 22% first year decline rate and a time constant n value of 0.0588 are values not observed in the US shale gas experience. The initial productivity of 160,000 cubic meters, for instance, is four times that of the average initial productivity of the 18 largest shale gas wells in the U.S. The first year well decline rate of 22% is also much lower than what has been observed in U.S. shale gas wells, which have typically had decline rates in the 50% to 70% range. Likewise, the time constant n value of 0.06 is also significantly lower than typical values around 0.20. The parameters needed to meet the higher end of the 2020 targets (i.e., 80 or 100 billion cubic meters) are also difficult to achieve, but the lower end of the targets (i.e., 60 or 65 billion cubic meters) have greater likelihood of being achieved since those parameters are more reasonable and have been observed in U.S. shale gas wells. However, meeting the 2020 production targets would nevertheless requires that the multitude of challenges that exist today be resolved and that all other conditions (e.g., drilling, transport capacities) be obtained.

12.2.3. Coal Seam Methane Supply Outlook

The outlook on China's coal seam methane supply from its latest reported production of 11.5 billion cubic meters in 2011 through 2030 is determined mostly by existing or expected targets, with an upper bound set for annual production at the 2008 U.S. peak level of 56 billion cubic meters (EIA 2013b). In particular, it is assumed that China will be able to meet its 2015 coal seam gas production target of 30 billion cubic meters and an unconfirmed target of 50 billion cubic meters by 2020. A simple linear extrapolation is used for the supply outlook from the 2011 level to the 2015 target, and then again from the 2015 target to the 2020 target. From 2020 to 2030, the simplifying assumption that China will reach the 2008 U.S. peak production of 56 billion cubic meters is used as the basis for a linear extrapolation. As with shale gas, this outlook assumes that China will be able to resolve the remaining challenges with expanding its coal seam methane – and particularly with rapidly expanding its coal bed methane – production in the short-term.

12.2.4. Overall Gross Gas Extraction Outlook

In evaluating China's conventional and nonconventional gas supply outlook, two scenarios of high and low gross gas extraction outlooks are presented to capture the maximum likely ranges of gross gas extraction outlooks in conventional gas and shale gas. Because coal seam methane is smaller in magnitude and there are relatively defined production targets for 2015 and 2020, only one outlook is included for coal seam methane as described in section 12.2.3. However, the most likely high-end and low-end scenario outlooks of conventional gas and shale gas extraction are used in two separate scenarios, combined with the coal seam methane outlook. Table 21 summarizes the different underlying assumptions and gross gas extraction scenarios between the high and low extraction scenarios.

Table 21. Key Assumptions of China's Gross Gas Extraction Outlook Scenarios

	Low Gross Gas Extraction Scenario	High Gross Gas Extraction Scenario
Conventional Gas	Modified logistics curve using China MLR 2010 estimate of technically recoverable reserves of 3.2 trillion cubic meters.	Modified logistics curve using ultimate recoverable resource of 6.8 trillion cubic meters from Laherrere 2008.
Coal Seam Methane	Meets 2015 and 2020 production targets, reach U.S. 2008 peak production level by 2030.	Meets 2015 and 2020 production targets, reach U.S. 2008 peak production level by 2030.
Shale Gas	Production outlook based on China's low-end technically recoverable resource estimate of 15 trillion cubic meters and a 10% resource to reserve ratio.	Production outlook based on the EIA's revised technically recoverable resource estimate of 32 trillion cubic meters and a 30% resource to reserve ratio.

The high and low gross gas extraction scenario outlooks by type of gas are shown in Figure 41 and Table 22, and Figure 42 and Table 23, respectively.

Table 22. Annual Gross Gas Extraction by Type of Gas, High Scenario

	Conventional Gas	Tight Gas	Coal Seam Methane	Shale Gas	Total
2015	97.5	39.4	30.0	1.7	168.6
2020	122.3	58.9	50.0	44.7	275.9
2025	130.7	74.3	53.0	193.2	451.2
2030	116.6	77.7	56.0	170.2	420.5

Under the high gross gas extraction scenario shown in Figure 41 and Table 22, nonconventional gas resources and shale gas in particular will play an increasingly important role in China's total gas extraction between 2020 and 2030. Prior to 2020, coal seam methane will be the primary nonconventional gas resource for China, with as much as 17% of the gross gas extraction in 2020. By the mid-2020s, however, shale gas and coal seam methane together will constitute the bulk of China's total gas extraction. In the shale gas peak production year of 2028, shale gas will make up nearly half of China's total gross gas extraction with a 48% share while coal seam methane holds an 11% share. The role of tight gas within China's conventional gas supply will also continue to grow, resulting in an 18% share of the total gas extraction by 2030.

