The Shale Revolution

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Connections Series

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- **The early impact of the shale revolution may now be well understood.** With the evolution of hydraulic fracturing, extracting unconventional gas first became economical in the late 1990s, with the US leading the innovation.
- **Less understood are the global implications of the unconventional shale boom.** Several countries, China the most notable, hold significant shale potential, but most are still years away from the time, technology and policy needed to unlock shale's potential. We explore the countries and regions that could reap shale's returns in coming years.
- **Considerable reverberations exist throughout the supply chain.** From the infrastructure build needed to foster the movement to chemical companies for which natural gas is a key input, the implications of the shale revolution are great and deeply explored in this report.
- **This report leverages the expertise of over 40 research strategists and analysts** and paints a clear geographic and sector picture of the shale phenomenon, uncovering significant investment opportunities globally.

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.

Although the full impact of this "game-changing" revolution is yet to fully play out, it is clear that significant effects are already under way. In this report, we explore the highly interrelated nature of the global energy system and, leveraging the work of more than forty analysts, the increasing impact of this revolution.

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 US 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 that there are many geopolitical reasons why the US will remain closely engaged with the Middle East, not least because many of its trading partners remain dependent on energy from the region.

The potential for shale gas beyond North America is a key question. 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 US and facing energy security as a crucial concern.

What of the price of the more conventional sources of energy? The impact on coal markets already has been significant as power generation has shifted from coal to gas. Although this trend may abate in the near term, the structural direction is likely to 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 while to attract the investment needed to bring on supply. But, ultimately, looking to the latter part of this decade and beyond, we believe that 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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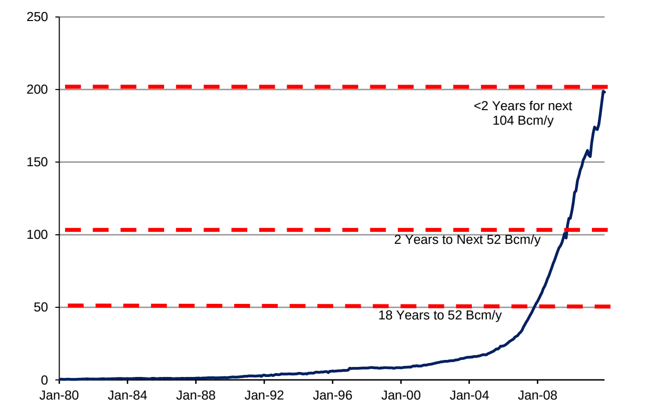
Source: Credit Suisse

Focus Charts

Exhibit 1: Shale production growth in the US has been nothing short of extraordinary

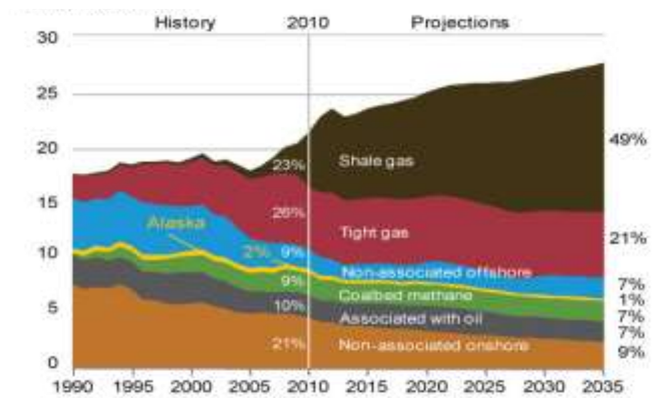
Bcm/y



Source: HPDI, Credit Suisse se

Exhibit 2: Gas expectations are high in the US…

EIA projections for unconventional gas supply, Tcf

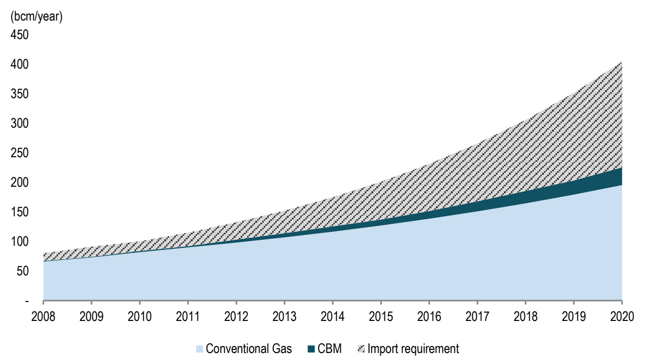


Source: EIA, Credit Suisse

Exhibit 3: …import needs are high abroad (i.e., China)

Without shale, China could be 50% dependent on imported gas by 2020

China's import requirement (Bcm/year)

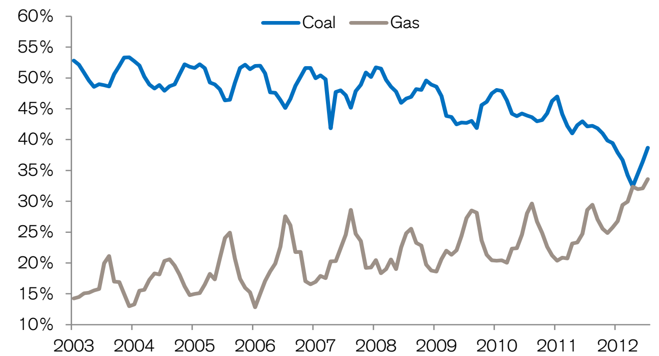


Source: Credit Suisse

Exhibit 4: Coal has been the biggest loser in the US

The fall in nat gas prices drove coal to below 35% of the power generation mix

US electricity generation by source (%share of total, monthly)

