

Q-Series®

China Integrated Natural Gas

Are demand and margins at risk as prices rise?



Gas prices are rising as the government implements pricing policy

The Chinese government is proceeding with policies to raise domestic natural gas prices closer to international levels. In the past, increases in city gate prices have been mostly passed on to end-users and, as a result, we believe investors have a presumption that the passing on of higher prices (fuel-cost pass-through) will continue in the future too. A critical question for investors is whether that is necessarily true? Will gas price increases be passed on but gas become unaffordable and demand be reduced, or could margins in the gas value chain be squeezed in an effort to maintain affordability?

Extensive modelling to gauge customer affordability and supplier profitability

The UBS Asia utilities and oil and gas research teams have met with industry experts in China and performed extensive industry-level modelling. We provide a bottom-up analysis to see how customers could cope with higher gas prices and what mitigating factors are possible or necessary to support continued use of gas at higher prices, and we assess the tipping point at which gas becomes unattractive for each user-group. We also detail the economics and required price of China's gas supply by source.

Growing risk to the gas utilities

We think the number of industrial users unable to afford gas from the gas utilities will increase significantly over the next two years. This could result in a combination of reduced demand growth expectations, a reluctance of local pricing bureaux to allow full fuel-cost pass-through, or enhanced subsidisation, in our view. We remain cautious on the gas utilities because we believe investors have not allowed for any significant margin risk when valuing the stocks.

Upstream suppliers stand to gain, but midstream returns uncertain

Higher city gate prices should translate to higher well-head prices, although poor customer affordability suggests a risk that the pace of price hikes could disappoint. However, many mid-stream operators' (provincial pipelines, LNG processing terminals) margins could be squeezed in an attempt by regulators to mitigate the effect of higher prices. We are positive on the competitiveness of gas as a transport fuel, which should support CIMC Enric (Buy).

Equities

China

Energy

Stephen Oldfield

Analyst

stephen.oldfield@ubs.com

+852-2971 7140

Peter Gastreich

Analyst

peter.gastreich@ubs.com

+852-2971 6121

Ken Liu

Analyst

ken.liu@ubs.com

+852-2971 7516

Benson Chen

Analyst

benenson.chen@ubs.com

+852-3712 2597

William Li

Analyst

william-w.li@ubs.com

+852-2971 6123

Nina Yan

Analyst

S1460511080002

nina.yan@ubssecurities.com

+86-213-866 8884

Bonan Li

Analyst

bonan.li@ubs.com

+852-2971 8186

Contents

Executive summary.....	3
Methodology.....	3
Stock implications.....	4
Affordability set to deteriorate.....	6
Residential: sensitivity is political not economic	8
Commercial: users should find gas affordable.....	9
Industrial: affordability reduced in step changes.....	10
Power: further margin compression for gas-fired	15
Transport: gas to remain competitive for vehicles.....	19
District heating: losses likely subsidised	21
Chemical: fertilizer producers getting squeezed	24
Economics of supply	27
Supply-side arguments for price hike valid as ever.....	27
Share of cheap conventional sources has dwindled.....	27
Gas imports driving the per unit cost increase.....	28
Domestic gas price hikes struggling to catch up.....	30
Gas cost inflation could moderate after 2015E	30
Comparing cost of incremental supply by source	31
Mitigating the risk of high-cost LNG	36
What can China's gas giant bear?.....	36
Appendix.....	41

UBS's Q-Series® products reflect our effort to aggressively anticipate and answer key investment questions, to help drive better investment recommendations. Q-Series® is a trademark of UBS AG.

Stephen Oldfield

Analyst
stephen.oldfield@ubs.com
+852-2971 7140

Peter Gastreich

Analyst
peter.gastreich@ubs.com
+852-2971 6121

Ken Liu

Analyst
ken.liu@ubs.com
+852-2971 7516

Benson Chen

Analyst
benenson.chen@ubs.com
+852-3712 2597

William Li

Analyst
william-w.li@ubs.com
+852-2971 6123

Nina Yan

Analyst
S1460511080002
nina.yan@ubssecurities.com
+86-213-866 8884

Bonan Li

Analyst
bonan.li@ubs.com
+852-2971 8186

Executive summary

On 12 August 2014, the National Development and Reform Commission (NDRC) announced an increase in the city gate gas price ceiling effective from 1 September 2014. Except for Guangdong and Guangxi provinces, where the increase was Rmb0.12/cum, the increase for all other provinces was Rmb0.40/cum. The increase was part of a continuing implementation of gas price reform in China.

By the end of 2015, the government wants the price of gas for supplies in place before 2013 (existing gas volume) to converge with the price of supplies put in place since 2013 (incremental gas volume), thereby increasing the weighted average city gate price to be 85% of the price implied by fuel oil and LPG (at a Shanghai pricing point). As we show in the supply section of this report, the continuation of this policy is being driven by more expensive incremental gas supplies. This means that in addition to coping with the increase in gas price being implemented in 2014, customers will need to cope with another similarly sized increase next year.

Recent news from some companies, suggests affordability issues are starting to affect fuel price decisions. At its 2014 interim results briefing, ENN Energy said it was ordered by the local government to offer discounts to ceramic makers in its Quanzhou project. At China Resources Gas's briefing, management said that the Tianjin government only allowed 38% of its July 2013 city gate gas price increase to be passed on to customers.

The question we seek to answer in this Q-series® report is: can users afford this? And, if they cannot what will happen? Will demand growth fail to meet investor expectations because gas prices are unattractive? Will margins for the gas suppliers (within the cities, the gas distribution utilities) be squeezed either through incomplete fuel-cost pass-through or will suppliers presume to offer discounts to the regulated price? Will the government give subsidies to support user-groups in need? Or will upstream suppliers ultimately fail to push sales prices up to the NDRC policy ceiling due to customer resistance?

Methodology

To address this, we have performed an affordability analysis for each customer. Most of these customers get their gas from the gas distribution utilities but some, such as large chemical companies and power plants outside of cities, are direct customers of the major gas suppliers, such as PetroChina. However, we think ongoing gas price increases have been reflected in share prices for the upstream companies, as well as in our assumptions, and we believe the risk could be slower price increases if resistance to higher prices proves too much to bear.

The method of analysis is different for each user-group but, in general, we consider the margins and returns of the users and how those margins may be affected by higher gas prices, and we also compare the cost of the gas to alternative fuel supplies. In each case, we consider whether the customer would have the pricing power to reflect higher gas costs in the price of their products. To assess prices required for upstream projects, we use both UBS proprietary models and Wood Mackenzie. As a reality check, we test the sensitivity of PetroChina's ROCE to various natural gas price outcomes.

Stock implications

Overall, we believe there are several user-groups for whom higher gas prices will be extremely challenging to absorb and this will likely result in both margin squeeze for them, potential margin squeeze for the gas utilities, or failure of upstream suppliers to push through gas price hikes.

Downstream utilities

The most obvious group of companies at risk from higher gas prices would be the gas distribution companies. We have no Buy-rated stocks among this group of companies that have all delivered significant share price outperformance over the past four years. We believe share prices fully reflect the solid demand growth, facilitated by the strong growth outlook in gas supplies that is also discussed in this report. Investors, in our view, also have a presumption of full fuel-cost pass-through, simply because this has happened in the past.

The issue is that, with each gas price increase, affordability declines, making passing on the next city gate gas price increase harder. We do not think margin risk is reflected in market expectations. At a minimum, we think the share price performance of these companies is likely to remain subdued until the companies are able to confirm successful fuel-cost pass-through regarding the 2014 increase.

The risk is that gas utilities are quite profitable: we project returns on equity approaching 20% or more for 2015 among the companies we cover. Faced with customers who are struggling to afford gas, we think it will be tempting for local pricing bureaux to question why such profitable companies should see their margins so well protected.

We are neutral/negative on the downstream gas utilities (no Buy ratings) because we are concerned about the gas utilities' ability to realise full fuel-cost pass-through. We also believe connection fees for the gas utilities are drying up due to growing penetration rates across China. In the downstream sector we favour **ENN Energy (Neutral)** because it has the highest margin among peers as well as a good track record of execution. We have Sell ratings on China Gas and Beijing Enterprises.

Gas distribution companies most at risk from higher gas prices

In the downstream sector we favour ENN Energy (Neutral); it has the highest margin among peers and a good track record

Customers: under pressure from gas price increases

To the extent city gate gas prices are increased, we think the customer groups least able to pass on higher gas prices are the glass and ceramics makers. These customers have high energy intensity in their businesses and narrow margins. UBS does not cover any ceramics makers. UBS covers two glass makers, but both companies specialise in higher-margin products where we think gas prices can be absorbed. We also believe fertilizer producers, such as **China Blue Chemical (Sell)**, will continue to come under pressure as feedstock costs rise.

Gas suppliers: benefit but price hikes could disappoint

This group benefits from higher gas prices. Low gas prices in China have resulted in a growing subsidy burden as the volume of gas supplied has risen. Higher gas prices should reduce this subsidy burden. The primary supplier of gas in China (57% of total supplies) is PetroChina. However, our key concern is whether UBS and the market may be too aggressive regarding gas price hike expectations, particularly on existing natural gas volume sales, given the apparent low affordability of so many users in China.

PetroChina (Neutral) could fail to push its gas sales prices up to the new NDRC ceiling price levels

One area of risk is midstream suppliers, such as companies that own mid-stream pipelines or LNG processing facilities. Like gas distribution utilities, margins have the potential to be squeezed if regulators are reluctant to subject customers to higher gas prices as upstream prices rise. For pipeline operators, regulators may see the opportunity for returns to be reduced from high levels; for LNG processing facilities, significant overcapacity has resulted in minimal pricing power.

We believe the recent market valuation of **PetroChina (Neutral)** suggests investors are pricing in little risk that the company could fail to push its gas sales prices up to the new NDRC ceiling price levels in the coming 12 months. **Kunlun (Sell)** will also continue to look vulnerable, in our view, unless overcapacity in the LNG processing industry can be absorbed more quickly than we expect and, therefore, allow pricing power to return. Among China oil and gas stocks our top pick is **Sinopec (Buy)**; it is less sensitive to natural gas prices.

Sinopec (Buy) is our top pick in the oil and gas sector; it is less sensitive to natural gas prices

Equipment manufacturers: demand growth to re-accelerate

We believe gas equipment manufacturers, especially those that target the transport sector (ie, LNG or CNG) will benefit from a boom in natural gas demand from transport. Transport is identified as among the most affordable downstream demand drivers of natural gas, and we believe the gas demand related to it will deliver a 21% CAGR from 2013 to 2023. In addition, we believe developing gas for transport use is an effective way of mitigating gas import costs, given our estimated doubling of LNG imports from 30bcm in 2014 to 61bcm in 2018. We highlight **CIMC Enric as our top Buy-rated stock in the gas equipment sector**.

We highlight CIMC Enric as our top Buy-rated stock in the gas equipment sector

Figure 1: China integrated natural gas sector stocks under UBS coverage

	Rating	Curr. price	Price Target	Potent. Upside	12m yield	Mkt cap US\$bn	PE 2014E	PE 2015E	EV/EBITDA 2014E	EV/EBITDA 2015E	P/B 2014E	P/B 2015E	ROE 2014E	ROE 2015E	EV/IC 2014E	EV/IC 2015E	ROIC 2014E	ROIC 2015E
National Oil Companies																		
CNOOC	Neutral	15.6	14.1	-9.5%	3.6%	90.0	9.4x	9.4x	4.1x	3.9x	1.4x	1.3x	16%	15%	1.4x	1.3x	13%	11%
PetroChina (H-sh)	Neutral	11.0	11.6	5.5%	4.1%	237.9	12.6x	11.0x	5.5x	5.0x	1.3x	1.2x	11%	12%	1.1x	1.1x	8%	9%
PetroChina (A-sh)	Buy	7.9	8.7	10.1%	4.5%	237.9	11.5x	10.0x	5.5x	5.0x	1.2x	1.1x	11%	12%	1.1x	1.1x	8%	9%
Sinopec (H-sh)	Buy	7.9	9.3	18.3%	4.3%	107.8	9.9x	8.7x	4.4x	4.1x	1.2x	1.1x	13%	13%	1.2x	1.1x	10%	10%
Sinopec (A-sh)	Buy	5.5	6.2	12.1%	4.9%	107.8	8.8x	7.8x	4.4x	4.1x	1.1x	1.0x	13%	13%	1.2x	1.1x	10%	10%
Transmission and LNG																		
Beijing Enterprise	Sell	66.8	69.0	3.3%	1.8%	11.0	17.0x	14.3x	13.7x	11.9x	1.5x	1.4x	9%	10%	1.6x	1.4x	5%	5%
Kunlun	Sell	12.8	12.0	-6.3%	1.9%	13.3	14.5x	12.7x	6.8x	5.8x	1.9x	1.7x	14%	14%	1.6x	1.5x	12%	13%
Sinopec Kant.	Buy	6.5	9.2	41.8%	0.9%	2.1	21.1x	13.2x	2.0x	13.2x	1.3x	1.2x	6%	10%	0.3x	0.7x	4%	0%
City Gas Distributors																		
China Gas	Sell	13.8	10.0	-27.5%	0.9%	8.9	22.7x	21.2x	11.8x	14.2x	2.9x	3.7x	18%	19%	2.4x	3.0x	13%	13%
China Res. Gas	Neutral	22.6	28.2	25.1%	1.2%	6.5	19.2x	17.2x	8.5x	7.3x	3.1x	2.7x	17%	17%	3.4x	2.9x	24%	23%
ENN Energy	Neutral	54.8	60.0	9.6%	1.2%	7.6	21.3x	19.9x	10.6x	9.8x	4.2x	3.6x	21%	19%	3.7x	3.5x	20%	20%
HK & China Gas	Neutral	17.6	18.0	2.4%	2.1%	23.9	26.5x	24.5x	19.3x	18.8x	3.5x	3.3x	14%	14%	3.8x	3.7x	12%	12%
Towngas China	Neutral	8.3	10.2	23.5%	1.1%	2.8	18.8x	16.8x	14.3x	14.9x	1.6x	1.5x	9%	9%	1.5x	1.5x	5%	4%
Oil field serv. & equip.																		
Anton	Sell	3.3	3.0	-9.9%	1.6%	0.9	20.3x	17.9x	10.8x	10.5x	2.5x	2.2x	13%	13%	2.2x	1.9x	13%	12%
Honghua	Buy	2.1	2.3	11.7%	3.5%	0.9	8.0x	6.6x	6.8x	5.5x	1.0x	0.9x	13%	14%	1.2x	1.1x	12%	13%
SPT	Buy	3.9	5.8	47.2%	1.7%	0.8	15.4x	10.4x	8.4x	6.1x	2.5x	2.1x	17%	22%	2.8x	2.2x	22%	24%
Eng. and equip. supply																		
Sinopec Eng.	Buy	8.8	12.0	35.7%	5.2%	5.1	7.6x	7.4x	3.6x	3.5x	1.3x	1.2x	18%	17%	1.8x	1.4x	34%	28%
CNCEC	Buy	5.7	9.9	73.1%	1.2%	4.6	6.8x	5.4x	2.6x	1.6x	1.1x	0.9x	18%	19%	1.6x	1.0x	44%	45%
CIMC Enric	Buy	8.6	13.0	51.5%	1.7%	2.1	12.8x	11.5x	8.3x	6.8x	2.1x	1.8x	19%	18%	2.9x	2.5x	27%	27%
Yingde	Buy	8.3	9.7	17.0%	3.1%	1.9	11.1x	9.1x	7.0x	6.4x	1.7x	1.5x	16%	17%	1.4x	1.3x	11%	11%
Gas-based fertilizer																		
China Blue	Sell	3.8	3.6	-5.8%	4.4%	2.3	8.2x	8.8x	3.6x	3.6x	0.9x	0.8x	11%	10%	0.9x	0.8x	14%	12%

Note: Above data as at 29 August 2014. Share prices and price targets are in local currency.

Source: Bloomberg, company data, UBS estimates

China Upstream and Downstream Natural Gas Map

Major pipelines					
Line sample	Pipeline	Diameter (cm)	Length (km)	Capacity (bcm/a)	Capacity (mmcf/d)
	West - East pipeline I	102	3,900	17.0	1,645
	West - East pipeline II	122	4,859	30.0	2,900
	West - East pipeline III	na	na	30.0	2,900
	Sinopec Xinjiang - Guangdong - Zhejiang	na	na	30.0	2,900
	Hebei - Nanjing	102	1,494	9.0	870
	Huaiyang - Wuhan	61	475	1.5	145
	Jingbian - Yinchuan	43	302	0.5	50
	Jingbian - Hohhot	na	511	1.0	100
	Jingbian - Xi'an I	41	489	1.0	97
	Jingbian - Xi'an II	61	485	3.0	290
	Lanzhou - Yinchuan	61	402	3.5	338
	Ningbo - Taizhou - Wenzhou	516	na	10	na
	Pinghu - Shanghai	36	389	0.8	77
	Shaanxi - Beijing I	66	860	3.0	290
	Shaanxi - Beijing II	102	935	12.0	1,160
	Shaanxi - Beijing III	102	900	15.0	1,450
	Shaanxi - Beijing IV	na	na	na	na
	Seninglan (Sebei - Lanzhou)	66	945	3.4	330
	Yacheng - Hong Kong	71	780	3.4	330
	Zhongwei - Guiyang	101.6	1,613	15	1,553
	Zhongxian - Wuhan	102	719	3.0	290
	China-Myanmar	102	803	12.0	1,100
In which:	Guiyang - Guigang	na	636	12.0	1,100
	Chuxiong - Panzhihua	na	240	1.8	174
	Golmud - Lhasa pipeline	na	na	na	na
	Jilin - Changling	na	221	2.332	na
	Ruding	276.1	14	101.6	na
	Yulin - Jinan	71	1,045	3.0	290
	Sichuan - East China (Shanghai)	99	1,702	12.0	1,160
	Others	na	na	na	na
	Offshore	na	na	na	na
	Cross-border pipeline	na	na	na	na
	Beijing - Qinhuangdao - Shenyang	na	na	na	na
	Dalian - Shenyang	na	na	na	na

Proven natural gas reserve by major basin (2012)						
	PetroChina		Sinopec		CNOOC	
	bcm	tcf	bcm	tcf	bcm	tcf
Changqing	637.8	22.5	na	na	na	na
Tarim	573.5	20.3	na	na	na	na
Sichuan	310.9	11.0	102.1	3.6	na	na
Bohai Bay	na	na	na	na	16.8	0.6
Western South China Sea	na	na	na	na	67.5	2.4
Eastern South China Sea	na	na	na	na	33.3	1.2
East China Sea	na	na	na	na	8.7	0.3
Others	391.8	13.8	88.5	3.1	58.3	2.1
Total	1,913.9	67.6	190.6	6.7	184.6	6.5

● Major city	△ In operation
▲ Under construction	▲ Approved (FEED stage)
■ Coal to gas projects	■ Gas field
■ Coal-bed methane areas	— Existing pipeline
--- Pipeline under construction/proposed	
Distribution Projects:	
● Beijing Enterprises	
● China Gas	
● China Resources Gas	
● HKCG (excl. Towngas China)	
● Towngas China	
● ENN Energy	

2P Gas Reserve (2013)		
	Location	Proven reserve
		bcm tcf
1	Junggar	NA NA
2	Tuoha	15.9 0.6
3	Tarim	384.0 13.6
4	Tibet	NA NA
5	Jiuquan	NA NA
6	Qaidam	138.4 4.9
7	Ordos	874.9 30.9
8	Sichuan	781.4 27.6
9	West South Sea	72.1 2.5
10	Subei	NA NA
11	Jiangnan	NA NA
12	East South Sea	15.0 0.5
13	Hailar	NA NA
14	Songliao	120.5 4.3
15	North China	42.4 1.5
16	Yellow Sea	NA NA
17	East China Sea	94.1 3.3

LNG Terminal					
	Location	Start up	Phase I capacity (mtpa)	Operator	
1	Shenzhen	2006	3.7	CNOOC	
2	Putian	2009	5.0	CNOOC	
3	Shanghai	2010	3.0	CNOOC	
4	Nantong	2011	3.5	PetroChina	
5	Dalian	2011	3.0	PetroChina	
6	Ningbo	2012	3.0	CNOOC	
7	Zhuhai	2013	3.5	CNOOC	
8	Caofeidian	2013	3.5	PetroChina	
9	Hainan	2014	2.0	CNOOC	
10	Qingdao	2014	3.0	Sinopec	
11	Tianjin	2014	3.0	CNOOC	
12	Beihai	2015	3.0	Sinopec	
13	Jieyang	2015	2.0	CNOOC	
14	Tianjin	tbd	3.0	Sinopec	

Coal-To-Gas Projects		
Project	Total Capacity (bcm/p.a.)	Inception of phase I operation
Datang Keqi	4	2013
Kingho III	5.5	2014
Datang Fuxin	4	2014
Huining Ordos	1.6	2014
Xintian III	10	2015



Source: UBS

UBS China Oil and Gas Research		Peter Gastreich Analyst peter.gastreich@ubs.com +852 - 2971 6121	Bonan Li Analyst bonan.li@ubs.com +852-2971-8186	Benson Chen Analyst benenson.chen@ubs.com +852- 3712 2597	UBS China Utilities Research		Stephen Oldfield Analyst stephen.oldfield@ubs.com +852 - 2971 7140	Yuxiao Peng Analyst yuxiao.peng@ubs.com +852 - 2971 7526	William Li Analyst william-w.li@ubs.com +852 - 2971 6123	Ken Liu Analyst ken.liu@ubs.com +852 - 2971 7516
--------------------------------	--	---	---	--	------------------------------	--	---	---	---	---

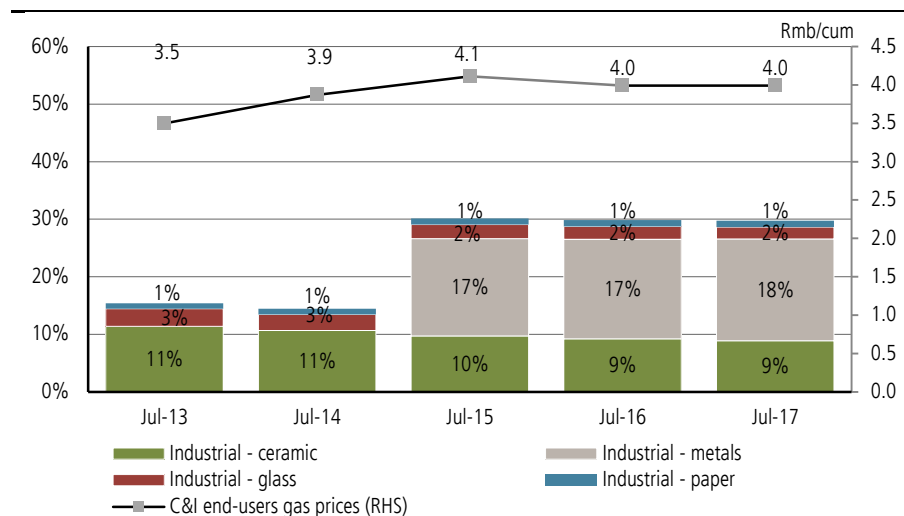
Affordability set to deteriorate

City gate gas price ceiling levels are set to rise by Rmb0.4/cum (about 18%) for most provinces in China from 1 September 2014. A similar-sized increase in the ceiling city gate gas prices is likely next year if the current gas pricing policy remains unchanged. We expect a significant rise in the proportion of gas user-groups that will struggle with gas affordability over the next two years.