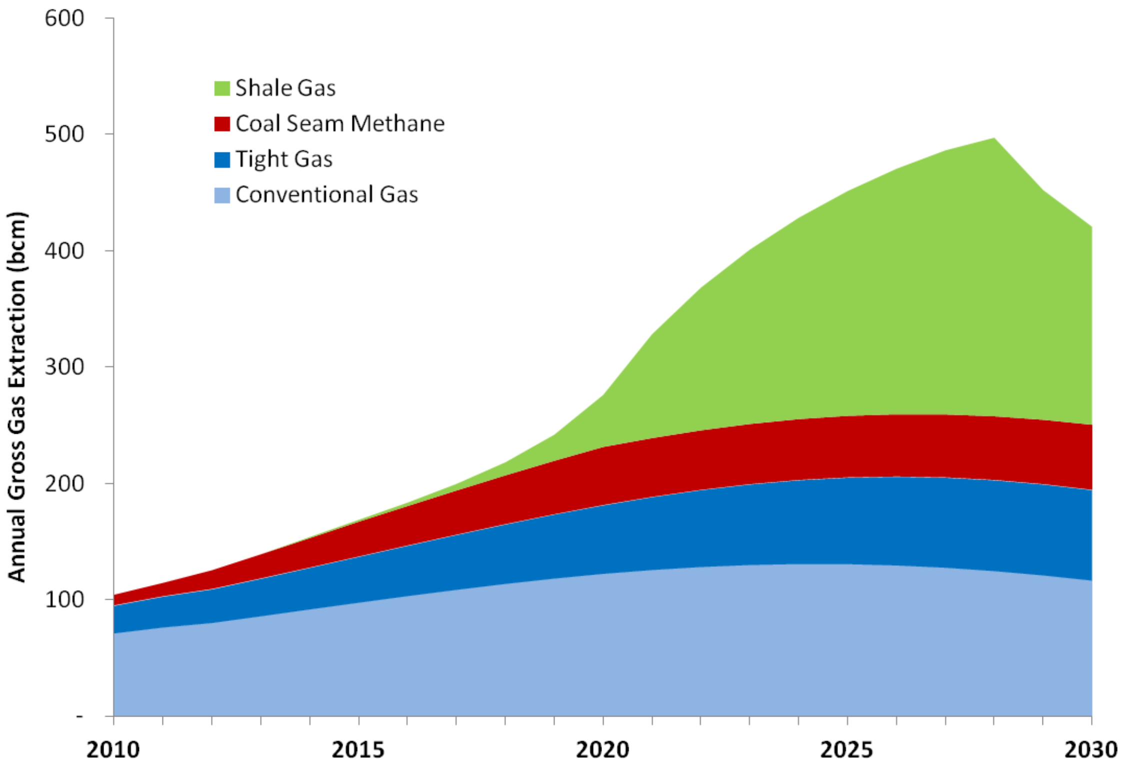

Figure 41. China's Annual Gross Gas Extraction Outlook by Type of Gas, High Scenario

Under the low gross gas extraction scenario depicted in Table 23 and Figure 42, there is a markedly different composition of gas resources in China's gas extraction outlook due to the significantly lower outlook for shale gas production. In particular, of the two nonconventional gas resources, coal seam methane is expected to play a bigger role than shale gas in most years through 2030. For example, during the peak shale gas extraction year of 2021, shale gas will hold a 24% share of total gas supply, compared to 20% for coal seam methane, 18% for tight gas and 37% for conventional gas. By 2030, however, declining shale gas extraction will result in only 14% share for shale gas - the smallest share of all gas resources - with 46% for coal seam methane, 16% for tight gas and 24% for conventional gas. Similar to the high gas extraction scenario, nonconventional resources and coal seam methane in particular will be responsible for the majority of China's total gross gas extraction by the mid-2020s.

