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The shale revolution

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Introduction
The shale revolution

The global unconventional shale boom is arguably one of the biggest technology breakthroughs in decades. What started in a field in Texas has turned into a worldwide phenomenon, with ramifications spreading across a wide range of countries, commodities and industries. The high cost of energy is once again stimulating the search for new energy supplies, alternative fuels and efficiency gains, with technology as always at the foreground of new developments.

While the full impact of this "game changing" revolution is yet to fully play out, it is clear that significant effects are already underway. In this report, we explore the highly interrelated nature of the global energy system. In parallel with this report, our investment banking research department is publishing a more detailed study of the theme and its impact, reflecting the work of more than forty analysts.

We draw conclusions about the likely spillovers from the shale revolution to other energy markets, countries and energy-intensive industries. There are fundamental messages for relative price shifts in commodities, relative competitiveness regionally, relative industry cost curves and potential technological innovation. We also consider the impact of the required capital spending on infrastructure.

Of course politics as well as economics come into play – particularly given the perceived links to energy security or independence, though we question some of the accepted wisdom on the latter where the USA is concerned, namely that of the US becoming the "new Middle East of oil" or at least "not dependent anymore on the Middle East for its energy needs." We believe there are many geopolitical reasons why the USA will remain closely engaged with the Middle East, not least because many of its trading partners will remain dependent on energy from the region.

The potential for shale gas beyond North America is a key question, as is the issue of local adverse environmental impacts, which needs to be addressed, and the issue of global climate change effects, where there are many uncertainties but some prospect of shale gas to an extent replacing much dirtier coal. Indeed, resources exist in Europe, Latin America, Asia and Australasia, though various constraints suggest that the most optimistic production targets may not be fulfilled. We particularly focus on the role and strategy of China, possessing twice the recoverable resources of the USA and with energy security a crucial concern.

What of the price of the more conventional sources of energy? A major effect has already been felt in coal markets as power generation has shifted from coal to gas. While this trend may abate in the near term, the structural direction should remain downward – eventually dethroning "King Coal." As for oil, the high prices seen for most of the past five years probably have to continue for a period to attract the investment needed to bring on supply. But, ultimately, looking to the latter part of this decade and beyond, we believe high prices will be the primary cure for high prices. The shale revolution seems set to play a crucial role in that process, providing a major new energy source to facilitate global economic development.

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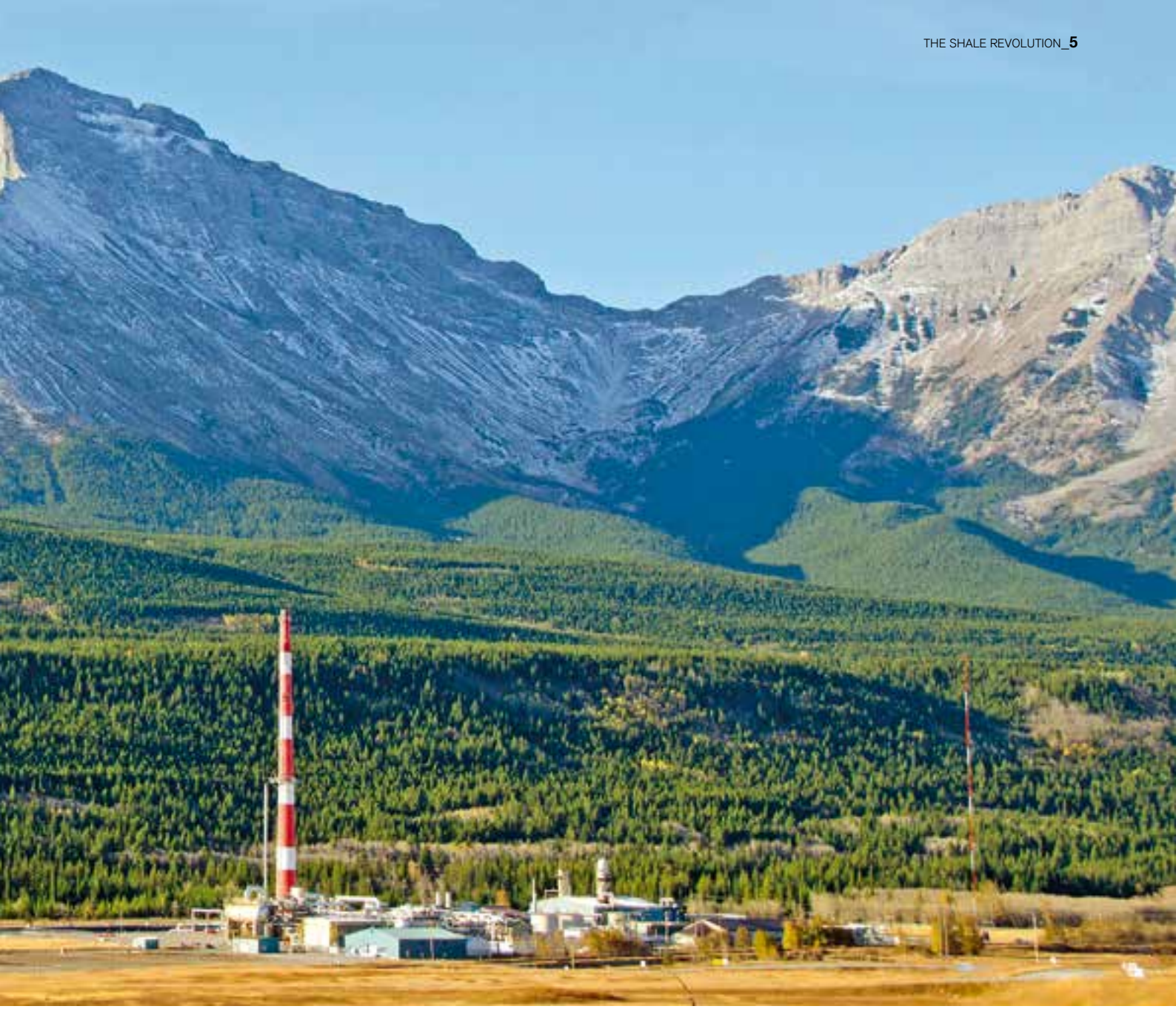
The shale revolution: A game changer

Shale gas production is growing at breakneck pace. However, the vast majority of reserves remain untapped. What is the real potential of this resource? How much investment will it take to fully exploit this potential? Which industries stand to benefit most as a result? It's still early days, but significant implications are already starting to emerge.

Richard Kersley, Ric Deverell, Kathryn Iorio, Mujtaba Rana



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The US gas revolution is ongoing as discoveries today are advancing at a faster rate than production, suggesting that production has a long way to go before it peaks. The share of US gas production from shale increased from ~5% in 2000 to ~23% in 2010; after incorporating tight gas and coal-bed methane (CBM), unconventional production accounted for nearly 60% of all production in 2010. The US Energy Information Administration (EIA) expects this trend to continue at its fervent pace with 50% of production coming from shale by 2035, rising to a total of 78% of production when accounting for other unconventional methods. Our base case has US shale gas volume growth remaining at +20% per year for the rest of this decade with production approaching ~827 Bcm/y in 2020.

The potential capital spending to support this structural story extends across the energy complex in the USA. Investment in the US oil and gas sector has grown steadily to reach around USD 140 billion per year over the past couple of years. While only 1% of GDP, the sector has accounted for an outsized 10% of total business fixed asset investment, and nearly one fifth of growth in investment over that period. Oil and gas has also been punching well above its historical weight in industrial production, accounting for 9% of the total in the past year, and for nearly 30% of total initial production growth over the past couple of years. We expect this high level of investment to continue for some time, as the industry continues to exploit the potential of the new technology.

We expect the downward price pressure on natural gas prices (underpinned by the higher than previously anticipated domestic reserves and surge in US production) to be sustained for many years.

While Henry Hub prices are likely to rise modestly from the historically low USD 3/MMBtu (million British thermal units, real 2011 USD) seen on average this year, we do not expect them to move above USD 5/MMBtu by 2020, despite strong demand and the possibility of exports.

Moreover, we also expect US gas prices to remain depressed relative to international (oil-linked) gas prices for years to come with US shale gas exports likely capped for now. The high capital costs associated with developing LNG projects limit their development to major players and this factor is

Figure 1

US natural gas price: Cheap historically

Source: Credit Suisse Securities Research

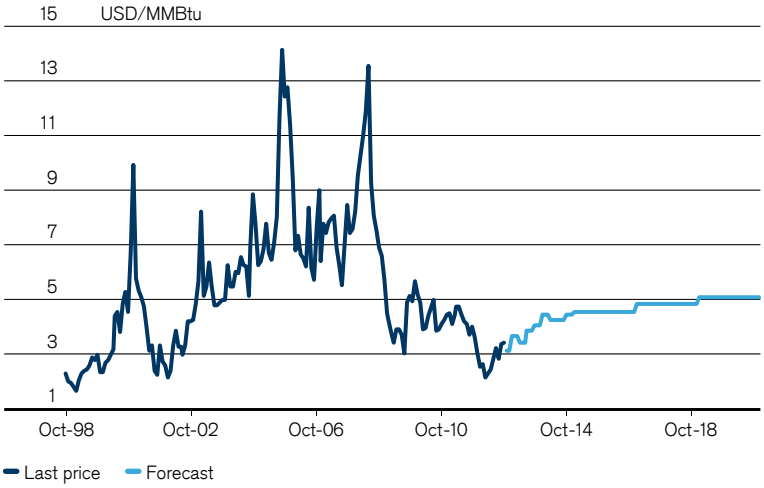
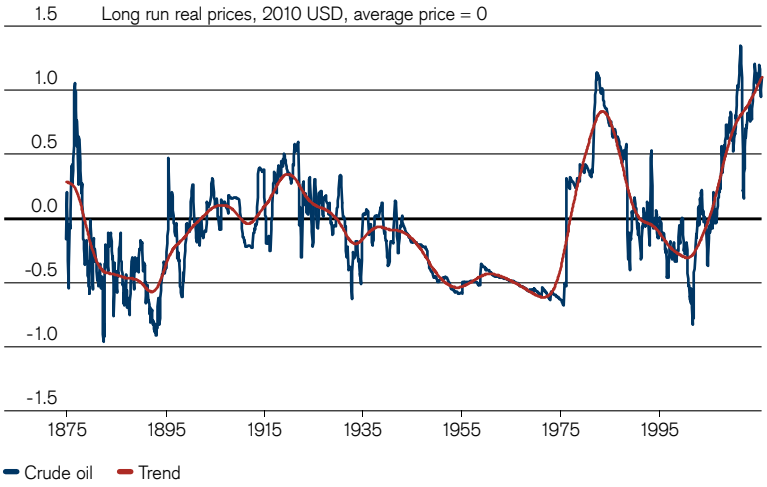


Figure 2

Real oil prices remain near historical highs

Source: the BLOOMBERG PROFESSIONAL™ service



also likely to play a hand in preserving industry and marketing structures.

This underlines an ongoing competitive advantage for the USA in those industries where natural gas is a key feedstock and a potential driver of, and incentive for, related capital spending.

Can the "shale gas revolution" spill over to other countries? Yes…but not yet. More detailed research published in our investment banking report analyzes the significance of shale gas region by region, in turn highlighting the geological and technological challenges that do exist and may indeed be underestimated by the more bullish forecasters. With twice the recoverable shale reserves of the USA, the biggest potential is in China. The question is when? In our view, large industrial scale production looks unlikely until the end of this decade at the earliest. Despite ambitious targets of reaching 60 to 100 Bcm (billion cubic meters) per year by 2020, China is not yet at the inflection point that the USA found itself at in 2006. There seems little reason as yet for the LNG (liquified natural gas) price premium in Asia (and elsewhere) to disappear.

Shale oil will boost US oil production provided prices stay relatively high. We calculate that US oil production could reach over 10 Mb/d (million barrels per day) by 2020 and maintain that going forward. However, considerable capital will be required to fund the growth, with a price of USD 90/bbl Brent likely to be necessary for the next few years to ensure the expected capex goes ahead. It is unlikely to provide energy self-sufficiency for the USA or provide the same low cost dividend of gas given its cost of extraction. Outside the USA there is also shale oil potential, which may become more relevant later in this decade. Argentina and Germany stand out, in addition to the gas potential in China.