Within the customer base of the city gas distribution utilities, we think about 15% of customers (mostly industrial) will struggle to afford gas at pre-September 2014 prices. As shown in Figure 2, we expect this to jump to 30% by 2016.

15% of customers (mostly industrial) will struggle to afford gas at pre-September 2014 prices

Figure 2: Estimated % of unaffordable users (city gas) (LHS) versus commercial and industrial end-user gas price (RHS)



Source: CEIC, UBS estimates

The situation looks even more challenging once we include users outside of cities and those that are not customers of the gas utilities. Once we add in customers such as power generators, chemical manufacturers and district heating companies, the proportion of current customers that may struggle to afford gas could reach as high as 46%.

46% of total users may find gas unaffordable

Our analysis assumes city gate gas prices for non-residential users to increase by Rmb0.35/cum in September 2014, Rmb0.25/cum in July 2015 and a reduction of Rmb0.1/cum in July 2016 – ie, less than the likely increase in the city gate ceiling price. City gate prices for 98% of PetroChina's customers were raised to the ceiling level in the July 2013 price hike, but could be less so in the next rounds of increase as customers' affordability deteriorates.

Admittedly our analysis has shortcomings. In particular it considers industry averages and does not take into account that some top companies in each sector may find higher gas prices affordable and that the government might be happy to see lower performing companies in a sector exit the business. There are likely to be more nuances at the regional level, in terms of costs and profitability, that we have also not fully attempted to consider. But even allowing for this, there are likely to be, at a minimum, negative demand volume implications relating to higher gas prices.

At the same time, we believe that there are mitigating factors to alleviate the margin pressure on gas users; such as government subsidies and using alternative fuel sources. Though not quantifiable, any slower-than-expected trajectory of gas price increases than UBS currently assumes would give more time to gas utilities to focus on serving customers for whom gas remains affordable; and also time to some users to upgrade their products to higher margins or relocate their production base to inland regions for better affordability.

Mitigating factors to alleviate the margin pressure on gas users include government subsidies and alternative fuel sources

This report will discuss in detail each of the user type's affordability, highlighting:

- (1) Affordability of natural gas
- (2) Natural gas' pricing competitiveness versus its alternatives
- (3) Regional differences in affordability (if any)
- (4) Mitigating factors (if any) if natural gas is unaffordable to the user-group

We think the main margin risk/affordability pressure is for industrial customers. We think prices are, and should remain, affordable, for residential and commercial customers.

Figure 3: Gas demand forecasts and the category of customers which we think affordability is a concern

Segments (bcm)	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E	2021E	2022E	2023E	2013 % Total	2023 % Total	Affordability a concern?
Glass	2	2	2	2	2	3	3	3	3	3	3	1%	1%	Yes
Ceramics	6	7	9	10	12	13	15	17	20	22	25	4%	5%	Yes
Metals	8	10	12	15	18	20	23	26	29	32	34	5%	6%	Yes*
Chemical products	25	24	25	25	25	25	25	25	25	26	26	14%	5%	Yes
Power	22	22	28	36	40	45	49	53	57	61	65	13%	12%	Yes
District heating	17	21	25	31	39	47	55	64	72	79	87	10%	16%	Yes
Residential	18	20	22	24	26	28	29	30	31	32	33	10%	6%	No
Commercial	5	6	8	10	11	14	16	19	22	25	28	3%	5%	No
Transport	13	20	26	34	41	49	56	64	72	80	88	8%	16%	No
Storage and transmission loss	12	16	17	10	11	13	14	15	17	18	20	7%	4%	NA
Petroleum extraction	13	14	15	16	17	19	20	21	23	24	26	8%	5%	No
Petroleum processing	11	11	12	13	14	15	16	17	18	20	21	6%	4%	No
Other industries	4	5	6	8	10	12	14	17	19	22	25	2%	5%	No
Other mining	2	2	3	4	5	6	7	8	10	11	13	1%	2%	No
Other manufacturing	12	15	20	24	29	34	39	44	49	54	57	7%	10%	No
Other utilities	1	2	2	2	3	3	4	4	5	5	6	1%	1%	No
Total	170	197	231	264	303	344	385	429	472	514	556			
YoY	16%	16%	17%	14%	14%	14%	12%	12%	10%	9%	8%			

Note: * Affordability is only a concern after 2015 for this group of users.
Source: CEIC, UBS estimates

Residential: sensitivity is political not economic

In the 2014 increase, the government has not raised the city gate prices for residential users. Track records have shown that the government has been reluctant to raise city gate prices for residential users. We think the government was worried about public opposition to raising residential gas prices.

Even if gas prices were to rise for residential users, we do not see a significant impact: we estimate that natural gas bills account for only 2% of residential customers' disposable income at the current gas price. In the absence of any residential price hikes, the burden of the gas bill will shrink even lower because UBS economic research team expects disposable income to grow at 8% per year.

Natural gas bills account for only 2% of residential customers' disposable income

Assuming the government will need to increase city gate prices for residential users, we believe the recently announced tier pricing policy should help facilitate fuel-cost pass-through for residential end-user prices. Users with higher consumption will pay more at higher levels of consumption, essentially subsidising low-volume users.

Tier pricing for end-users

In March 2014 the government formulated a tier pricing policy for residential gas users. It sets three pricing segments based on volume of gas consumption, with a pricing ratio of 1:1.2:1.5. The government estimated tier one covers 80% of users, while tier one and two cover 95% of users.

We believe the idea of implementing tier pricing is good, because it discourages excessive consumption and paves the way for fuel-cost pass-through if city gate prices for residential users increase. We think that if city gate prices were to increase in the future, the government could consider raising the prices for tier two or three, which essentially means the higher energy consuming households will share the burden of the poor's gas bills.

Residential users exhibit high affordability

Figure 4 shows our estimation of residential users' gas bills compared to their disposable income in China and some major cities. It shows that gas bills, despite ongoing increases in gas price, still account for only 1-2% of residential users' disposable income overall, and less than this for larger, generally wealthier major cities. This calculation assumes disposable income to grow at 8% each year, and the annual gas consumption per household to stay relatively stable each year.

Figure 4: Gas bill as a percentage of disposable income

	National (36 city)	Beijing	Dalian	Hangzhou	Guangzhou	Chengdu
Residential gas price (Rmb/cum, incl. VAT)	2.48	2.28	3.30	2.40	3.45	1.89
Annual gas consumption per households (urban, excl. district heating) (cum)	214	222	104	164	150	288
Estimated 2013 gas bill (Rmb)	532	507	343	393	518	544
2013 annual disposable income per capita (Rmb)	26,955	40,321	25,578	37,851	33,090	22,368
Gas bill as % of disposable income in 2013	2.0%	1.3%	1.3%	1.0%	1.6%	2.4%

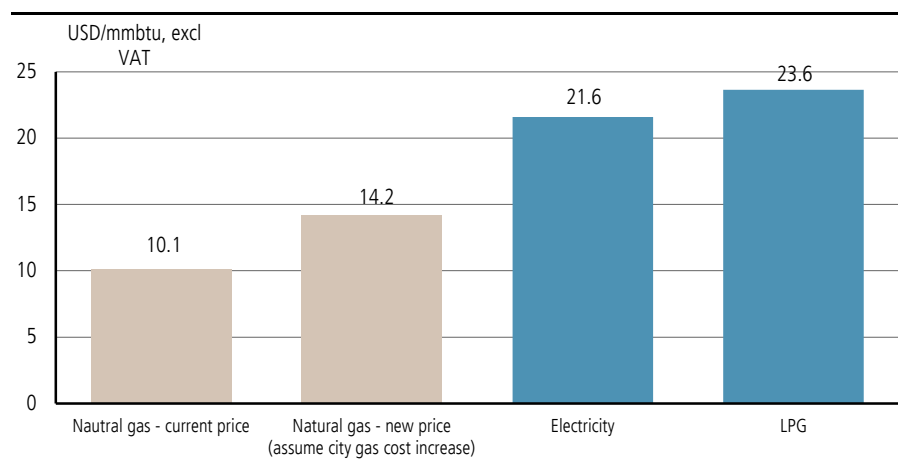
Source: CEIC, Ministry of Housing and Urban-Rural Development, Pricing Bureau, UBS estimates

Natural gas is still inexpensive compared to alternatives

We think that natural gas, despite ongoing price increases, will still be competitively priced compared to its alternatives, including bottled LPG and electricity. As shown in Figure 5, assuming the city gate gas prices for residential users increases similarly to that of non-residential users by around Rmb1/cum, and the increase is fully passed through to the end-users, residential end-user prices will still be at a 20-40% discount to LPG and electricity.

Natural gas for residential will still be competitively priced compared to bottled LPG and electricity

Figure 5: Pricing competitiveness for residential natural gas versus alternatives



Source: CEIC, UBS estimates

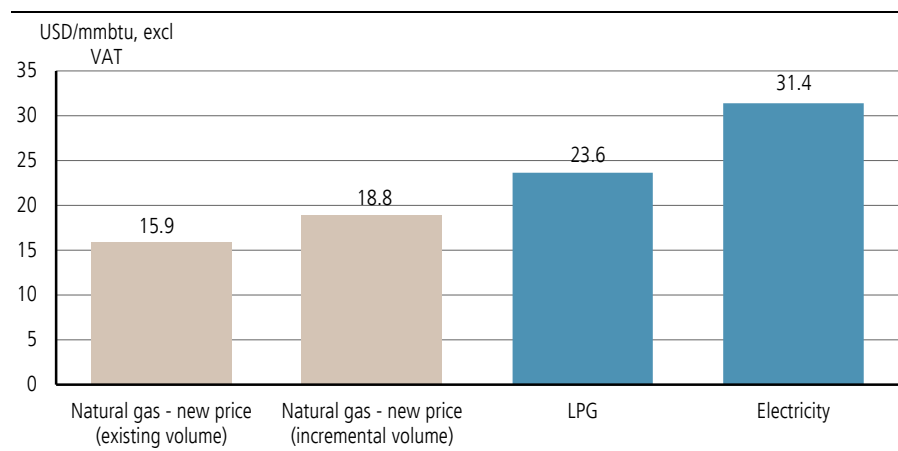
Commercial: users should find gas affordable

We think commercial users, such as hotels, offices and restaurants, can afford higher gas prices. Utilities expenses (including electricity and water) only account for less than 5% of their cost of goods sold, and they have relatively high gross margins (c60-80%) to absorb higher gas costs.

Commercial users, such as hotels, offices and restaurants, can afford higher gas prices

We believe it should be relatively easy for commercial users to pass through higher gas costs, given most of them are using natural gas, so it is less likely to result in a pricing disadvantage relative to peers. We still see natural gas, at incremental gas prices, to be cheaper than alternatives such as LPG and electricity (Figure 6).

Figure 6: Commercial natural gas price versus alternatives



Source: CEIC, UBS estimates

Industrial: affordability reduced in step changes

We believe many energy-intensive industries will be vulnerable to higher gas prices because of their low margins. We think high levels of competition and market fragmentation will make it hard for gas users in many segments to pass on higher costs. So, unless conversion of the whole industry is mandated, with conversion implemented rapidly, companies who convert to gas first will be at a significant disadvantage.

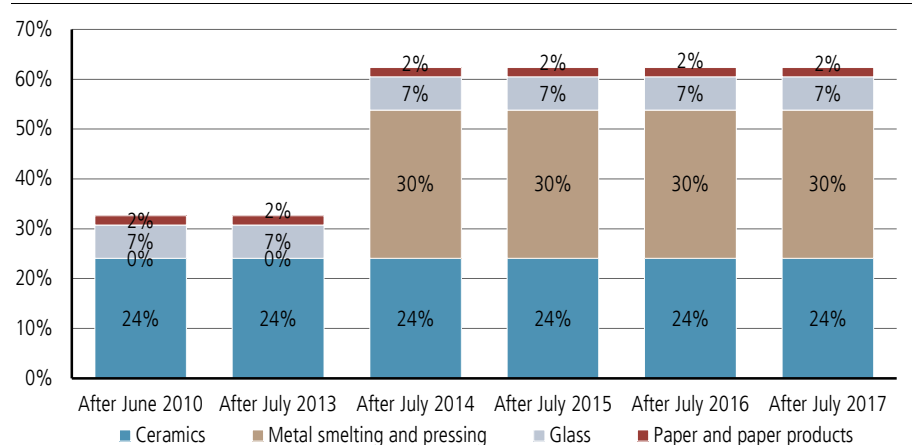
Energy-intensive industries will be vulnerable to higher gas prices because of their low margins

Currently, most industrial users consume coal, coal gas, petroleum coke etc. to heat furnaces or boilers to provide heat for smelting, blending or drying during their production processes. As shown in Figure 7, we estimate that the percentage of users finding gas unaffordable will increase to 62% starting from July 2015, compared to 33% now.

These users struggling to afford gas are primarily in segments such as glass, ceramics, metal smelting and pressing, and paper products manufacturers. We expect metal smelting and pressing will also be included in this group from 2015.

We think the likely consequence of this could be margin squeeze for the gas utilities. Although evidence of government subsidies on up-front investment costs to facilitate conversion from coal to natural gas have been seen, subsidies for ongoing gas consumption are less likely and we do not think the government necessarily wants a heavy, ongoing subsidy burden.

Figure 7: Estimation of the percentage of unaffordable industrial users to natural gas over time



Source: CEIC, UBS estimates

Ceramics, glass, metal products at risk

Figure 8 summarises the effect on major industrial user-groups of higher gas prices – these account for over three-quarters of total industrial demand. The figure shows a seven-year average and 2014 gross margins for these groups using CEIC and national statistical data. For many of the user-groups, a full conversion to gas using July 2013 prices has the effect of reducing margins considerably and each further Rmb0.1/cum increase in gas costs will cut gross margins further again by between 0.1 and 0.8 percentage points. We assume that once gross margins have fallen by half from successive gas price increases, the price becomes unaffordable for the users at that point.

Ceramics, glass and metal products particularly at risk; considerable margin reductions expected

Figure 8: Affordability summary for each industry segment

	Ceramics	Metal smelting and pressing	Machinery and equipment	Glass	Food and beverage production	Medical and pharmaceutical products	Paper and paper products
Share of gas sales							
2012 gas consumption as % of total industrial users	24%	30%	12%	7%	4%	2%	2%
Affordability assessment							
Fuel costs as a % of COGS	20%	2%	1%	20%	1%	2%	3%
7-year historical average gross margin	18%	10%	13%	13%	20%	30%	14%
2014 first four months gross margin	17%	9%	13%	9%	21%	29%	14%
Gross margin assuming full conversion to gas, at July 2013 gas price	5%	5%	10%	-3%	19%	25%	5%
Each Rmb0.1/cum (or 3%) increase in gas price, gross margin will drop by	0.8ppt	0.2ppt	0.1ppt	0.8ppt	0.1ppt	0.2ppt	0.3ppt
Ability to pass through higher gas cost to their end-products							
Industry fragmentation: no. of enterprises	1,967	26,528	73,742	230	7,645	6,700	11,001
Affordable?							
After July 2013	No	Yes	Yes	No	Yes	Yes	No
After July 2014	No	No	Yes	No	Yes	Yes	No
After July 2015	No	No	Yes	No	Yes	Yes	No
After July 2016	No	No	Yes	No	Yes	Yes	No
After July 2017	No	No	Yes	No	Yes	Yes	No

Source: National Bureau of Statistics of China, company data, UBS estimates

Ceramics

We think converting to natural gas from existing fuel sources (primarily coal gas) will be uneconomic for ceramic makers. We estimate that gross margin for the industry will become negative. Ceramics users are the second-largest users of natural gas in the industrial sector at present.

We forecast fuel cost will increase from accounting for 20% of cost of goods sold currently, to 30% if the users are converted to natural gas. Figure 9 shows the comparison of fuel costs using coal gas and natural gas.

Figure 9: Cost per ton of ceramics by fuel type

Unit	Coal gas Rmb/cum	Natural gas (existing gas price) Rmb/cum	Natural gas (incremental gas price) Rmb/cum
Price (incl. VAT)	0.55	3.9	4.1
Price (excl. VAT)	0.47	3.5	3.6
Kcal /unit	2,200	8,000	8,000
Energy needed per tonne of prod (kcal)	3,150,000	3,150,000	3,150,000
Fuel cost per tonne of ceramics	875	1,510	1,568

Note: Existing gas price refers to the estimated end-user price, after adding on the Rmb0.4/cum to be effective on 1 September 2014.

Source: Company data, UBS estimates

We think it is challenging for the ceramic makers to pass on its gas costs to its end-products. This is because the industry is highly fragmented and has overcapacity with around 2,000 companies. Also, ceramic prices have been flat because of weak property demand; building ceramics account for 94% of the ceramic products in China.

Metal smelting and pressing; metal products

Although the energy cost accounts for 1.5% of the total cost of goods sold, the thin margins make the industry vulnerable to increasing gas costs once they are converted from coal. We estimate that gross margin will reduce from 9% currently by more than half, to 4% in the long term.

We think it is difficult for the sector to pass through gas costs. Our global commodities research team expects metal prices to be weak, primarily because of slow economic growth.

Machinery and equipment

We estimate machinery and equipment manufacturers in general, will be able to afford natural gas. This is because the energy cost accounts for only 1% of its cost of goods sold, and its current gross margin of around 13% has enough cushion to absorb higher gas prices.

Glass

We estimate that by using natural gas, glass makers would report a gross profit loss. In Figure 10, we compare the cost of manufacturing a standard case of glass using traditional fuel sources to that of using natural gas.

Figure 10: Cost per glass case by fuel type

Unit	Coke oven gas Rmb/cum	Coal tar Rmb/t	Petroleum coke Rmb/t	Avg. of existing fuel cost	Natural gas (existing price) Rmb/cum	Natural gas (incremental gas price) Rmb/cum
Price (incl. VAT)	1.5	2,600	1,700	NA	3.9	4.1
Price (excl. VAT)	1.3	2,222	1,453	NA	3.5	3.6
Kcal /unit	7,500	8,598,420	7,433,628	NA	8,000	8,000
Energy needed to produce one case (kcal)	84,000	84,000	84,000	NA	84,000	84,000
Fuel cost per glass case (Rmb)	16.8	25.4	19.2	20.5	36.2	37.6

Source: Company data, UBS estimates

We do not think the gas manufacturers could easily raise their product prices to pass through higher gas costs, given overcapacity and weak demand in glass.

Based on our discussions with China Glass Holdings, overcapacity was mainly driven by a burst of optimism in the property sector a few years ago as around 70% of glass in China is used in property construction. The optimism had led to a sharp rise in capex in the past.

Newly commissioned production lines have been forced to operate despite weak demand because the companies need cash to repay the debt from their investments. Additionally, existing production lines are difficult to shut down because glass production is a 24-hour continuous process. Once the production line is stopped it would require more capex to restart the line. As a result, glass prices have remained low in the past two years due to oversupply.