Table 23. Annual Gross Gas Extraction by Type of Gas, Low Scenario

	Conventional Gas	Tight Gas	Coal Seam Methane	Shale Gas	Total
2015	97.6	39.4	30.0	1.7	168.6
2020	92.4	44.5	50.0	44.7	231.7
2025	60.0	34.1	53.0	27.2	174.4
2030	29.8	19.9	56.0	16.6	122.2

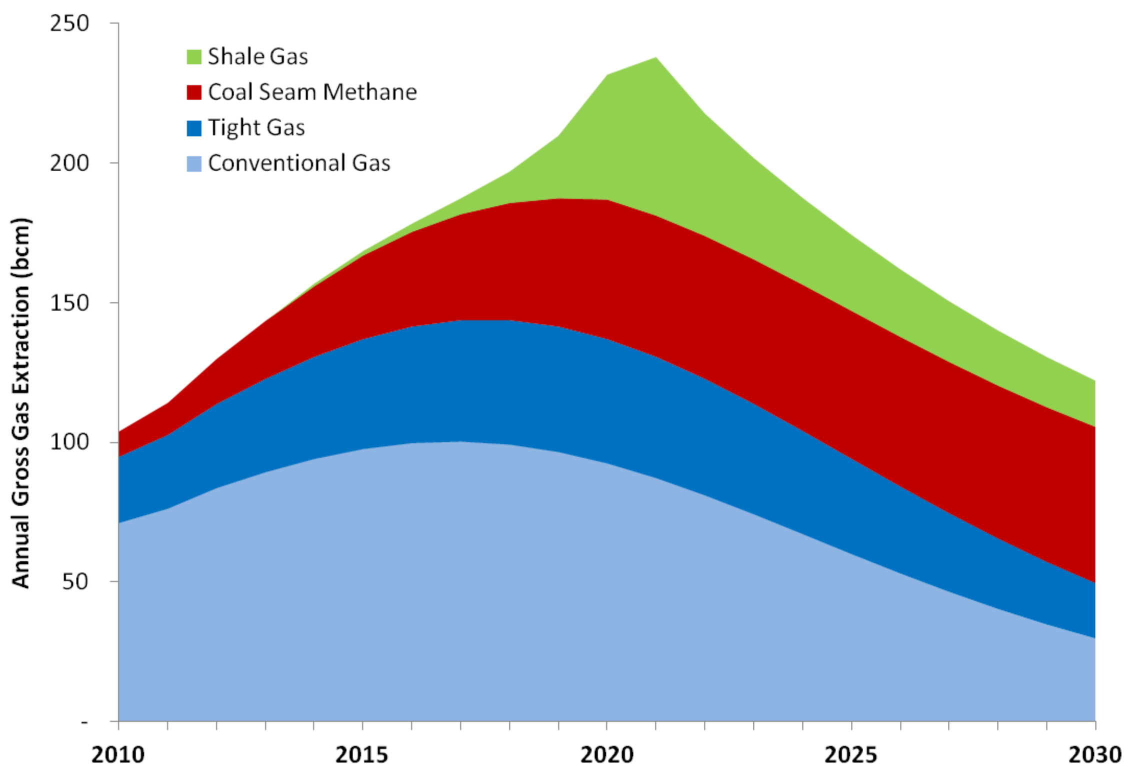

Figure 42. China's Annual Gross Gas Extraction Outlook by Type of Gas, Low Scenario

12.3. Demand-Supply Gap Analysis

In order to compare the two scenarios of total (conventional and nonconventional) gross gas extraction outlook for China to its natural gas demand outlook, some adjustments were made to convert the gross extraction to the net marketed supply available for consumption, taking into account repressuring, venting and flaring, removal of nonhydrocarbon gases and extraction losses. In the U.S., for instance, EIA reports that of the gross total natural gas withdrawals, 12% is used in repressuring, 3% is used in removing nonhydrocarbon gases and 1% and 4% are lost in venting and flaring and extraction losses, respectively (EIA 2013c). In the absence of detailed public data on Chinese natural gas production losses, EIA data for the U.S.'s 2011 natural gas gross extraction and marketed supply was used to derive a gross to net ratio of 80%. This ratio was confirmed by Chinese experts to be a reasonable estimate for China, and applied to calculate the net supply of conventional and tight gas, coal seam methane and shale gas calculated for the high and low extraction scenarios in the previous section.