An unconventional brake on the rising price of oil? Putting aside the near-term influence of the

Figure 3

The potential spread of hydraulic fracturing (fracking) technology

Source: Credit Suisse

Region	Timeframe	CS View
US LNG Exports	Post-2017	Significant US LNG exports will only come online from 2017 and 46 Mt/y (metric tons per year) or 5-7 Bcf/d (billion cubic feet per day) is likely to be the level at which they are capped.
China	Post-2020	Material production above 60 Bcm is possible but is likely to be achieved post rather than pre-2020.
Argentina	Uncertain	In-place infrastructure and initial drilling successes highlight the potential opportunity but a lack of sector confidence in political stability is likely to inhibit requisite capex.
Australia	Long-term	Cost escalation for traditional LNG projects means that an expansion of CBM to LNG is unlikely in the near term as existing projects face both cost and stakeholder challenges; meanwhile with less than 30 shale wells drilled it is too early to determine prospectivity/commerciality at this point. Meanwhile, the shale industry's infancy makes it too early to determine its long-run potential.
Europe	Long-term	Severe stakeholder headwinds mean the prospect of significant shale development in Europe remains low for now. We note Germany seems to have the best CBM and shale gas potential thus far. France has prospective acreage if drilling is allowed.
Canada	Late decade	Potential for first train of one or more LNG projects to come online.
Russia	Late decade	The industry should test the giant Bazhenov oil-shale reserve in 2013.

cycle and specific regional supply issues, structural downward pressure on prices should emerge in the next year or two, though the decline is likely to be less dramatic than some might assume given the price level required to bring unconventional supply on stream. Our base case assumes that US oil production growth accounts for nearly 80% of the global net gain in oil production capacity that we foresee by 2015; this would allow for prices to gravitate down towards more sustainable long-run levels nearer USD 90/bbl.

However, we do see more production growth in the 2015–2020 timeframe from other non-OPEC producers. This could put further downward pressure on prices.

Further downward pressure on thermal coal prices, but not for a few years at least. The change in relative energy prices in the USA has already had a substantial impact on the global thermal coal market. While coal to gas switching will likely be less pronounced in 2013, US demand is in structural decline given relative price dynamics and environmental legislation. However, in analyzing the global picture for coal, we find the speed with which the displacement of coal has occurred in the USA is not easily replicable in any other location, both for reasons of supply and demand. A switching away from coal should not therefore be immediate, as it will remain the predominant baseload fuel in key markets. Nevertheless, beyond 2020 onwards, gas' dethroning of king coal does look increasingly inevitable, as China and India move to diversify their energy mix.

Major consequences for other industries

The impact of the shale revolution across the energy complex within equities is significant across a wide range of industries and regions, with some outright winners and some relative losers. Consequences emerge in terms of shifting cost curves, relative competitiveness, new infrastructure and technological innovation. As much as the direct impact is major on the energy and commodity-related industries and the companies operating within it, we will highlight impacts across the construction, capital goods, utilities, automotive and basic material sectors.

Figure 4

The impact of shale gas on other commodities

Source: Credit Suisse

Commodity	Change	Impact	Timeframe
Oil	Increased production of oil and natural gas liquids	In combination with Gulf of Mexico and, potentially, Artic resources the USA can continue to grow oil production, it will however remain a net importer.	Ongoing
Oil	Substitution of oil for natural gas in the USA	Up to 3.7 Bcf/d of demand by 2020 from 2.7 million natural gas vehicles?	Ongoing
Thermal coal	Coal to gas switching in US generation	Coal to gas switching has made the USA a net exporter of coal, contributing to a surfeit of seaborne supply.	Ongoing
Thermal coal	Coal to gas switching outside of the USA	Cheap gas on the back of growing shale production could displace coal post-2020 but would require considerable changes to installed electricity generating capacity.	Post-2020

Unconventional gas supply in the USA

While geologists have long known about unconventional gas sources, new production processes, improved infrastructure, deregulation and policy incentives have transformed the industry dramatically. With unconventional production now around 60% of all production in the USA, and production of shale gas expected to double between 2010 and 2035, the country's natural gas reserves can last for years.

Jan Stuart, Ed Westlake, Stefan Revielle, Arun Jayaram, John Edwards, Andrew Kuske, Paul Tan

Figure 5

Lower 48 states shale plays

Source: INGAA, Energy Information Administration (EIA).

The perfect string of events

The United States' unconventional shale boom is arguably one of the biggest technological breakthroughs in decades. What started in a field in Texas has turned into a worldwide phenomenon with ramifications spreading across various commodities and industries. As is the case with many innovations, the path to the current levels of production were not straightforward and required almost a perfect string of events to turn the technology known as hydraulic fracturing ("fracking") into what it is today.

While natural gas – or methane by chemical composition – was once thought to be a scarce commodity in the USA, the industry reversed long-term trends of declining gas reserves by scaling up unconventional production techniques (especially hydraulic fracturing) extremely fast. The costs of the new drilling boom fell fast and "economic reserve" size grew multifold. Just to give an idea of the transformation, merely four years ago the industry was still applying for permits to site LNG import terminals (much to the chagrin of some of California's most famous residents) and today is advancing to export gas by 2015 by retrofitting those very same import terminals.

With the higher domestic reserves and surge in production, natural gas prices have recently hit new 20-year lows, dipping below USD 2/MMBtu in late winter 2012 on the Henry Hub measure. US gas prices are expected to remain depressed relative to international (oil-linked) gas prices for years to come.

Unconventional versus conventional: What's the difference?

In oil and gas exploration and production, the difference between conventional and unconventional sources is almost purely defined by rock permeability. Whereas conventional oil and gas source rocks tend to be highly permeable, allowing oil and gas to flow with relative ease through rock openings, unconventional hydrocarbons are locked in layers of rock (often shale) that in their natural state are virtually impermeable.

To put this in perspective, most conventional oil and gas reservoirs produce from source rocks with a permeability of tens to several hundred millidarcys (md) while permeability in the "new" shale plays is closer to 1 md. Conventional drilling (typi-

Figure 6

Estimated technically recoverable shale gas by country

Source: EIA, Credit Suisse

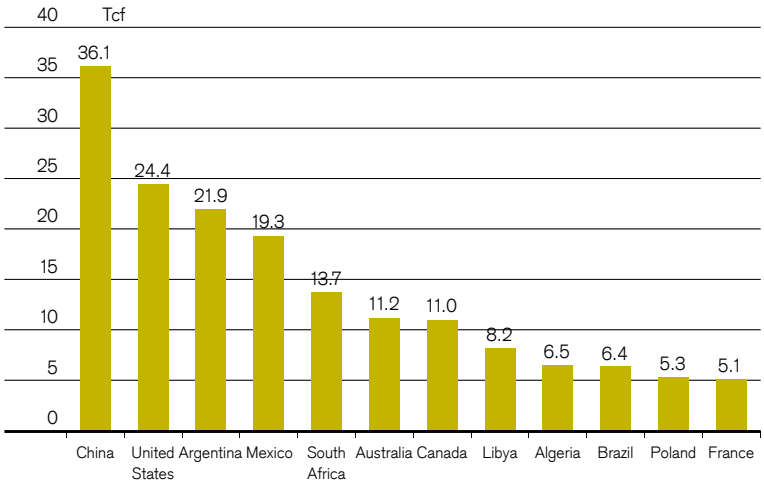


Figure 7

Additions to US gas pipeline infrastructure by year – actual and expected

Source: EIA, Credit Suisse

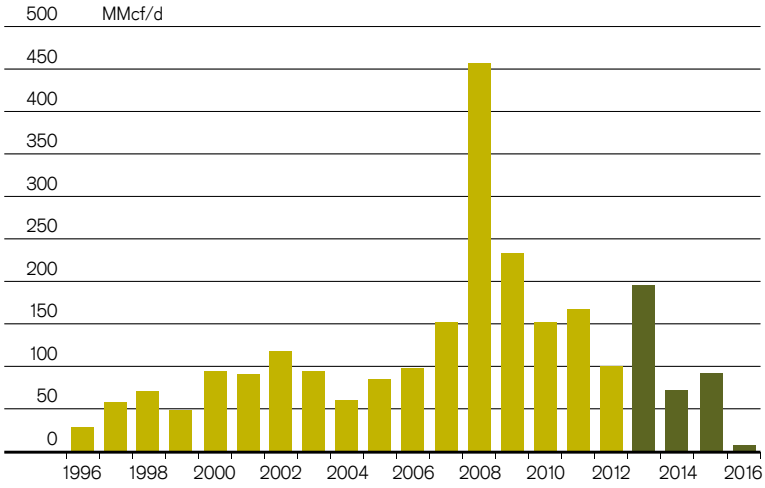
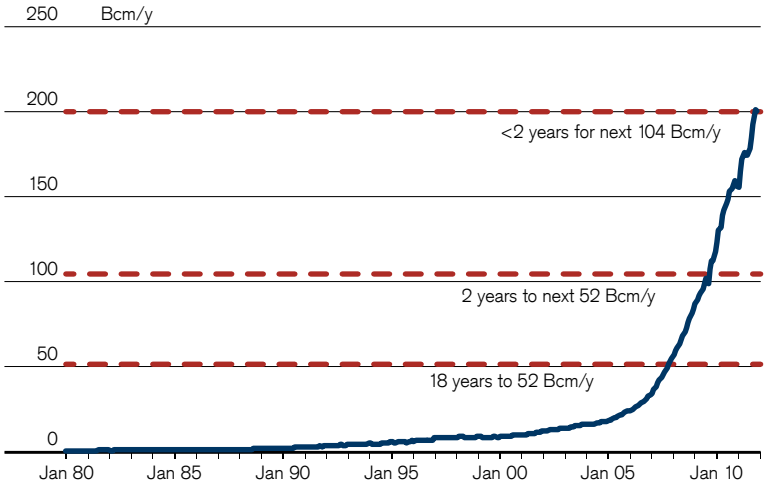


Figure 8

US shale gas production through time

Source: HPDI, Credit Suisse



cally vertical) yields very little if any oil and gas from such shale.

Geologists have long known about the vast reserves of hydrocarbons locked up in so-called tight or otherwise impermeable rocks. However, it was not until horizontal drilling and hydraulic fracturing techniques were used on unconventional onshore sources that these shale gas, tight sands and other related unconventional resources became economically available.

The prerequisites for North American supply success

There is no doubt that there are a number of factors unique to the USA that have aided in moving unconventional gas production forward. In addition to key policy enactments that deregulated wellhead prices and incentivized investment in unconventional resources, favorable geology, an established service sector and private mineral rights created the stable investment environment needed for the supply expansion.

Following the passing of the Natural Gas Policy Act (NGPA) of 1978, wellhead sale prices of natural gas from shale, coal seams, etc. took their first steps towards deregulation. In previous market structures, price controls had been set to protect consumers from market manipulation. However, it soon became clear this discouraged producers, leading to supply shortages. With the NGPA, gas prices were partially set by market forces while there was the ability to increase prices in order to incentivize producer activity; this included granting tight gas the highest ceiling price of all NGPA-regulated categories. The subsequent passing of the Natural Gas Wellhead Decontrol Act of 1989 fully deregulated gas prices, eliminating all wellhead price controls from the NGPA of 1978.

Section 29 of the Crude Oil Windfall Tax Act of 1980 provided tax credits to qualified unconventional gas wells and formations and upon its passing became known as the Section 29 Tax Credits. Under these rulings, drilling in tight gas and shale gas formations was provided with about USD 0.50/MMBtu in economic credits while CBM was afforded ~USD 1.00/MMBtu to help incentivize investment and reduce the burden of initial infrastructure.