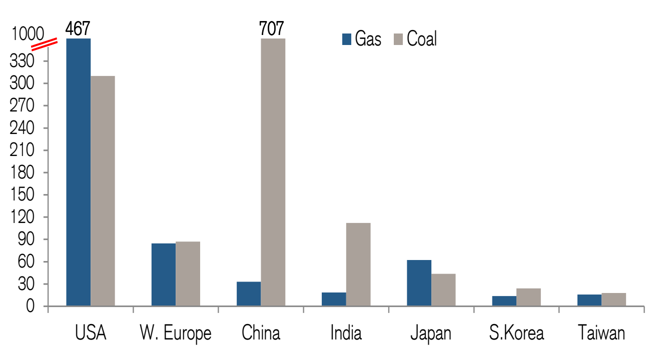


Source: Credit Suisse, US EIA

Exhibit 5: And there is some room for further switching abroad

Installed generating capacity

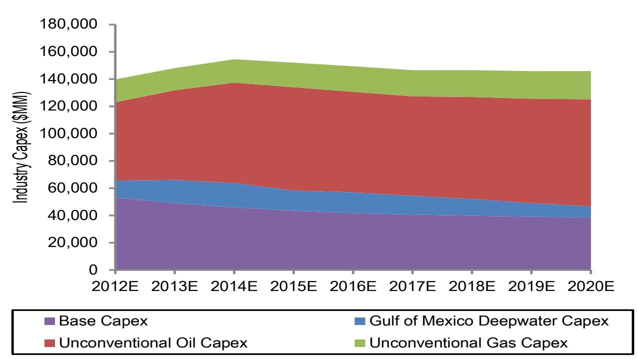
GW



Source: Credit Suisse, EIA, CEIC, CEA, Eurostat, Taiwan BoE, Japan FEP

Exhibit 6: A substantial capex opportunity exists in the US (upstream capex), $150bn pa

$150bn pa of capex can be sustained through 2030



Source: Credit Suisse, US EIA

Executive Summary

The shale revolution

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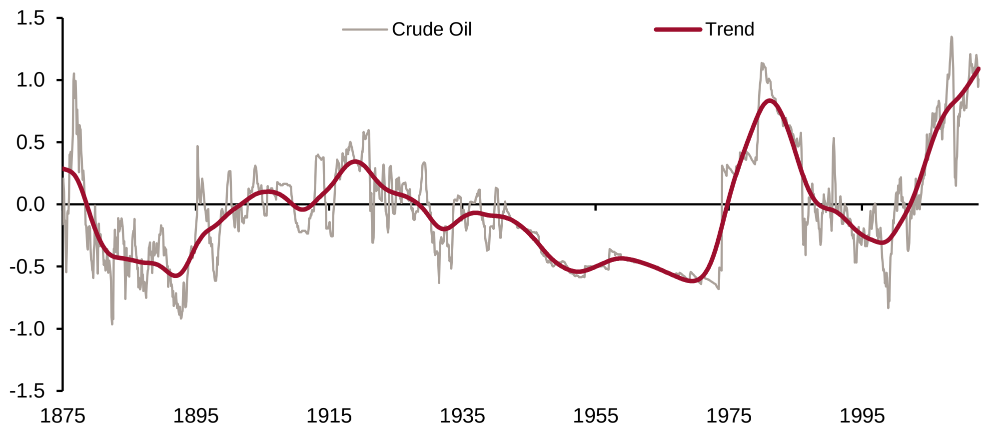
The United States' unconventional shale boom is arguably one of the biggest technology breakthroughs in decades. What started in a field in Texas has turned into a worldwide phenomenon, with ramifications spreading across various commodities and industries. As specific a phenomenon as this may seem, it is arguably reflective of the broad economic principle – and historical experience – that high prices kill high prices. 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.

Although the impact of high prices is yet to fully play out across the energy space, it is clear that significant changes are already under way. In this report, we explore the highly interrelated nature of the global energy system and draw conclusions about the likely spillover impact from the shale revolution in the US to other energy markets, other countries and the related industries to which the cost of energy and its associated sources of supply is central.

