Lantau Pique

In this edition

In this issue of Lantau Pique we discuss the future supply of natural gas and compare the economics of coal- and gas-fired generation serving the peak and intermediate load in China. We find that with the help of potential emission charges, gas-fired power generation with the latest available technologies can compete with the most efficient coal fired technologies. Indeed, gas demand growth could sustain double digit rates for years. But like Sisyphus pushing a great boulder up the mountain only to have it roll back down, the promise of gas in China is still just a promise. Challenges lurk in almost every corner.

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The Myth of Sisyphus China-style: Will Large Amounts of Domestic Gas Ever Get Into Power?

China's power system is struggling to meet enormous challenges. Financially, China's coal-fired generators fared poorly in 2010 and 2011 because of escalating coal-prices and non-responsive tariffs. Power shortages led to rationing of electricity. Recent reductions in coal prices, in parallel with a slowing of economic growth, have enabled coal-fired generators to get off life-support, but they are hardly out of the hospital. As China's economic engine zooms again, upward pressure on delivered coal prices could well follow. Nothing has changed materially with respect to the regulatory risk facing China's fossil fuel-dominated power sector.

Similarly, wind generators, as a group, have fared poorly due mainly to transmission constraints that prevented dispatching these resources to their full potential. Development of the ultra-high-voltage (UHV) transmission grid has lagged plans. Agreeing and executing a long-term grid "vision" has become one of the more technically, politically and economically difficult challenges facing the sector.

In any other country, these two challenges alone would be enough to raise serious concerns regarding the sector's future technical and financial performance. But two other potentially disruptive stresses are emerging: natural gas resource development and environmental regulatory reforms. With the attention given unconventional gas resources by the dramatic transformation of the energy sector in the USA, is China close behind?

In this edition of The Lantau Pique, our second deep dive on China, we take a hard look at the future role of natural gas in China's power sector. When it comes to China's power sector, "fair winds and following seas" remain elusive.

Can Gas-to-Power Compete in China's Coastal Sectors?

Coal so dominates China's current fuel mix that many coal plants cannot operate consistently in base load mode, and must reduce output during non-peak periods, raising costs. This invites consideration of alternative technologies more economically suited to such flexible operations, such as combined cycle gas turbine (CCGT) technology.

Despite technically plentiful natural gas resources, China's gas sector faces numerous obstacles to more rapid development, with many challenges still ahead. Unconventional gas – tight gas, shale gas and coal bed methane – is potentially abundant. The infrastructure required to access these resources, however, is substantial. In addition, unconventional gas resource development involves a high level of "learning by doing", which benefits from more flexible approaches than commonly seen in China. Despite China's keen interest in the US shale gas success story, key factors behind that success remain widely misunderstood and virtually impossible to replicate without far more sophisticated regulatory regimes and much higher levels of decentralized competition than found in China's energy sector. And last, but not least, unconventional resource development benefits from the latest extraction technology, all of which needs to be imported, and which may be restricted by preferences for local content.

And yet, the commercial opportunity for gas is attractive in the power sector (especially due to the extraordinary reliance on coal for both base load and mid-merit generation requirements). On our numbers, as we explain below, we forecast that a delivered price of gas of RMB 2.7 cu m or USD 12.1 mmbtu can compete with coal for mid-merit new build. Including CO_2 emissions pricing makes gas even more attractive.

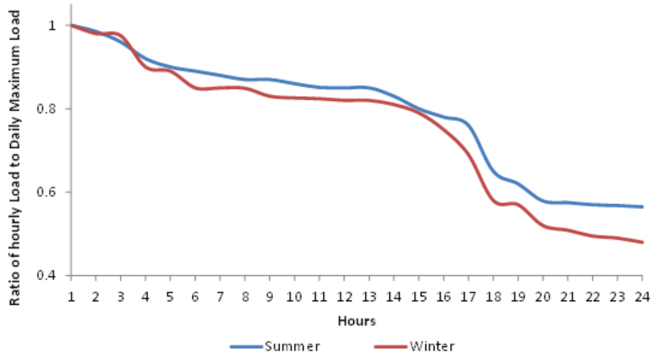
Ultimately, meaningful leaps forward depend on reforms to the power sector, including new wholesale "on grid" power pricing from gas-fired capacity to properly reflect mid-merit power economics.