For coal seam methane, additional adjustments were made to account for the non-utilized portion of coal mine methane. For 2015, China is assumed to reach its 12th FYP target of 60% for CMM utilization, and then assumed to reach an 80% utilization rate by 2020. After 2020, CMM is assumed to reach a 100% utilization rate so both CMM and CBM are fully utilized. This adjustment slightly lowers the total coal seam methane production available for utilization prior to 2030, but does not change the general composition of China's total gas supply under both scenarios.

The adjusted total net gas supply outlook for China under the high and low scenarios as well as the demand outlook is shown in Figure 43. These results show that China's demand for gas will continue to outpace its domestic supply prior to 2020 under both scenarios.

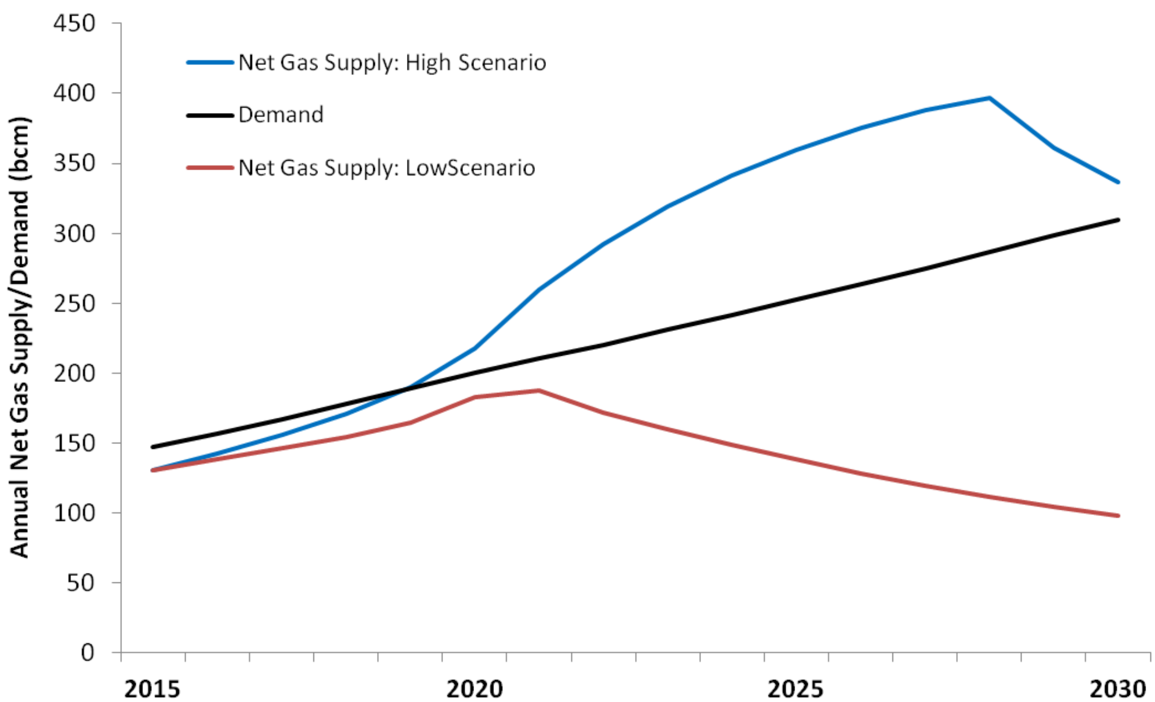

Figure 43. China's Annual Net Gas Supply and Demand Scenario Outlook

Figure 44 and Figure 45 show the gap between China's domestic gas demand and supply in five-year increments for the high and low supply scenarios, respectively. After 2020, China will be able to meet its gas demand with its domestic net gas supply only under the high supply scenario, with significant increases in supply from its growing shale gas production. However, after shale gas extraction peaks in the late 2020s, China's domestic net gas supply will begin to approach its gas demand, suggesting that China will need to rely on gas imports again to meet its gas demand after 2030 if the current trajectories continue. These results highlight that increases in nonconventional gases such as shale gas and coal seam methane can ease the pressure on China's imports for gas in the early 2020s, but only until peak production is reached.