Exhibit 7: Real oil prices remain near historical highs…

Long run real prices, 2010 US$, average price = 0



Source: the BLOOMBERG PROFESSIONAL™ service

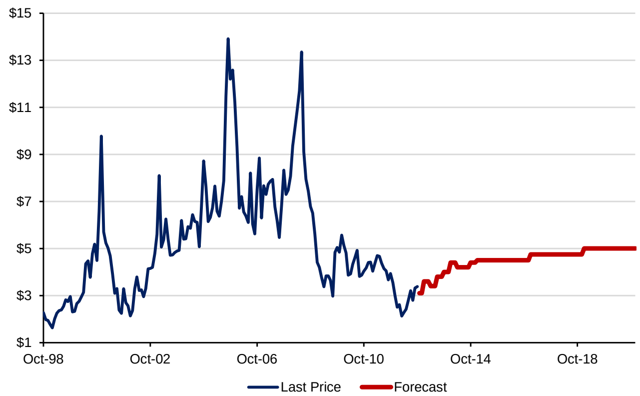
The following key findings emerge:

- **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 EIA expects this trend to continue at its fervent pace, with 50% of production coming from shale by 2035 and a total of 78% of production when accounting for other unconventional methods. See Unconventional Gas Supply in the US.
- **The potential related capital spending to support this structural story extends across the energy complex in the US.** 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 accounting for 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 US 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.

- **A structural competitive advantage exists.** We expect the downward price pressure on natural gas prices (underpinned by the higher than previously expected domestic reserves and surge in US production) to be sustained for many years.[1]
  - While Henry Hub prices are likely to rise modestly from the historically low $3MMBtu seen on average this year, we do not expect them to move above $5/MMBtu (real 2011 US$) by 2020, despite strong demand and the possibility of exports.[2]
  - Moreover, we also expect US gas prices to remain depressed relative to international (oil-linked) gas prices for years to come.3 with US shale gas exports likely capped for now. The high capital costs associated with developing LNG projects limits their development to major players, and this factor too is likely to play a role in preserving industry and marketing structures for longer.
  - This underlines an ongoing competitive advantage for the US in those industries where natural gas is a key feedstock and a potential driver of and incentive for related capital spending.

Exhibit 8: US natural gas: Cheap historically ...

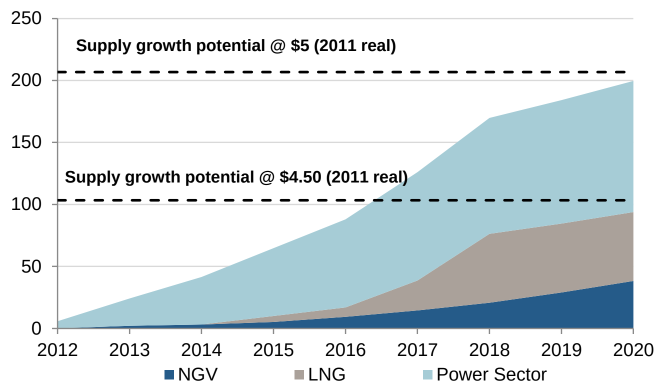
$/MMBtu



Source: Credit Suisse Securities Research

Exhibit 9: … and likely to stay that way

Bcm/y of mid-range forecast of new US gas demand



Source: Credit Suisse

- **Can the "shale gas revolution" spill over to other countries? Yes…but not yet.** This 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 under-estimated by the more bullish forecasters. With twice the recoverable shale reserves of the US, 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 60-100 Bcm by 2020, China is not yet at the inflection point where the US found itself in 2006. While there seems little reason yet for the LNG price premium in Asia (and elsewhere) to disappear (see Impact on Global Gas Markets), as we move into the next decade, Chinese shale gas production has the potential to be a game changer.

1 Credit Suisse Fixed Income Commodities Research estimates
2 Credit Suisse Fixed Income Commodities Research estimates
3 Credit Suisse Fixed Income Commodities Research estimates

Exhibit 10: Commodities Research forecasts – short and long term*

Commodity Forecasts	2013	2014	Long-Run Real Prices
Brent (US$/bbl)	115	110	90
WTI (US$/bbl)	106	102	83.5
Henry Hub (US$/MMBtu)	3.7	4.3	4.5
NBP (GBp/therm)	62	68	50.6
Newcastle Coal (US$/t)	98	108	110
API #2 Coal (US$/t)	98	108	110

*This reflects 2015-2020 period, though some hydrocarbons display further downside risk beyond this period.
Source: Credit Suisse Commodities Research estimates

Exhibit 11: The potential spread of fracking technology

Region	Timeframe	CS View
US LNG Exports	Post-2017	Significant US LNG exports will only come on line from 2017, and 46 Mt/y (5-7 Bcf/d) 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 that Germany seems to have the best CBM and shale gas potential thus far. France has prospective acreage if drilling is allowed.
Canada	Late decade	The potential exists for the first train of one or more LNG projects to come on line.
Russia	Late decade	The industry should test the giant Bazhenov oil shale reserve in 2013.

Source: Credit Suisse

- **Shale oil should 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 level going forward. However, considerable capital will be required to fund the growth; we think that a price of USD 90/bbl Brent is likely to be necessary for the next few years to ensure that the expected capex goes ahead[4]. It is unlikely to provide energy self-sufficiency for the US or provide the same low-cost dividend of gas given its cost of extraction. Outside the US, there is also shale oil potential, which may become more relevant later in this decade. Argentina and Germany stand out, as does the gas potential in China (see Oil's Shale Shake-Up).
- **An "unconventional" brake on the rising price of oil?** Putting aside the near-term influence of the cycle and specific regional supply issues, structural downward pressure on prices could emerge by the middle of the decade, 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 toward more sustainable long-run levels nearer US$90/bbl.
  - We do expect more production growth in the 2015-2020 time frame from other non-OPEC producers. This could put further downward pressure on prices.
- **Further downward pressure on thermal coal prices is likely but not for a few years at least.** The change in relative energy prices in the US has already had a substantial impact on the global thermal coal market. While coal to gas switching is likely to 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 that the speed with which the displacement of coal has occurred in the US is not easily replicable in any other locations, with coal likely to remain the predominant base-load fuel in key markets for the remainder of this decade.