Mineral rights in the USA are unique and allow for relative ease of resource exploitation. In many oil and gas-producing countries around the world, land owners typically have no rights to the subsurface minerals; these are typically owned by central governments, making the process of obtaining rights challenging for explorers and developers. However, within the USA, with the option of some owners to extract minerals from a property, producing companies can directly negotiate with the owner rather than a government, greatly reducing barriers and time to receive access to mineral rights

compared to elsewhere. Teaming favorable North American geology (Figure 6) with incentivizing mineral rights has helped move supply growth forward at a steady pace.

Significant build-out of natural gas infrastructure has reduced bottlenecks, allowing gas to flow and help create liquid regional markets for physical gas trading. Gas pipeline infrastructure advanced as bottlenecks developed, giving many of the major US consuming regions access to unconventional gas resources. One of the more significant major pipeline expansions came with the Rocky Mountain Express (REX) pipeline which for the first time connected once-stranded gas in Colorado/Wyoming to higher-priced, regions with high demand in the north-east.

Nature of success in the USA has been nothing short of extraordinary

Advancement in unconventional resources and technology has led to significant growth trends in US gas production. After first becoming commercially viable a little over ten years ago, fast development has transformed the industry.

- It was not until 2008, and nearly 18 years of development, that the first 52 Bcm/y of production from unconventional sources was seen.
- In the two-year stretch that followed (2008-2010), unconventional gas production doubled, moving the total to 104 Bcm/y. EIA estimates that in 2010, 23% of total production came from shale.
- In the past two years, the industry has again doubled unconventional production, moving the total to ~206 Bcm/y or 27% of total US gas supply.

Discoveries are now outpacing the rate of production

Through the use of horizontal drilling, advances in completion technology and improved drill bits, the domestic reserve base has reversed a decade-long trend of declines, sending the reserve life of natural gas to ~13 years according to EIA data (Figure 9). In fact, new discoveries today are advancing at a faster rate than production (Figure 10), indicating that production has a long way to go before it peaks.

Today, US natural gas production is on an aggressive growth path that could be sustained for years. In 2000 the majority of gas production within the USA came from conventional sources with less than ~5% coming from shale. In 2010, roughly ~23% of production came from shale; adding in tight gas and coal-bed methane (CBM), this brings unconventional production close to 60% of all production. In its latest long-term forecast, the EIA projects nearly 50% of production will come from shale by 2035, with an additional 21% from tight gas and 7% from CBM.

Figure 9

Gas proved reserves vs. reserve life

Source: EIA, Credit Suisse

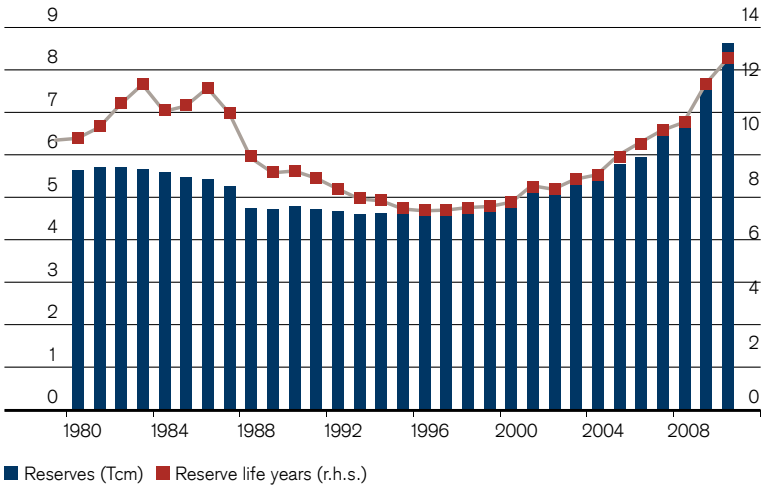
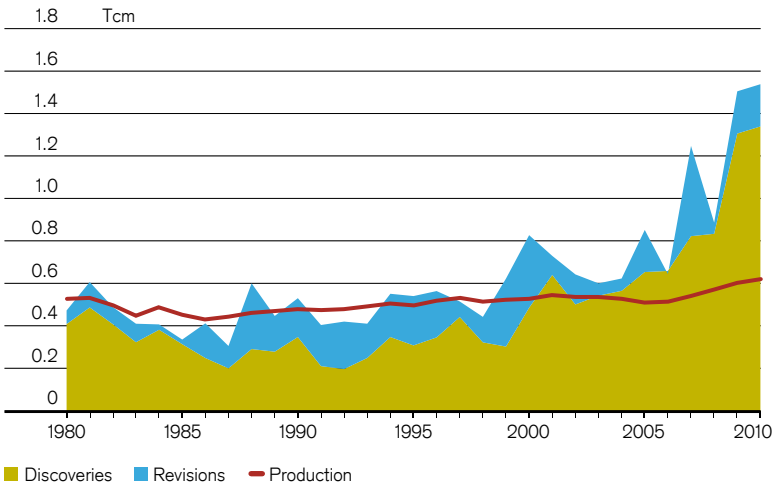


Figure 10

Natural gas reserve additions vs. supply

Source: EIA, Credit Suisse



What are the major environmental risks of unconventional gas production?

Environmental concerns have emerged as unconventional gas exploitation has grown. Some of these concerns have held back exploration and development in other countries. For example, the French government has placed a moratorium on fracking. The main worries center on:

- Large scale use of water in hydraulic fracturing inhibits domestic availability and aquatic habitats.
- Hydraulic fluids that contain hazardous chemicals can be released by leaks, faulty well construction, etc.
- Wastewater contains dissolved chemicals and other contaminants that need treatment before disposal or re-use.
- The US Geological Survey (USGS) has confirmed that hydraulic fracturing can cause small earthquakes and seismic activity.

China: Security of supply

Potential for shale gas goes beyond North America, stretching across Europe, Latin America, Australia, New Zealand, and most notably, China. The size of its reserves and its desire of energy security make it key to the shale story.

David Hewitt, Horace Tse

PHOTO: ISTOCKPHOTO.COM/SAMXMEG

Challenges and opportunities

China's journey to shale is driven by radically different factors than North America. Facing major oil import challenges going forward, China does not want to replicate its oil import dependence in gas; especially as China has twice the recoverable shale reserves estimated in the USA and the vestiges of a command economy capable of accelerating national priority projects.

Time and technology are the two major challenges for Chinese shale. Time as China has drilled less than 100 shale gas wells (versus over 150,000 in the USA), and technology with the need to find the commercial pathway to shale production under different geological challenges than North America.

Why China is focusing on shale

Energy security is at the heart of China's push into shale. China is set to be the world's largest importer of oil – potentially having to import 10 million barrels per day by 2020, 10% of our estimated global production. While gas only plays a minor role in primary energy use (currently at 4%), China wants to increase gas' share of the total mix, for both environmental reasons and overall growth factors.

Without shale production China could be 50% dependent on imported gas by 2020. Assuming conventional domestic production attains a 9% compound annual growth rate (CAGR), CBM hits 30 Bcm/year by 2020 and demand sees a 15% CAGR, the call on import gas (LNG and pipeline) would be 180 Bcm/year – around 50% of total gas demand at that time. Currently, China has long-term LNG contracts for 51 Bcm/year (including options for projects not yet sanctioned, i.e., APLNG) and 87 Bcm/year of pipeline contracts with Turkmenistan, Kazakhstan and Myanmar leaving a shortfall of 42 Bcm/year.

Import dependency could reduce to 20–30% depending on shale gas production. The government has a quoted target of shale gas production of between 60 Bcm (6 bcfd) and 100 Bcm/year (10 bcfd) by 2020 (and 6.5 Bcm in 2015) – if this is achievable, it significantly reduces the need for further gas imports beyond those already committed to. We include the recently announced additional 35 Bcm/year of Turkmenistan gas in our base case view, and when added to the other firm sources of gas supply, China would effectively have no need to net import gas until 2018, before any shale gas production. If China were to ramp up to meet its 60 Bcm lower shale gas target in 2020, it would still have excess resources at the end of the decade, and significantly more if it were to achieve the yet more ambitious 100 Bcm/year target in 2020.

Domestic shale should be far cheaper than LNG. For LNG, we expect landed prices in North Asia to sit in the USD 18–19/MMBtu range until the middle of the decade, then fall back to circa USD 14/MMBtu as crude moves back into an equilibrium pricing range (we would add USD 1/MMBtu as a placeholder for re-gas cost to convert LNG prices (delivered ex-ship) to a provincial gate price). If shale is produced in Sichuan and it follows a broadly similar scale/unit cost-to-produce reduction to the USA, shale gas could be produced at circa USD 4/mcf (wellhead), and hence a provincial gate supply cost (including a return to the upstream) of circa USD 6/mcf in the eastern seaboard provinces.

Figure 11

Potential imports with 60 Bcm shale scenario

Source: Credit Suisse estimates

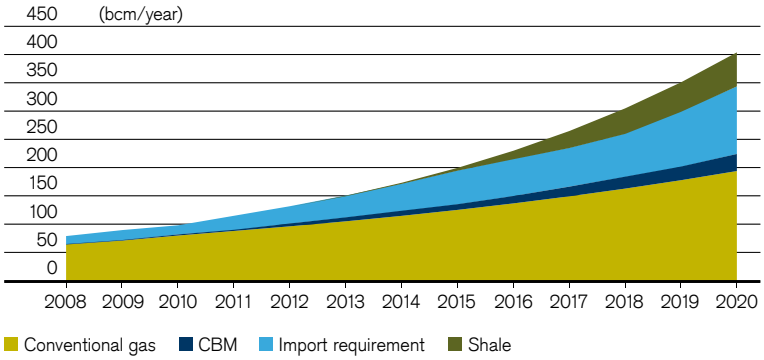


PHOTO: ISTOCKPHOTO.COM/RICKWANG

Ambitious production targets – US analogue?

China production target: 6.5 Bcm by 2015, 60 to 100 Bcm by 2020. The current five-year plan is primarily dedicated to China accelerating through the exploration and appraisal phase for domestic shale gas production, with the hope that this preparation translates into an aggressive production ramp-up in the 2016–20 plan period – hence, the target of 6.5 Bcm/year by 2015 and a broad target range of 60 to 100 Bcm/year by 2020.

Is China hoping that 2015 is "USA 2006"? The USA recorded a very pedestrian rate of shale production growth during 2000–05, but really accelerated on both percentage and absolute production growth terms in and after 2006, going from 15 Bcm in 2005 to 31 Bcm in 2006 (+107% YoY), then adding 40–50% annually thereafter. If we make a series of well production assumptions (explained in a later section) and assume China "inflects" in 2015 and follows the US production growth trajectory (2006 forward) it would hit 56 Bcm in 2020 and 110 Bcm by 2022. Is 2023 more realistic to hit the 60 Bcm target? Using 2015 as the inflection point seems very optimistic given the lack of wells drilled to date (<100 wells), so we ran another scenario, assuming 2018 as the inflection point. In this delayed scenario, China would hit 60 Bcm in 2023, and 100 Bcm in 2025.