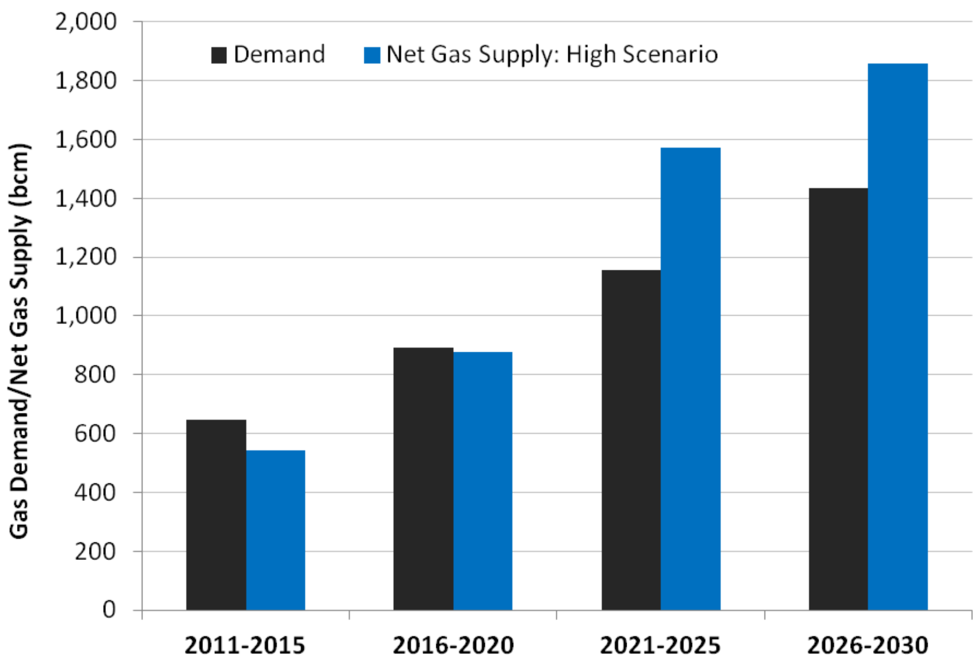

Figure 44. Comparison of China's Gas Demand and Net Gas Supply High Scenario

Under the low net gas supply scenario, the gap between China's domestic net gas supply and demand will drastically widen after 2020, with demand outpacing domestic supply by a factor of 2 by the mid-2020s and a factor of 3 by 2030 as seen in Figure 45. These results suggest that China will face mounting pressure on its natural gas imports, which would dominate China's total gas supply, particularly after 2020. In the near-term, there could also be growing pressure on imports if the actual demand is larger than the demand outlook used in this study, which took into consideration continued efficiency improvements. For example, if China's demand reaches 250 billion cubic meters by 2015 and 400 billion cubic meters by 2020 as some industry experts expect (Gao 2012), then its imports would exceed the domestic net supply by a factor of 2 even before 2020.