[4] Credit Suisse Equity Research Oil & Gas team estimates

- Nevertheless, **from 2020 onward, gas's dethroning of "King Coal" does look increasingly inevitable**, as China and India move to diversify their energy mix (see Coal – The Biggest Loser?).

Exhibit 12: The impact of shale gas on other commodities

Commodity	Change	Impact	Timeframe
Oil	Increased production of oil and natural gas liquids	In combination with Gulf of Mexico and potentially Artic resources, the US can continue to increase oil production; it will, however, remain a net importer.	Ongoing
Oil	Substitution of oil for natural gas in the US	Up to 38.2 Bcm/y (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 US a net exporter of coal, contributing to a surfeit of seaborne supply.	Ongoing
Thermal Coal	Coal to gas switching outside of the US	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

Source: Credit Suisse

- Contrary to many reports, we do not expect the shale revolution to have a seismic impact on macroeconomic outcomes either in the US or elsewhere. Rather, the transformational impact of shale gas is likely to be more industry specific than a major macro driver. In this report, we analyze the impact on the key macro variables of GDP, investment, inflation, trade and employment in the US, where the shale story is most immediate.
  - The significance of its impact on these headline variables can be over-stated. Natural gas and petroleum production still accounts for slightly less than 1% of GDP, though it is still a significant driver to industrial production, representing 9% of the total.
  - The significance of shale is likely to be witnessed and concentrated among the beneficiaries of the capital/infrastructure spending and the energy-intensive producers. **It also continues to drive the ongoing theme of energy efficiency** (see Economic Impact).

Significant sector implications and conclusions

- **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. A detailed analysis of the drivers at work in these industries and the related companies is detailed here.
  - **US energy equities**: The shale revolution has transformed the reserve opportunity set for the US 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 on the demand for US oilfield services, once near-term margin pressures have been navigated. Logistical spend to bring crude and NGLs to market should create an opportunity for MLPs and refiners alike. Not all companies will win – the downshift in the gas cost curve is likely to render some higher-cost natural gas properties non-profitable.
  - **APAC energy equities**: The focus for shale should be in China, given the imperative of energy security. The traditional Chinese "super-majors" are all focused on the development of unconventional on-shore gas (with CNOOC expanding beyond its traditional off-shore domain), and the exploration work should starts in earnest as 2013 begins. The question is whether China can "crack the shale code" and, if so, how quickly it can ramp up production; the answers have a material bearing on the LNG and pipeline gas development plans of Gazprom and LNG supply proponents in the wider APAC region.
  - The shale revolution is set to unleash significant capital spending. North America's **energy infrastructure** related to the 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.

– 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 overall creating helpful bill reductions for customers. This transition is likely to be structurally durable, with gas generation remaining a cost-competitive resource in power markets into the future. Europe, in contrast to the US, is experiencing a “Coal King” phenomenon as a result of the low coal and carbon prices in Europe. Coal-gas switching should occur in the region if gas prices happen to fall.

– 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 reference prices, though an increased “gasification” would be to the benefit of metering and gas-processing companies. The potential for a breakthrough is significant in terms of energy use from fuel switching in transport applications and the adoption of natural gas vehicles, particularly in the US. China and Asia broadly remain questions, as they are largely dependent on the ultimate domestic supply of natural gas and government policies.

– We find the potential implications to be very significant for the **steel industry**. In terms of demand, steel should play an important part of 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 EAF/mini-mill configurations, which may emerge in China more predominantly in the longer run. For now, there is likely to be a limited impact on traditional BF/BOF 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 US. European and Middle Eastern 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 – that is, by more than 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. Not surprisingly, North American producer margins are running at all-time highs.

– Beneficiaries are likely to 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 the gas turbine manufacturers that aid in gas-fired power generation to process instrumentation and flow equipment manufacturers. The theme of automation is central here. In the US engineering and construction space, we believe that meaningful spend is likely across six major verticals relevant for a range of industrial companies, including petrochemical, liquefied natural gas, gas-to-liquids, gas new generation, emissions retrofit and gas pipeline.

For specific stock implications, please see this table.

The US Shale Gas Revolution

Unconventional Gas Supply in the US

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Historical perspective: the perfect string of events

In this section, we set the stage for the shale revolution and outline the landscape that fostered this dramatic shift in energy utilization and consumption. We focus on the drivers of the revolution, the necessary prerequisites and broad implications.

The unconventional shale boom in the US 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 various commodities and industries. As is the case with many innovations, the path to the current levels of production were not straightforward and required an almost perfect string of events to turn the technology known as hydraulic fracturing (“fracking”) into what it is today.