Natural gas losing competitiveness to alternatives

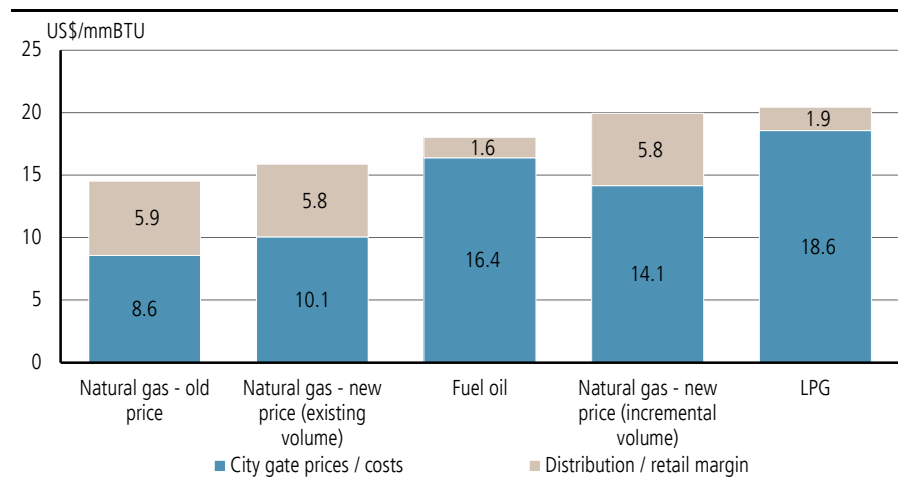
Under government policy, city gate gas prices are targeted to be set at a 15% discount to alternatives (LPG and fuel oil). To compare the prices at the end-user level, distribution margins of provincial grid companies and city gas utilities must be added and, once this is done, the discount removed due to higher margins for city gas distributors.

At city gate, provincial grid companies, which are usually owned by provincial governments and the oil majors, will charge a distribution margin and transmit gas to the gas utilities companies. The gas utilities companies will then charge another distribution margin to end-users.

Figure 11 summarises the pricing parity between natural gas prices (existing gas and incremental gas prices) and its alternatives. It shows that although the incremental city gate price was at 15% discount to fuel oil and LPG, the high distribution margin of natural gas of US\$6/mmBTU has resulted in price parity between alternatives.

The high distribution margin of natural gas results in price parity between alternatives

Figure 11: Pricing parity for commercial and industrial users using alternative fuels



Source: CEIC, NDRC, UBS estimates

We summarise the margins for industrial users in 23 cities in China according to the data provided by C1 Energy in Figure 12. These cities show that the differences between city gate prices and end-user prices are 50%, on average, after allowing for provincial transmission fees and the margins of the city gas distributors.

Figure 12: End-user prices for industrial and CNG users, and the corresponding margins to city gas companies

	End-user price (Rmb/cum, incl. VAT)		Non-residential city gate price (Rmb/cum, incl VAT) (Existing gas)	% of mark up	
	Industrial	CNG users		Industrial	CNG users
Beijing	3.23	5.12	2.26	43%	127%
Tianjin	3.25	4.20	2.26	44%	86%
Shijiazhuang	3.45	3.75	2.24	54%	67%
Taiyuan	2.75/3.80	4.45	2.17	51%	105%
Hohhot	2.00	3.56	1.60	25%	123%
Zhengzhou	3.23	3.60	2.27	42%	59%
Shenyang	3.90	4.70	2.24	74%	110%
Harbin	4.30	4.50	2.02	113%	123%
Ji'nan	4.14	4.71	2.24	85%	110%
Shanghai	3.79 (above 5mcm); 4.29 (1.2-5mcm); 4.59 (1.2mcm)	5.10	2.44	55%	109%
Nanjing	3.25 (Huagang Natural Gas); 3.65 (China Gas Holdings)	4.90	2.42	34%	102%
Hangzhou	4.84	NA	2.43	99%	NA
Hefei	3.60	3.98	2.35	53%	69%
Haikou	3.98	4.06	1.92	107%	111%
Changsha	3.48	4.50	2.22	57%	103%
Wuhan	3.41	3.55	2.22	54%	60%
Xi'an	2.30	3.58	2.17	6%	65%
Yinchuan	1.78	4.07	1.77	1%	130%
Urumqi	2.11	3.10	1.41	50%	120%
Lanzhou	1.82/2.68 (Above 0.6mcm) 1.99/2.87 (Below 0.6mcm)	2.99	1.69	33%	77%
Xi'ning	1.70	4.00	1.53	11%	161%
Chengdu	3.25	3.65	1.93	68%	89%
Chongqing	2.54 (Public network); 2.49 (Private pipelines)	2.54 (Public network); 2.49 (Private pipelines)	1.92	31%	31%

Note: The end-user price and non-residential city gate prices shown have not taken into account the upcoming price hikes to be effective on 1 September 2014.
Source: C1 Energy, NDRC

Better affordability inland than at the coast

Chinese natural gas prices in the inland region are lower than at the coast, and we think this will remain so in the future. We think unaffordable industries could gradually move their factories inland. However, this may not necessarily be true for all sectors, because some products have regional differences in margins; and transportation costs for certain raw materials could also reduce the incentive to move inland. This is particularly the case for glass and ceramic makers.

We think unaffordable industries could gradually move their factories inland

Methods to mitigate pressure on affordability evident

Upfront subsidy on converting to natural gas

Examples of an upfront subsidy offered on conversion from coal to gas have been seen in certain cities for the industrial users, especially for ceramics manufacturers and boiler users. We think further subsidies of similar kinds could be announced later in more cities or provinces. Figure 13 summarises the government subsidy for the conversion of boilers from coal to gas in major cities.

Upfront subsidies for ceramics manufacturers and boiler users

Figure 13: Summary of boiler policies

	Period	Subsidy	Comment
Beijing	2013-17	50% of conversion cost	Phase out coal boilers in inner city areas by 2015
Dalian	NA	NA	Converted 982 industrial boilers before 2012 Eliminate < 10t/hour boilers in city areas by 2017
Hangzhou	2013-15	40% of conversion cost	Phase out coal boilers in inner city areas by 2015
Guangzhou	2014-17	Rmb8,000 per tonne of steam capacity	Eliminate < 10t/hour boilers in city areas by 2015
Chengdu	2012 +	Environmental projects of Rmb1-2m - Rmb100,000 subsidy Environmental projects over Rmb2m - Rmb200,000 subsidy Extra Rmb50,000 subsidy for each Rmb1m spent	Max subsidy per project: Rmb 1.5m

Source: City and Provincial Development and Reform Commissions

Using coal gas instead of natural gas

We are also seeing evidence of industrial users substituting natural gas with less expensive fuel options such as coal gas. Coal gas has a lower calorific value than natural gas but is still cheaper than natural gas. Listed companies, such as KEDA Clean Energy (600499.SS, Buy), have been expanding their coal-gas projects to provide alternatives to natural gas. As of end-2013, KEDA has numerous coal-gas projects spanning Shenyang, Guangxi, Sichuan, Shandong, as well as expansion and new projects planned in Anhui, Shandong, Shenyang, Guangdong, Guangxi and Sichuan.

There is evidence of industrial users substituting natural gas with coal gas (less expensive)

Cutting transmission tariffs

We believe government could also consider reducing the transmission margins for provincial grids, which are currently earning high returns. Based on financial data from some of the provincial grid companies, the Shandong provincial pipeline earned 12% ROA and 14% ROE in 2012; Jiangsu provincial pipeline earned 12% ROA and 15% ROE in 2012. Evidence of transmission tariff cuts was seen back in July 2013 and is summarised in Figure 14.

Figure 14: Provinces with announced transmission tariff cuts

Province	Pipelines affected	Transmission/distribution tariff (Rmb/cum, incl VAT)				Effective date
		Old	New	Change	%	
Jiangxi	Provincial lines	0.500	0.400	(0.100)	-25%	10-Jul-13
Shandong	PetroChina's lines average	0.224	0.187	(0.037)	-20%	10-Jul-13
Shandong	Sinopec's lines	0.317	0.270	(0.047)	-17%	10-Jul-13
Jiangsu	Sichuan to East	0.350	0.270	(0.080)	-30%	10-Jul-13
Hebei	Provincial lines	NA	NA	(0.050)	NA	10-Jul-13
Northern China	Shaanxi-Beijing	0.400	0.346	(0.054)	-13%	H1 2014

Source: Provincial Development and Reform Commissions, Company data

Power: further margin compression for gas-fired

We think rising gas costs will increase margins and dispatch risks for gas-fired power plant operators. We believe the likely outcomes will be further margin compression for gas-fired power plants, the government forcing gas utilities or upstream oil majors to sell at bigger discounts to gas-fired power plants, or both.

Gas-fired power plants earning below their cost of capital

We estimate that gas-fired power plants are currently earning around 2% unlevered internal rate of return (IRR) at their current spark spread of Rmb0.15/kWh, assuming an average utilisation rate of 3,500 hours per year, which is the planned utilisation hours for peaking plants in China. This IRR is much lower than the cost of capital which we estimate at about 7%.

2% IRR at gas-fired power plants is much lower than the cost of capital, which we estimate at about 7%

Figure 15 shows the tariffs, gas costs and gross margins (spark spreads) for gas-fired power plants in major locations in China, and Figure 16 shows the corresponding unlevered project IRR sensitivity at different levels of spark spreads and margins.

Figure 15: On grid tariffs, gas costs and sparks spreads for major gas-fired power plants, post July 2013

	On grid tariffs (Rmb/kWh, incl. VAT)	Gas cost (Rmb/cum, incl. VAT)	Spark spread (Rmb/kWh, excl. VAT)
Zhejiang - F level	0.904	3.22	0.22
Zhejiang - Amber Energy	0.960	3.22	0.14
Jiangsu - F level	0.606	2.22	0.13
Jiangsu - E level	0.690	3.30	0.02
Guangdong - Dapeng contract LNG **	0.533	1.56	0.19
Guangdong - Spot LNG **	1.170	5.31	0.17
Guangdong - West to East II	0.745	3.02	0.12
Beijing *** ****	0.762	2.67	0.21
Fujian **	0.513	1.66	0.15
Henan	0.609	2.22	0.14
Average			0.15

Note: ** Gas cost hike in July 2013 does not apply to Guangdong and Fujian province.

*** Tariffs shown for Beijing include on-grid tariff of Rmb0.573/kWh (incl. VAT), tariff subsidy of Rmb0.0447/kWh (incl. VAT) to fill in the gap between on-grid tariff and approved tariff of Rmb0.6177/kWh, and the gas cost subsidy (ex. VAT, calculated as 0.2cum/kWh x Rmb0.33/cum gas cost hike in 2010).

**** Assuming the Beijing municipal government will follow the same formula to grant gas cost subsidy (ex. VAT, calculated as 0.2cum/kWh x (Rmb0.33/cum gas cost hike in 2010 and Rmb0.39/cum gas cost hike in 2013)).

Source: Provincial Pricing Bureaux

Figure 16: IRR sensitivity to spark spreads and utilisation hours

		Spark spread (Rmb/kWh, excl. VAT)										
		0.10	0.11	0.12	0.13	0.14	0.15	0.16	0.17	0.18	0.19	0.20
Utilisation hours	2,500	NA	NA	NA	NA	NA	-8.9%	-5.7%	-3.5%	-1.8%	-0.4%	0.9%
	3,000	NA	NA	-13.0%	-6.8%	-4.0%	-1.8%	-0.1%	1.4%	2.8%	4.0%	5.2%
	3,500	NA	-7.5%	-4.0%	-1.5%	0.4%	2.1%	3.6%	5.0%	6.3%	7.5%	8.6%
	4,000	-5.8%	-2.5%	-0.1%	1.9%	3.6%	5.2%	6.6%	8.0%	9.3%	10.5%	11.7%
	4,500	-1.8%	0.7%	2.8%	4.6%	6.3%	7.8%	9.3%	10.6%	12.0%	13.2%	14.5%
	5,000	0.9%	3.2%	5.2%	7.0%	8.6%	10.2%	11.7%	13.1%	14.5%	15.8%	17.1%
	5,500	3.2%	5.4%	7.3%	9.1%	10.8%	12.4%	13.9%	15.4%	16.8%	18.2%	19.6%

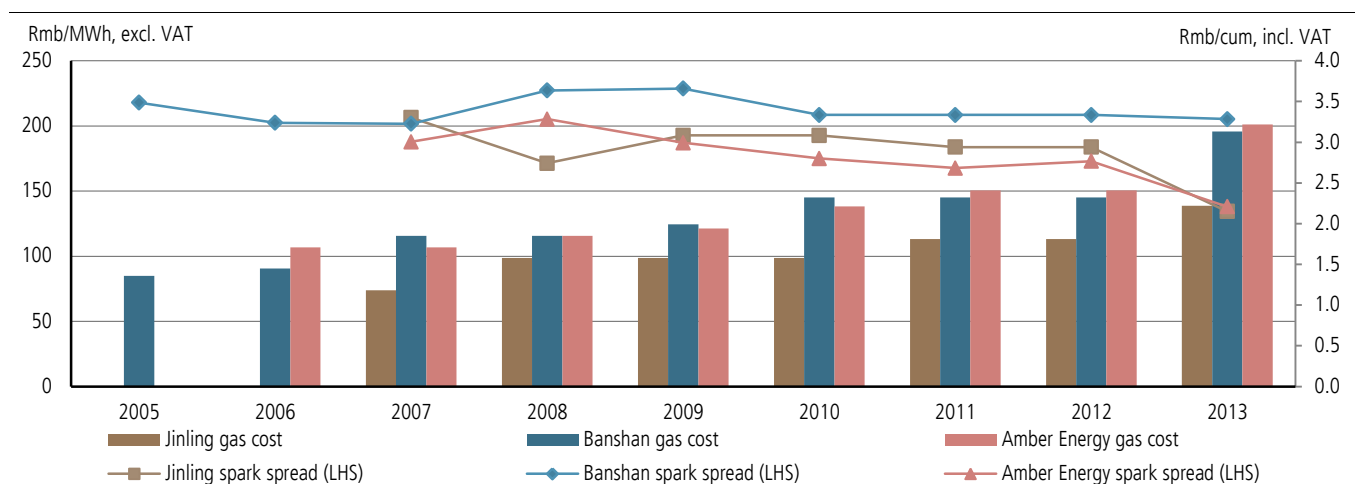
Source: UBS estimates

Fuel-cost pass-through is challenging

Gas costs have not been fully passed on to on-grid tariffs in most regions for the July 2013 tariff increases.

Figure 17 shows the historical track record of fuel-cost pass-through for power plants in Zhejiang and Jiangsu. Post the gas cost increase in July 2013, Figure 18 shows that Amber Energy has been able to pass through 80% of the change in fuel costs, while Jiangsu's power plants only passed through 30-35% of gas costs, and 67% for Henan's gas-fired power plants.

Figure 17: Historical spark spread (LHS) and gas prices of gas-fired units (RHS) in Zhejiang and Jiangsu



Source: Company data, UBS estimates

Figure 18: Gas-fired tariff adjustments upon gas cost increases in July 2013 for provinces with meaningful exposure to gas-fired power

	Gas-fired tariff (Rmb/kWh, incl. VAT)		Gas cost (Rmb/cum, incl. VAT)		Spark spread (Rmb/kWh, excl. VAT)		% gas cost pass through to tariff
	Before gas price hike	After gas price hike	Before gas price hike	After gas price hike	Before gas price hike	After gas price hike	
Zhejiang – F level	0.744	0.904	2.41	3.22	0.22	0.22	100%
Zhejiang – Amber Energy	0.800	0.960	2.41	3.22	0.17	0.14	80%
Jiangsu – F level	0.581	0.606	1.81	2.22	0.18	0.13	30%
Jiangsu - E level	0.605	0.69	2.09	3.3	0.16	0.02	35%
Shanghai *	0.454	0.504	2.32	2.72	(0.01)	(0.04)	NA
Guangdong - Dapeng contract LNG**	0.533	NM	1.56	NM	0.19	NM	NA
Guangdong - Spot LNG **	1.170	NM	5.31	NM	(0.00)	NM	NA
Guangdong - West to East II	0.745	NM	3.16	NM	0.09	NM	NA
Beijing *** ****	0.684	0.762	2.28	2.67	0.20	0.21	100%
Fujian**	0.513	NM	1.66	NM	0.15	NM	NA
Henan	0.553	0.609	1.81	2.22	0.16	0.14	67%

Note: *Tariffs shown for Shanghai are unit tariffs. This is in addition to capacity tariff of Rmb0.22/kWh (incl. VAT) for 2,500 hours.

**Gas cost hike in July 2013 does not apply to Guangdong and Fujian province.

***Tariffs shown for Beijing include on-grid tariff of Rmb0.573/kWh (incl. VAT), tariff subsidy of Rmb0.0447/kWh (incl. VAT) to fill in the gap between on-grid tariff and approved tariff of Rmb0.6177/kWh, and the gas cost subsidy (ex. VAT, calculated as 0.2cum/kWh x Rmb0.33/cum gas cost hike in 2010).

****Assuming the Beijing municipal government will follow the same formula to grant gas cost subsidy (ex. VAT, calculated as 0.2cum/kWh x (Rmb0.33/cum gas cost hike in 2010 and Rmb0.39/cum gas cost hike in 2013)).

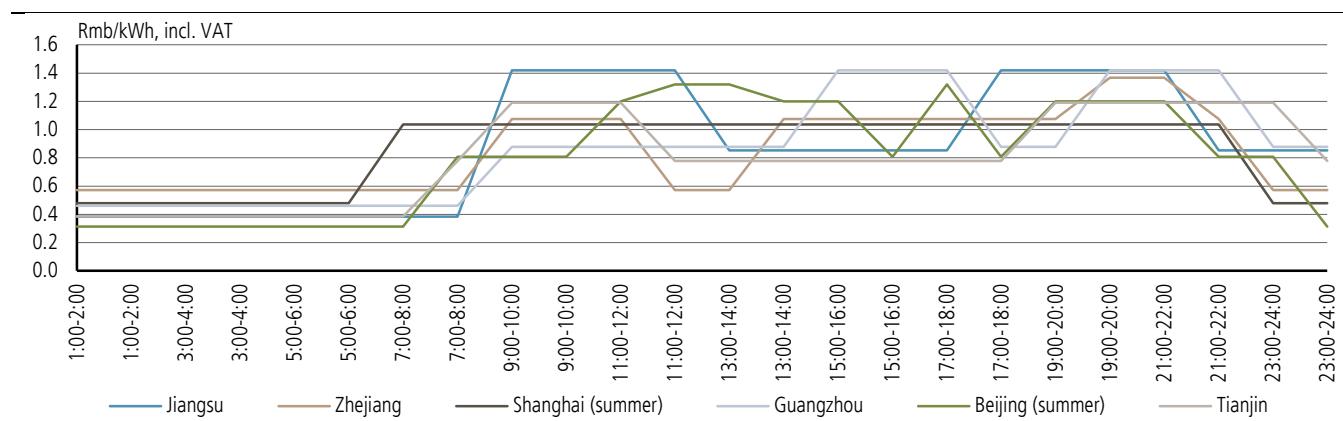
Source: Provincial Pricing Bureaux

Time-of-use pricing possible but not implemented

We think that, despite high gas prices, gas-fired units still have a technical advantage over other fuel types when used to meet peak demand for electricity. This is because it can be started much more quickly than nuclear or coal-fired power plants and, unlike wind and solar, is dependable/not intermittent.

We believe the solution to accommodate the high fuel costs would be the implementation of time-of-use tariffs for end-users. However, we think the policy was poorly implemented and government did not fully pass through higher gas costs to on-grid tariffs. Figure 19 shows the time-of-use tariffs for industrial users in major cities.

Figure 19: End-user power tariffs for industrial users (time-of-use)



Source: Local Pricing Bureaux

Gas power not competitive versus its alternatives

Natural gas is among the least competitive fuel type in China. Gas-fired on-grid tariffs are the second highest after solar (Figure 20), even though at this high tariff level the gas-fired power plants are earning below their cost of capital. We think this is mainly caused by expensive fuel costs and the lack of capital cost advantage.

Figure 20: On-grid tariff for different fuel types in different provinces

Rmb/kWh	Coal	Nuclear	Wind	Gas	Solar
Beijing	0.387	NA	0.610	0.762	0.950
Jiangsu	0.430	0.430	0.610	0.606	1.000
Shanghai	0.452	NA	0.610	0.724	1.000
Zhejiang	0.457	0.430	0.610	0.772	1.000
Guangdong	0.502	0.430	0.610	0.816	1.000

Source: NDRC, company data

Beijing and Zhejiang have better affordability; not others

Beijing and Zhejiang have by far demonstrated a stable fuel-cost pass-through regime for gas-fired power plants, and we estimate their gas-fired power plants are earning around 8-9% unlevered IRR.

Power plant operators in other regions, such as Henan and Jiangsu, have already experienced margin squeeze. For Tianjin, our discussion with the independent power producers (IPP) also shows that it has yet to develop a proper fuel-cost pass-through process for gas-fired power plants. For Guangdong, fuel-cost pass-throughs have yet to be tested because gas costs were not increased in July 2013.

Data for Sichuan and Liaoning's gas-fired power plants is unavailable, but their scale of gas-fired power development is relatively small.