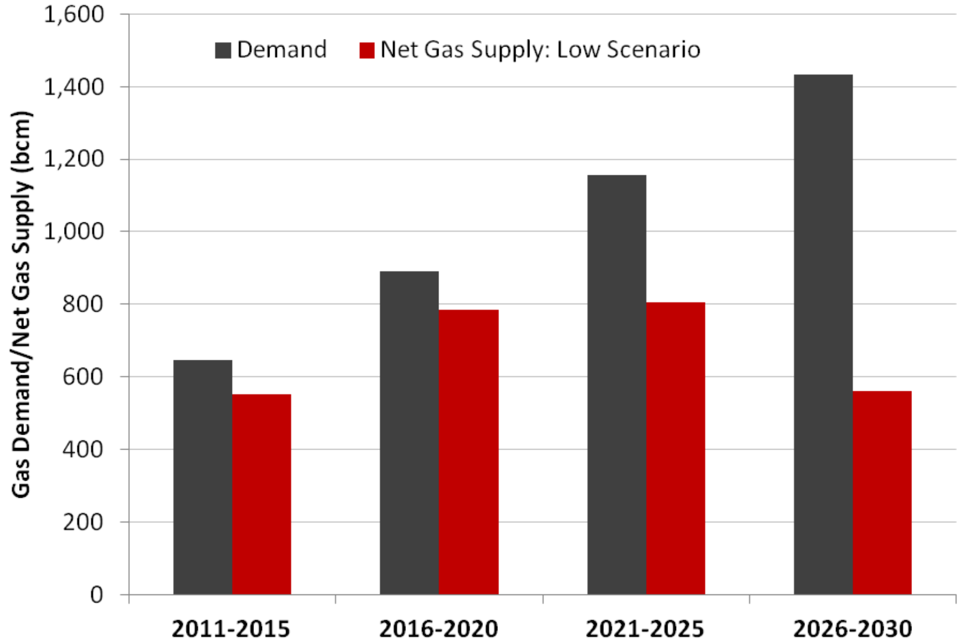

Figure 45. Comparison of China's Gas Demand and Net Gas Supply Low Scenario

A comparison of the high and low net gas supply scenarios for conventional gas with China's total gas demand highlights a large resource gap that will need to be met with either nonconventional resources and/or gas imports. In the case of the high net conventional gas supply scenario (assuming a recoverable resource base of 6.8 trillion cubic meters), the implied resource gap grows from 37 billion cubic meters in 2015 to 154 billion cubic meters in 2030 (Figure 46). This in turn means that even under an optimistic supply scenario, China's domestic conventional gas supply can only meet about half of its demand and that the remaining half will need to come from nonconventional gas resources and/or imported gas.

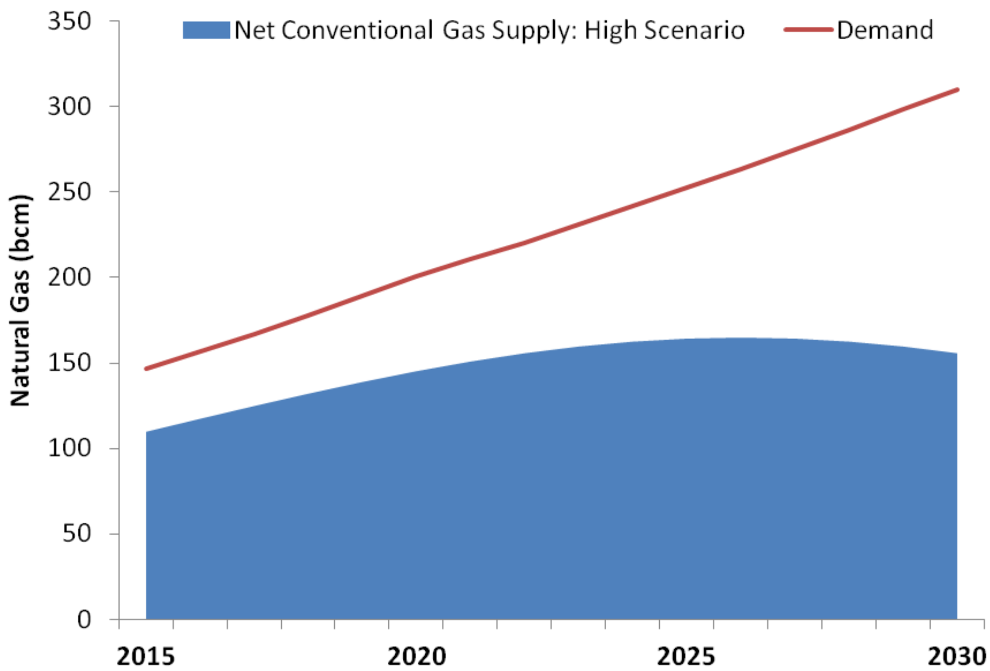

Figure 46. Gas Resource Gap under High Net Conventional Gas Supply Scenario

Under a less optimistic scenario where China's domestic net conventional gas supply is assumed to be lower with a lower recoverable resource base of 3.2 trillion cubic meters, the resource gap is much more significant as shown in Figure 47, particularly in the later years. By 2020, the gap that needs to be met by nonconventional resources and imports will reach 91 billion cubic meters, nearly tripling from 37 billion cubic meters in 2015. By 2030, the gap would have tripled to 270 billion cubic meters, implying that the vast majority (87%) of domestic demand will need to be met by nonconventional gas and imported gas.