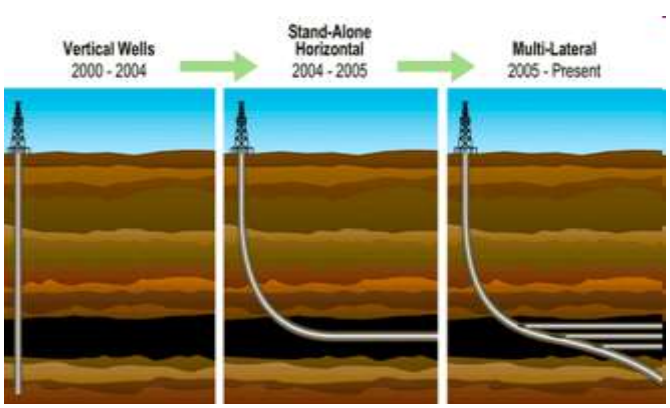
While natural gas – or methane by chemical composition – was once thought to be a scarce commodity in the US, the industry reversed long-term trends of declining gas reserves by scaling up unconventional production techniques (especially hydraulic fracturing) extremely fast. The costs of the new drilling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

With the higher domestic reserves and surge in production, natural gas prices recently hit new 20-year lows, dipping below US$2/MMBtu in late winter 2012 on the Henry Hub measure. And while prices have recovered somewhat of late, we expect them to remain depressed relative to international (oil-linked) gas prices for years to come.[5]

Unconventional vs. conventional: what’s the difference?

In oil and gas exploration and production, the difference between *conventional* and *unconventional* sources is almost purely related to 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.

Exhibit 13: Evolution of unconventional drilling



Source: Trident Exploration Corp.

Exhibit 14: Horizontal rigs are a gauge of unconventional activity

No. of rigs

Source: Baker Hughes, Credit Suisse

5 Credit Suisse Fixed Income Commodities Research estimates

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 (typically 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 become economically available.**

A brief history of hydraulic fracturing in the US

The techniques that sparked the unconventional gas boom have been around for close to 100 years, with initial uses mainly for the separation of granite blocks from bedrock rather than for extraction of oil and gas. In fact, the first commercial use of hydraulic fracturing came in the 1940s as a way to re-recover oil and gas from older, declining wells – acting as a way to re-stimulate the depleting reservoirs.

It wasn't until the energy crisis of the 1970s, and the associated price spike, that a major push to expand gas exploration within the US was made. The geology of unconventional resources was first studied through core samples and maps of various locations of deposits, while techniques to extract the oil and gas were tested through government-funded programs and partnerships with universities. Massive hydraulic fracturing (MHF) was then developed in 1977 as part of the DOE's Eastern Gas Shales Project and was the first move toward making the process of fracking available on large scale. By 1997, through refinement by Mitchell Energy and others within the Barnett shale, the current process of extracting unconventional gas, known as slick-water fracturing, became economical.

The prerequisites for North American supply success

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

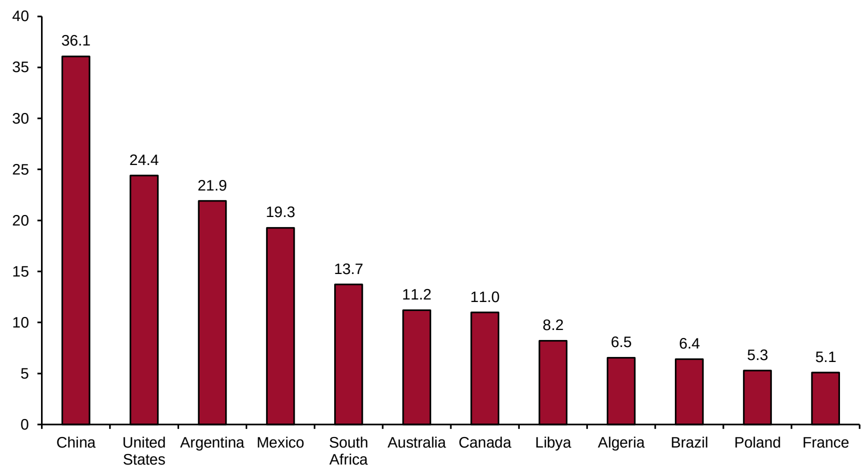
Following the passing of the **Natural Gas Policy Act (NGPA) of 1978**, well-head sale prices of natural gas from shale, coal seams, etc. took their first steps toward deregulation. In previous market structures, price controls had been set to protect consumers from market manipulations. However, it soon became clear that 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 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 Well-head Decontrol Act of 1989** fully deregulated gas prices, eliminating all well-head 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 US$0.50/MMBtu in economic credits, while CBM was afforded ~$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 sub-surface minerals; these are typically owned by central governments, making the process of obtaining rights challenging for explorers and developers. However within the US, 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** (Exhibit 15) with incentivizing mineral rights has helped move supply growth forward at a steady pace.