Figure 12

China NDRC's shale gas production target range

Source: National Development and Reform Commission, US EIA

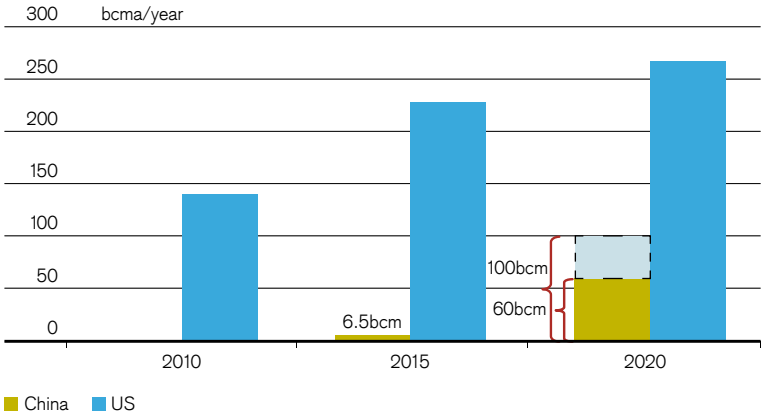


Figure 13

USA actual vs. Credit Suisse China shale gas production scenarios (time sequenced)

Note: For demonstration purposes we show the first inflection point year for the USA (2006) as 2015 for China—purely for comparison purposes
Source: US EIA, National Development and Reform Commission, Credit Suisse estimates

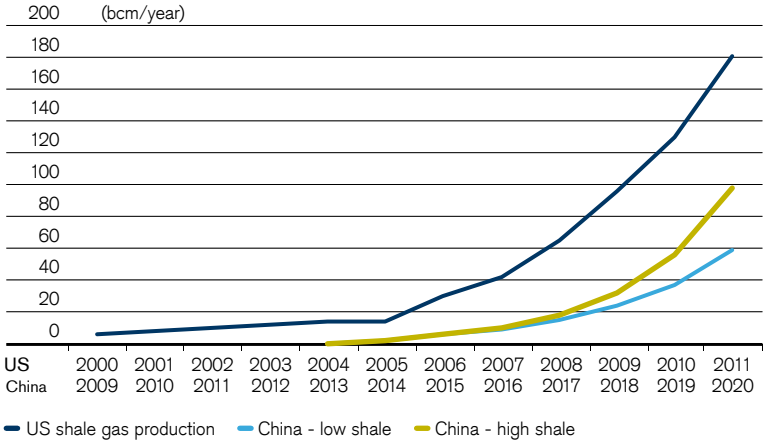
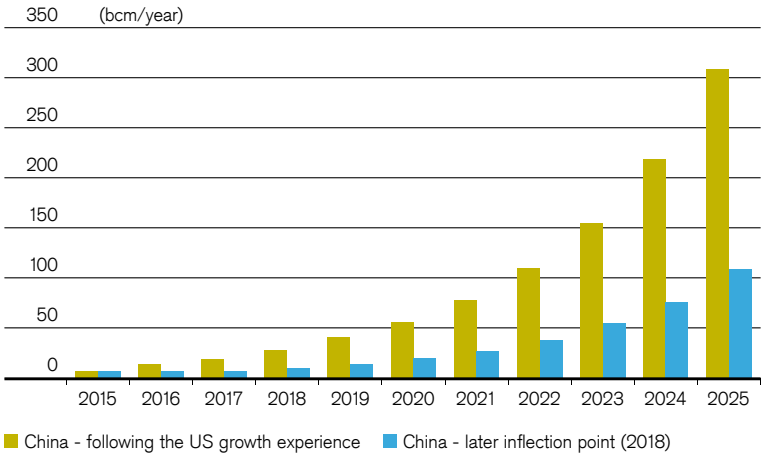


Figure 14

China – extrapolated US growth to 2023

Source: Credit Suisse estimates



Running the numbers

Figure 15

China 100 Bcm shale gas production scenario – CS base case

Source: Credit Suisse estimates

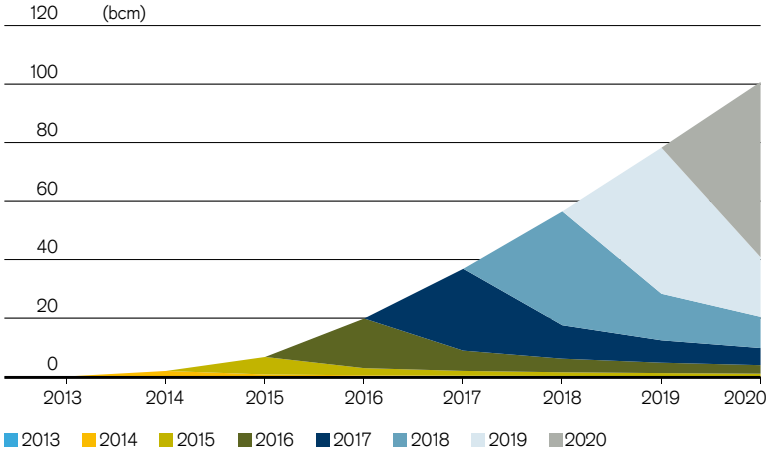
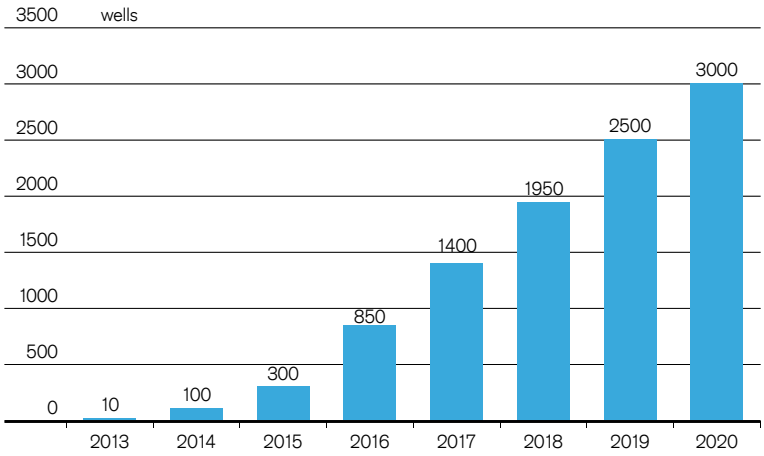


Figure 16

Number of shale gas wells assumed

Source: Credit Suisse estimates



Shale gas production declines rapidly in the first few years of well cycle. Unlike conventional oil and gas production wells, shale wells typically decline rapidly in the early part of a well cycle and then slow toward the middle and latter part. In our typical shale gas well, we have production declining by 73% by the end of year 1, 37% by year 2 and a further 25% by year 3. At the start of year 4, we already have flow rates 90% below the initial production. This mirrors production declines of 75% in the first four years in the Marcellus shale area in the USA.

We assume an initial production (IP) rate of 4 mmcfd in our base case scenario. And apply a Marcellus shale decline rate (73%, 37%, and 25% in the first three years) to generate a well forecast.

Under our base case, we estimate China needs to drill 6,800 wells by 2020 to get to the bottom-end of the National Development and Reform Commission (NDRC) production target. To reach the NDRC's 6.5 Bcm target by 2015, we estimate 410 wells need to be drilled. As we enter the latter part of the decade, we expect drilling activities to ramp up significantly, with the number of wells drilled increasing by 400 per year until 2018. In essence, we estimate 6,400 wells to be drilled in the latter part of the decade.

It is worth noting that Figure 15 is simply an illustrative example of China's shale gas production profile to achieve the 60 Bcm target. We did not carry on with the drillings post 2020 in our exercise; hence the sharp decline in production once China hits the 2020 target. We estimate China therefore needs 10,000 wells by 2020 to achieve the 100 Bcm production target. We therefore assume an even more significant ramp-up in drilling activities starting 2016; under this scenario, we expect China to drill 9,000+ wells in the latter part of the decade.

The challenges

Costs: US horizontals range between USD 5 m and USD 10 million per well. Based on our US E&P Equity Research team's estimates. Vertical wells on average are closer to USD 2–3 million, but obviously depth-dependent.

Current (initial pilot) drilling costs in China are high. Our understanding from industry players suggests that the first few horizontal wells drilled in China cost 2–3 times that of the USA.

Land access: The Ministry of Land and Resources (MLR) controls the allocation of land use rights, both on and below the ground in China. Hence, there is a clear pathway to land access for shale gas developers in China, for future blocks to be awarded. Shale is almost certainly also on blocks of land currently allocated for another primary exploitation (i.e., coal bed methane or coal). The principle to be applied in these cases is that the holder of land for the initial purpose has the right of first approval to reapply to the MLR to extract shale. Given the infancy of the shale gas story in China, what is not yet clear is whether there will be a significant issue between above- ground land users (primarily agricultural) and shale exploitation.

Rigs: Based on our knowledge, we estimate China has around 1,500 land rigs on the ground. However, hardly any of them are tailored for shale gas drilling. We estimate China needs 280 additional rigs in our base case scenario for producing 60 Bcm by 2020. This is based on the assumption that it takes 1.5 months to drill one well, and all the rigs operate at a 70% utilisation rate. Should China produce 100 Bcm by 2020 (the high-end of the target), it will need 540 additional rigs based on our analysis. The additional 280 rigs represent 19% of the current rig fleet – or looking at it another way, China needs to buy 40 rigs every year from 2013 onwards.

Horizontal wells: We understand that China had drilled 63 wells up to April 2012. Of that, 58 were shale gas and five shale oil wells, with 15 of these being horizontal wells. In 2011, 18 shale wells were drilled in China – of which 16 were vertical and two horizontal. This compares to 16,100 horizontal wells drilled in the USA in 2011, according to Spears & Associates.

Pressure pumps: Industry experts estimate one million HP (fracturing horsepower) currently in China, compared to 14 million in the USA. Given the early stage of fracturing technology, there is no official estimate in terms of fracturing horsepower in China. Our understanding from industry experts suggests that there is around 1,000,000 HP of pressure pump in China. This compares to about 14,000,000 HP in the USA currently, according to Spears & Associates. In China, to drill one horizontal fracturing well, one would roughly need 1,000 horsepower of pressure pump equipment, according to industry experts.

Water: Global social/environmental concerns over unconventional gas developments are rising. Several US states have banned fracking; in France, the practice has also been (re)banned by the Hollande administration and in the UK there has been major public concern over initial drilling carried out in the north-west of the country being linked to increased seismic activity in that area. In Australia, there has been a significant pushback between certain CBM developers and the farming community, both around the use of water as well as commercial terms for land access to place well pads/drill wells. In China, given the lack of shale wells drilled, the degree of public concern is unclear. We would not be surprised if national public concerns regarding water quality and usage, and CO2 emissions were to be less likely, at least in the initial phase of shale gas exploration in China, but local concerns may be real and important as shale moves from initial exploratory drilling to the commercial drill-up phase.

Pipeline reach: This will be an issue in China. Currently, China's gas pipeline reach is approximately 50,000 km, of which 35,000 km is primary distribution. In contrast, in the USA there are some 400,000 km of gas pipeline. The current plan to extend China's gas pipeline reach is to achieve 100,000 km coverage by 2015 as per the NDRC, and 150,000 km by 2020, in our assumption. At this point China would have only 38% of the current USA gas pipeline reach.

Chinese Bcm per kilometer of pipeline could exceed that of the USA: At the moment the implied amount of shale gas to be carried per 1,000 km in China is very low. Interestingly, if China hits the 60 Bcm target by 2020, it would carry a similar quantity of shale per 1,000 km to current volume in the USA , but would exceed the USA by 50% if the 100 Bcm upper target is achieved that year.

Sub-surface experience is likely to be the largest challenge currently. With less than 100 shale wells drilled (versus a cumulative 35,000 shale wells in the USA over the past three years), Chinese/foreign developers have virtually no experience drilling the Chinese shale resource base.

Oil's shale shake-up

Growth in US shale oil production and 100 years of natural gas resources are driving hopes of complete energy independence for the USA and fears of a correction in medium-term oil prices. We question this simplistic assessment.

Jan Stuart, Edward Westlake

US energy independence and global tension

We disagree with the currently fashionable point of view that the USA will become the "new Middle East of oil," and enter a longer-run upturn of GDP driven solely by cheap energy. In our view, the shale-oil "revolution" is more limited than that of US natural gas. Oil production from shale and other "unconventional plays" is more difficult and more expensive, and oil markets are global, not isolated on particular continents as are natural gas markets. It will take longer to drive down the price of oil globally than it did to drive down the price of natural gas in the USA and Canada, and the global price of oil will continue to be highly sensitive to developments in the Middle East.

Summary of what we think is the shake-up for oil

It is possible that ten years from now, the energy content in US exports of coal and natural gas will be higher than that of its much-reduced net imports of oil. Hence US energy independence is indeed a possibility. But even if we assume that oil demand in this country enters into a structural decline, and that oil supplies continue to grow dramatically in the next ten years, the USA will still need to import about one-sixth of its oil (compared to one half today).

Equally as important, the price of oil will probably still find a relatively high floor. We think this floor will be near USD 90 (real, 2011) per barrel of Brent for at least the next few years, which is the cost of either producing a new "marginal" barrel of oil (shale oil in the USA) from out of the ground at a profit, or buying it from the world's main sovereign exporters. While full-cycle upstream costs in the USA are eventually likely to deflate, prices will need to stay elevated to elicit historically high spending for years to come.