We do not think the success of fuel-cost pass-through in Zhejiang and Beijing is easy to replicate in other provinces. This is because Zhejiang historically experienced peak power shortages and needed to encourage gas-fired unit investments with favourable economic incentives. However, management of IPPs have said that peak power shortages have become less of a problem in Zhejiang recently. Therefore, the IPPs are slowing construction progress because they are concerned that reasonable tariffs cannot be guaranteed. The case for Beijing was more of a political decision to make the capital of China clean.

The success of fuel-cost pass-through in Zhejiang and Beijing is not easy to replicate in other provinces

Transport: gas to remain competitive for vehicles

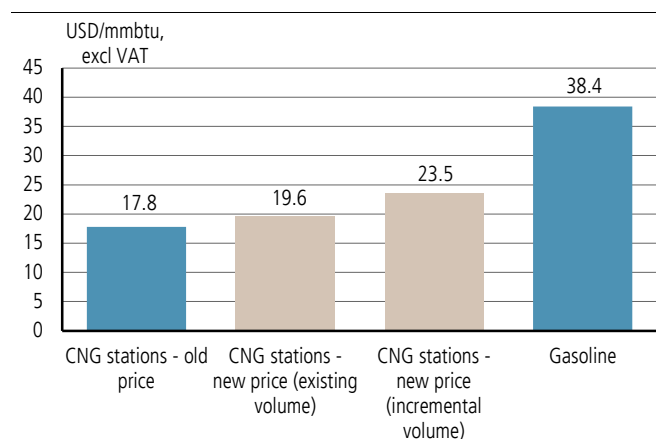
We anticipate that CNG and LNG as fuel sources will be competitively priced when used in vehicles, despite ongoing increases in gas prices because both fuel types are, and will be cheaper than the alternatives. As shown in Figure 21 and Figure 22, we estimate CNG and LNG will still cost 40% and 20% less, respectively, than the alternatives.

We estimate CNG and LNG will still cost 40% and 20% less, respectively, than the alternatives

We do not think conversion cost is an issue for CNG vehicles because the upfront investment is minimal, while we think the high conversion costs for LNG vehicles could be mitigated through government subsidies.

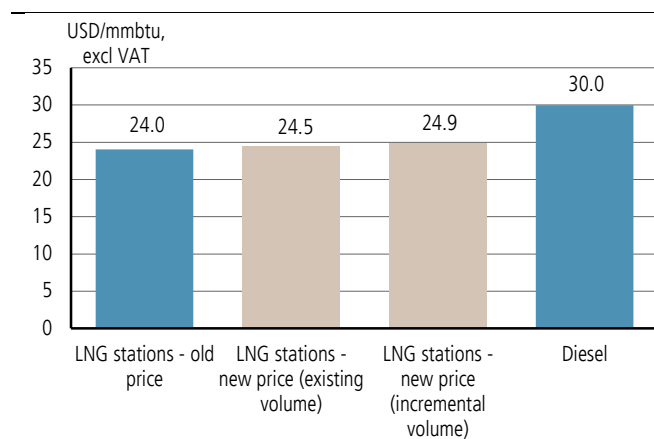
Despite high affordability for vehicle users, one risk is that the government still does not allow gas costs to pass through. Some governments have disallowed a CNG gas-cost pass-through in the July 2013 price hike to protect taxi drivers, because they consider taxi drivers as citizens in need of protection, similar to residential users. This happened in some cities in Anhui and Henan.

Figure 21: CNG versus gasoline price



Source: CEIC, Wind, UBS estimates

Figure 22: LNG versus diesel price



Source: CEIC, Wind, UBS estimates

Payback periods are short for CNG vehicles

Figure 23 shows the payback period for CNG vehicles. Even assuming the incremental city gas price hike was to be fully passed through to the CNG vehicle users, we estimate the payback period for the conversion cost would only be lengthened slightly to four months from three months.

Payback for CNG vehicles lengthened slightly to four months from three months

Figure 23: Payback period for CNG vehicle users at current and projected gas prices

	Gasoline	Current CNG price	Projected CNG price at UBSe incremental gas price
Price	6.0 Rmb/L	4.0 Rmb/cum	4.5 Rmb/cum
Consumption/km	0.1 L	0.095 cum	0.095 cum
Cost/km	0.6 Rmb	0.380 Rmb	0.428 Rmb
One-year distance travelled	100,000 km	100,000 km	100,000 km
One-year fuel cost	60,000 Rmb	38,000 Rmb	42,750 Rmb
Upfront conversion costs from gasoline to CNG		5,000 Rmb	5,000 Rmb
Cost saved per year by using CNG		22,000 Rmb	17,250 Rmb
Payback period		2.7 months	3.5 months

Source: UBS estimates

LNG vehicles payback could be shortened in the future

We estimate that the payback period is relatively long at around two years at the current gas price for LNG vehicles. However, we think the payback period could be shortened in the future, because:

The LNG price discount to diesel could be maintained, despite ongoing gas price increases

- We expect tighter government regulation on vehicle emissions will require diesel trucks to spend Rmb20,000 to Rmb30,000 per vehicle to retrofit their equipment, such that the emissions will comply with Euro IV standard by 1 January 2015. Taking this cost into account would reduce the payback period to a year or less.
- We think the LNG price discount to diesel could be maintained, despite ongoing increases in the gas price. This is because we believe the oversupplied LNG processing industry lacks the pricing power to push through high gas costs. Should there be any meaningful closure of LNG processing capacity, we could see more resistance of margin compression in LNG processing plants, which could reduce the relative competitiveness of LNG to vehicle users.

Figure 24: Payback period for LNG vehicle users at current and projected gas prices

	Diesel		Current LNG price		Projected LNG price at UBSe incremental gas price	
	Highway buses	Heavy duty trucks	Highway buses	Heavy duty trucks	Highway buses	Heavy duty trucks
Price	7.5 Rmb/L	7.5 Rmb/L	5.0 Rmb/cum	5.0 Rmb/cum	5.0 Rmb/cum	5.1 Rmb/cum
Consumption/km	0.4 L	0.5 L	0.520 cum	0.600 cum	0.520 cum	0.600 cum
Cost/km	3.0 Rmb	3.8 Rmb	2.600 Rmb	3.000 Rmb	2.600 Rmb	3.060 Rmb
One-year distance travelled	100,000 km	100,000 km	100,000 km	100,000 km	100,000 km	100,000 km
One-year fuel cost	300,000 Rmb	375,000 Rmb	260,000 Rmb	300,000 Rmb	260,000 Rmb	306,000 Rmb
Upfront conversion costs from diesel to LNG			70,000 Rmb	80,000 Rmb	70,000 Rmb	80,000 Rmb
Cost saved per year by using LNG			40,000 Rmb	75,000 Rmb	40,000 Rmb	69,000 Rmb
Payback period (current)			1.8 years	1.1 years	1.8 years	1.2 years
Payback period (if considering tighter standards)			1.0 years	0.7 years	1.0 years	0.7 years

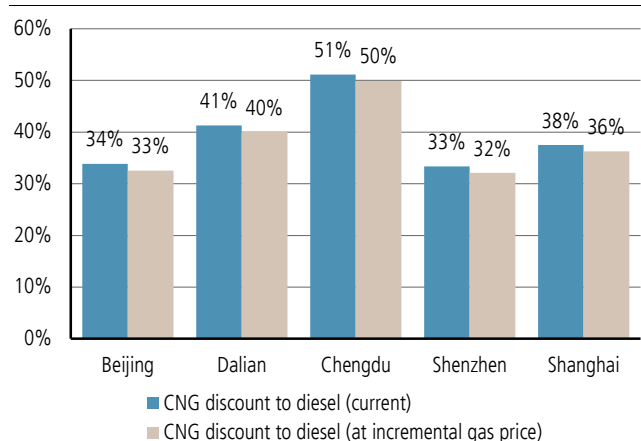
Source: UBS estimates

Affordability is similar across regions

For CNG, Figure 25 shows the price discounts compared to gasoline in major cities in China. It shows that the price discounts for CNG, both currently and at the incremental gas price, remain attractive at 30% or above for most cities. We therefore do not see a huge difference in affordability across cities.

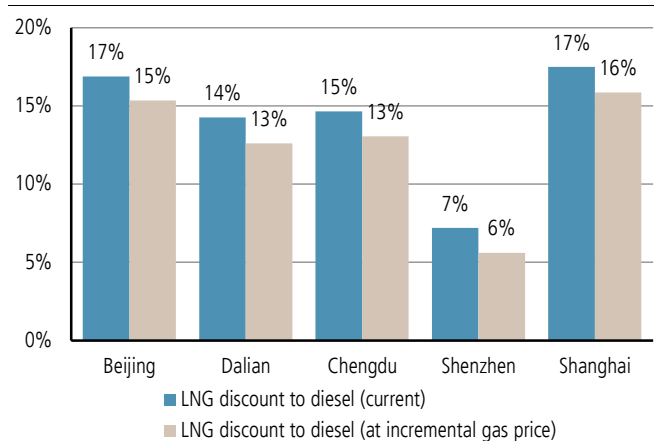
For LNG, Figure 26 shows the price discounts compared to diesel in major cities in China. We do not see a major regional difference in affordability except for Shenzhen. Affordability is relatively low in Shenzhen and we expect conversion to be slow.

Figure 25: CNG vehicle price discounts to gasoline



Source: Wind, CEIC, UBS estimates

Figure 26: LNG vehicle price discounts to diesel



Source: Wind, CEIC, UBS estimates

Government could continue subsidising conversion costs

Given that the major obstacle for vehicle users to convert to LNG is the high upfront investment cost of around Rmb80,000-100,000 per truck, we think the government could continue to facilitate the conversion through subsidisation. This is currently a local government policy and we think this could be rolled out on a larger scale, given the government's plan to reduce emissions.

Figure 27: Examples of government subsidies on vehicle conversions to LNG

Province	City	Type of users	Amount per vehicle on one-off purchase costs	Announced date
Jiangsu	Nanjing, Changzhou, Jiangsu, Nanyong, Yancheng, Yangzhou	Public transport	Rmb20,000	Jun-14
Guangdong	Guangzhou	Public transport	To be decided	Jul-13
Guangdong	Foshan	Public transport	Not less than Rmb10,000	Sep-13
Liaoning	Dalian	Public transport	Rmb60,000-80,000	Apr-13
Liaoning	Shenyang	Public transport	50% of purchase cost	Aug-13
Shandong	All excluding Qingdao	Public transport	Rmb30,000 for purchase cost > Rmb200,000	Feb-14
Fujian	All	Public transport	Reasonable financial subsidy for qualified vehicles	Feb-14
Hunan	Changsha	Public transport	Rmb80,000	Oct-12

Source: Provincial Development and Reform Commissions

District heating: losses likely subsidised

We believe that, either at existing or incremental gas prices, district heating companies (mostly located in Northern China) have affordability issues if current heating prices remain the same. We think it is difficult for district heating companies to pass through gas costs by raising heating prices in the near term, because heating price reforms have been slow.

However, we think that the government may still want to expand the use of natural gas and have the interest to subsidise the losses, because a centralised district heating company demonstrates higher energy efficiency than a scattered heating system.

We think the low affordability of district heating companies is insignificant to the gas utilities. We think the government will continue to subsidise the unprofitable heating companies, and perhaps gradually reform the heating prices to improve affordability.

We think the government will continue to subsidise the unprofitable heating companies

District heating is still encouraged for its efficiency

Gas is unaffordable – Beijing as an example

We have looked at the profitability of Beijing district's heating as a reference point. Financial data for other district's heating companies are unavailable because most of these companies are state-owned enterprises.

We estimate that supplying heat by coal boilers has a relatively high margin of around 53%, which is substantially higher than that of 20% when using natural gas at existing gas prices. Figure 28 shows the district heating margins for residential users in Beijing when using different types of fuel. This only shows the margin for residential users because it is the major customer group, accounting for 73%.

Figure 28: District heating cost breakdown for residential users

District Heating (Beijing)	Coal boiler	Natural gas (existing gas price)	Natural gas (incremental gas price)
Unit	Rmb/t	Rmb/cum	Rmb/cum
Price (incl. VAT)	600.0	2.5	3.0
Price (excl. VAT)	512.8	2.2	2.6
KCal/unit of fuel	5,500,000	8,000	8,000
KCal/m ²	75,000	75,000	75,000
Unit fuel cost (Rmb/m ²)	7.0	20.6	24.5
Resident price (Rmb/m ² , excl. VAT)	14.1	25.6	25.6
Gross margin (Rmb/m ²)	7.1	5.1	1.2
Gross margin (%)	53%	20%	5%

Source: Company data, UBS estimates

Heating price reforms have been slow

We believe the obvious solution to improve profitability of the district's heating companies is to reform heating prices. The government will need to:

- Raise heating prices, or;
- Introduce time-of-use pricing to charge for heating based on actual consumption instead of the heating area. Time-of-use pricing could also reduce fuel costs because it would discourage wasting energy.

However, we think the progress on heating price reform could be slow based on historical track record.

In Beijing, the majority of its heating sales (73%) currently are to residential users. The residential heating sales price has been unchanged for the past 13 years – the previous heating price hike took place in 2001. In Tianjin, the government last raised the residential heating price six years ago in 2008.

In Beijing, the residential heating sales price has been unchanged for the past 13 years

Time-of-use pricing for heating sales was first announced by the Ministry of Housing and Urban-Rural Development (MOHURD) in 2003. However, implementation has been very slow. We believe the major reasons include:

- **A lack of metres.** Time-of-use heating pricing requires heating metres to be installed to measure the heat consumed.

- **A lack of a temperature adjustment function.** Currently district heating in China provides heat at a fixed temperature. Users need to adjust the temperature by either turning off the heater, or opening windows, which causes heat wastage. Heating pipelines and appliances would need to be retrofitted to enable a temperature adjustment function.

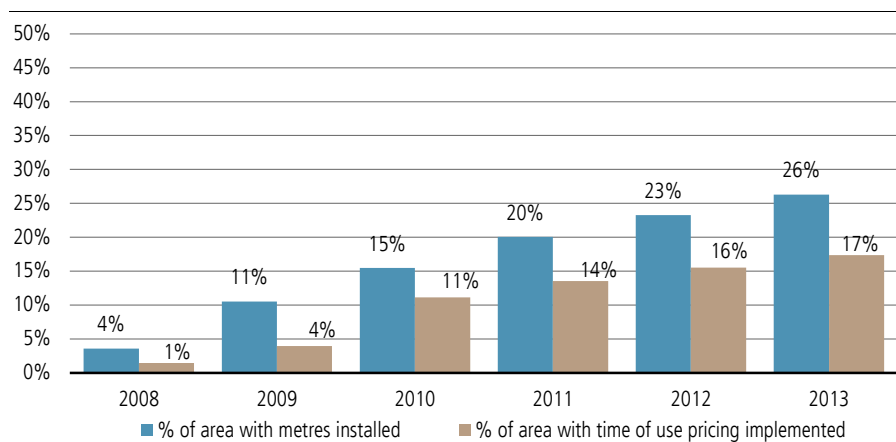
According to the Beijing Heating Supply Association, total retrofitting costs would be around Rmb20-30/sqm. Currently, the retrofitting costs are paid by the government in most cities, which partly explains the slow progress in retrofitting.

We remain sceptical about places with metres installed, because:

- Even if metres are installed, some cities still charge users based on heating area but not actual consumption. This is because of the push back from some users, who end up paying higher prices due to poor heat insulation in their apartment.
- Even if time-of-use pricing is implemented, some users like those in Beijing still enjoy a cap limiting the maximum amount on their heating bills.

Figure 29 shows the percentage of heating area in China with metres installed and time-of-use pricing mechanism implemented. It shows that China only started to install metres in 2008, five years after the first reform policy was announced in 2003. As of end-2013, although 26% of the heating area in China has metres installed, and only 17% has implemented time-of-use pricing.

Figure 29: Percentage of heating area in China with metres installed, and with time-of-use pricing implemented



Source: Ministry of Housing and Urban-Rural Development

Similar affordability across cities

Heating prices are similar across cities in the Northern region, at Rmb22-25/sqm except in Harbin, at Rmb40/sqm. Because heating prices are similar, we think another key indicator to look at in differentiating affordability is the success of implementing time-of-use pricing.

Figure 30 shows the breakdown of the percentage of heating area with time-of-use pricing implemented for some key provinces, as of end-2011. It shows that the North Eastern provinces are the least successful in implementing time-of-use pricing.

Figure 30: Percentage of heating area with time-of-use pricing implemented in China as of end-2011, by province

Province	Total heating area (m sqm)	Length of heating pipelines (km)	Area with time-of-use pricing implemented (sqm)	% of area with time-of-use pricing implemented
Beijing	508	11,775	56	11%
Tianjin	272	15,278	65	24%
Hebei	420	10,132	39	9%
Shanxi	328	5,973	49	15%
Inner Mongolia	297	6,365	38	13%
Liaoning	816	24,977	28	3%
Jilin	348	11,388	16	5%
Heilongjiang	429	14,970	38	9%
Shandong	611	26,747	77	13%
Henan	118	4,051	27	23%
Shaanxi	101	1,293	10	10%
Gansu	122	3,718	21	17%
Ningxia	68	2,241	10	15%
National	4,738	147,353	642	14%

Source: Ministry of Housing and Urban-Rural Development

Chemical: fertilizer producers getting squeezed

We believe that the chemical producers will find natural gas unaffordable, although some regions especially closer to the gas fields have better affordability than the others. We do not expect many chemical users will wish to convert to natural gas, nor will the government subsidise them to convert. This is because the government has classified the chemical producers as a restricted user-group in their natural gas users' priority list. We believe chemical users will be predominantly coal-based in the future.

Chemical users unlikely to rush conversion to natural gas; government subsidy also unlikely

Too fragile to absorb further gas price hikes

We estimate last year's Rmb0.25/cum gas price hike translated to an increase of Rmb150-160/ton and Rmb225-240/ton for gas-based urea and methanol producers, respectively, which represent around 10-12% of ASPs as of July 2014 prices.

We believe most of the urea producers in China were loss-making in Q214, while some methanol producers have also started to struggle. Any further hikes in natural gas costs could bring most of the gas-based producers into negative operating cash flow.

We believe most of the urea producers in China were loss-making in Q214,...

We believe the phase-out of gas-based chemical production is the long-term trend and we have already started to see companies voluntarily shut down small-scale and uneconomic plants, or start switching feedstock to coal, or add coal-based production capacities to hedge losses on the gas end (eg, CNOOC Group's China BlueChem, Chitianhua).

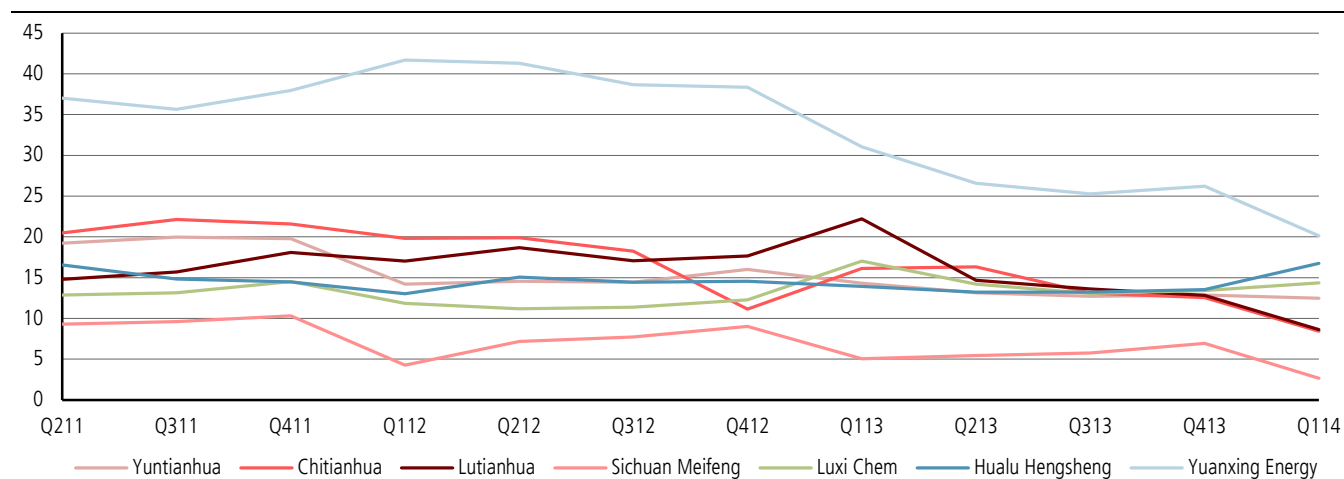
...while some methanol producers have also started to struggle

However, the process of capacity shut down could be slow. Given gas-based urea and methanol capacities account for around 27-30% and 18-20% of total capacities, respectively, any meaningful reduction in gas-based production utilisation rates and strong regionalisation could create tightness and drive up ASPs, thus bringing back the idled capacities.

One of the key risks in phasing out natural gas-based chemical producers is the coal price. We expect coal prices to remain low because of limited demand growth and plentiful supply from both domestic and imports. However, should there be any coal price increases, whether cyclically- or policy-driven, the cash flow burden of natural gas-based players could be reduced.

Figure 31 shows the historical gross margin for the coal-based and gas-based chemical producers.