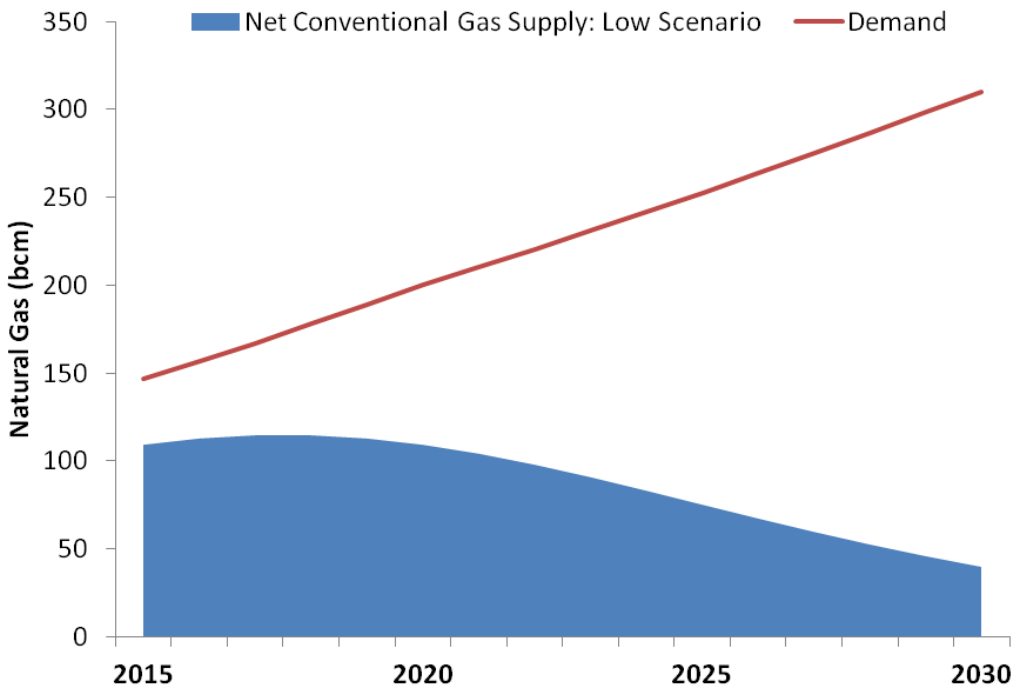

Figure 47. Gas Resource Gap under Low Net Conventional Gas Supply Scenario

In terms of the import capacity needed to meet this wide resource gap, China's recent infrastructure expansion and build-out suggests that there will be sufficient pipeline and LNG terminal capacity to support this level of imports. Specifically, China's two import gas pipeline routes from Central Asia to China and Myanmar to China will have annual import capacities of 55 and 12 billion cubic meters, respectively, once all construction is completed (BMI 2013). Additionally, China has 25.3 billion cubic meters of existing LNG terminal capacity for imports, with an additional 35.8 billion cubic meters of planned capacity through 2015 (BMI 2013). Combined, China would have access to a total of 128 billion cubic meters of annual import capacity by 2015, which could be used to meet the resource gap through the mid-2020s under the low conventional gas supply scenario. By the end of the 2020s, however, the import infrastructure capacity currently under construction will not be sufficient to meet the widening resource gap without additional import capacity. Thus, this suggests that both nonconventional resources and imported gas will likely be needed to meet the growing gap between domestic supply and demand in China.

13. Conclusions

China has taken concerted efforts to curb its rapid growth in energy consumption with a dual focus on increasing energy efficiency and expanding its domestic energy supply. For petroleum and natural gas, however, an imbalance between limited domestic resources and rapid demand growth has made China increasingly dependent on imports. In order to address the intensifying energy security concerns with its import dependency, China under the 12th FYP is emphasizing the development of both conventional and nonconventional oil and gas resources as well as rapid build-out of supporting infrastructure. For nonconventional oil and gas resources, China has focused in on promoting the development of shale gas, coal seam methane, tight gas, in-situ coal gasification, gas hydrates, tight oil and oil shale.