Oil production, including (un)conventional crude, condensates, natural gas liquids and biofuels, has

grown faster in the USA than in any other country outside OPEC over the last three years. Widespread application of the revolutionary drilling that brought about dramatic growth in the supply of natural gas is playing a modest, but fast-growing role. Generally speaking, high prices have driven a large-scale, ongoing surge in upstream activity in the USA, partly because the industry is increasingly denied access to cheaper oil reserves elsewhere. In addition, steeper decline rates in aging conventional reservoirs everywhere keep pushing global activity higher up the cost curve, pushing shale oil into focus.

• Onshore crude oil production in the USA has risen by some 600–700 thousand barrels per day (kb/d) this year (>10%), rivaling what was seen as exceptional growth last year. We have investigated results from the thousands of wells drilled and their costs. We mapped all locations and extrapolated across all known hydrocarbon basins as to what reserves may be recoverable. We assumed ongoing, rapid efficiency gains and more technological breakthroughs. Our model shows that US oil production can continue to grow by around 600 kb/d of crude oil and another 100–200 kb/d of other liquids every year for another 6–8 years. But this also assumes relatively high prices:

- To fund around USD 150 billion of required annual industry capex would need oil prices equivalent to Brent USD 95 this year and next. As cash flows grow, the price of Brent oil could fall to around USD 80/bbl in five years to fund capex. There is an element of circularity in the breakeven assumptions: prices lead to cash flows, which lead to production.
- While we can tweak every assumption in the model and drive production growth up or down by about 10% around our base case scenario, varying prices has by far the largest impact on supply growth.

• In addition, our model shows that production from shale oil reservoirs will reach a plateau and a maximum sustainable rate that falls well short of trajectories widely advertised by others. Recent much-publicized studies by the International Energy Agency (IEA), for instance, project not only higher but also continually rising output from shale in the USA well into the 2030s. As the share of shale oil in US oil supplies grows from <5% in 2010 to roughly one third of 10 Mb/d total crude oil and condensates in our 2020 base case view, the higher decline rates mean that the industry will have to keep investing and drilling at historically very high levels simply to hold production steady.

- Of course, depending on how the "unknowns" pan out, that plateau may prove to lie higher or lower than what we project. Interestingly, various company scientists agree with the concept of flattening growth. They also project sustainable oil production rates that are 20% below ours.
- More well locations could emerge over time. We have limited the well count in our model so that over the next 20-years it does not exceed the overall effective liquid-rich acreage in each play and the probable well spacing per acre. Down-spacing tests to increase the number of wells that can be drilled per acre will also be important to watch. On the other hand, the industry is currently focused on "sweet spots."

• We should also remember that on an energy-content basis, drilling shale-gas wells is more efficient than drilling shale-oil wells. On an energy-yield basis, the expected ultimate recovery (EUR) of gas wells is up to five times higher than oil wells, which suggests many more oil wells will need to be drilled than for natural gas or, if oil prices were to fall too much, then the industry would drill gas wells, not oil wells.

How to square the circle – bring down oil demand

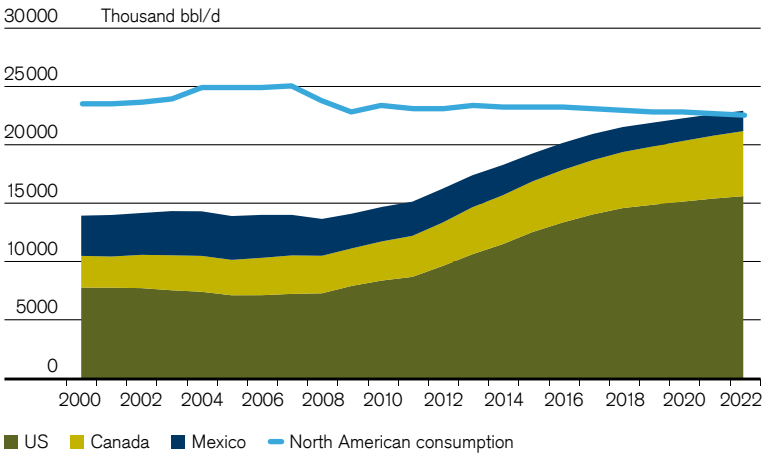
Promoting natural gas usage will likely provide the best value payoff for the economy – particularly if it can replace higher-priced oil consumption. For oil markets, a policy promoting domestic oil production growth and closer integration across North America could improve domestic energy security – the goal of North American oil independence thus looks more attainable, particularly if oil consumption can be reduced through the use of natural gas vehicles.

Since oil prices have global drivers, prospects for shale oil production need to be viewed globally as well. US oil production growth now or in the next ten years is only one part of that ever-changing puzzle. That said, it is already clear that we can no longer assume that global demand growth will be curtailed by constraints on supply. Nevertheless, in our base case scenario, sovereign producers will retain the ability to manage supply through 2022. We therefore expect that, even as price trends begin to roll in coming years, ending ten years of increases, new declines will be quite muted and moderate. The most plausible way for oil prices to fall more steeply would be for oil demand growth to slow.

Figure 17

Crude oil and liquids production and consumption in North America

Source: Credit Suisse



Key questions on shale oil growth prospects

How fast can US oil production grow?
Based on high oil prices and a set of improving assumptions – i.e. a 27% higher oil well count by 2016 versus 2012 (58% higher than 2011) and a 25% improvement in 30 – day initial production (IP) rates per well, we calculate that US oil production could reach just over 10 Mb/d by 2020 and maintain this level for a number of years. Although the well count increases by 27%, we note that our oil rig count only increases by 11% owing to improvements in drilling efficiency – i.e. the number of days to drill a well.

What oil price is required to fund this growth?
Single well economics suggest breakevens in the USD 60–75/bbl range for US shales today. However, driving growth at forecast rates requires substantial capital; access to capital could be a greater constraint. In a simple calculation, we estimate that the US oil industry needs around USD 95/bbl Brent near-term to fund the capital expenditure required to deliver this growth, based on self-generated cash flow alone. This could be lowered by external funding, but we have already seen some companies reduce capex when WTI recently fell through USD 90/bbl. As US oil production volumes rise, this breakeven could fall toward USD 80/bbl. It is important to note that the average recovery of a gas well is 3–5 times the recovery of a typical oil well on a Btu basis. The oil shale revolution should help meet rising global demand but looks less likely to lead to a collapse in domestic pricing similar to US gas markets.

How long can the underlying rocks maintain this rate of growth?
In the short term, growth can be maintained or even accelerate (depending on rig counts – i.e. oil prices). However, there are two key challenges for oil production growth versus natural gas:

First, shale oil wells are less productive than gas. Each individual shale oil well is less productive than gas wells from the Haynesville/Marcellus areas that have lowered the cost of natural gas. Second, terminal decline rates are unknown. We do not know yet the terminal decline rates from new oil shale plays (given the limited history). Physics would suggest oil decline could be higher than in natural gas shales. This decline treadmill will likely lead to a plateau in US production. We forecast a 10 Mb/d plateau for US oil production by 2020–22. At that time, we would need to add 1–1.5 current Bakken fields every year just to offset declines in existing production (note: we have compared our drilling program assumptions to the core acreage in each play as a cross check).

Downstream implications?
Accommodating 600,000 bbl/d of year-on-year oil growth from the USA and 300,000 bbl/d each year of Canadian growth through to 2017 will require new trunk-line pipes and gathering systems. Our short-term model suggests WTI-LLS spreads will remain wide through 2H 2012 but narrow as Seaway, southern Keystone XL and Permian pipes are built in 2013. Even as WTI-LLS spreads narrow, it is likely that a wider discount will remain for Bakken and Canadian heavy crude through 2014. In the medium term, the Gulf Coast will be overwhelmed with light sweet crude requiring shipments to the USA and Canadian East Coast or even exports (if policy allows). It would be better for consumers that US light sweet crude is refined in Europe where refineries are less complex than to force heavy refineries in the Gulf to run light crudes that they were not designed for.

Service implications?
Growing US production will require a significant increase in the number of wells drilled from 9,200 in 2011 to 16,000 per annum by 2022. This will require a higher rig count (our assumed oil rig count rises by 112 rigs by 2017). Each rig will also need to drill more wells each year. Although the near-term outlook for onshore services remains challenged by weak natural gas prices, North American oil shale potential and rising gas demand should require substantial investment, people and services activity.

US oil – a pipedream?
The gap between US oil production and consumption is large and may not close in the period which our analysts have assessed in detail (to 2022). That said, North American oil self sufficiency (USA, Canada, Mexico) looks more achievable with appropriate policies to promote safe drilling, energy efficiency, regional coordination, and gas substitution.

However, we do not hold out high hopes of the same low cost dividend to the US economy as is provided by natural gas due to the relatively high cost of oil shale extraction and Canadian oil sands recovery. Natural gas appears the best low-cost energy policy option.

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Implications for global oil shale potential?

North American shale success is leading a wave of entrepreneurial spirits. Thus far, we are most impressed with oil shale results in Argentina, but aboveground politics need to be resolved. In the medium term, the Russian Bazhenov oil shale merits monitoring, so too the shale gas potential of China, and there is some excitement over Australian potential. Globally, shale hydrocarbon potential will take time to delineate and develop, but could be a meaningful source of energy later this decade and in the 2020s.

Impact on the oil price?

Supply from the USA and Canada is visibly growing. However, outside North America non-OPEC supply growth is negative in 2012. Markets may still reflect some risk premium over marginal costs. Risks from that perspective seem balanced. Spare capacity could rise faster if curtailments in Nigeria, Iran, Venezuela and Sudan were resolved. Spare capacity could fall if a global economic recovery takes hold.

In our base case, US oil production growth would account for nearly 80% of the global net gain in oil production capacity that we foresee by 2015. However, in that same base case, spare capacity only grows from 2% to 3% by 2015. That would be lower than in 2009 and 2010 and on a par with the 2004–08 timeframe of rapid oil price increases. It would take away a prop under fundamentals and allow for prices to gravitate down towards more sustainable long-run levels nearer USD 90/bbl. Moreover, without relatively high prices (USD 90/bbl Brent or more), US and other non-conventional growth would be less.

That said, in our long-range model, there is the prospect of still more production growth to come in the 2015–20 timeframe from other non-OPEC producers (e.g. pre-salt Brazil, pre-salt Angola, Russian shale). This could put a brake on the rising price trend that has been in place since 2003 in the absence of stronger-than-expected demand growth. Risks would then tilt to the downside.

Figure 18

Demand and supply framework: Global oil balance no longer shows inexorable tightening

However, our base case forecast of many moving parts still leaves spare capacity manageable by Saudi Arabia, which when added to our belief that NA production growth requires hefty, ongoing investments means that oil prices should remain supported at relatively high levels near USD 80–90/bbl (real, 2011) through 2020.
Source: Credit Suisse

Demand	2011	2012E	2013E	2014E	2015E	2020E
Global	89.5	90.6	92.0	93.1	94.0	98.0
YoY growth, %	1.0%	1.2%	1.5%	1.3%	1.0%	
OECD	45.8	45.6	45.5	45.3	44.7	
YoY growth, %	-1.0%	-0.3%	-0.3%	-0.4%	-1.3%	
Non-OECD	43.7	45.0	46.4	47.8	49.3	
YoY growth, %	3.3%	2.9%	3.3%	3.0%	3.1%	

Supply	2011	2012E	2013E	2014E	2015E	2020E
Global	88.6	90.5	92.0	93.2	94.1	102.0
YoY growth, net mb/d	0.8	1.8	1.5	1.2	0.9	
Non-OPEC	50.6	50.9	51.7	53.0	54.6	
YoY growth, net mb/d	0.1	0.3	0.8	1.3	1.5	
North America	15.5	16.7	17.5	18.3	19.3	22.5
YoY growth, net mb/d	0.5	1.2	0.8	1.3	1.5	
Non-OPEC less NA	35.1	34.2	34.2	34.7	35.3	
YoY growth, net mb/d	-0.5	-0.9	0.0	0.5	0.6	
Processing gain	2.4	2.5	2.5	2.6	2.6	
OPEC	35.7	37.1	37.8	37.6	36.9	
YoY growth, net mb/d	0.6	1.5	0.7	-0.2	-0.7	
OPEC crude oil	30.2	31.5	32.3	32.0	31.3	
YoY growth, net mb/d	0.3	1.3	0.7	-0.3	-0.7	

Balance, stocks						
Implied inventory change	-0.8	-0.1	0.1	0.0	0.1	

Spare capacity						
All Saudi Arabia	2.4	1.9	2.0	2.5	3.0	4.0
% of total supply	2.7%	2.1%	2.1%	2.7%	3.2%	4.0%

Coal – the biggest loser?