Figure 31: Historical gross profit margins for selected coal vs gas-based fertilizer/methanol producers



Note: Natural gas-based chemical players are marked in reds, whereas coal based players are marked in blue; Yuanxing Energy has gone through a product/feedstock (from gas to coal) portfolio shift, thus profitability trend is a little different to pure coal-based producers.

Source: WIND

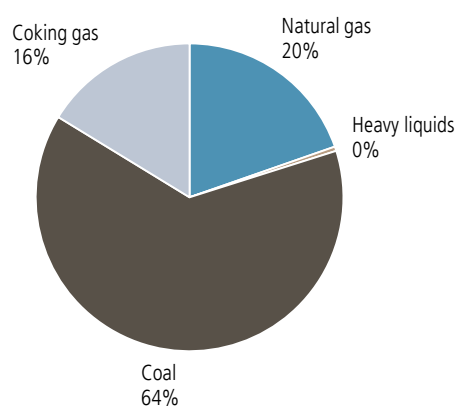
Affordability is better in regions close to gas fields

We think there is a large disparity in affordability across the different regions. Those located close to gas fields are more likely to find natural gas affordable than the coastal players.

Gas-based chemical producers are mainly concentrated in gas-rich regions, such as Sichuan and Ordos. The resilience of gas-based chemical producers is especially strong in Sichuan, given the high transportation cost of diverting cargoes from major coal-based production regions (eg, Inner Mongolia, and Shaanxi).

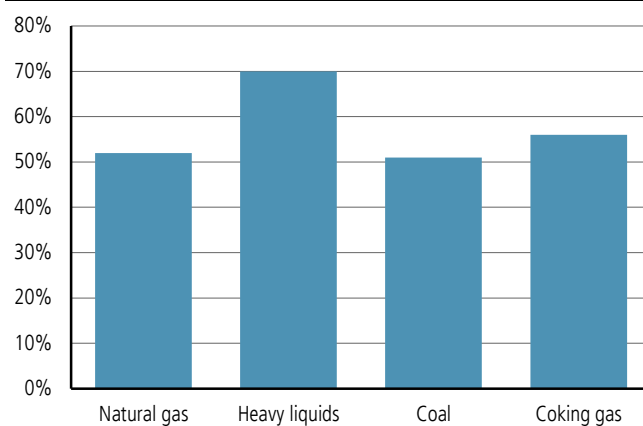
According to IHS CMAI, the utilisation rates of gas-based methanol producers in China have been stable at around 50-55% since 2010, although there have been two rounds of natural gas price hikes since then.

Figure 32: China methanol capacity by feedstock



Source: IHS CMAI

Figure 33: China methanol plant utilisation rate (end July)



Source: IHS CMAI

Economics of supply

Supply-side arguments for price hike valid as ever

Aside from the obvious need to reduce natural gas import losses, higher gas prices are also a must from the perspective that China needs to build up its domestic gas supply in a sustainable way. This means putting the right incentives in place to ensure that gas exploration and development generates reasonable returns, and therefore encourages plentiful supply.

Higher natural gas prices can also help support the economics of oil production in China. This is given that natural gas is often produced alongside oil in major projects (eg, Daqing oil field). A higher natural gas price can therefore help to raise combined average selling prices of oil and gas fields. This, in turn, can help to counter the risk of falling oil prices and rising costs.

Raising natural gas prices to a level that is fair for suppliers has long been the intent of the National Development and Reform Commission (NDRC). However, only recently did the pace of price reform take on a more aggressive tone. In our view, lower inflation and more stable energy prices (oil and coal) have provided a good back drop for the policy measures.

Lower inflation and more stable energy prices (oil and coal) have provided a good back drop for the policy measures

However, while we are encouraged that the NDRC will raise the natural gas ceiling price again starting from 1 September, we cannot discount the risk that gas suppliers, like PetroChina, meet resistance from customers as the suppliers attempt to push sales prices up toward the higher ceiling price levels. This is certainly a risk, in our view, given the lower affordability of many customers.

We also note that there are a number of non-price related factors that could lead to an overall reduced burden for suppliers, like PetroChina, and hence reduce the company's urgency to push through rapid price hikes. These include the potential for cost cuts post state-owned enterprise (SOE) reform and also the chance that the NDRC could ease the existing tax regime (windfall profit tax on oil, resource tax, VAT).

Share of cheap conventional sources has dwindled

We estimate that last year, about 44% of China's gas supply came from lower cost onshore conventional sources. This is down from levels near 65% just five years prior. We expect the relative share to fade gradually to about 20% within 10 years from now. Tight gas (abundant although more costly when compared to conventional gas) has maintained a share of near 20%.

Imported natural gas supply surged to account for an estimated 29% of overall supply last year (up from 8% in 2008). LNG has been imported into China since 2006 and pipeline gas imported into China since 2010. We expect the import share to peak at around 36% by 2018, with about 19% of supply coming from LNG and about 17% coming from pipeline gas.

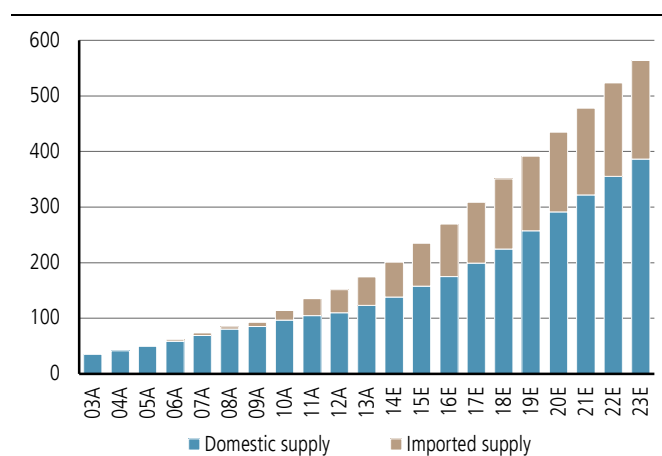
Meanwhile for the remainder of this decade, we expect to see shale gas and coal-to-gas start to make up for a material portion of gas supply (a combined 15% by the end of this decade). While this is good news for edging out further market share gains for imported gas, as we discuss in this report, the required prices will still be high when compared to the historical cost of other domestic sources.

Figure 34: Natural gas supply forecasts (bcm)

New	11A	12A	13A	14E	15E	16E	17E	18E	19E	20E	21E	22E	23E
Conventional	68	70	77	82	89	93	99	104	108	112	115	120	124
Tight	25	27	32	35	40	44	49	55	61	66	71	77	83
Coal-to-gas	-	-	0	2	5	8	12	18	30	44	54	62	66
Offshore	10	10	11	13	16	18	22	25	27	29	30	32	35
Shale gas	-	-	0	1	3	5	8	11	15	21	29	37	47
CBM	2	3	3	4	6	8	10	13	16	19	23	28	33
Pipeline gas	14	22	28	33	36	45	53	65	67	71	80	87	95
LNG	16	20	23	30	41	49	56	61	68	72	77	81	82
Total	135	151	174	201	235	270	308	351	392	435	478	524	564
% growth	18%	12%	15%	15%	17%	15%	14%	14%	12%	11%	10%	9%	8%

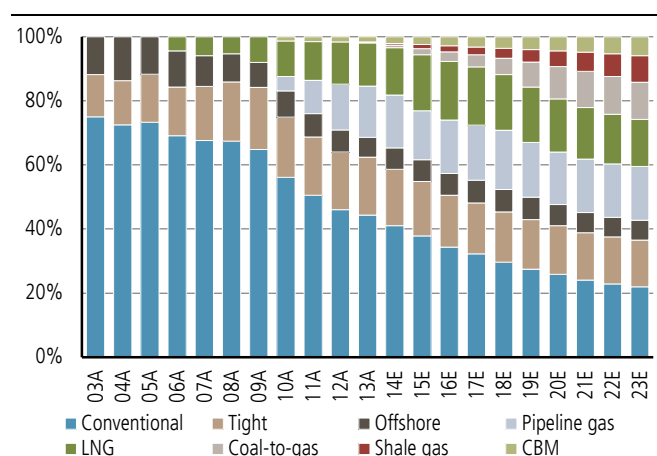
Source: NDRC, Wood Mackenzie, Xinjiang Daily, UBS estimates, Bloomberg, C1 Energy, Reuters

Figure 35: Gas supply forecast (bcm)



Source: Wood Mackenzie, BP Statistical Review 2013, UBS estimates

Figure 36: Breakdown of gas supply forecast



Source: Wood Mackenzie, BP Statistical Review 2013, UBS estimates

Gas imports driving the per unit cost increase

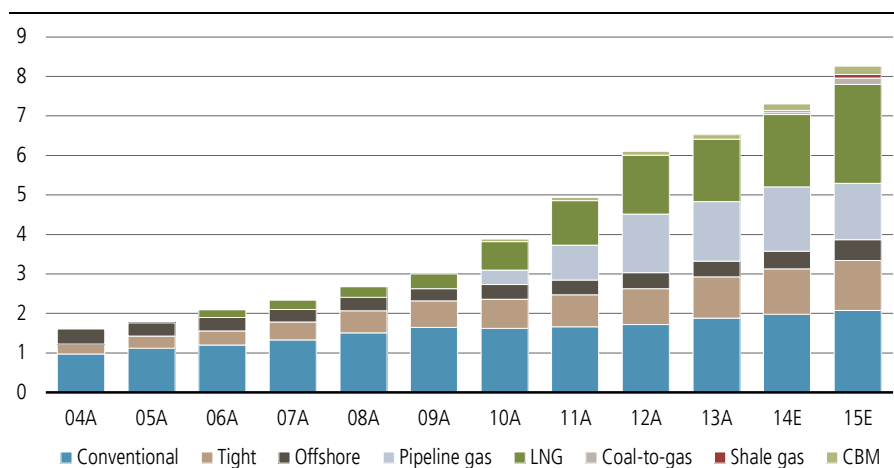
Gas imports first entered China via LNG in 2006 but it wasn't until 2010 that the per-unit cost of gas imports started to surge, led by LNG and pipeline imported gas. While domestic gas sources have remained inexpensive relative to imports, the price required for all types of gas projects (conventional, tight, shale and coal gas) has also been on the rise.

In Figure 37, we estimate the average per unit cost of China's natural gas supply. We define the cost to China as the price required to achieve a 12% project IRR on domestic projects, and the cost of imported gas at the border (irrespective of IRR). We exclude VAT, transmission tariffs, re-gas fees and other non-source related costs. To derive the chart, our cost estimates are weighted by the percentage contribution from different supply sources.

Our analysis indicates that the cost to China more than doubled from less than US\$3.0/mcf (Rmb0.73/cum) in 2008 to more than US\$6.0/mcf (Rmb1.3/cum) in 2013. While natural gas imports accounted for only 29% of the overall supply by 2013, we estimate that the high, and on average rising, import prices were behind 71% of the increase in per unit cost of supply from 2008 to 2013. Also based on our expectations for cost escalation, we could see another nearly US\$2.0/mcf (Rmb0.44/cum) increase from 2013 to 2015.

We estimate that the high import prices were behind 71% of the increase in per unit cost of supply during 2008-13

Figure 37: Contribution to annual cost of supplying gas to China (US\$/mcf)



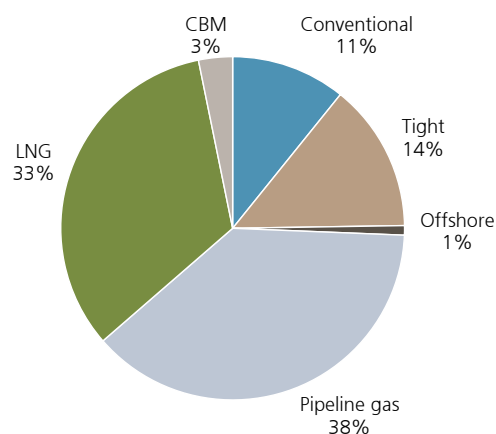
*Note: Figures represent well-head gas prices at 12% IRR, LNG and pipeline imports at border prices, excluding VAT, pipeline transmission tariffs, re-gas and other non-source-related costs.
Source: PetroChina, Sinopec, Wood Mackenzie, CEIC, UBS estimates

Figure 38: Assumed gas prices to achieve 12% IRR for onshore projects and the gas price at the border for imports (all estimates exclude VAT)

	04A	05A	06A	07A	08A	09A	10A	11A	12A	13A	14E	15E
Conventional	1.3	1.5	1.7	2.0	2.2	2.5	2.9	3.3	3.7	4.2	4.8	5.5
Tight	1.8	2.1	2.4	2.7	3.0	3.5	3.9	4.5	5.1	5.8	6.5	7.4
Coal-to-gas	-	-	-	-	-	-	-	-	-	-	8.2	8.2
Offshore	2.8	2.8	3.1	3.3	3.8	4.0	4.5	5.2	5.8	6.5	7.2	7.8
Shale gas	-	-	-	-	-	-	-	-	-	-	7.4	7.4
CBM	-	-	-	-	-	-	4.9	5.5	6.1	6.8	7.5	8.4
LNG	-	-	4.4	3.9	5.0	4.6	6.5	9.3	11.3	11.8	12.4	14.4
Pipeline gas	-	-	-	-	-	-	8.1	8.5	10.4	9.5	9.9	9.3

Source: Wood Mackenzie, CEIC, UBS estimates

Figure 39: Contribution to incremental increase in the per unit cost of supply (US\$/mcf) (2008-13)



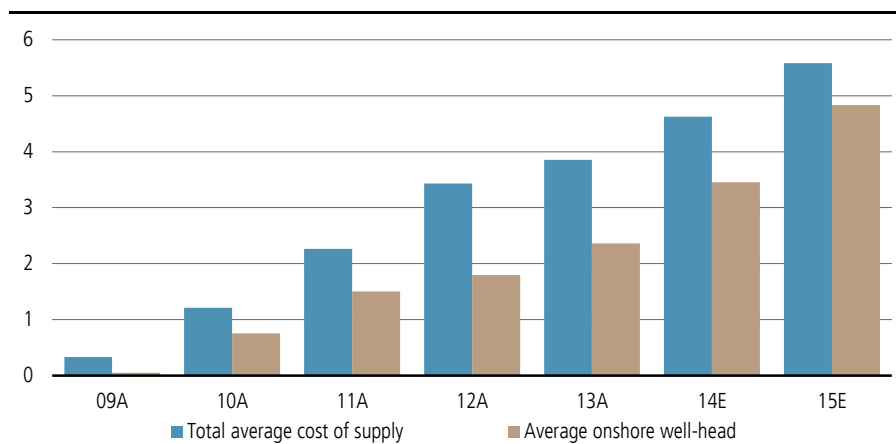
Source: Wood Mackenzie, BP Statistical Review 2013, UBS estimates, Reuters, CEIC

Domestic gas price hikes struggling to catch up

While we estimate that the total average cost of supply rose by about US\$4/mcf from 2008 to 2013, we estimate that average domestic well-head prices rose by only about 50-60% of that level. Under our base case, we expect that the gap will close further to 87% (US\$5.6/mcf increase in cost of supply versus US\$4.8/mcf rise in onshore well-head prices). However, as our demand analysis suggests that there is a risk of reduced affordability in 2015, it is possible that our price hike scenario could prove to be too aggressive in the next 12-24 months.

It is possible that our price hike scenario could prove to be too aggressive

Figure 40: Cumulative change in domestic well-head gas prices versus cumulative change in cost of supplying gas to China (US\$/mcf)



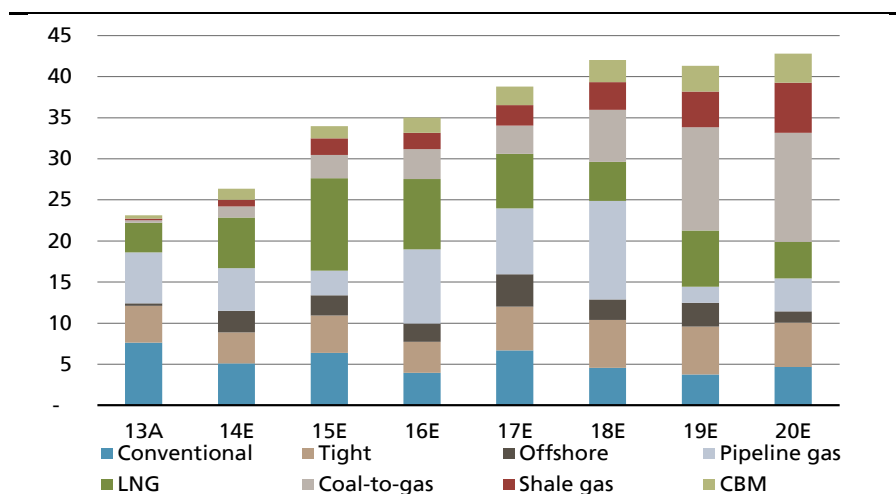
Note: Figures represent incremental well-head gas prices at 12% IRR, LNG and pipeline imports at border prices, excluding VAT, pipeline transmission tariffs, re-gas and other non-source-related costs.

Source: PetroChina, Sinopec, Wood Mackenzie, CEIC, UBS estimates

Gas cost inflation could moderate after 2015E

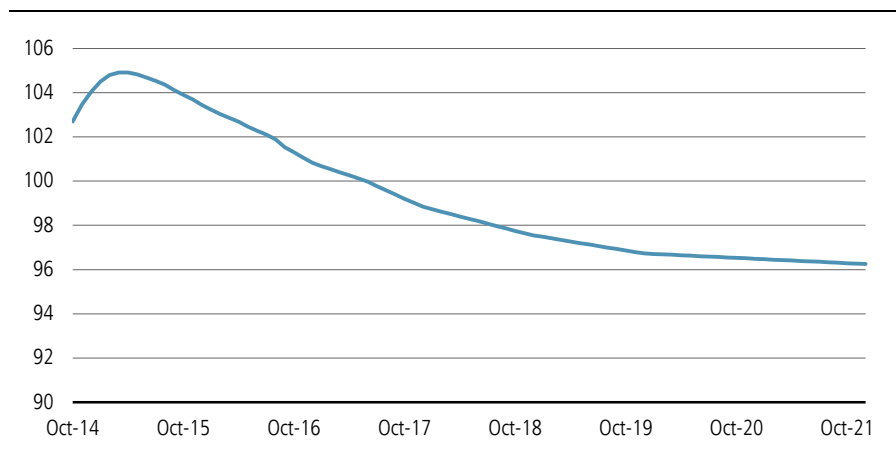
We believe the cost to China of sourcing natural gas is not likely to escalate much after 2015E. First, we expect global oil prices to moderate. Given the city gate prices are linked LPG and fuel oil, and these are in turn linked to oil prices, this should bring down the incremental cost of imported natural gas. Second, we expect slightly less costly domestic sources, particularly coal-to-gas and shale gas, to begin to take market share back from the major imported sources.

Figure 41: Annual incremental contribution to gas supply (bcm/annum)



Source: Wood Mackenzie, BP Statistical Review 2013, UBS estimates

Figure 42: Brent futures curve (US\$/bbl)



Source: Bloomberg

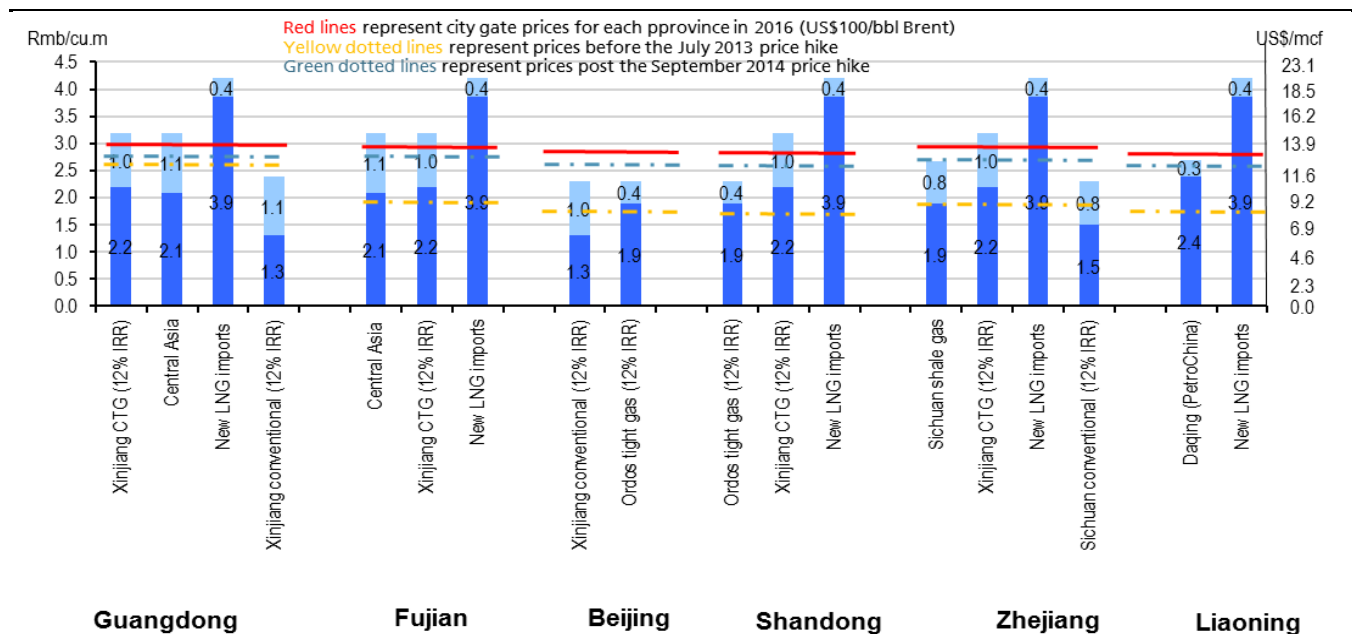
Comparing cost of incremental supply by source

LNG economics still poor under new price regime

In Figure 43, we illustrate the implied natural gas price that domestic producers will require in order to achieve an incremental IRR of 12%. This includes the implied well-head price as well as transportation fee. We have also included the gas import arrival prices on the Eastern seaboard. The price estimates are then compared to our forecast city gate gas prices under an assumed US\$100/bbl Brent.