What is the Value of Gas for Power?

In this section we consider what the price of gas would need to be to compete with a new coal-fired power station in China for the purpose of serving the upper mid-merit segment of the demand curve. This is the segment supporting a capacity factor of about 60 percent on average per annum or roughly 16 hours per day. A typical load duration curve for Guangdong, one of China's most prosperous provinces, is shown in Figure 1.

We base our estimates on reported local costs for new power plants. These estimates reflect the lower cost of land, labour and engineering in China relative to many other countries. We assume a coal price of RMB 800 per tonne or USD 127 per tonne—a price somewhat higher than the current spot market. But if history is any guide, present depressed coal prices reflect a temporary blip due to the economic slowdown.

Figure 1: Typical Daily Load Duration Curve in Guangdong Province



Source: Hua, et al, South China University of Technology.

As shown in Table 1, we estimate the LRMC for a new coal plant to be approximately USD 88 per MWh at the target mid-merit capacity factor. Working backwards, we calculate the "net back" gas price into a CCGT that could compete with coal-fired capacity to be about USD 12.1 mmbtu or RMB 2.7 per cu m, a value that is below the currently capped city gate price in Guangzhou of RMB 2.74 per cu m under a recently proposed new gas pricing mechanism.

Table 1: Key Assumptions on Coal and Gas New Build in Coastal Regions with only SO_2 and NOx Pricing

	H-class CCGT	New Build Coal Plant
USD kW	534	726
Capacity Factor%	63	63
Heat Rate (HHV)mmbtu/MWh	5.8	9.0
Efficiency %	59	38
USD mmbtu	12.1	5.9
Gas RMB cu m/ Coal RMB Tonne	2.7	800
CO_2 USD per MWh	0.0	0.0
SO_2 USD per MWh	0.002	3.3
NOx USD per MWh	0.4	1.7
Long Run Marginal Cost USD MWh	88	88

Notes: - Calorific value of coal GJ 22.814 per tonne, Gas MJ 36.35 cum, coal fired plant own use 7%, coal plant HHV degraded from 40% efficiency to 38% to reflect ramping down and up to cope with mid merit

Plenty of Gas in the Ground

China is not short of gas resources. Even using our 2030 demand number of 0.5 trillion cubic metres per annum (Tcma), the country has hundreds of years' worth of technically recoverable resources. China's Ministry of Land and Resources, in its 2010 Dynamic Assessment on Oil and Gas Resources, as shown in Figure 2, says the nation has:

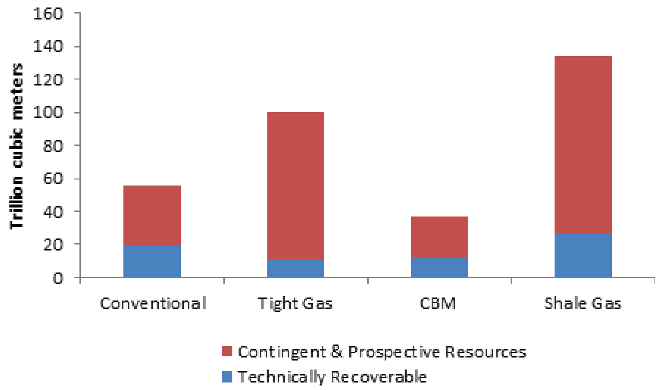
- Conventional natural gas initially in place is 56 trillion cubic meters (Tcm), of which 19 Tcm is technically recoverable.

- Tight gas in place is estimated at 100 Tcm of which 11 Tcm is technically recoverable.

- The unconventional gas initially in place from Coal Bed Methane (CBM) is estimated at 37 Tcm of which 12 Tcm is estimated to be technically recoverable.

- For shale alone gas initially in place is estimated at 134 Tcm of which 26 Tcm is technically recoverable.

Figure 2: China's Conventional and Unconventional Gas Initially in Place - Resources and Technically Recoverable



Source: Ministry of Land and Resources, TLG Analysis .