Exhibit 15: Estimated technically recoverable shale gas by country

Tcm

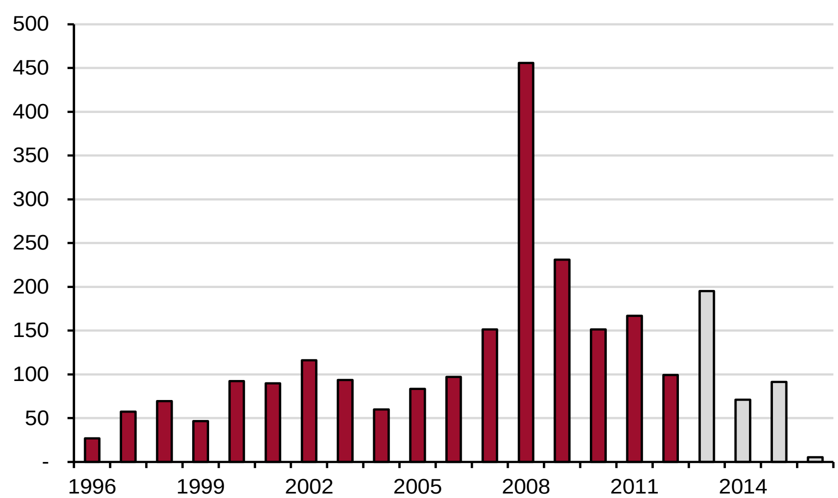


Source: EIA, Credit Suisse

Significant build-out of natural **gas infrastructure** has reduced bottlenecks, allowing gas to flow and helping to 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 Northeast.

Exhibit 16: Additions to US gas pipeline infrastructure by year – actual and expected

Capacity additions in Bcm/y



Source: EIA, Credit Suisse

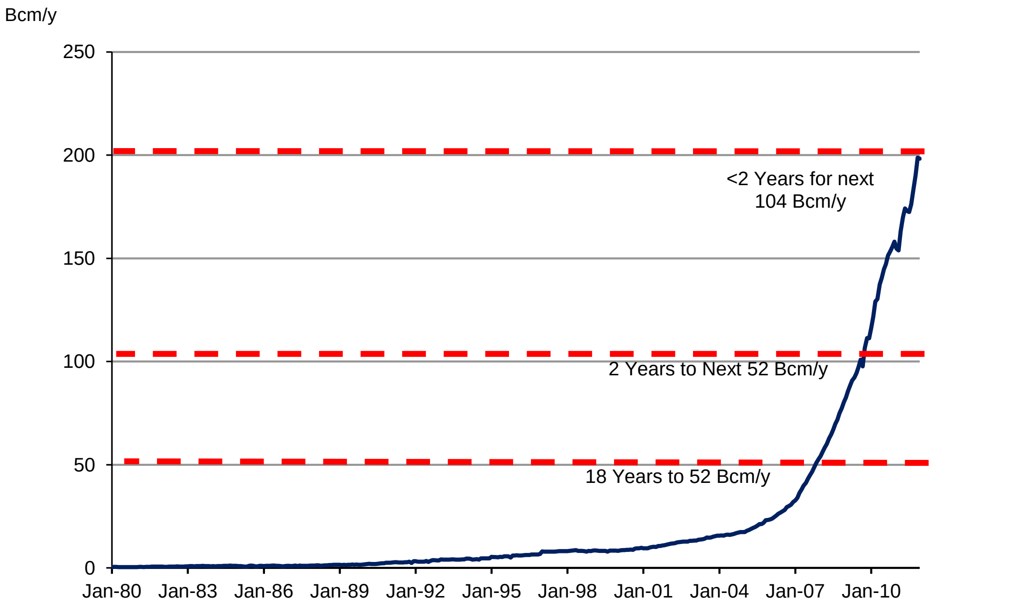
Nature of success in the US has been nothing short of extraordinary

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.

Exhibit 17: US shale gas production through time



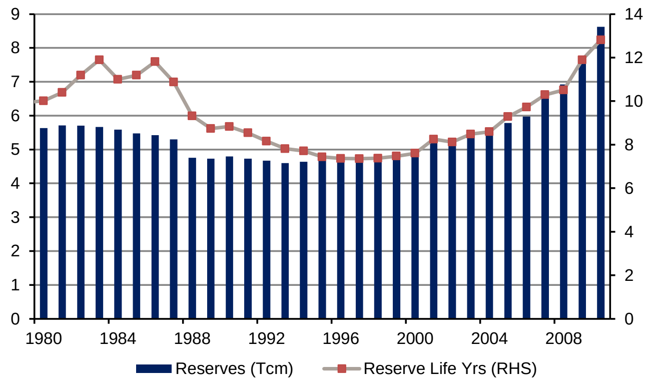
Source: HPDI, Credit Suisse

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 (Exhibit 18). In fact, new discoveries today are advancing at a faster rate than production (Exhibit 19), indicating that production has a long way to go before it peaks.