The chart shows us that while the economics of LNG imports will still struggle even in the long term, and pipeline imports may barely break even, all other gas supplies should be profitable. The economics of conventional and tight gas projects should remain particularly strong for the foreseeable future, although the cost to extract these sources has also risen materially. However, some producers, for example coal-to-gas (CTG), may need to accept an IRR slightly below 12%.

Figure 43: Domestic and imported gas supplies compared to new incremental city gate prices



Source: UBS estimates, NDRC, Wood Mackenzie

Assumptions behind incremental cost of supply estimates

Conventional and tight gas to generate solid returns

The implied prices for conventional and tight gas, not surprisingly, all fit comfortably below our anticipated city gate prices (assumed US\$100/bbl Brent) along China's major Eastern seaboard cities. We base this on the modelling of major projects by Wood Mackenzie.

While the gas prices required for conventional and tight gas projects to achieve a 12% IRR are well below estimated city gate prices, the discount is not as wide as one might expect. We note, for example, that Wood Mackenzie puts the required gas prices for conventional gas projects in Xinjiang and Sichuan as high as US\$5.9/mcf and US\$6.8/mcf, respectively, if assuming a 12% project IRR. Meanwhile, Ordos basin tight gas projects would require up to US\$8.6/mcf if we assumed a 12% IRR.

Figure 44: Required well-head price to justify 8-12% project IRR in China

	Rmb/cum	US\$/mcf
Xinjiang conventional (8% IRR)	1.1	5.0
Xinjiang conventional (12% IRR)	1.3	5.9
Sichuan conventional (8% IRR)	1.3	5.9
Sichuan conventional (12% IRR)	1.5	6.8
Ordos tight gas (12% IRR)	1.9	8.6
Ordos tight gas (8% IRR)	1.7	7.7

Source: Wood Mackenzie

Shale gas: Sinopec's Fuling project economics look good

We assess the economics of shale gas in China based on Sinopec's Fuling project in Chongqing. We believe Fuling can meet a 12% IRR based on a well-head price of US\$8.6/mcf. This puts the required delivery price to the East coast comfortably below our estimated city gate price. Therefore, this suggests good economics. We are less convinced of the economics of other shale projects at this stage, and this is what underpins our modest view on total shale gas production in China.

Figure 45: Fuling shale gas model 12% IRR scenario assumptions

	Unit	Assumptions
Gas price (incl. VAT; excl subsidy)	Rmb/cum	1.90
Gas price (incl. VAT; excl subsidy)	US\$/mcf	8.6
Subsidy (pre-2015)	Rmb/cum	0.40
Subsidy (post-2015)	Rmb/cum	0.40
Current well cost	Rmb m	83
Current well cost	US\$ m	13.4
Annual decline in well cost (first 10 yrs)	percent	2%
Annual decline in well cost (post 10 yrs)	percent	2%
Operating cost (incl. exploration exp)	Rmb/cum	0.80
SG&A as % of total revenue	percent	3%
First 3-year daily production (avg)	'000 cumd	50
First 3-year daily production (avg)	m cufd	1.8
Decline rate after first 3 years	percent	15%
Gas recovery per well	m cum	152
Gas recovery per well	m cuf	5,353
Gas recovery per well	'000 boe	892
Wells drilled		499

Source: UBS estimates

Offshore China: projects getting more costly

We use the Wenchang 9-2/9-3/10-3 production and cost profile estimates by Wood Mackenzie to run our sensitivity for new offshore gas projects. CNOOC plans to bring these three gas fields on stream in 2016. The fields will connect into the Yacheng-to-Hong Kong gas pipeline and peak at 65mmcf by 2018. Project cost will run near US\$1.0bn.

Based on these assumptions, we conclude that the project will require about a US\$8.8/mcf well-head price to achieve a 12% IRR. Over time, as CNOOC continues to drill deeper (both in terms of water depth and below surface depth), costs, and therefore required price, should continue to rise.

Coal gasification: may need to accept IRR slightly below 12%

To sustain a 12% IRR, we estimate that coal gasification projects would be at risk of requiring a gas price slightly above our anticipated city gate prices. If city gate prices were to drop on the back of the long-term crude oil price falling significantly below US\$100/bbl, then there is risk that the economics would deteriorate. At the same time, we believe our coal cost and steel cost assumptions are conservative. (See *Q-Series®: Will a coal-to-gas boom eventually go bust?*, 23 August, 2013.)

Figure 46: Estimated pro-forma income statement of CTG projects

	Project Xinjiang		Project Ordos	
	Rmb m	Pro forma	Rmb m	Pro forma
Sales	10,559	100%	9,581	100%
Natural gas	9,102	86%	8,124	85%
By-product	1,457	14%	1,457	15%
COGS	(5,562)	(53%)	(5,744)	(60%)
Coal	(3,060)	(29%)	(3,570)	(37%)
Water	(115)	(1%)	(115)	(1%)
Other (utilities etc)	(837)	(8%)	(609)	(6%)
DD&A	(1,550)	(15%)	(1,450)	(15%)
Gross profit	4,997	47%	3,837	40%
SG&A	(317)	(3%)	(287)	(3%)
EBIT	4,680	44%	3,550	37%
Interest expense	(987)	(9%)	(923)	(10%)
Income tax	(923)	(9%)	(657)	(7%)
Net profit	2,770	26%	1,970	21%

Assumptions

Capacity	5.5bcm	4bcm
Natural gas price (VAT included)	Rmb2.2/cum / US\$10.2/mcf	Rmb2.6/cum / US\$12.0/mcf
Coal consumption	20mtpa	15mtpa
Coal price	Rmb180/t / US\$29.4/t	Rmb280/t / US\$45.7/t
Capex	Rmb31bn / US\$5.1bn	Rmb29bn / US\$4.7bn
Coal quality	Bituminous coal	Bituminous coal

Note: Financial projections are based on ex-plant gas prices net back from long-term city gate gas prices based on US\$100/bbl long term Brent crude oil assumptions.

Source: UBS estimates

Figure 47: Lurgi CTG process IRRs (bituminous/thermal coal)

Natural Gas Price (Incl. VAT)							
Coal Price ↓	US\$/mcf	9.2	10.2	11.1	12.0	12.9	
	Rmb/cum	2.0	2.2	2.4	2.6	2.8	
	US\$/ton						
	Rmb/ton						
	29	180	11%	12%	14%	16%	17%
	33	200	10%	12%	13%	15%	16%
	36	220	9%	11%	13%	14%	16%
	39	240	8%	10%	12%	14%	15%
	42	260	7%	9%	11%	13%	14%
	46	280	7%	9%	10%	12%	14%
49	300	6%	8%	10%	11%	13%	

Note: Gas price of Rmb2.2/cum and coal price of Rmb180/t is our base estimate for a typical Xinjiang project, gas price of Rmb2.6/cum and coal price of Rmb280/t is for a typical Ordos project. Capex only includes CTG project and excludes the investment cost of coal mines.

Source: UBS estimates

Coal bed methane: economics are uncertain

For coal bed methane (CBM), we believe there is much variability in the economics from project to project, and for this reason we do not model an explicit 12% IRR. Our channel checks with the many listed profit sharing contract (PSC) holders in China since 2010 have suggested break-even economics at a level of US\$3-5/mcf. However, disappointing industry-wide production since then suggests that the break-even level for the industry as a whole may be significantly above this range. (For the purpose of our incremental cost exercise, we assume CBM requires a US\$1.0/mcf premium to tight gas.)

For coal bed methane, we believe there is much variability in economics from project to project

Pipeline imports: break-even if not for import VAT

For natural gas pipeline imports, we anticipate that those from Central Asia and Myanmar will still sustain losses ranging from US\$1.0/mmbtu to US\$2.1/mmbtu, while imports from Russia will break even, according to our estimates. If VAT rebates were raised to reflect the entire 13%, we estimate that losses could be nearly eliminated, with the exception of Myanmar imports.

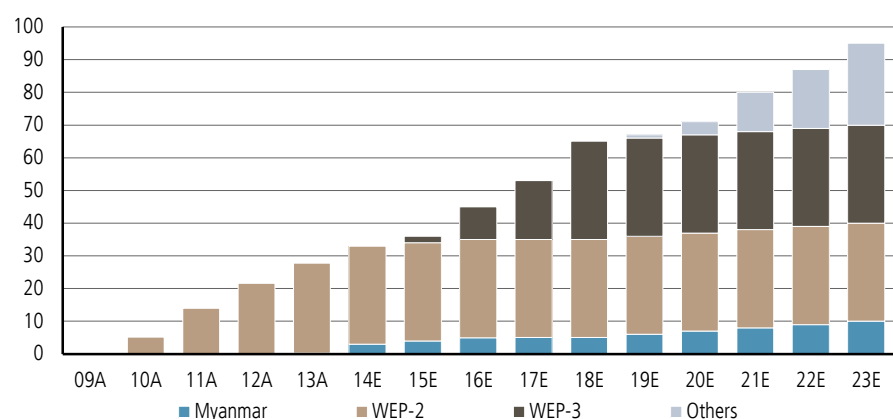
Figure 48: Pipeline import value chains and implied per unit loss (US\$/mcf)

	Myanmar	WEP-2	WEP-3	Russia
Major gas field sources	Mye and Shwe	Galkynysh	Galkynysh	Chayandinskoye, Kovyktinskoye
Major field operators	CNPC, Daewoo, ONGC	Turkmengaz	Turkmengaz	Gazprom
Implied well-head at China city gate price	5.5	7.0	7.0	7.7
Implied well-head price (US\$/mcf)	7.6	8.4	8.0	8.0
Transportation cost to China border	3.4	0.6	0.6	2.0
VAT	1.4	1.2	1.1	1.3
VAT rebate	(0.4)	(0.1)	(0.1)	(0.3)
Import price at Brent US\$100/bbl	11.0	9.0	8.6	10.0
Domestic transportation cost	1.5	5.0	5.0	1.5
City gate price (US\$/mcf)	11.4	13.6	13.6	12.2
Loss (US\$/mcf)	(2.1)	(1.4)	(1.0)	(0.3)
Loss (Rmb/cum)	(0.47)	(0.31)	(0.22)	(0.07)

Note: City gate prices refer to corresponding destinations of the different gas sources, our assumed destinations are Kunming in Yunnan for Myanmar gas, Guangzhou in Guangdong for WEP-2 and WEP-3, and Shenyang in Liaoning for Russia gas.

Source: UBS estimates, Wood Mackenzie

Figure 49: China pipeline gas imports by source



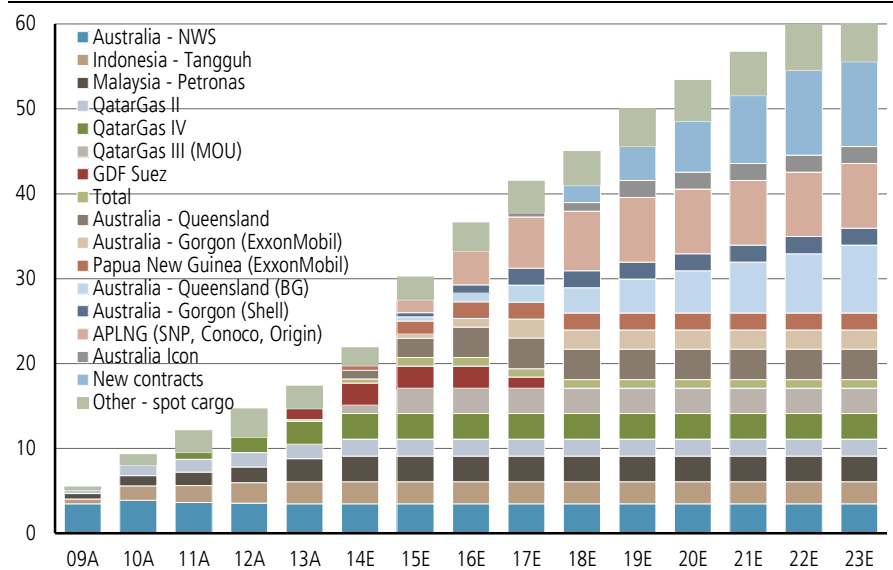
Note: Others could include some upside from Central Asia after compressors along WEP-2 are installed and some potential volume from Russia.

Source: Wood Mackenzie, UBS estimates

LNG: price significantly above city gate

Our analysis suggests that LNG imports based on JCC (Japanese crude cocktail) contracts prices are still likely to imply significant losses in the range of about US\$3-4/mmbtu, so long as the JCC is maintained as a benchmark for determining pricing slopes.

Figure 50: China's LNG gas sales contracts (mmtpa)



Source: Reuters, Bloomberg, C 1 Energy, company data, UBS estimates

Mitigating the risk of high-cost LNG

Extending the value chain further from imported LNG into high-value-added downstream uses for example in the **transportation sector**, will be a key aim of natural gas importers. We believe the long-term LNG prices will still be about Rmb1.5/cum (or US\$6.5/mmbtu) more expensive than most city gate prices.

Comparing among non-subsidised sales channels, LNG retail price is the highest at about Rmb4.5-5/cum, which is significantly higher than the second-highest non-subsidised segment, industrial sector's cRmb3.5/cum.

In addition, **internal fuel substitution** could be another area where high cost LNG imports could be absorbed. There are four Sinopec refineries in Shandong province, where Sinopec's first LNG import cargo is expected to deliver to in September or October of 2014. Refineries could burn LNG instead of fuel oil to heat their main reactors. At a similar cost or even slightly lower prices for import LNG than fuel oil, this could create meaningful cost savings.

Internal fuel substitution could be another area where high-cost LNG imports could be absorbed

What can China's gas giant bear?

PetroChina's financial health still critical to price discussion

A discussion of natural gas supply economics in China would not be complete without an understanding of the implications to PetroChina. The gas giant is China's largest upstream producer and importer. We believe PetroChina's overall financial health will always be important to its bargaining power both with the government as well as with its customers.

PetroChina's overall financial health will always be important to its bargaining power

Essentially, we argue that PetroChina's operations will remain very reliant on gas price hikes in the next couple of years. The catastrophe that would result should the company be unable to raise gas prices is so bad as to be an almost unthinkable outcome, from the market's perspective. This is why the market does not subscribe to this ultimate bear case. Still, we question whether a more moderate scenario than that envisioned in our base case could transpire.

Gas import losses reached the peak in 2013

PetroChina's natural gas import losses grew from just Rmb3.5bn in 2010 to a peak of Rmb41.9bn in 2013. As China continues to hike natural gas prices in the coming years, we estimate that the loss on imports will begin to decline at PetroChina. Rising natural gas prices should also relieve some of the stress from rising costs in the upstream business, coupled with potentially falling oil prices.

While natural gas prices are being reformed in China, the new incremental city gate prices are nonetheless explicitly set below the cost of LNG imports. This suggests sales of domestic gas are explicitly losing opportunity, and that LNG imports will lose money for the foreseeable future.

PetroChina will bear less of a subsidy burden than in the past, but it will not be able to fully escape a part of its national burden, in our view. This is why our PetroChina NAV estimates explicitly assume a terminal loss for natural gas imports. The question remains as to what that burden will ultimately be, and whether the market is fairly discounting such a scenario.

PetroChina will bear less of a subsidy burden than in the past, but it will not be able to fully escape a part of its national burden

PetroChina's operations sensitive to gas prices

Tracking the historical deterioration

To illustrate just how important natural gas price increases are to PetroChina, we demonstrate how the company's financial metrics have deteriorated in recent years in the segments that incorporate natural gas as an operational driver (exploration and production, and pipeline).

- The company's pipeline segment has seen its return on assets decline from levels above 10% before the start-up of natural gas imports in 2010 to zero by 2012. We can point to sluggish natural gas price increases as the sole cause of this decline. Therefore if prices rise as we and the market expect, we will see a significant improvement in returns for that segment.
- The E&P segment has seen its return on assets decline from about 22% in 2011 to about 16% in 2013. However, in the case of this segment, the declines have come more due to the rise in costs of production, for both oil and gas. Therefore, a rise in natural gas prices is only likely to stem the fall in returns, and not necessarily improve them.

Forecast returns still highly reliant on gas price hikes

After years of deterioration, PetroChina's after-tax ROCE has come down from 14% in 2010 to 9.4% in 2013. This should be considered a critical level for company operations, given ROCE has come down close to the cost of capital. In our view, poor returns on capital and poor cash flow are the reasons why the company started offloading its pipeline assets to other parties well before this kind of activity was branded as a 'mixed ownership' scheme of SOE reform in China.

So how should we judge what is acceptable for PetroChina to bear? We show three scenarios below. In our analysis, we assume all other factors are held constant and try to isolate the downside risk presented by natural gas prices alone. Areas not included in this analysis that could provide positive support to ROCE include: pipeline asset disposals, better-than-expected refining, marketing and chemical operating performance, success in reducing costs and capex, and the potential for windfall profit tax easing.

- **Base case:** Our existing base case for PetroChina (Neutral) assumes gas price increases continue at the accelerated pace of the past 12 months. This would imply that PetroChina's well-head gas prices rise by about 20% per year and the domestic city gate sales price of imported natural gas grows at 10-12% per year from 2014 to 2016. Under our base-case scenario, the ROA of the pipeline segment rebounds to above 10% by 2016, upstream ROA remains steady at 15% through 2016, and the company's after-tax ROCE moves up to 10.4% by 2016; the highest level since 2011. Overall, we believe our current base case for gas price hikes is reflecting the best potential outcome for PetroChina, hence we believe it could be vulnerable to downside risk.

- **Slow case:** Our slow case assumes that the NDRC's policy to link existing gas contract prices to new contract prices is extended over a longer period. This would imply that PetroChina's well-head gas prices rise by about 10-15% per year and domestic city gate sales prices of imported natural gas grow at just 5-6% per year from 2014 to 2016. This could occur if the NDRC wavered on its policy objectives or gas suppliers met resistance from customers for price hikes. In this scenario, the ROA of the pipeline business segment would rebound to just 8% by 2016, upstream ROA would deteriorate to 12% by 2016, and the company's after-tax ROCE would remain low near 8%. Given the demand analysis in this report, we believe a slow case for gas price hikes is a valid downside risk.
- **Worst case:** Finally, we demonstrate a worst-case scenario that shows the impact in the unlikely event that gas prices are not increased further from H114 levels. We also assume no mitigating factors, for example, improved cost controls, or the limiting of gas imports. This scenario would occur in the event that China's inflation rate spiked unexpectedly over the next few years. In this scenario, the ROA of the pipeline business segment would remain in low single digits, upstream ROA would deteriorate to 10% by 2016, and the company's after-tax ROCE would deteriorate to just 6%. We believe this scenario is very unlikely, given the economic outcome is simply unbearable for PetroChina.

Figure 51: PetroChina gas price sensitivity analysis

	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Brent oil price (US\$/bbl)	72.6	100.0	61.8	80.0	111.1	111.7	108.9	109.5	105.0	100.0
Well-head gas price (US\$/mcf)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	2.6	3.3	3.4	4.0	4.7	5.1	5.6	6.8	8.1	9.7
Slow case								6.5	7.1	7.8
No increase case								6.2	6.2	6.2
Well-head gas price (Rmb/cum)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	0.69	0.81	0.81	0.94	1.08	1.12	1.22	1.49	1.82	2.18
Slow case								1.43	1.60	1.76
No increase case								1.37	1.39	1.39
Upstream EBIT (US\$/boe)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	24.6	29.5	12.8	18.5	26.4	25.4	22.0	20.9	20.4	20.8
Slow case								20.4	18.4	16.8
No increase case								19.8	16.5	13.3
Import volume (bcm)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Pipeline + LNG				5.0	16.5	26.8	35.0	40.5	45.5	55.9
Import losses (Rmb bn)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case				(3.5)	(21.4)	(41.9)	(41.9)	(36.6)	(28.3)	(13.8)
Slow case								(39.5)	(37.5)	(30.9)
No increase case								(42.4)	(46.5)	(49.2)
Upstream EBIT/segment assets (%)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	38%	36%	14%	17%	22%	19%	16%	15%	15%	15%
Slow case								15%	13%	12%
No increase case								14%	12%	10%
Pipeline EBIT/segment assets (%)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	16%	13%	10%	8%	5%	0%	1%	3%	7%	11%
Slow case								3%	5%	8%
No increase case								2%	3%	4%
Downstream EBIT/segment assets (%)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	-3%	-18%	6%	4%	-6%	-4%	-2%	-1%	0%	0%
Slow case								-1%	0%	0%
No increase case								-1%	0%	0%
Total EBIT/total assets (%)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	19%	13%	10%	11%	10%	8%	8%	8%	8%	9%
Slow case								7%	7%	7%
No increase case								7%	6%	5%
Company ROE (%)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	22.2	15.0	12.6	15.7	13.7	11.2	11.8	10.8	11.6	12.9
Slow case								10.3	10.1	10.0
No increase case								9.9	8.6	7.2
Company after-tax ROCE	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	21.9	14.8	11.0	13.7	12.0	9.8	9.4	8.7	9.3	10.4
Slow case								8.4	8.1	8.1
No increase case								8.0	7.0	6.0
Company EPS (Rmb/sh)	2007	2008	2009	2010	2011	2012	2013	2014E	2015E	2016E
Base case	0.82	0.63	0.56	0.76	0.73	0.63	0.71	0.69	0.79	0.93
Slow case								0.66	0.68	0.71
No increase case								0.63	0.57	0.50

Source: Company data, UBS estimates, Bloomberg

Potential mitigating factors

There are some recent developments that indicate PetroChina's urgency to push through very rapid gas price increases to its customers may begin to ease. These could provide comfort in the case that the company's customers pushed back on the new NDRC ceiling levels.