Limited Gas Infrastructure

It is in getting the gas to market that the main obstacles are faced. Gas transmission infrastructure build out is desperately needed and work continues apace. The main incumbents in gas transmission, CNPC/Petrochina and Sinopec are not keen to let others participate in this business, but in our view will have to work hard and fast to build enough new pipelines by themselves. In addition third party access (which would also help get gas to market by connecting sellers direct to buyers) is a distant dream. At present the use of natural gas is often partly constrained to the areas in which it can be produced. For example, gas-fired generation is most commonly found in three areas:

- Close to production basins in central China where conventional gas (and in future shale gas) is common;

- Around Shanxi Province in North China where CBM is prevalent; and

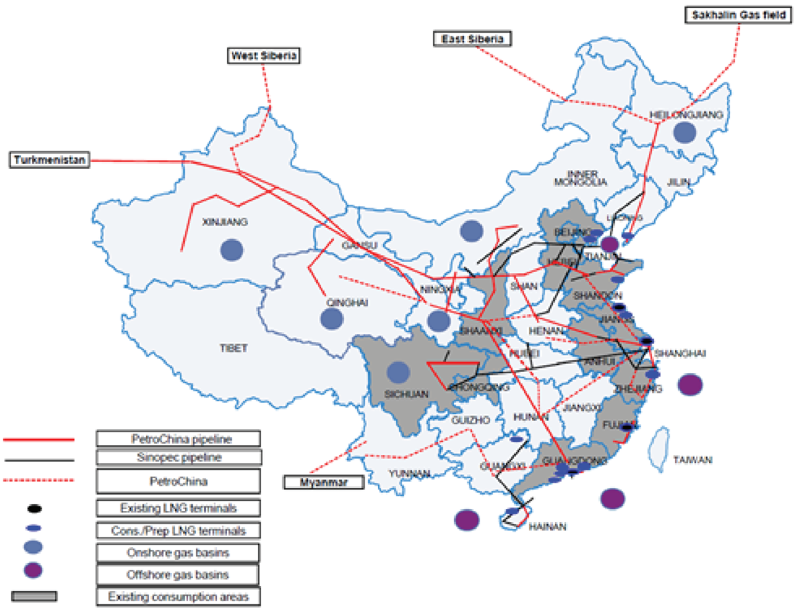
- In coastal areas where offshore gas and imported LNG are accessible.

China started its first West-to-East Gas Pipeline system (capacity 20bcma, initially 12 bcma) in 2002 and started sending gas to Shanghai at the end of 2004. The second West-to-East Gas Pipeline (capacity 30 bcma), which mainly imports Central Asian gas to China, and was completed in 2011; and gas imported from Turkmenistan reached Guangzhou in South China in middle of 2011. A decision to start the third West-to-East Gas Pipeline was recently taken with planned capacity of 30 bcma and completion by 2015.

In the southwest region, China is constructing the China-Myanmar pipeline system to Yunnan Province. Originally scheduled to be completed in June 2013, the China Myanmar pipeline is likely to be delayed until 2015. Once completed, this new pipeline is expected to transport 12 bcma of natural gas into Yunnan province and onto the rest of China.

In the North, China has been in talks with Russia for two gas pipeline import routes, one in West Siberia and the other in East Siberia. However, progress is slow mainly because the two sides cannot reach an agreement on gas prices. These pipelines are intended to import up to 68 bcma per year. In addition, there is potential to import gas from offshore at Sakhalin (although Gazprom has poured cold water on this idea by saying that Kovytka gas would instead go to the Yakutia-Khabarovsk-Vladivostok pipeline to be prioritized first for domestic use ahead of being available for export as LNG to the Asia-Pacific region).

Figure 3: China's Gas Resources, Pipelines and LNG Terminals



Source: Goldman Sachs, 21 August 2012.