For nonconventional oil resources, tight oil and oil shale are unlikely to contribute significantly to total petroleum output due to limited scales of production, environmental concerns, and low net energy returns, suggesting that imports will be the primary source of marginal supply.. Of the five types of nonconventional gas resources, China has most successfully developed and commercialized tight gas (classified as a conventional resource), with its contribution to total supply already reaching 25% of the total in 2010. As the currently most viable addition to conventional natural gas, tight gas will account for a growing proportion of China's domestic natural gas supply. Both coal seam methane and shale gas resources are abundant in China, with 10 and 15 to 25 trillion cubic meters of recoverable resources, respectively. Both types of nonconventional resources have seen strong policy-driven push for increased resource evaluation, exploration and commercial development in recent years; but both also face similar challenges in insufficient understanding of the resource base, and technical, economic and institutional barriers to deploying the advanced drilling technologies needed to commercialize production. The shale gas industry, in particular, is still in nascent stage of development and faces additional environmental concerns about groundwater contamination and methane leakage, as well as water resource constraints. In-situ coal gasification and gas hydrates both still need significant research and development and are unlikely to be major supply prospects in the near to medium term.

China's energy demand is expected to continue growing from current levels at an annual average growth rate of over 1% through 2030, driven by rapidly growing demand from commercial buildings and the transport sector. Petroleum demand is projected to grow at an annual average rate of 3% to reach a 25% share of total primary energy demand in 2030, driven by demand from growing stock of trucks, buses, and light-duty passenger vehicles as well as the petrochemical industry. Natural gas demand will grow even faster at an annual average rate of 6% and across multiple end-use sectors, with rising shares of consumption from the power, transport and commercial buildings sectors. Besides the power sector, which accounts for nearly a quarter of total final consumption in 2030, other significant end-use consumers of natural gas in 2030 include urban residential space heating (15% share), residential urban water heating (7%), heavy-duty freight trucks (8%), hotel water heating (5%) and office space heating (5%). A comparison of the LBNL natural gas demand outlook with other recently published outlooks show similarly fast paces of growth through 2030, with 2030 annual consumption ranging from 210 to 285 billion cubic meters for final use (not including transformation input to the power sector).

As the most abundant nonconventional gas resource, shale gas could potentially play a large role in China's future gas supply. Using both U.S. and Chinese resource estimate and analogues to U.S. shale gas well productivity and decline rates, shale gas modeling shows that at maximum rates of successful exploitation, extraction rates peaks within a decade of commercialization, but that commercialization at the early stage is dependent on several key technology breakthroughs. The modeling results further illustrate that the maximum net shale gas supply in the worst and best resource scenario could displace as much as 85 to 357 million tonnes of raw coal in thermal equivalent terms. While this level of shale gas would account for 14% to 40% of China's 2030 net natural gas supply, it still represents only 2 to 9% of current coal consumption. The expectation that the exploitation of China's shale resources could provide a path to substantially offset coal consumption does not appear to be supported by the modeling results. The main impact of successful shale gas development, assuming all barriers can be overcome and all conditions can be met, is to ease the pressure off China's rising gas import dependency through the mid-2020s until peak production is reached. In the longer run towards 2030, the gap between domestic net gas supply and continuously growing gas demand will widen. Without successful shale gas development or if shale gas resources are not as high as expected, then the gap between China's natural gas demand and domestic net gas supply would widen quickly, with demand outpacing supply by a factor of 2 in 2025 to a factor of 3 in 2030. Coal seam methane may provide a path to more quickly supplementing conventional gas supplies if breakthroughs in research and development are achieved, and although its ultimate annual production capacity is unclear, under analogue conditions with the US, it would still contribute to less than half of China's total gas supply depending on the success of shale gas production. Successful exploitation of China's nonconventional gas resources would provide an important and significant boost to cleaner energy development in the country and could help moderate China's gas import dependency in the near-term, but their longer-term role will remain limited given the expected scale and rapid rate of continued growth in China's demand for natural gas.

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