Exhibit 18: Gas proved reserves vs. reserve life

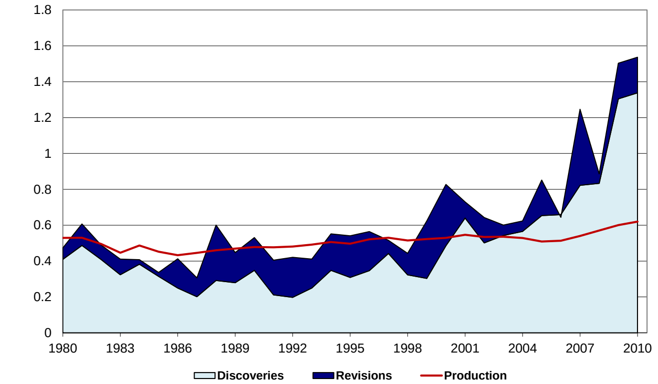
Tcm and years



Source: EIA, Credit Suisse

Exhibit 19: Natural gas reserve additions vs. supply

Tcm

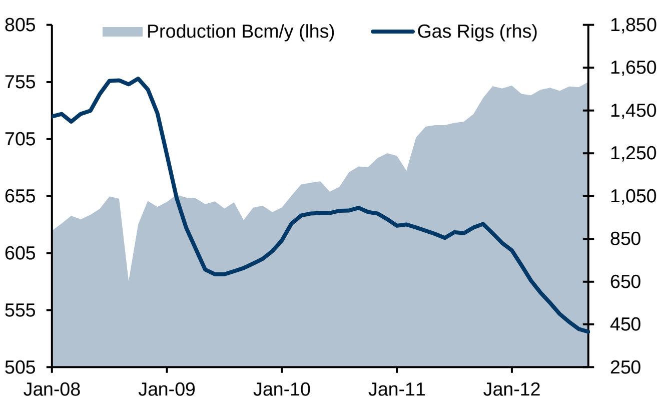


Source: EIA, Credit Suisse

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 US came from conventional sources, with less than 5% coming from shale (Exhibit 21). In 2010, roughly 23% of production came from shale, and 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 that nearly 50% of production will come from shale by 2035, with an additional 21% from tight gas and 7% from CBM (Exhibit 21).

Exhibit 20: US gas production is at all-time highs

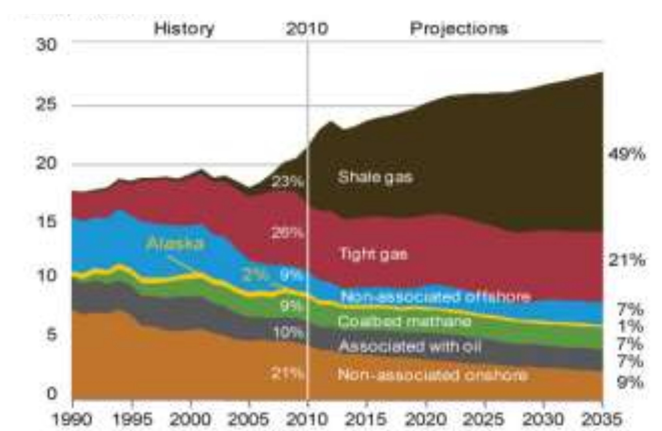
Bcm/y vs. rigs



Source: EIA, Credit Suisse

Exhibit 21: EIA projections for unconventional gas supply

Tcf



Source: EIA, Credit Suisse

Exhibit 22: US natural gas supply and demand balance through 2015

(Bcm/y)	2008	2009	2010	2011	2012	2013	2014	2015
Dry Gas Production	**569**	**584**	**604**	**651**	**673**	**661**	**670**	**684**
Y-o-Y	24	15	20	47	22	-12	9	14
Y-o-Y%	45%	27%	35%	81%	35%	-18%	14%	21%
Canadian Imports (Net)	**86**	**73**	**72**	**61**	**56**	**53**	**50**	**47**
Y-o-Y	-8	-13	-1	-11	-5	-3	-3	-3
Y-o-Y%	-88%	-154%	-12%	-152%	-86%	-51%	-62%	-62%
Mexican Exports (Net)	**-9**	**-9**	**-9**	**-14**	**-18**	**-20**	**-22**	**-24**
Y-o-Y	-2	0	0	-5	-4	-2	-2	-2
Y-o-Y%	371%	-37%	-24%	658%	285%	142%	97%	97%
LNG Imports (Net)	**9**	**12**	**10**	**8**	**4**	**4**	**3**	**2**
Y-o-Y	-12	3	-1	-3	-4	0	-1	-1
Y-o-Y%	-587%	356%	-127%	-253%	-464%	-68%	-315%	-315%
Total Supply	**681**	**689**	**708**	**739**	**751**	**733**	**736**	**744**
Y-o-Y	**2**	**8**	**19**	**31**	**12**	**-19**	**3**	**8**
Y-o-Y%	**4%**	**12%**	**29%**	**46%**	**16%**	**-26%**	**5%**	**12%**
Industrial	**188**	**175**	**185**	**190**	**192**	**193**	**197**	**201**
Y-o-Y	0	-14	10	6	1	2	4	4
Y-o-Y%	-1%	-75%	59%	32%	6%	9%	21%	19%
Electric Power	**188**	**194**	**209**	**215**	**260**	**243**	**254**	**262**
Y-o-Y	-5	6	14	6	45	-17	11	7
Y-o-Y%	-28%	34%	77%	30%	217%	-66%	47%	29%
Res/Comm	**228**	**225**	**225**	**225**	**210**	**227**	**226**	**225**
Y-o-Y	7	-3	0	0	-15	17	-1	-1
Y-o-Y%	33%	-14%	0%	0%	-67%	85%	-5%	-5%
Other (Lease Fuel, Pipeline Distribution)	**53**	**56**	**56**	**59**	**62**	**64**	**66**	**68**
Y-o-Y	0	2	0	3	2	2	2	2
Y-o-Y%	8%	47%	5%	62%	41%	31%	31%	31%
Total Demand	**658**	**650**	**674**	**690**	**724**	**728**	**743**	**755**
Y-o-Y	**2**	**-8**	**25**	**15**	**34**	**4**	**16**	**12**
Y-o-Y%	**3%**	**-13%**	**39%**	**23%**	**51%**	**6%**	**22%**	**16%**