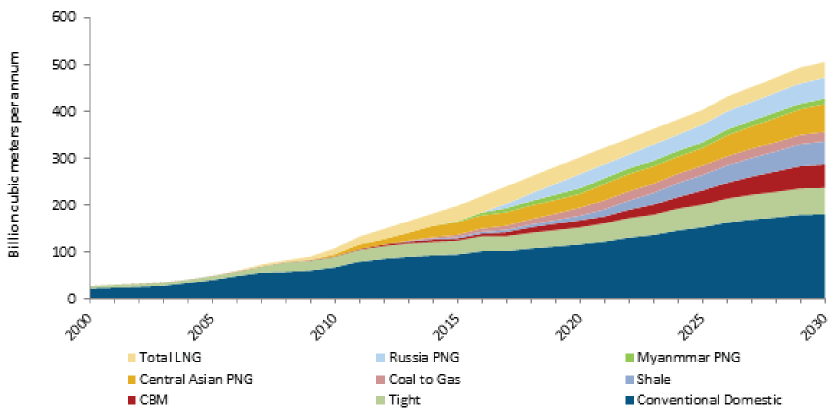
China consumed 133 bmca in 2011 through a network of approximately 40,000 km of transmission pipelines. According to various forecasts, China might consume 507 bcma by 2030 – an increase that could require nearly 110,000 km of additional transmission pipeline capacity by 2030. The necessary expenditures are significant but achievable. However they exceed the levels seen to date. For example, we estimate a total spend for network expansion and extension of perhaps USD250bn to USD300 bn in real terms or USD14bn to USD 18bn per year. In 2011, Petrochina spent USD 11bn on constructing pipelines, supported by cash-flow from operations of USD46bn and net debt to equity of only 20%. Depending on timing and magnitude, the expenditure levels could however be a challenge to China's gas oligopoly. In contrast, US shale gas development has been financed with expenditures of several hundred billion dollars over a relatively short period of time. The difference is that US shale gas development started with nearly 10,000 different companies willing to raise and invest capital.

China's Gas Supply Outlook

China's indigenous production of natural gas was sufficient for demand until the early 2000s, when shortfalls had to be met through imports. In 2011 domestic gas production was 106 bcma which required imports of some 27 bcma to meet demand in that year of 133 bcma. China started to import LNG from Australia in 2006, with total volumes of LNG reaching 12.2 million tonnes in 2011 or close to 17 bcma. China's gas pipeline from Central Asia started operation in 2009, with volumes reaching 10 bmca in 2011, according to the statistics of China's Ministry of Commerce. The production and development of tight gas has reached 25 bcma (or 25% of the total natural gas production) in 2011.

Based on TLG's modeling, we summarize the historical and forecast outlook in Figure 4. Including imports and indigenous production we forecast total supplies of 198 bcma will be available to gas markets in 2015, 303 bcma in 2020 and 507 bcma by 2030. Unconventionals such as CBM and shale play a significant role in future supplies of gas and hence hamper the growth of LNG beyond 2015.

Figure 4: Historical and Forecast Supply of Natural Gas



Source: CNPC, TLG Analysis.

To turn China's large prospective and contingent CBM and shale gas resources into proven reserves in a timely manner is task that will take deft handling by the authorities. The Ministry of Land Resources looks like being the main regulatory body for shale gas, as this type of gas has been classified as a mineral resource. This might mean there will be some flexibility in the fiscal terms and plans of development. This is key for unconventionals (be they CBM or shale) as the testing, exploration and appraisal and development process is a case of learning-by-doing. The exploration and production (E&P) companies do not really know the exact method, timing, or the number of wells they will drill in any year in unconventionals. By contrast the traditional production sharing contract (PSC) system suits conventional oil and gas where a detailed plan of development is finalised, approved, built and then operated over many years to exploit a fairly well defined oil or gas trap. But by their very nature CBM and shale gas do not lend themselves to such detailed planning ahead: flexibility is valuable —a theme we raise time and time again in virtually all of our Lantau Piques. Flexibility comes with concession type of systems as exist in the USA, Australia and the UK. If the PSC system is used for unconventionals in China it will need to have the characteristics of a royalty type concession. Either this or else special purpose joint venture companies might offer the flexibility in capital and operating spending that unconventionals need. The Ministry of Land Resources is familiar with the joint venture method as this is used in the coal business which it regulates.