We believe US coal consumption to be in structural decline, with little or no incentive to build additional generating capacity beyond that already under construction. Globally, we expect coal to eventually be replaced by natural gas for environmental reasons, although switching from coal to gas is likely to take some time in countries like China and India.

Marcus Garvey, Andrew Shaw

PHOTO: ISTOCKPHOTO.COM/OPLA

"Old King Coal" set to be dethroned – but not this decade…

The revolution in US gas supply has already begun to have an impact on other energy sources. To date, the most obvious impact has been in the global thermal coal market, where cheap US gas has seen substantial switching from coal to gas among electricity producers. This has driven a dramatic change in the USA's involvement in the seaborne market, moving from being a net importer of thermal coal in 2010 to being a significant exporter over the past two years. The additional 60 million tons of thermal coal per year "freed up" by the USA has been a key factor depressing coal prices over the past year.

With coal remaining the bedrock of the energy complex in many developing countries (including most importantly China and India), the potential for a replication of the US phenomenon will be a key factor over coming years, with coal's negative environmental impact effectively meaning that, in the absence of an economically viable clean coal breakthrough (e.g. far cheaper integrated coal gasification combined cycle generation), its current role is one of filling the gap while the world resolves the question of its preferred fuel mix. The time it takes to do this will be a key factor in determining medium and long-run thermal coal demand. In the near term, coal is likely to remain vital to the energy requirements of many nations, with the scope for near-term substitution limited. In time, however, these nations will also reduce their call on coal, with the biggest impacts likely to be felt in the 2020s, particularly if China is able to follow the USA's lead and effectively utilize its large-scale shale-gas resources.

The USA – what happened?

The increase in US gas production, and the associated fall in gas prices has seen large scale coal-to-gas switching, with coal's share of the power generation mix falling to around a third this year, down from around half prior to the Great Recession.

The follow-on from weaker domestic coal demand has been a dramatic shift in the USA's net coal exports (see Figures 19 and 20). Though the initial 2009 leg lower for US thermal imports was driven by the recession, the domestic shale gas glut has since turned a cyclical move into a structural shift.

Consequently, US net exports of thermal coal have been running at 45 Mt/y (metric tons per year, seasonally adjusted), as domestic producers, struggling in their soft home market, have sought to export as much surplus material as possible. This change in the dynamics of US thermal coal trade has been a key factor in pushing the seaborne market into surplus.

Figure 19

US electricity generation mix

Source: Credit Suisse, Customs Data

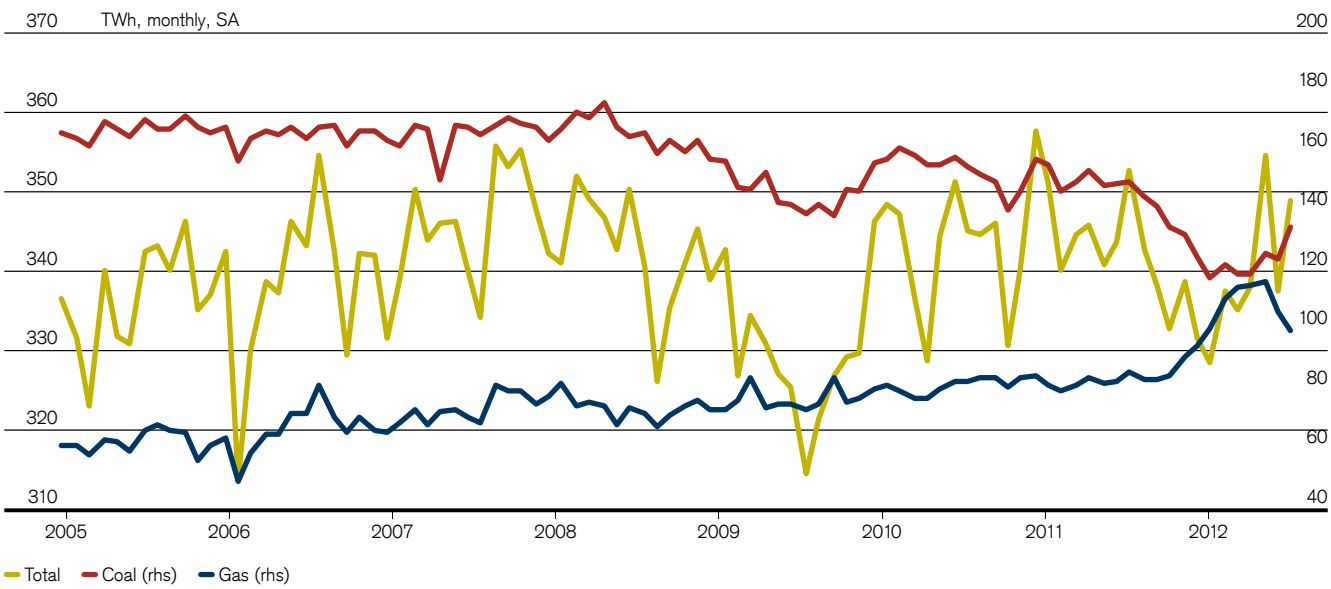
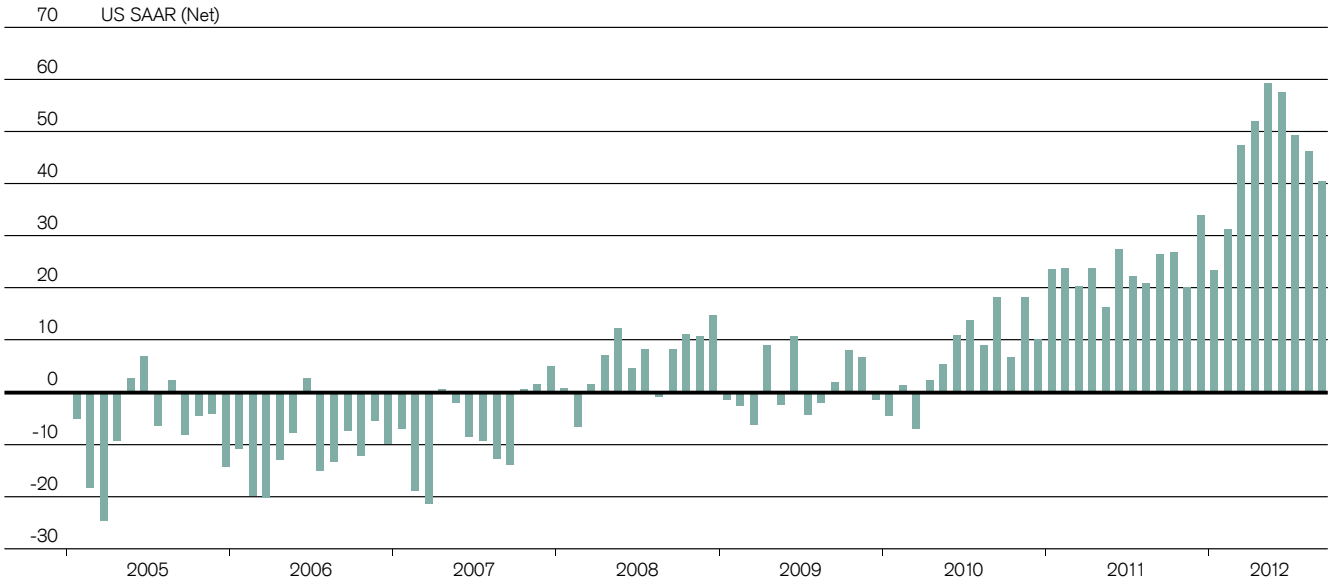


Figure 20

US net thermal coal exports

Source: Credit Suisse, Customs Data



US coal consumption in a structural decline?

We believe that US coal consumption is in terminal decline with little or no incentive to build additional generating capacity, beyond that already under construction. According to the EIA, US power plants consumed 954 Mt of thermal coal in 2007 and, since then, there has been a clear downward trend (Figure 21). Year-to-date, consumption is 83 Mt lower than 2011 levels and, while this year's exceptionally low natural gas prices have cyclically exacerbated the 2012 coal demand decline, potentially beyond what is structurally justified, we would view any 2013 increase in coal consumption as a mere short-term move. To put this in context, the Credit Suisse US Utilities Equity Research team estimates that current price dynamics and changing environmental legislation will lead to the retirement of 60 gigawatt (GW) of coal generating capacity between 2011 and 2015. To date, an estimated 10 GW of capacity has been retired, an additional ~28 GW has been earmarked for retirement, and a further 22 GW is expected to be announced over the course of the next few years.

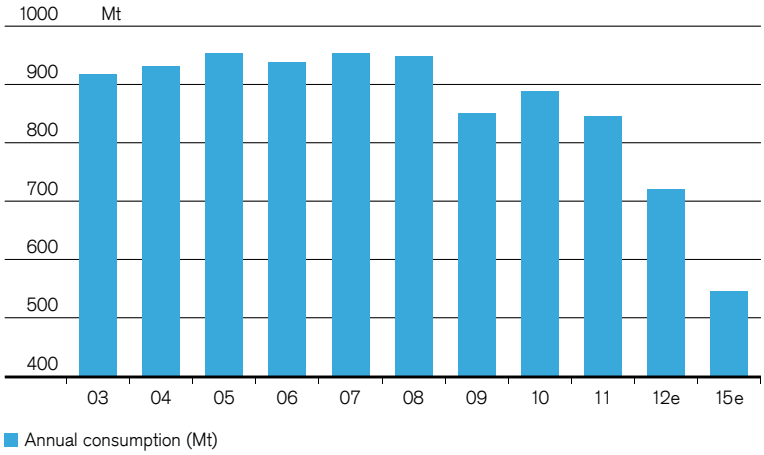
Freeing up more material to export

Our US Mining and Metals Equity Research team expect 2012 exports of around 130 Mt/y, with current ambitions set to add a further 95 Mt/y by 2017 through the expansion of existing facilities and construction of greenfield projects. This suggests that US export capacity will rise to well over 200 Mt/y by the latter years of this decade.

Figure 21

US power plant thermal coal consumption

Source: Credit Suisse, the BLOOMBERG PROFESSIONAL™ service, EIA



Global coal implications

Most analysts agree that, in the long run, coal is likely to be displaced by natural gas in many markets as, bar a dramatic CCS (carbon capture and storage) breakthrough, its environmental credentials place it at an inherent disadvantage – gas emits roughly 60% less carbon dioxide per kilowatt hour (kWh) of electricity generated. The key, however, is timing, with the speed at which this displacement has occurred in the USA unlikely to be replicated in any other major country.

Broadly speaking, the obstacles to replication can be broken down into supply- and demand-side constraints. From our analysis, no other region will match the magnitude of US natural gas supply growth in this decade and the USA, though becoming an LNG exporter, will keep much of its gas at home. Consequently, no other regions are likely to have a surfeit of cheap gas supply with which to displace coal until the best part of 2020.