New factors could ease the urgency to hike gas prices

- **Impact of SOE reform and focus on costs:** Part of SOE reform has also included the introduction of performance bonuses based not only on growing the scale of businesses, but also the profitability (focus on reducing costs and raising returns). If such efforts are successful at materially raising profits, we believe these could also reduce the need for a rapid rise in natural gas prices.
- **Impact of weeding out corruption:** It is probably impossible to truly measure the degree to which company mismanagement may have impacted SOE margins in the past. However, we believe the idea that some margin was lost due to such activities is a valid one. Therefore, if we can believe that the elimination of corruption can improve profits, we believe this might also suggest that bargaining power for gas price hikes may be reduced.
- **Tax relief is always possible.** In addition, our channel checks indicate that the oil industry is again talking about the prospect of easing the windfall profit tax on oil. If the tax is indeed eased, this could also greatly improve the economics for upstream oil and gas operators and therefore ease the need for dramatic natural gas price increases in the near term. A modification of VAT rebates on natural gas imports is also possible, in the long term.

Figure 52: Timeline of key gas price and tax reform measures

	Event	Details
Mar-06	Windfall profit tax	Initiated a threshold of US\$40/bbl and stepwise tax rate from 20% to 40% on each US\$5/bbl increment.
May-10	Natural gas price hike	Rmb0.23/cum hike across all suppliers and customers.
Nov-11	Windfall profit tax	Threshold lifted to US\$55/bbl.
Nov-11	Resources tax	Changed resources tax from volume-based to value-based and determined tax rates for oil and gas sales ranging from 5-10%.
Dec-11	Natural gas price hike	Initiated the link of city gate prices with alternative fuel prices (fuel oil and LPG) and determined the prices in Guangdong and Guangxi province as the pilot programme.
Jul-13	Natural gas price hike	Promoted the pilot programme in Guangdong and Guangxi to the entire nation and introduced different prices on existing volume (2012 demand) and incremental volume (volume in excess of 2012 demand), hiked existing volume price by Rmb0.4/cum, except Rmb0.25/cum hike to fertilizer makers and no hike to residential users.
Aug-14	Natural gas price hike	Further hiked existing volume price by Rmb0.4/cum for industrial customers. No hike for fertilizer and residential customers.

Source: NDRC

Appendix

Summary of Chinese companies with natural gas exposure

Figure 53: Companies with China natural gas exposure (H-share and overseas)

Sector	Company	RIC	Currency	Share price	Market value (US\$m)	1m avg trading vol (US\$m)
Upstream / Integrated	CNOOC	0883.HK	HK\$	15.28	88,024	121.7
	PetroChina	0857.HK	HK\$	11.36	239,694	123.1
	Sinopec	0386.HK	HK\$	8.04	107,500	84.7
Upstream CBM	Enviro Energy	1102.HK	HK\$	0.141	64	0.3
	Far East Energy	FEEC.OB	US\$	0.0685	24	0.0
	Fortune Oil	FOOI.L	GBP	9.5	407	0.2
	Sino Gas & Energy	SEH.AX	A\$	0.24	345	1.7
	Sino Oil & Gas	0702.HK	HK\$	0.246	570	1.9
	Zhongyu Gas	8070.HK	HK\$	2.45	798	0.1
Upstream CBM, and CNG	Green Dragon	GDG.L	GBP	485	1,143	0.0
LNG and / or CBM operator	BG Group	BG.L	GBP	1200.5	67,784	88.3
	Shell	RDSB.L	GBP	2532	260,467	123.3
	Woodside	WPL.AX	A\$	43.095	33,067	103.1
LNG/CNG equipment manufacturer	CIMC Enric	3899.HK	HK\$	8.8	2,152	5.0
Gas-fired power equipment	Dongfang Electric	1072.HK	HK\$	13.2	3,958	2.9
	Harbin Electric	1133.HK	HK\$	4.76	846	2.0
Transmission pipelines	Kunlun Energy	0135.HK	HK\$	13.02	13,561	33.7
	Sinopec Kantons	0934.HK	HK\$	6.64	2,130	9.4
	Beijing Enterprises	0392.HK	HK\$	71.45	11,840	10.9
City gas distribution	China Gas	0384.HK	HK\$	8.04	107,500	84.7
	China Natural Gas	CHNG.US	US\$	0.51	11	0.0
	China Resources Gas	1193.HK	HK\$	22.7	6,514	8.6
	China Tian Lun Gas	1600.HK	HK\$	9.22	985	0.6
	ENN Energy	2688.HK	HK\$	53.9	7,532	12.4
	Hong Kong & China Gas	0003.HK	HK\$	18	24,422	16.7
	Towngas China	1083.HK	HK\$	8.26	2,806	4.1
	Suntien	0956.HK	HK\$	2.4	1,150	3.4
Gas-fired IPP	Amber Energy	0090.HK	HK\$	0.8	43	0.0
Oil & gas field services	Anton Oilfield	3337.HK	HK\$	4.01	1,145	9.8
	SPT	1251.HK	HK\$	3.96	784	3.6
	Petroking	2178.HK	HK\$	2.25	314	1.0
Engineering and construction	Sinopec Engineering	2386.HK	HK\$	8.88	5,073	5.2
Shale gas equipment	Honghua	0196.HK	HK\$	2.18	911	3.6
Oil & gas pipe manufacturers	Anhui Tianda Oil & Gas Pipe	0839.HK	HK\$	1.75	228	0.2
	Chu Kong Pipe	1938.HK	HK\$	2.71	354	0.4
	Shengli Oil & Gas Pipe	1080.HK	HK\$	0.51	163	0.9
	Hilong	1623.HK	HK\$	4.26	932	3.3
Coal-to-gas equipment	Yingde	2168.HK	HK\$	8.01	1,891	2.3
Gas-based fertiliser	China Blue Chemical	3983.HK	HK\$	3.87	2,302	3.1

Note: Above data as at 29 August
Source: Bloomberg

Figure 54: Companies with China natural gas exposure (A-Share)

Sector	Company	RIC	Currency	Share price	Market value (US\$m)	1m avg trad vol (US\$m)
Upstream services	Jereh Oilfield	002353.SZ	Rmb	38.84	6,062	56.5
	BHP	002554.SZ	Rmb	12.85	952	17.7
	Tong Oil	300164.SZ	Rmb	13.21	816	8.3
	GI Tech	300309.SZ	Rmb	21.55	761	5.9
CBM separation	Tianyi Science	600378.SS	Rmb	13.54	654	6.5
CBM developer	Xinjiang Guanghui Industry	600256.SS	Rmb	7.86	6,673	109.3
LNG producer	SJ Environmental Protection	300072.SZ	Rmb	22.88	1,882	21.3
LNG construction	Offshore Oil Engineering	600583.SS	Rmb	7.91	5,686	41.6
LNG vehicle equipment	Furui Equipment	300228.SZ	Rmb	50.38	1,108	46.8
LNG vehicle	CNHTC Truck	000951.SZ	Rmb	13.87	946	10.8
	Weichai Power	000338.SZ	Rmb	20.47	7,087	56.2
Coal-to-gas operator	Datang Power International	601991.SS	Rmb	3.86	8,099	10.5
Coal-to-gas engineering	China Chemical Engineering	601117.SS	Rmb	5.72	4,588	39.1
	East China Engineering	002140.SZ	Rmb	17.66	1,281	12.7
Coal-to-gas equipment	Beijing Water Doctor	300055.SZ	Rmb	30.13	1,121	11.7
	Hangzhou Hangyang	002430.SZ	Rmb	7.27	983	4.5
	Keda Industrials	600499.SS	Rmb	19.35	2,194	27.2
	Sunway Engineering	002469.SZ	Rmb	11.9	641	8.0
Transmission pipelines	Kingland Pipeline	002443.SZ	Rmb	6.32	535	10.0
	Shaanxi Gas	002267.SZ	Rmb	10.13	1,675	9.6
City gas distribution	Changchun Gas	600333.SS	Rmb	7.42	639	11.9
	Datong Gas	000593.SZ	Rmb	7	319	9.2
	Shenzhen Gas	601139.SS	Rmb	7.04	2,267	9.1
Gas-fired power equipment	Dongfang Electric	600875.SS	Rmb	12.49	3,958	33.5
	Hangzhou Boiler	002534.SZ	Rmb	13.6	886	3.8
Gas-fired engine	Jinan Diesel	000617.SZ	Rmb	9.14	427	9.9
Gas-based chemical	Liaoning Tongda Chemical	000059.SZ	Rmb	6.75	1,318	65.7
	Yihua Chem	000422.SZ	Rmb	5.72	835	19.9

Note: Above data as at 29 August
Source: Bloomberg

Summary of company stock implications

Figure 55: Company stock implications

Company	Rating	Analyst	Comment
PetroChina (H and A Shares)	H Share (Neutral) A Share (Buy)	Peter Gastreich and Nina Yan	About half of PetroChina's proven oil and gas reserves and about a third of its production are in natural gas. This and the company's large loss-making gas import exposure (about 40bcm estimated for 2014), make PetroChina the most operationally leveraged to gas prices among the upstream oil and gas stocks under UBS coverage in China. On the one hand, rising natural gas prices will inevitably benefit the company's operations (unlock upstream reserve value and reduce gas import losses). On the other hand, we believe the market expectations are now for an orderly pass-through of NDRC pricing policy objectives from suppliers to customers. As this report suggests, there is a risk that PetroChina's price hikes may fail to reach the ambitious ceiling prices that are being set by the NDRC, and therefore may disappoint the market. In any case, the company's core business remains crude oil, and this we believe will be under pressure from rising costs, falling oil prices, and more challenging reserve recovery. Key upside risks include easing of the windfall profit tax, cost-saving measures, and better corporate governance post SOE reform.
Sinopec (H and A Shares)	H Share (Buy) A Share (Neutral)	Peter Gastreich and Nina Yan	Sinopec's upstream natural gas business will grow faster than that of PetroChina's and CNOOC's over the next five years, in our view, although the overall scale and relative importance of gas to Sinopec is less than that of PetroChina (Sinopec has a large focus in oil refining and marketing). The following should further enhance the company's exposure to gas in this decade: 1) the company's large Fuling shale gas discovery with production reaching at least 10bcm/yr; and 2) coal-gasification capacity (up to 8.0bcm/yr) and a dedicated long-distance coal gasification pipeline (30bcm/yr). However, the company's plan to ramp up LNG imports in the next five years could present a risk of loss unless the company is successful at diverting the LNG toward the transportation sector or toward internal fuel consumption needs. Key drivers in our view include: the company's refined product marketing business segment upgrade and spin-off; rising prices for higher transport fuel grades; and group-wide restructuring for example of the parent company's oil service business. Falling oil prices and rising costs are the key risks, in our view.
CNOOC	Neutral	Peter Gastreich	For CNOOC, we estimate natural gas is less than 20% of total production, and that this ratio is unlikely to change significantly in the coming years. In any case we believe CNOOC will benefit from a combination of rising production volume in natural gas (we think offshore China gas production can double in the next five years) and rising natural gas prices (CNOOC's well-head gas price is up 60-70% in the past five years, and we think this could rise a further 50% over the next five years). However, with the operations dominated by oil business, rising costs and falling oil prices are the key risks.
Beijing Enterprises	Sell	Stephen Oldfield	We have a Sell rating on the stock. We still like the company's strong gas sales volume growth in the next few years, but, we believe the current valuation has fully reflected the company's positive fundamentals. We think investors should be aware of the emerging risks from diversification. Although the plans to acquire China Leason, an upstream coal-bed-methane company, and China Green Energy, a waste-to-energy company, were terminated, the company said it is still looking for expansion into upstream gas and waste-to-energy businesses. In addition, we think there might not be any material benefits to Beijing Enterprises from the cooperation with China Gas on the gas business, apart from having earnings contribution as an associate from its 22.4% stake in China Gas. Moreover, we believe a medium-term risk could be a possible tariff cut for the Shaanxi-Beijing gas transmission pipelines, because the government may want to reduce the impact of increasing gas prices on end-users.
China Gas	Sell	Stephen Oldfield	We have a Sell rating on the stock. Although we like the company's fundamentals with strong gas sales volume growth, we believe the current valuation has not allowed for any margin or volume risks in the upcoming gas price hikes. We think the downside risk to our view would be new and attractive investment opportunities coming from the cooperation with Beijing Enterprises, which may support share prices. We believe the recent share price strength has given some benefits of doubt to the company on its scope of cooperation, because the details including valuation and scale of the cooperation with Beijing Enterprises are not announced yet.

Figure 55: Company stock implications (Cont'd)

China Resources Gas	Neutral	Stephen Oldfield	We have a Neutral rating on CR Gas. The shares have increased by >100% over the past three years, reflecting the positive fundamentals with strong volume growth. Growth expectation for CR Gas should moderate because the acquisition of projects from the parent has been completed, in our view. We believe the downside risk could be margin squeeze, which we think is not assumed by the market. We think gas sales volume for CR Gas will moderate in the medium term and could be lower than management's guidance of 20bcm by 2015, which implies a two-year CAGR of 29% YoY. This is because the construction of gas-fired power plants in Tianjin has been slower than management has guided and problems of affordability are starting to emerge. The company has announced that it has been unable to pass on higher city gate prices at its Tianjin project. Falling affordability led to disappointing gas volumes in the first half of 2014 as a major customer in Chongqing stopped buying gas from the company. We currently forecast a gas sales volume of 18bcm in 2015, implying a 2-year CAGR of 23%. We use an 8.1% WACC, explicit cash flow to 2020E, and 5% terminal growth at 10.5% ROIC.
ENN Energy	Neutral	Stephen Oldfield	We keep our Neutral stance on ENN. The shares have increased by 135% over the past three years. Although we see a strong demand growth outlook in the medium term, we see ongoing risks from a margin squeeze as city gate gas prices rise and from the risk that connection fees may be reduced as penetration rates reach higher levels. In its 2014 interim results announcement the company conceded it had been required to offer discounts to ceramics customers in its Quanzhou project in Fujian and had struggled to be reimbursed from the increase in gas costs as the proportion of gas priced at incremental volumes price has increased. ENN has announced it will invest in Sinopec's 30,000 petrol stations nationwide. The transaction would represent a major change of business for ENN and elevate the significance of its CNG/LNG refuelling station segment. A major synergy would result from the ability to put CNG/LNG refilling points in Sinopec sites. Both scenarios would give Sinopec a 9% stake in ENN. Our price target is based on an 8.2% WACC, explicit cash flow to 2020, and 5% terminal growth at 12.5% ROIC.
HK & China Gas	Neutral	Stephen Oldfield	We have a Neutral rating on Hong Kong & China Gas (HKCG). The share price has dropped by 18% from its peak of HK\$22 in 2013. We think the current valuation is demanding. We like the company's utilities businesses. Its low-growth but high-return business in Hong Kong continues to provide significant, stable free cash flows to the group and the Chinese gas distribution business is growing strongly with good and improving returns. However, the company's upstream New Energy business remains risky, in our view. The company, like other gas utilities, is facing a margin squeeze as affordability worsens. It may face similar problems to other gas utilities such as losing large industrial customers and experiencing difficulty in achieving full fuel-cost pass-through. Our price target includes about HK\$9 in the EV estimate for the Hong Kong business, HK\$6 for the China gas utilities and HK\$3 for upstream businesses, based on a DCF.
Kunlun	Sell	Bonan Li	Kunlun will continue to look vulnerable in light of China's ongoing natural gas price hikes. Overcapacity in the LNG processing industry will remain a key issue for Kunlun's LNG producing plants. The company will kick off large LNG producing plants in H214 and we believe those plants will not be profitable given the low utilisation rate.
Towngas China	Neutral	Stephen Oldfield	We maintain our Neutral stance on Towngas China. The shares have increased by 132% over the past three years. Although we see a strong demand growth outlook in the medium term, we see ongoing risks from margin squeeze as city gate gas prices rise and from the risk that connection fees may be reduced as penetration rates reach higher levels. If we exclude connection fees, the shares would trade at a higher PE multiple.
Sinopec Engineering	Buy	Bonan Li	Natural gas price hikes will provide support for China's coal-to-gas industry. SEG could benefit from the growing coal-to-gas industry, particularly considering Sinopec's large coal-to-gas project in Xinjiang province.

Figure 55: Company stock implications (Cont'd)

Company	Rating	Analyst	Comment
Yingde Gas	Buy	Edwin Chen	Yingde is the largest and fastest growing onsite industrial gases supplier in China. With a strong order backlog on hand, we believe it can maintain fast capacity expansion in the next three years. Now with its strategic financial cooperation with China Development Bank, investor concerns about its funding ability may ease. Given the defensive business model of onsite projects (long term, minimum take-or-pay, full-cost pass-through), we expect Yingde's IRR to be stable and decent. We thus have a Buy rating on Yingde for its fast growth and sustainable returns. Yingde is trading at 9x 2014E PE, below 1 standard deviation below its historical mean since listing, which we view as attractive.
Anton Oilfield	Sell	Bonan Li	Anton Oilfield Services (Anton) is a private oil services company in China, with a focus on conventional gas and tight gas services. Overseas, Anton is following China's state-owned energy enterprises to penetrate foreign markets. We have a positive view on the oilfield services space in the long term, given booming natural gas development in China. However, in the near term, we are bearish on Anton as we believe the company's growth could slow due to PetroChina's upstream capex discipline, growing competition from peers, and anti-corruption investigations into CNPC's overseas projects.
Honghua	Buy	Bonan Li	Honghua Group (Honghua) is the second-largest land rig builder in the world. Honghua also aims to develop its offshore rig manufacturing business. We are turning relatively cautious on its offshore rig business due to the continued delays to its first jack-up order and the uncertainty of its profitability outlook. The onshore oilfield services area could potentially become a growth driver for the company, particularly considering China's shale gas prospects and market-oriented reforms in the energy sector. The company's valuation looks undemanding after a big share price underperformance since early 2013. We think the downside risk to current share price level is limited.
SPT Energy Group	Buy	Bonan Li	SPT Energy Group (SPT) is our top pick in China's oil services space. SPT is the leading service provider for CNPC in Tarim Basin (China) and Central Asian countries Kazakhstan and Turkmenistan. SPT focuses on high-end oriented drilling services and has expressed strong confidence in maintaining a ~30% revenue CAGR for the next three years. Leveraging its cooperation with Halliburton, we believe SPT will further expand its high-end oriented business, including shale gas, in the next couple of years.
China Blue Chemical	Sell	Bonan Li	We believe China Blue Chemical is facing a structural rise in its gas costs while urea prices will remain under long-term pressure from low coal prices (alternative feedstock for urea). Methanol prices rallied late in 2013 but have since fallen to depressed levels. Management's strategy is to convert its Inner Mongolia gas-based plants into coal-based plants by 2016. However, we lack confidence in the smooth execution of the plan considering its track record (Shanxi coal-based urea project suspended, Heilongjiang coal-based urea project delayed, exiting from Inner Mongolia coal-chemical business). We believe risks regarding the execution and profitability of its Heilongjiang coal-based urea project could become another market overhang in 2014, especially considering the ancillary coal mines of this urea project have not been approved by the local government.
CIMC Enric	Buy	Benson Chen	About 50% of Enric's total sales and c60% of total profit is highly correlated to natural gas equipment (eg, LNG/CNG trailers, storage tanks and refuelling stations). Market consensus has been that continuous upstream gas price hikes will squeeze the profitability of the entire LNG value chain and cause gas equipment demand growth to stall. However, as we believe gas price increases will see increasingly more resistance, price hikes to the LNG supply chain could fall short of people's expectations in these years. In addition, given the price hike is mostly absorbed at LNG liquefaction segment, which is not related to Enric's business, key growth drivers for Enric (ie, LNG trailers, fuel tanks and refuelling stations) should remain largely intact. We expect the equipment demand to re-accelerate from 2015.