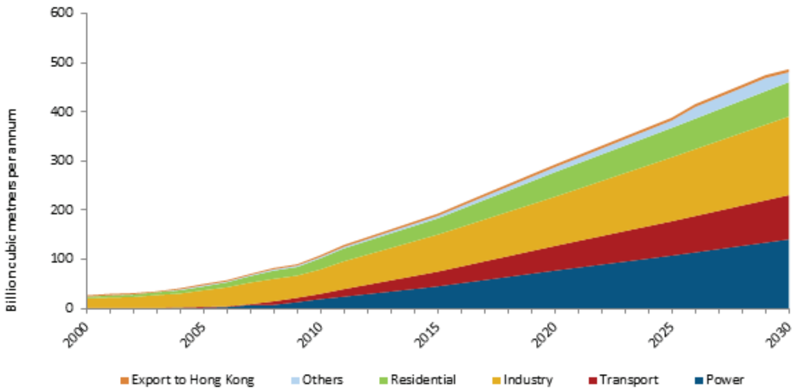
Another potential obstacle that could hamper unconventionals is the imposition of minimum local content in development plans. This would hamper access to the technology used in shale gas resource development in the USA. But it is duplicating the US story in shale that is a key thrust to official Chinese policy on shale. Therefore we believe that minimum local content considerations will need to be set aside with respect to unconventional oil and gas in China.

Indeed, Indonesia's disappointing progress with CBM development is at least partly due to efforts to apply the traditional PSC system coupled with minimum local content requirements. Since the first CBM PSC was signed in Indonesia in 2008, no significant CBM has been commercially produced and sold.

Demand for Gas

Given the positive outlook for gas supply in the future how much might be used for more gas powered generation? It is projected that total consumption will increase to 198 bcma in 2015 to 303 bcma in 2020 and 507 bcma by 2030. In the power sector demand was 24 bcma in 2011 and is forecast to rise by 117 bcma (or by seven fold) to 141 bcma by 2030, accounting for one fifth of gas demand as projected by TLG in that year. Industrial demand was 56 bcma in 2011 and we forecast this to rise by 103 bcma or to triple by 2030 to 160 bcma as fuel oil and coal are displaced and as gas distribution network build out continues. Use of gas in transport is forecast to rise from 15 bcma in 2011 to reach 90 bcma by 2030. This would make it the third largest consumer of gas by sector by that time. Our forecast demand for natural gas by sector is shown in Figure 5. (Note this projection of consumption by sector is for the scenario without carbon pricing, which would serve to increase gas demand by the power sector further).

Figure 5: Historic and Forecast Demand For Gas by Sector Forecast to 2030



Source: NDRC 12th Five Year Plan, Ministry of Housing and Urban Redevelopment 12th Five Year Plan, TLG Analysis.

In 2010 electricity generation from natural gas was only around 2%, whereas coal accounted for more than 80%. There were 32,650 MW of gas fired plants in China, compared with 706,670 MW of coal fired plants at the end of 2011. In our view by 2015 installed gas-fired capacity will nearly double to 62,000 MW and by 2020 rise to 92,000 MW, before reaching 152,000 MW by 2030. This fleet would generate close to 800 TWh by 2030 (which is still only 6% of total generation forecast in that year of 12,600 TWh on TLG numbers). The absolute numbers for gas new build and gas demand by power look large but placed in context of overall gas demand or overall generation they look quite reasonable, even conservative.

Table 2: Key Assumptions on Coal and Gas New Build in Coastal Regions with CO_2, SO_2 and NOx Pricing

	H-class CCGT	New build coal plant
USD Kw	534	726
Capacity Factor%	63	63
Heat Rate (HHV)mmbtu/MWh	5.8	9.0
Efficiency %	59	38
USD mmbtu	12.9	5.9
Gas RMB cu m/ Coal RMB Tonne	2.9	800
CO_2 USD per MWh	3.2	8.1
SO_2 USD per MWh	0.002	3.3
NOx USD per MWh	0.4	1.7
Long Run Marginal Cost USD MWh	97	97

Notes: 1- Calorific value of coal GJ 22.814 per tonne, Gas MJ 36.35 cu m, coal fired plant own use 7%, coal plant HHV degraded from 40% efficiency to 38% to reflect ramping down and up to cope with mid merit.

The Other Disruptive Force: Emissions Pricing

Environmental considerations are increasingly important to the Chinese power sector, though the challenges run deep. Increasingly environmental costs will be incorporated in the new build decision, and this will favour gas-fired plant over coal, particularly in the mid merit operating segment. Here we have assumed that a price of RMB 60 per tonne or USD 9.52 per tonne of CO_2 applies in coastal areas. But government regulations on carbon dioxide pricing are not yet clear. Power generated from coal produces more tonnes of CO_2 per MWh than gas fired plant. So the imposition of any form of CO_2 pricing increases the competitiveness of gas relative to coal.