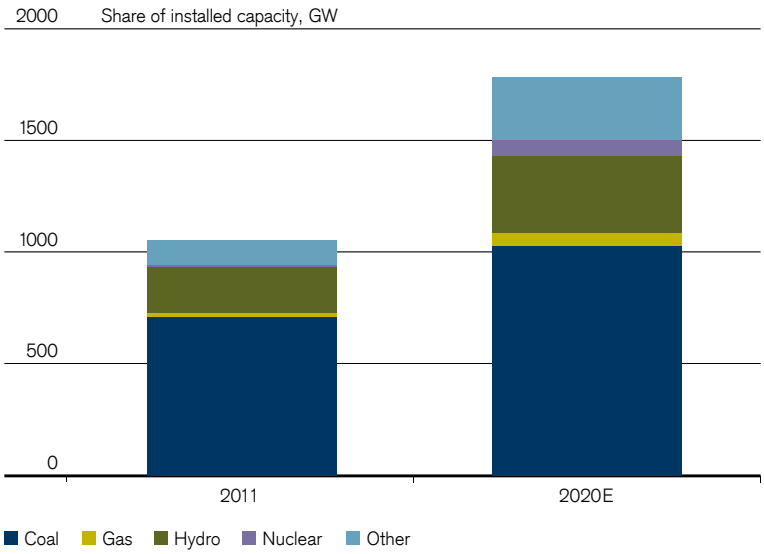
China – coal remains the energy bedrock, for now

China accounts for roughly 50% of global coal consumption and it has to date been the energy bedrock upon which the country has built its economic growth. Indeed, coal makes up 67% of China's installed generating capacity versus 3% for natural gas, with hydro providing the second-largest source of Chinese generation, accounting for 20% (Figure 22).

Figure 22

2011 vs. 2020E installed capacity in China

Source: Credit Suisse, China NBS, CEC



Notably, within the current infrastructure in the power sector, there is currently very limited scope for coal-to-gas switching. Given its use for base-load and greater reliability than alternative energy sources, coal generally accounts for 75%–85% of monthly power output. Strong hydro generation on the back of heavy rainfall has recently pushed coal's market share into the low 70% range, but the seasonality and year-on-year volatility exhibited by hydro makes it a considerably less dependable power source.

Any question of a major switch away from coal is therefore some way off. More relevant, however, is the potential for other power sources to cannibalize coal's demand growth and gradually take a greater market share. To this end, the China Electricity Council's outline of capacity additions sees total capacity rising to 1,786 GW by 2020, with coal's market share falling back to 58%. Hydro capacity, on this roadmap, is predicted to reach 340 GW by the end of the decade, at which point it would be approaching its estimated economically exploitable geological maximum of ~400 GW. In itself, this is an ambitious target. Gas would see capacity expand to around 60 GW, implying only modest growth in market share.

That said, gas should see greater gains over coal in direct industrial use and the development of a peaking Chinese power market will also play a key role in determining the future expansion and utilization of gas generating capacity. Moreover, the interplay between coal and nuclear power as base-load power sources, and the development of further renewables capacity will also influence the

PHOTO: ISTOCKPHOTO.COM/MICHAEL UTECH

extent to which China continues to rely on thermal generation. The scene does appear set for coal to experience a declining market share, but the window for significant shifts is unlikely to arrive within this decade. Beyond 2020, however, if China is able to replicate the USA's growth in non-conventional gas production, the days of "Old King Coal" may be numbered.

India – the once and future coal king?

Following in China's wake, India is seen as the other major growth story for global energy demand. Within the country's power mix, coal currently overshadows other forms of generation, with 112 GW accounting for 56% of installed capacity. Moreover, based on Credit Suisse's India Utilities team's current forecasts, coal's dominance is not only set to continue, but actually expand further, peaking at 63.5% of installed capacity in 2016.

In stark contrast, gas capacity of 18 GW makes up just 9.2% of the current 200 GW total and, though growing in absolute terms, is expected to fall back to 7.7% by 2017. More so than in China, the scope for any short-term coal-to-gas switching is therefore severely limited and unlikely to be possible for many years to come.

Japan – searching for a nuclear alternative

Though the government has somewhat backed away from initial indications that all nuclear power would be phased out before 2040, the potential for a closure plan somewhat more aggressive than had been the Credit Suisse base case does remain on the table. The means by which Japan will replace this lost generating capacity, though there is clearly a heavy bias towards renewables, is still extremely unclear.

While there had previously been some scope for coal to gas switching, the chances of this being recreated within the short term are now extremely slim. The overall burden being carried by thermal generation leaves little or no room for inter-fuel substitution. While a restart of some nuclear generation should offer a degree of respite, we still would not expect any significant switching in the power mix.

South Korea and Taiwan – unfulfilled potential

In contrast to China and India, on an installed generating capacity basis, South Korea should have some room for coal to gas switching. Coal has consistently run at higher utilization levels than gas capacity due to its role in base-load generation and, as a consequence, accounted for a considerably greater share of electricity output. The countries do therefore, in theory, have some scope for a switch away from thermal coal, towards natural gas.

Despite this, the potential for reduced coal demand on the back of fuel switching is unlikely to be either a short or medium-term factor in South Korea or Taiwan. The reason being that, as mentioned in the case of Japan, for East Asian consumers of seaborne LNG, the economics of coal to gas switching neither make sense now nor are they likely to within a small number of years.

Providing the infrastructure

The shale revolution has unleashed considerable capital investment opportunities with regard to infrastructure for natural gas and crude oil, particularly given the upheaval in traditional production locations. In addition to storage and processing facilities, more pipelines will need to be built as they are the most economical way of transporting oil and gas over long distances.

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Since many shale plays require significant infrastructure development, we believe the shale revolution should provide infrastructure companies and US Master Limited Partnerships (MLPs) with continued opportunities for capital allocation. With a relatively modest rise in price outlook for natural gas, the INGAA Foundation's 2011 study[1] concluded USD 338 billion worth of infrastructure would be required in nominal US dollar terms from 2011 to 2035. The trend in switching from coal to natural gas underpinned some of the INGAA's views, along with incremental generation from natural gas. The INGAA's breakdown consists of:

- ~USD 132 billion for large-diameter natural gas mainline pipelines;
- ~USD 59 billion for small-diameter gas gathering pipelines;
- ~USD 41 billion for small-diameter gas lateral pipelines;
- ~USD 29 billion for natural gas processing plants;
- ~USD 60 billion for natural gas liquid (NGL) and oil pipeline; and,
- the remainder for pipeline compression and storage facilities.

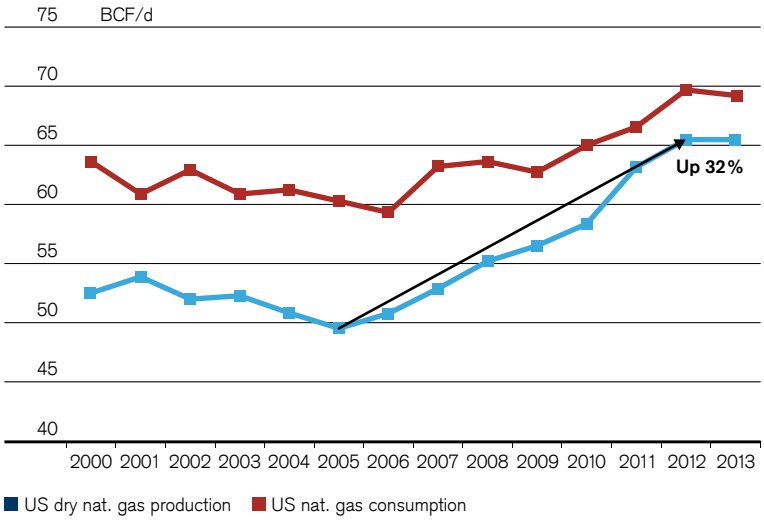
We believe the study underestimates the infrastructure opportunity. Given the 110,000 inch miles added each year and approximately USD 100,000 per inch mile estimated for 2013, this would translate to approximately USD 275 billion in total from pipelines alone – setting aside storage and gas processing.

Underscoring the capital investment opportunity unleashed by the shale revolution, capital spending in the MLP sector has increased rapidly over the last six years, rising at a compound

Figure 23

US dry natural gas production up 32% since 2005, driven by shale gas

Source: Credit Suisse estimates

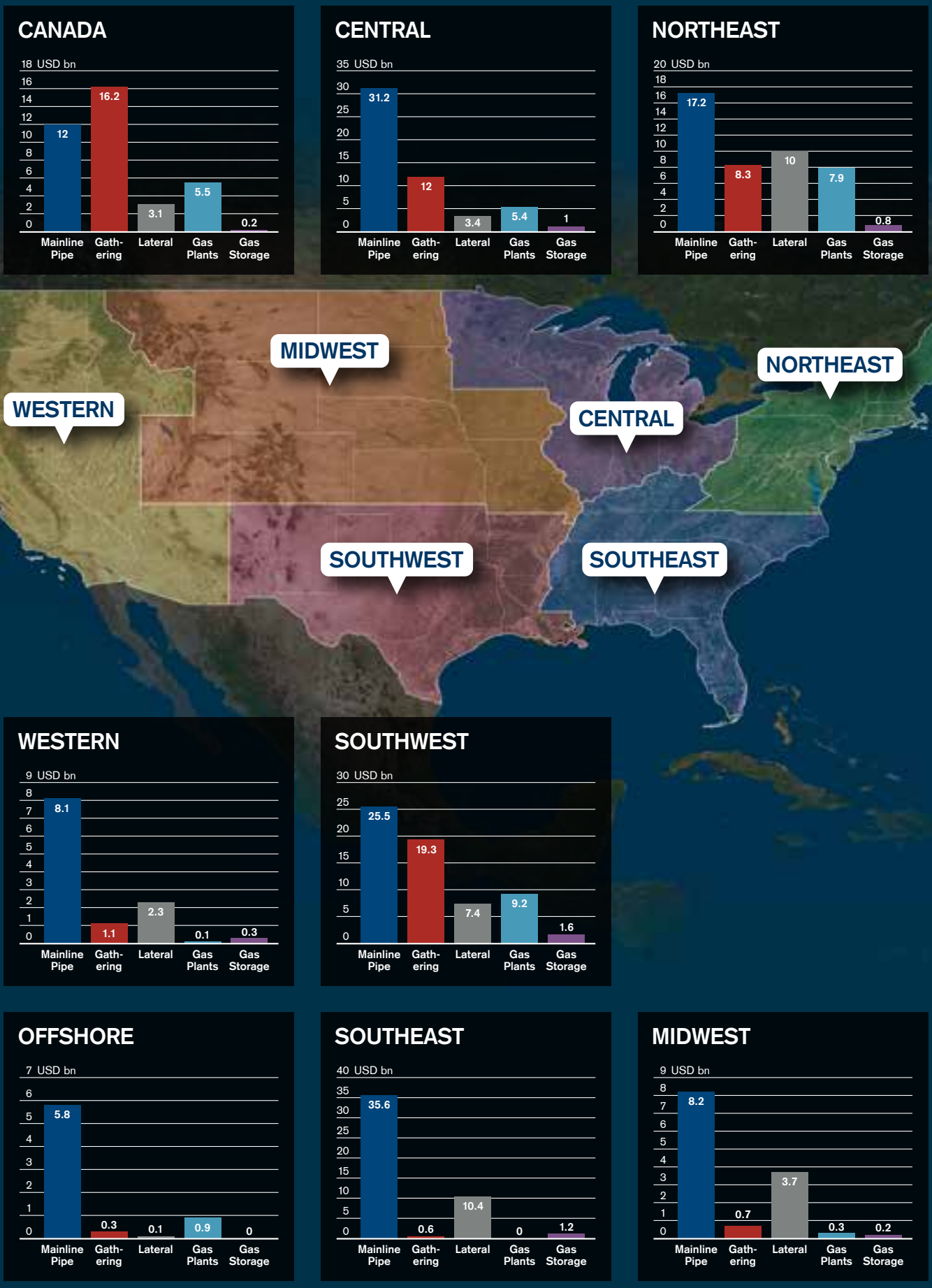


[1] "North American Midstream Infrastructure Through 2035 – A Secure Energy Future," INGAA Foundation, 28 June 2011

Figure 24

Capital spending on gas infrastructure by region and type of spending over the next 25 years

Source: INGAA, ICF International, Credit Suisse estimates



growth rate of over 22% per year, and expected to exceed USD 75 billion in 2012–2014. Significant investor demand for yield-oriented products offered by long-dated pipeline assets has had a positive effect on capex. Historically, low interest rates provide a rather compelling argument for the cash flow predictability, duration and somewhat unique growth offered by infrastructure companies. The shale revolution is at least likely to drive demand for infrastructure through the end of the decade. Consequently, we are not overly concerned about the growing capex figures in the current environment.