Source: UBS estimates

Statement of Risk

In China, we believe that government regulatory risk, for example in the event of a material spike in global energy prices, would be a key risk to our estimates. Government intervention can include policies related to, for example, upstream oil windfall profit taxes, regulation of downstream refined product prices and margins, fuel-cost pass-through for gas transmission and gas utilities businesses, and connection fees related to gas utilities. Changes to our outlook for global and Chinese GDP growth can materially affect our demand growth expectations. Given large projects planned in the sector, both upstream and downstream, there is also execution risk. There could be plant and pipeline mechanical failure.

Required Disclosures

This report has been prepared by UBS Securities Asia Limited, an affiliate of UBS AG. UBS AG, its subsidiaries, branches and affiliates are referred to herein as UBS.

For information on the ways in which UBS manages conflicts and maintains independence of its research product; historical performance information; and certain additional disclosures concerning UBS research recommendations, please visit www.ubs.com/disclosures. The figures contained in performance charts refer to the past; past performance is not a reliable indicator of future results. Additional information will be made available upon request. UBS Securities Co. Limited is licensed to conduct securities investment consultancy businesses by the China Securities Regulatory Commission.

Analyst Certification: Each research analyst primarily responsible for the content of this research report, in whole or in part, certifies that with respect to each security or issuer that the analyst covered in this report: (1) all of the views expressed accurately reflect his or her personal views about those securities or issuers and were prepared in an independent manner, including with respect to UBS, and (2) no part of his or her compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by that research analyst in the research report.

UBS Investment Research: Global Equity Rating Definitions

12-Month Rating	Definition	Coverage ¹	IB Services ²
Buy	FSR is > 6% above the MRA.	48%	33%
Neutral	FSR is between -6% and 6% of the MRA.	41%	30%
Sell	FSR is > 6% below the MRA.	11%	23%
Short-Term Rating	Definition	Coverage ³	IB Services ⁴
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	less than 1%	less than 1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	less than 1%	less than 1%

Source: UBS. Rating allocations are as of 30 June 2014.

1:Percentage of companies under coverage globally within the 12-month rating category. 2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.

3:Percentage of companies under coverage globally within the Short-Term rating category. 4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

KEY DEFINITIONS: **Forecast Stock Return (FSR)** is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months. **Market Return Assumption (MRA)** is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium). **Under Review (UR)** Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation. **Short-Term Ratings** reflect the expected near-term (up to three months) performance of the stock and do not reflect any change in the fundamental view or investment case. **Equity Price Targets** have an investment horizon of 12 months.

EXCEPTIONS AND SPECIAL CASES: **UK and European Investment Fund ratings and definitions are:** **Buy:** Positive on factors such as structure, management, performance record, discount; **Neutral:** Neutral on factors such as structure, management, performance record, discount; **Sell:** Negative on factors such as structure, management, performance record, discount. **Core Banding Exceptions (CBE):** Exceptions to the standard +/-6% bands may be granted by the Investment Review Committee (IRC). Factors considered by the IRC include the stock's volatility and the credit spread of the respective company's debt. As a result, stocks deemed to be very high or low risk may be subject to higher or lower bands as they relate to the rating. When such exceptions apply, they will be identified in the Company Disclosures table in the relevant research piece.

Research analysts contributing to this report who are employed by any non-US affiliate of UBS Securities LLC are not registered/qualified as research analysts with the NASD and NYSE and therefore are not subject to the restrictions contained in the NASD and NYSE rules on communications with a subject company, public appearances, and trading securities held by a research analyst account. The name of each affiliate and analyst employed by that affiliate contributing to this report, if any, follows.

UBS AG Hong Kong Branch: Stephen Oldfield; Peter Gastreich; Ken Liu; Benson Chen; William Li; Bonan Li. **UBS Securities Co. Limited:** Nina Yan.

Company Disclosures

Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
Anton Oilfield Services ¹³	3337.HK	Sell	N/A	HK\$3.40	28 Aug 2014
Beijing Enterprises Holdings ²	0392.HK	Sell	N/A	HK\$70.70	28 Aug 2014
China BlueChemical	3983.HK	Sell	N/A	HK\$3.72	28 Aug 2014
China Gas Holdings ²²	0384.HK	Sell	N/A	HK\$13.80	28 Aug 2014
China National Offshore Oil Corporation ^{2, 4, 16a, 16b}	0883.HK	Neutral	N/A	HK\$15.14	28 Aug 2014
China Petroleum and Chemical Corp - A ^{2, 3, 4, 16a, 16b}	600028.SS	Buy	N/A	Rmb5.52	28 Aug 2014
China Resources Gas Group ⁵	1193.HK	Neutral	N/A	HK\$22.80	28 Aug 2014
CIMC Enric Holdings	3899.HK	Buy	N/A	HK\$8.74	28 Aug 2014
ENN Energy Holdings ³	2688.HK	Neutral	N/A	HK\$55.25	28 Aug 2014
Hong Kong & China Gas	0003.HK	Neutral	N/A	HK\$17.84	28 Aug 2014
Honghua Group	0196.HK	Buy	N/A	HK\$2.06	28 Aug 2014
Keda Clean Energy	600499.SS	Buy	N/A	Rmb19.43	28 Aug 2014
Kunlun Energy ^{16a}	0135.HK	Sell	N/A	HK\$12.92	28 Aug 2014
PetroChina ^{16a, 16b}	0857.HK	Neutral	N/A	HK\$10.96	28 Aug 2014
PetroChina - A ^{16a, 16b}	601857.SS	Buy	N/A	Rmb7.93	28 Aug 2014
Sinopec ^{2, 3, 4, 16a, 16b}	0386.HK	Buy	N/A	HK\$7.79	28 Aug 2014
Sinopec Engineering Group ⁴	2386.HK	Buy	N/A	HK\$8.85	28 Aug 2014
Sinopec Shanghai Petrochemical ^{16b}	0338.HK	Buy	N/A	HK\$2.55	28 Aug 2014
SPT Energy Group	1251.HK	Buy	N/A	HK\$3.99	28 Aug 2014
Towngas China ⁴	1083.HK	Neutral	N/A	HK\$8.32	28 Aug 2014
Yingde Gases	2168.HK	Buy	N/A	HK\$8.04	28 Aug 2014

Source: UBS. All prices as of local market close.

Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date

2. UBS AG, its affiliates or subsidiaries has acted as manager/co-manager in the underwriting or placement of securities of this company/entity or one of its affiliates within the past 12 months.
3. UBS is acting as financial adviser to ENN Energy Holdings Ltd in its investment into Sinopec Marketing Co Ltd, a wholly-owned subsidiary of China Petroleum & Chemical Corporation.
4. Within the past 12 months, UBS AG, its affiliates or subsidiaries has received compensation for investment banking services from this company/entity.

- 5. UBS AG, its affiliates or subsidiaries expect to receive or intend to seek compensation for investment banking services from this company/entity within the next three months.
- 13. UBS AG, its affiliates or subsidiaries beneficially owned 1% or more of a class of this company's common equity securities as of last month's end (or the prior month's end if this report is dated less than 10 days after the most recent month's end).
- 16a. UBS Securities (Hong Kong) Limited is a market maker in the HK-listed securities of this company.
- 16b. UBS Securities LLC makes a market in the securities and/or ADRs of this company.
- 22. UBS AG, its affiliates or subsidiaries held other significant financial interests in this company/entity as of last month's end (or the prior month's end if this report is dated less than 10 working days after the most recent month's end).

For a complete set of disclosure statements associated with the companies discussed in this report, including information on valuation and risk, please contact UBS Securities LLC, 1285 Avenue of Americas, New York, NY 10019, USA, Attention: Publishing Administration.

Unless otherwise indicated, please refer to the Valuation and Risk sections within the body of this report.

Global Disclaimer

This document has been prepared by UBS Securities Asia Limited, an affiliate of UBS AG. UBS AG, its subsidiaries, branches and affiliates are referred to herein as UBS.

This document is for distribution only as may be permitted by law. It is not directed to, or intended for distribution to or use by, any person or entity who is a citizen or resident of or located in any locality, state, country or other jurisdiction where such distribution, publication, availability or use would be contrary to law or regulation or would subject UBS to any registration or licensing requirement within such jurisdiction. It is published solely for information purposes; it is not an advertisement nor is it a solicitation or an offer to buy or sell any financial instruments or to participate in any particular trading strategy. No representation or warranty, either express or implied, is provided in relation to the accuracy, completeness or reliability of the information contained in this document ('the Information'), except with respect to Information concerning UBS. The Information is not intended to be a complete statement or summary of the securities, markets or developments referred to in the document. UBS does not undertake to update or keep current the Information. Any opinions expressed in this document may change without notice and may differ or be contrary to opinions expressed by other business areas or groups of UBS. Any statements contained in this report attributed to a third party represent UBS's interpretation of the data, information and/or opinions provided by that third party either publicly or through a subscription service, and such use and interpretation have not been reviewed by the third party.

Nothing in this document constitutes a representation that any investment strategy or recommendation is suitable or appropriate to an investor's individual circumstances or otherwise constitutes a personal recommendation. Investments involve risks, and investors should exercise prudence and their own judgement in making their investment decisions. The financial instruments described in the document may not be eligible for sale in all jurisdictions or to certain categories of investors. Options, derivative products and futures are not suitable for all investors, and trading in these instruments is considered risky. Mortgage and asset-backed securities may involve a high degree of risk and may be highly volatile in response to fluctuations in interest rates or other market conditions. Foreign currency rates of exchange may adversely affect the value, price or income of any security or related instrument referred to in the document. For investment advice, trade execution or other enquiries, clients should contact their local sales representative.

The value of any investment or income may go down as well as up, and investors may not get back the full (or any) amount invested. Past performance is not necessarily a guide to future performance. Neither UBS nor any of its directors, employees or agents accepts any liability for any loss (including investment loss) or damage arising out of the use of all or any of the Information.

Any prices stated in this document are for information purposes only and do not represent valuations for individual securities or other financial instruments. There is no representation that any transaction can or could have been effected at those prices, and any prices do not necessarily reflect UBS's internal books and records or theoretical model-based valuations and may be based on certain assumptions. Different assumptions by UBS or any other source may yield substantially different results.

This document and the Information are produced by UBS as part of its research function and are provided to you solely for general background information. UBS has no regard to the specific investment objectives, financial situation or particular needs of any specific recipient. In no circumstances may this document or any of the Information be used for any of the following purposes:

- (i) valuation or accounting purposes;
- (ii) to determine the amounts due or payable, the price or the value of any financial instrument or financial contract; or
- (iii) to measure the performance of any financial instrument.

By receiving this document and the Information you will be deemed to represent and warrant to UBS that you will not use this document or any of the Information for any of the above purposes or otherwise rely upon this document or any of the Information.

Research will initiate, update and cease coverage solely at the discretion of UBS Investment Bank Research Management. The analysis contained in this document is based on numerous assumptions. Different assumptions could result in materially different results. The analyst(s) responsible for the preparation of this document may interact with trading desk personnel, sales personnel and other parties for the purpose of gathering, applying and interpreting market information. UBS relies on information barriers to control the flow of information contained in one or more areas within UBS into other areas, units, groups or affiliates of UBS. The compensation of the analyst who prepared this document is determined exclusively by research management and senior management (not including investment banking). Analyst compensation is not based on investment banking revenues; however, compensation may relate to the revenues of UBS Investment Bank as a whole, of which investment banking, sales and trading are a part.

For financial instruments admitted to trading on an EU regulated market: UBS AG, its affiliates or subsidiaries (excluding UBS Securities LLC) acts as a market maker or liquidity provider (in accordance with the interpretation of these terms in the UK) in the financial instruments of the issuer save that where the activity of liquidity provider is carried out in accordance with the definition given to it by the laws and regulations of any other EU jurisdictions, such information is separately disclosed in this document. For financial instruments admitted to trading on a non-EU regulated market: UBS may act as a market maker save that where this activity is carried out in the US in accordance with the definition given to it by the relevant laws and regulations, such activity will be specifically disclosed in this document. UBS may have issued a warrant the value of which is based on one or more of the financial instruments referred to in the document. UBS and its affiliates and employees may have long or short positions, trade as principal and buy and sell in instruments or derivatives identified herein; such transactions or positions may be inconsistent with the opinions expressed in this document.

United Kingdom and the rest of Europe: Except as otherwise specified herein, this material is distributed by UBS Limited to persons who are eligible counterparties or professional clients. UBS Limited is authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority. **France:** Prepared by UBS Limited and distributed by UBS Limited and UBS Securities France S.A. UBS Securities France S.A. is regulated by the ACP (Autorité de Contrôle Prudentiel) and the Autorité des Marchés Financiers (AMF). Where an analyst of UBS Securities France S.A. has contributed to this document, the document is also deemed to have been prepared by UBS Securities France S.A. **Germany:** Prepared by UBS Limited and distributed by UBS Limited and UBS Deutschland AG. UBS Deutschland AG is regulated by the Bundesanstalt für Finanzdienstleistungsaufsicht (BaFin). **Spain:** Prepared by UBS Limited and distributed by UBS Limited and UBS Securities España SV, SA. UBS Securities España SV, SA is regulated by the Comisión Nacional del Mercado de Valores (CNMV). **Turkey:** Distributed by UBS Limited. No information in this document is provided for the purpose of offering, marketing and sale by any means of any capital market instruments and services in the Republic of Turkey. Therefore, this document may not be considered as an offer made or to be made to residents of the Republic of Turkey. UBS AG is not licensed by the Turkish Capital Market Board under the provisions of the Capital Market Law (Law No. 6362). Accordingly, neither this document nor any other offering material related to the instruments/services may be utilized in connection with providing any capital market services to persons within the Republic of Turkey without the prior approval of the Capital Market Board. However, according to article 15 (d) (ii) of the Decree No. 32, there is no restriction on the purchase or sale of the securities abroad by residents of the Republic of Turkey. **Poland:** Distributed by UBS Limited (spółka z ograniczoną odpowiedzialnością) Oddział w Polsce. **Russia:** Prepared and distributed by UBS Securities CJSC. **Switzerland:** Distributed by UBS AG to persons who are institutional investors only. UBS AG is regulated by the Swiss Financial Market Supervisory Authority (FINMA). **Italy:** Prepared by UBS Limited and distributed by UBS Limited and UBS Italia Sim S.p.A. UBS Italia Sim S.p.A. is regulated by the Bank of Italy and by the Commissione Nazionale per le Società e la Borsa (CONSOB). Where an analyst of UBS Italia Sim S.p.A. has contributed to this document, the document is also deemed to have been prepared by UBS Italia Sim S.p.A. **South Africa:** Distributed by UBS South Africa (Pty) Limited, an authorised user of the JSE and an authorised Financial Services Provider. **Israel:** This material is distributed by UBS Limited. UBS Limited is authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority. UBS Securities Israel Ltd is a licensed Investment Marketer that is supervised by the Israel Securities Authority (ISA). UBS Limited and its affiliates incorporated outside Israel are not licensed under the Israeli Advisory Law. UBS Limited is not covered by insurance as required from a licensee under the Israeli Advisory Law. UBS may engage among others in issuance of Financial Assets or in distribution of Financial Assets of other issuers for fees or other benefits. UBS Limited and its affiliates may prefer various Financial Assets to which they have or may have Affiliation (as such term is defined under the Israeli Advisory Law). Nothing in this Material should be considered as investment advice under the Israeli Advisory Law. This Material is being issued only to and/or is directed only at persons who are Eligible Clients within the meaning of the Israeli Advisory Law, and this material must not be relied on or acted upon by any other persons. **Saudi Arabia:** This document has been issued by UBS AG (and/or any of its subsidiaries, branches or affiliates), a public company limited by shares, incorporated in Switzerland with its registered offices at Aeschenvorstadt 1, CH-4051 Basel and Bahnhofstrasse 45, CH-8001 Zurich. This publication has been approved by UBS Saudi Arabia (a subsidiary of UBS AG), a Saudi closed joint stock company incorporated in the Kingdom of Saudi Arabia under commercial register number 1010257812 having its registered office at Tatweer Towers, P.O. Box 75724, Riyadh 11588, Kingdom of Saudi Arabia. UBS Saudi Arabia is authorized and regulated by the Capital Market Authority to conduct securities business under license number 08113-37. **United States:** Distributed to US persons by either UBS Securities LLC or by UBS Financial Services Inc., subsidiaries of UBS AG; or by a group, subsidiary or affiliate of UBS AG that is not registered as a US broker-dealer (a 'non-US affiliate') to major US institutional investors only. UBS Securities LLC or UBS Financial Services Inc. accepts responsibility for the content of a document prepared by another non-US affiliate when distributed to US persons by UBS Securities LLC or UBS Financial Services Inc. All transactions by a US person in the securities mentioned in this document must be effected through UBS Securities LLC or UBS Financial Services Inc., and not through a non-US affiliate. **Canada:** Distributed by UBS Securities Canada Inc., a registered investment dealer in Canada and a Member-Canadian Investor Protection Fund, or by another affiliate of UBS AG that is registered to conduct business in Canada or is otherwise exempt from registration. **Brazil:** Except as otherwise specified herein, this material is prepared by UBS Brasil CCTVM S.A. to persons who are eligible investors residing in Brazil, which are considered to be: (i) financial institutions, (ii) insurance firms and investment capital companies, (iii) supplementary pension entities, (iv) entities that hold financial investments higher than R\$300,000.00 and that confirm the status of qualified investors in written, (v) investment funds, (vi) securities portfolio managers and securities consultants duly authorized by Comissão de Valores Mobiliários (CVM), regarding their own investments, and (vii) social security systems created by the Federal Government, States, and Municipalities. **Hong Kong:** Distributed by UBS Securities Asia Limited and/or UBS AG, Hong Kong Branch. **Singapore:** Distributed by UBS Securities Pte. Ltd. [Mica (p) 107/09/2013 and Co. Reg. No.: 198500648C] or UBS AG, Singapore Branch. Please contact UBS Securities Pte. Ltd., an exempt financial adviser under the Singapore Financial Advisers Act (Cap. 110); or UBS AG, Singapore Branch, an exempt financial adviser under the Singapore Financial Advisers Act (Cap. 110) and a wholesale bank licensed under the Singapore Banking Act (Cap. 19) regulated by the Monetary Authority of Singapore, in respect of any matters arising from, or in connection with, the analysis or document. The recipients of this document represent and warrant that they are accredited and institutional investors as defined in the Securities and Futures Act (Cap. 289). **Japan:** Distributed by UBS Securities Japan Co., Ltd. to professional investors (except as otherwise permitted). Where this document has been prepared by UBS Securities Japan Co., Ltd., UBS Securities Japan Co., Ltd. is the author, publisher and distributor of the document. Distributed by UBS AG, Tokyo Branch to Professional Investors (except as otherwise permitted) in relation to foreign exchange and other banking businesses when relevant. **Australia:** Clients of UBS AG: Distributed by UBS AG (Holder of Australian Financial Services Licence No. 231087). Clients of UBS Securities Australia Ltd: Distributed by UBS Securities Australia Ltd (Holder of Australian Financial Services Licence No. 231098). Clients of UBS Wealth Management Australia Ltd: Distributed by UBS Wealth Management Australia Ltd (Holder of Australian Financial Services Licence No. 231127). This Document contains general information and/or general advice only and does not constitute personal financial product advice. As such, the Information in this document has been prepared without taking into account any investor's objectives, financial situation or needs, and investors should, before acting on the Information, consider the appropriateness of the Information, having regard to their objectives, financial situation and needs. If the Information contained in this document relates to the acquisition, or potential acquisition of a particular financial product by a 'Retail' client as defined by section 761G of the Corporations Act 2001 where a Product Disclosure Statement would be required, the retail client should obtain and consider the Product Disclosure Statement relating to the product before making any decision about whether to acquire the product. The UBS Securities Australia Limited Financial Services Guide is available at: www.ubs.com/ecs-research-fsg. **New Zealand:** Distributed by UBS New Zealand Ltd. The information and recommendations in this publication are provided for general information purposes only. To the extent that any such information or recommendations constitute financial advice, they do not take into account any person's particular financial situation or goals. We recommend that recipients seek advice specific to their circumstances from their financial advisor. **Dubai:** The research distributed by UBS AG Dubai Branch is intended for Professional Clients only and is not for further distribution within the United Arab Emirates. **Korea:** Distributed in Korea by UBS Securities Pte. Ltd., Seoul Branch. This document may have been edited or contributed to from time to time by affiliates of UBS Securities Pte. Ltd., Seoul Branch. **Malaysia:** This material is authorized to be distributed in Malaysia by UBS Securities Malaysia Sdn. Bhd (253825-x). **India:** Prepared by UBS Securities India Private Ltd. (Corporate Identity Number U67120MH1996PTC097299) 2/F, 2 North Avenue, Maker Maxity, Bandra Kurla Complex, Bandra (East), Mumbai (India) 400051. Phone: +912261556000 SEBI Registration Numbers: NSE (Capital Market Segment): INB230951431, NSE (F&O Segment) INF230951431, BSE (Capital Market Segment) INB010951437.

The disclosures contained in research documents produced by UBS Limited shall be governed by and construed in accordance with English law.

UBS specifically prohibits the redistribution of this document in whole or in part without the written permission of UBS and UBS accepts no liability whatsoever for the actions of third parties in this respect. Images may depict objects or elements that are protected by third party copyright, trademarks and other intellectual property rights. © UBS 2014. The key symbol and UBS are among the registered and unregistered trademarks of UBS. All rights reserved.