The policy makers and regulators need to take innovative steps outside the traditional administrative ideologies to harmonize the operations of fuel and power markets, power and gas networks, environmental markets and secondary markets. For example, generators should have a clear and stable policy environment and should be able to pass through their generation costs on a competitive basis. Our key assumptions on new build including carbon dioxide pricing are shown in Table 2. These indicate that a delivered gas price of USD 12.9 per mmbtu or RMB 2.9 per cu m, or below can compete with a new build coal plant for the mid merit dispatch in with CO_2 pricing.

Conclusions

Helped by the advent of unconventional gas resources within ten years, China should have enough supply of domestic natural gas to support a material increase in gas-fired CCGT capacity on the grid.

At USD 12.1 mmbtu or RMB 2.7 per cu m, new CCGT capacity with an efficiency of 59% (e.g., H-class) could displace new build coal-fired plants for mid-merit dispatch. Including moderate emissions pricing for carbon dioxide this would raise the competing gas price to USD 12.9 mmbtu or RMB 2.9 per cu m.

Questions remain on the pace and scale of the construction of the pipeline system that is needed to get China's large gas resources to market, but new pipelines are being built and we believe there is some ullage in the existing pipeline system.

Regulations governing the exploration and development of unconventional gas will need to allow flexibility. Especially at this early stage the exploration and production companies are still learning about the subsurface and so are unable to provide detailed development plans.

More challenges are left to China's policy makers, market reformers and regulators. Reforming the dispatch procedures and ensuring that market prices are aligned to the cost of generation is essential. Moreover, this must also include various environmental emissions costs.

China has reformed its coal production industry so that it is more market-oriented. Now China is starting reform of its gas supply industry and gas pricing mechanisms. We might be getting closer to the time that China reforms its power industry, which in turn would enable the power sector to support the gas sector.

Appendices

Gas and Coal Details on New Build Costs

Gas-fired power plants have cost advantages over coal-fired plants as summarized in Table 3. However, this advantage will be somewhat meaningless if they are not properly fed through to prices in the dispatching mechanism.

Table 3: Comparison of Typical Coal and Combined Cycle Gas Fired Power Generation

	Coal-fired	NGas-fired (CCGT)
Unit cost (RMB/kW)	RMB 4,575/kW (cost of Pinghai Coal-fired Power Station (2x1000MW)	RMB 3,365/kW (10% increase on the cost of Fujian Putian Gas Power Station (9F))
Base Load Thermal efficiency	42% (average of units of 1000 MW or above)	59% for H class
Land use	One third more than gas fired plant	Typically 60% of coal-fired power stations of same size
Water use	Depending on cooling methods Typically 0.43 m3/MWh	Typically 30% of the same size of coal fired plants
Aux load	5.95% (average of 21 major generation companies in 2010)	Typically 2%
Time (minutes) to full load from given status	Hot: 90 Warm:180 Cold: 360-480	Hot: 80 Warm:90-140 Cold: 120-190
Emissions/ residues	Various	As percentage of that of coal-fired plants SO_2: virtually 0% NOx: <19% CO_2: 49% Particulates: 0% Dust: 0%

Source: State Electricity Regulatory Commission (SERC) of PRC, 2011, for water consumption and auxiliary load of coal fired plants.

China's Environmental Control Policies and Carbon Emissions Trading Schemes

China has been facing ever more serious environmental problems in the last decade, namely SO_2, NOx, CO_2, particulates, and other pollutants. According to PBL, the Netherlands Environmental Assessment Agency, China at 6.51 billon tonnes of CO_2 overtook the United States which emitted 5.84 billion tonnes of CO_2 in 2006. Figure 7 shows the trends of CO_2 and other pollutants in recent years. China's emissions of SO_2 and NOx in 2011 were 22.18 million tonnes and 24.04 million tonnes respectively, according to China's Ministry of Environmental Protection. Figure 7 shows that the emission of CO_2 and NOx are in a rapid upward trend which has to be curbed.