Notably, changing sources of natural gas supply from relatively new shale plays have altered transportation patterns. These changes provide investment opportunities, but can also significantly alter natural gas basis differentials at various geographic locations. Very wide basis differentials provide a signal for incremental infrastructure investment, whereas relatively flat basis differentials signal that pipeline capacity is adequately supplied and can raise questions about the underlying value of existing assets due to renewal risk with regard to existing gas transportation contracts. However, the existing pipelines are largely needed for basin connectivity, as shale natural gas produced close to consuming regions is not necessarily sufficient to satisfy demand in many cases. Over a longer period of time, basis differentials should allow a reasonable return on capital for the infrastructure assets and for the producers. Clearly, the changes to natural gas flows provide considerable opportunities for greater infrastructure buildup.

Figure 25

Inch-miles of additional pipe required: Approximately 110,000 inch-miles/year expected over the 2010–2035 time frame

Source: INGAA, ICF International

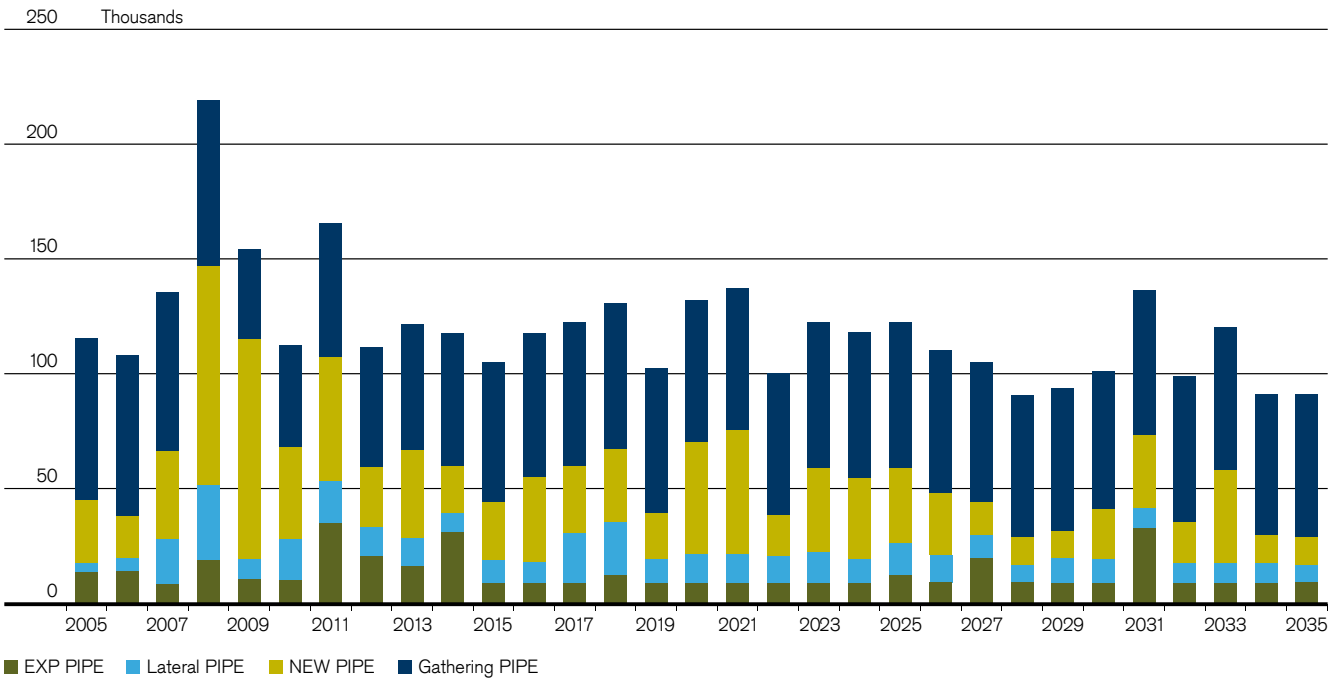


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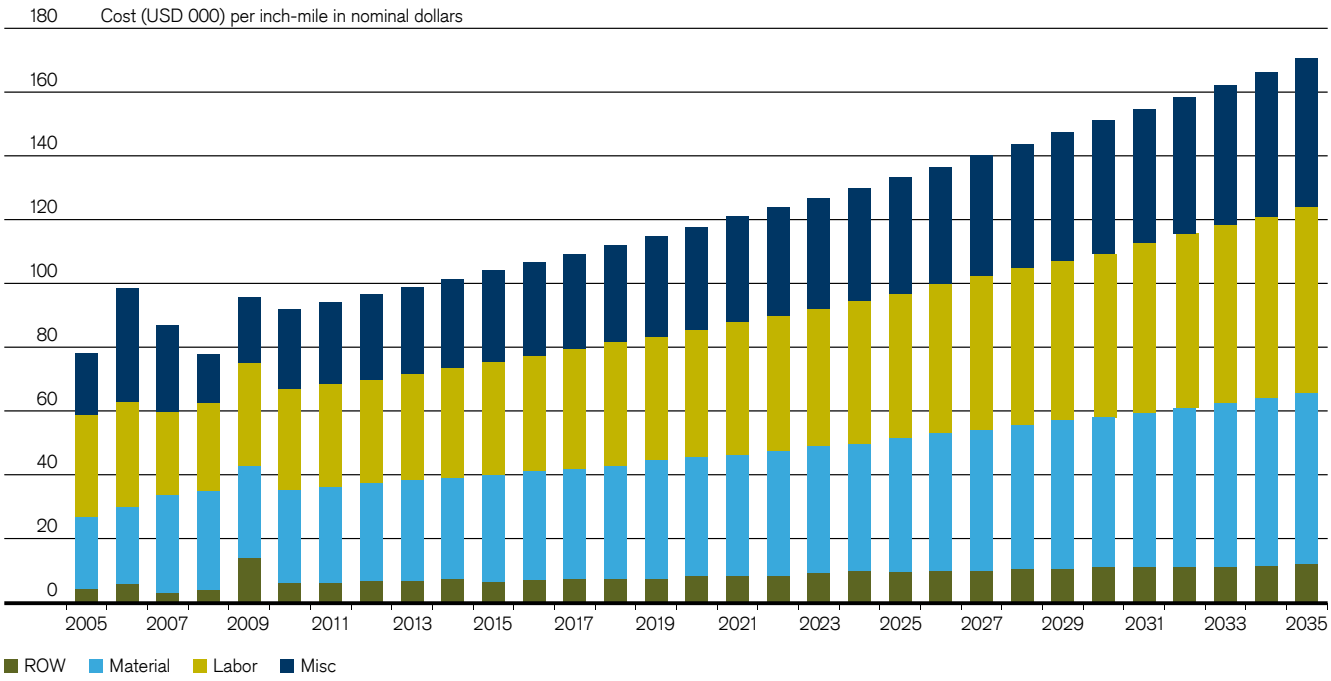
Figure 26

Equivalent projected nominal cost of additional pipe: Gas pipeline costs expected to average approximately USD 100,000/inch-mile in 2013

Source: INGAA, ICF International, Credit Suisse research



Sector implications

The impact of the shale revolution across the energy complex within equities is significant across a wide range of industries and regions. Consequences emerge in terms of shifting cost curves, relative competitiveness, new infrastructure and technological innovation[1]. We summarize the key highlights.

Richard Kersley, Mujtaba Rana, Kathryn Iorio

North American energy

The shale revolution has transformed the reserve opportunity set for the US exploration and production (E&P) universe and the cost structure of the US refiners relative to their global peers. The large inventory of well locations provides good visibility of the demand for US oilfield services, once near-term margin pressures have been navigated. Logistics spending to bring crude and NGLs to market will create opportunities for MLPs and refiners alike. Not all companies will win – the downshift in the gas cost curve will render some higher cost natural gas properties non-profitable. While investors may have thrown out WTI as a broken benchmark, significant infrastructure will eventually help improve domestic realizations, a following wind to domestic producers.

Asia Pacific energy

The focus for shale will be in China, driven by an imperative for energy security. The traditional Chinese super-majors are all focused on the development of unconventional onshore gas (with CNOOC expanding beyond its traditional off-shore domain), and the exploration work starts in earnest as we enter 2013. The question is whether China can crack the shale code and, if so, how quickly it can ramp up production the answers to which have a material bearing on the LNG and pipeline gas development plans of Gazprom and LNG supply proponents in the wider Asia Pacific region.

Energy infrastructure

The shale revolution is set to unleash significant capital spending. North America's energy infrastructure in terms of shale developments is dominated by several Canadian listed names, some US companies, and a long list of US Master Limited Partnerships. The asset bases of these entities touch most of the major resource basins across the continent. Ongoing development of shale natural gas across North America has fundamentally changed some of the dynamics of legacy natural gas infrastructure.

Power and utilities

Low natural gas prices are having a significant impact on the power and utility sectors, changing long-established strategies around power plant dispatch decisions, broadly lowering the profitability of competitive power generators, and generally creating helpful bill reductions for customers. This transition will be structurally durable with gas generation remaining a cost-competitive resource in power markets into the future. Europe, in contrast to the USA, is experiencing a "coal king" phenomenon due to the low coal and carbon prices in Europe. Coal-gas switching should occur in the region if gas prices happen to fall.

Clean technology and alternative energy

The impact of lower natural gas on the clean technology and alternative energy sectors is potentially transformative. There would be a challenge to the cost structure of the renewable sector given the lower effect of the reference price, though an increased gasification would be to the benefit of metering and gas processing companies. There is massive potential for a breakthrough in terms of energy use from fuel switching in transport applications and the adoption of natural gas vehicles, particularly in the USA. China, and Asia broadly, remain a wild card, largely dependent on the ultimate domestic supply of natural gas and government policies.

[1] In our accompanying investment bank report, we provide a detailed analysis of the key companies across this spectrum and the opportunities and challenges presented to them by this structural story.

PHOTO: ISTOCKPHOTO.COM/ANTIKAINEN

Materials

We find the potential implications to be very significant for the steel industry. In terms of demand, steel will play an important part in both oil and gas infrastructure, including many specialist applications. On the supply side, steel makers would benefit from using natural gas in the steel-making process with potential material cost savings and margin enhancement if they can retain them. However, this is likely to center on electric arc furnace/minimill configurations, which may emerge in China more predominantly in the longer run. For now, there is likely to be a limited impact on traditional blast furnace / basic oxygen furnace production in the world's largest steel-producing nation. Likewise, the shale revolution is having a meaningful impact on the chemical industry. US producers have enjoyed a favorable cost position given their ability to process natural gas derived liquids (NGLs) for the production of key basic petrochemicals (mainly ethylene). This is driving plans for capacity expansion in the USA. European and Middle East producers are disadvantaged by their position on the cost curve. In China, coal and gas feedstock choices will continue to be influenced by state regulatory factors, beyond simple economics. Gas is likely to face continued restrictions in certain industrial uses until priority uses are satisfied first. Thus, NDRC-guided pricing policies are likely to be maintained, aimed at creating a deliberate pecking order of gas uses and effectively subsidizing imported LNG. Likewise, in fertilizers, the North American nitrogen industry has witnessed major shifts down the cost curve with the increase in shale gas. Unsurprisingly, North American producer margins are running at all-time highs.

Industrials

Beneficiaries exist within the industrials space among those companies geared to providing the necessary capital equipment behind the increased projected capex. In the electrical equipment space, the theme stretches from the pressure pump manufacturers to gas turbine manufacturers, which aid in gas-fired power generation to process instrumentation and flow equipment manufacturers. The theme of automation is central here. In the USA engineering and construction space, we believe meaningful spending will likely occur across six major verticals relevant for a range of industrial companies. These include: petrochemical, liquefied natural gas, gas-to-liquids, gas new generation, emissions retrofit, and gas pipeline.

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