China has an on-going process to strengthen its controls on emissions of SO_2, NOx, Hg, flue gases, dusts and other poisonous emissions. For example, China in November 2009 announced that it would reduce its CO_2 emissions intensity per unit of GDP by 40-45% from 2005 levels by 2020. In particular, China announced limits[1] on emissions in its Comprehensive Working Plan for Energy Conservation and Emission Reduction in the12th Five Year Plan Period (2011-2015) and new Standards[2] on emissions for thermal plants were enforced from 1 January 2012.

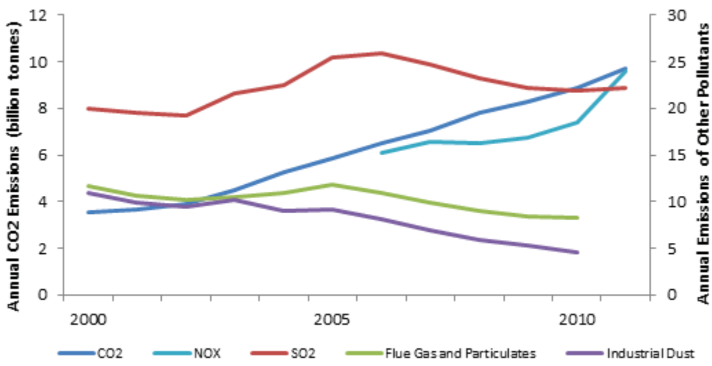
The power sector is a major contributor to China's emissions and this is largely blamed on coal-fired plants. China's 12th FYP Plan for Energy Conservation and Emission Reduction, which was issued by the State Council on 6 August 2012, has set specific targets for the power sector which are summarized below:

1. All coal-fired plants of 300 MW or above have to install denitrification equipment.
2. All existing coal-fired plants have to install desulfurization equipment with specified standards.
3. All new coal-fired plants have to install desulfurization and denitrification equipment.
4. By 2015, the GDP energy intensity is to be reduced to 0.869 tonne standard coal equivalent per 10,000 Yuan (2005 prices), which is less than the 2010 GDP energy intensity by 16%.
5. By 2015, national total emissions and the emissions from thermal power generation of SO_2 are to be capped at 20.864 million tonnes and 8 million tonnes respectively (2010 SO_2 emissions were 22.678 million tonnes and 9.56 million tonnes for the national total and thermal power generation respectively).

1 http://www.gov.cn/zwgk/2011-09/07/content_1941731.htm (2011) and http://www.gov.cn/zwgk/2012-08/21/content_2207867.htm (2012).

2 Emission standard of air pollutants for thermal power plants, GB13223-2011, revised from its first version of 1991.

Figure 7: Annual Emissions of Selected Pollutants in China



Source: CO_2 data from PBL, and others from Ministry of Environmental Protection, China

6. By 2015, national total emissions and the emissions from thermal power generation of NOx are capped at 20.462 million tonnes and 7.5 million tonnes respectively (2010 NOx emissions were 22.736 million tonnes and 10.55 million tonnes for the national total and thermal power generation respectively).

7. Coal consumption of thermal plants of supplying electricity (net) is to be reduced to 325 gsce/kWh by 2015 from 333 gsce/kWh in 2010 and plant auxiliary use is to be reduced to 6.2% by 2015 from 6.33% in 2010.

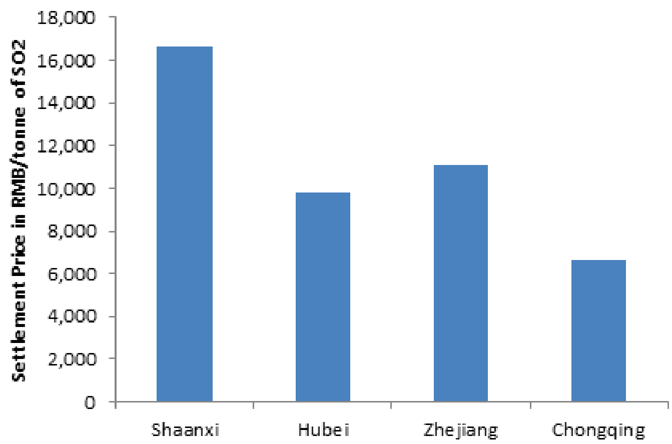
8. The electricity transmission losses are to be reduced to 6.3% by 2015 from 6.53% in 2010.

China has implemented various policies in the power sector to curb the emissions, including shutting down small coal-fired (condensing) plants and forcing coal-fired plants to install SO_2 and NOx removal equipment and dust-removal equipment. To reduce the cost burden incurred by coal-fired plants of installing and operating desulfurization and de-nitrification equipment, the government has increased the on-grid electricity prices of coal fired plants accordingly: a lift of RMB 0.015/kWh for desulfurization and an extra RMB 0.008/kWh for de-nitrification[3]. By the end of 2011, the share of thermal plant generation capacity with de-sulfurization was 89% and the share with de-nitrification was 16.9%.

China has also tried market-based mechanisms to curb emissions. China started trading of emissions rights of SO_2 in two cities in Liaoning and Jiangsu Provinces in September 1999[4] and from 2008, more than 20 emission rights-related trading houses were established in China. However actual transaction volumes are low.

There are several reported trades of SO_2, NOx, chemical oxygen demand and ammonia nitrogen in 2012 and Figure 8 shows recent settlement prices of SO_2 in 2012 in several Energy and Environmental Trading Markets in China, ranging from RMB 6,635/tonne in Chongqing to RMB 16,630/tonne in Shaanxi. However, trading in these markets is not active in terms of amount of emission rights or the number of participants. The settlement price of these emission rights was not fully determined by market forces or the fundamentals of supply and demand in our view.

Figure 8: Auction Settlement Price of Sulfur Dioxide



Source: from various media reports.

Undiscouraged by the mixed experience in trading markets for SO_2 and NOx, the NDRC announced in October 2011 a plan that China would pilot CO_2 emissions trading schemes in five cities and two provinces, which could start as early as 2013. The reported price of CO_2 emission rights in Guangdong in September 2012 was RMB 60/tonne, which is the first instance of carbon dioxide emissions trading in China and we use that number in our calculations of emission cost of coal and gas fired generation. For SO_2 and NOx we have not used the prices in the illiquid markets mentioned above but instead we assume the emission charges will stabilize at the low end of the range. We assume the following emission prices for our modeling in Table 4 for the base case and in the case with CO_2 pricing as well.

Table 4: Assumed Emissions Charges

	CO_2 (RMB/ tonne)	SO_2 (RMB/ tonne)	NOx (RMB/ tonne)
Base Case	0	3,000	4,000
With CO_2 Pricing	60	3,000	4,000

The emission intensities by fuel type are given in Table 5.

3 The estimated desulfurification cost ranges from RMB 12.03/MWh to RMB 28.18/MWh with an average of RMB 17.2/MWh in Guangdong's 16 desulferification projects (Wang, et al, 2007); and CEC estimated the average cost of denitrification cost for new plants and existing plants without denitrification equipment is RMB 11/MWh and RMB 13/MWh respectively (http://finance.china.com.cn/industry/energy/mtdl/20120803/921402.shtml).

4 http://www.cec.org.cn/xinwenpingxi/2011-11-08/73955.html.

Table 5: Assumed Emissions Factors for Selected Items

Emissions	Hard Coal	Gas
CO_2 (g/GJ)	94,600	56,100
SO_2 (g/GJ)	765	0.68
NOx (g/GJ)	292	93.3

Source: European Environment Agency, Air pollution from electricity-generating large combustion plants, 2008.

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Neil brings over ten years' experience as an advisor to gas and power stakeholders. For gas companies he has prepared gas monetization plans and strategies, assessed competition between piped gas and LNG, developed LNG terminal regasification tariff mechanisms, and analysed a wide variety of small and large gas-supply opportunities and applications, including transport. For power companies, he has advised on LNG vs piped gas and other fuel sources, and on the economics of various forms of electricity generation in merchant and non-merchant markets. Neil has an MA in economics from the University of Aberdeen, UK.

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Mike brings over 20 years' experience advising clients on the crucial economic, commercial, strategic and policy matters that continually reshape the global energy sector. Prior to co-founding The Lantau Group in 2010, he headed the Asia Pacific energy & environment practice of Charles River Associates. Before that he was with Putnam, Hayes & Bartlett. He combines rigorous economic analysis with a deep understanding of the major forces that drive change within the energy sector. Mike has an MPP from Harvard Kennedy School and a BA in economics from Carleton College.

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