Source: EIA, HPDI, Bentek Energy, Credit Suisse

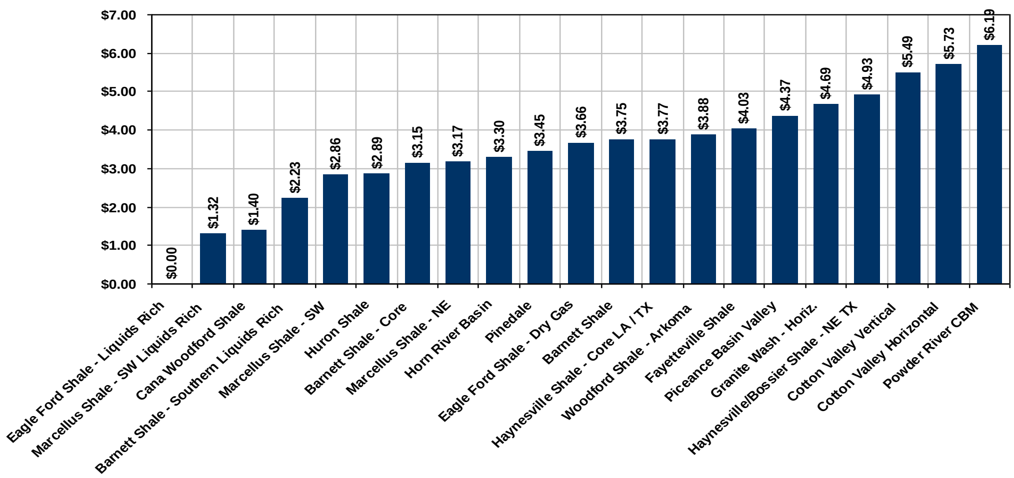
Why did this growth come as a surprise?

Analysts and markets routinely underestimated the rate of technological progress as well as the ability of the industry to fund unconventional gas extraction programs. As rig counts and other conventional yardsticks of future production fell, for instance, projections tended to follow suit; weaker producers too bemoaned poor market conditions and lack of profitability, and many went bankrupt. Consensus expectations were also for higher prices than eventuated on the basis of cost of production estimates. The industry's resilience and its ability to sustain production and find alternative sources of funding has universally come as a surprise, especially because the price of US gas has been on a downward spiral since peaking in June 2008, falling ~80%.

Today, the majority of producing basins feature wells and operations with costs above current prices and with insufficient margins to deliver economic returns (Exhibit 23). Of course, an E&P shift toward oil and liquids-rich drilling has helped producer balance sheets, but industry "discipline" is evident only in the higher-cost gas-only (or "dry-gas") basins (e.g., Haynesville, Barnett, etc.).

Exhibit 23: With sufficient demand growth, gas prices would need to rise; we (Commodities Research) forecast $4.5/MMBtu in 2015 and $5/MMBtu in 2020

NYMEX breakeven price for 10% after-tax ROR



Source: Credit Suisse Equity Research Oil & Gas team estimates

What are the major environmental risks with 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 are as follows:

- **Large-scale use of water in hydraulic fracturing inhibits domestic availability and aquatic habitats**. Water supply is a major concern of policymakers within the US, particularly given heightened competition between competing industries and shrinking supplies.
- **Hydraulic fluids that contain hazardous chemicals can be released by leaks, faulty well construction, etc**. The EPA has issued various reports linking contamination of residential water sources to nearby hydraulic fracturing. Although some of these studies have been deemed unreliable, the EPA aims to release a study in 2012 on the potential impacts from fracking on drinking water resources.
- **Wastewater contains dissolved chemicals and other contaminants that need treatment before disposal or re-use**. Despite the widespread use of fracking in the oil and gas sector, many municipal treatment plants are not designed to remove all water constituents associated with shale gas extraction. Disposal of wastewater is typically done using deep injection wells, onsite recycling or re-use, or it is sent to a facility equipped to process the contaminated water.
- **USGS has confirmed that hydraulic fracturing *can* cause small earthquakes and seismic activity**. Hydraulic fracturing “causes small earthquakes, but they are almost always too small to be a safety concern. In addition to natural gas, fracking fluids and formation waters are returned to the surface. This waste water is frequently disposed of by injection into deep wells. The injection of waste water into the subsurface can cause earthquakes that are large enough to be felt and may cause damage” – USGS.

Implications of cheap gas on US energy demand

US power markets: dethroning "King Coal"

Coal-to-gas switching (C2G) has recently become the big issue in US power markets. However, coal to gas switching is nothing new within the sector, during both the summer peak season and the lower-demand shoulder months. During peak summer load, after all base-load and mid-load generation had been fired (coal, nuclear, etc.), smaller gas units called "peakers" were used to meet summer loads above the levels base and mid-load sources could meet.

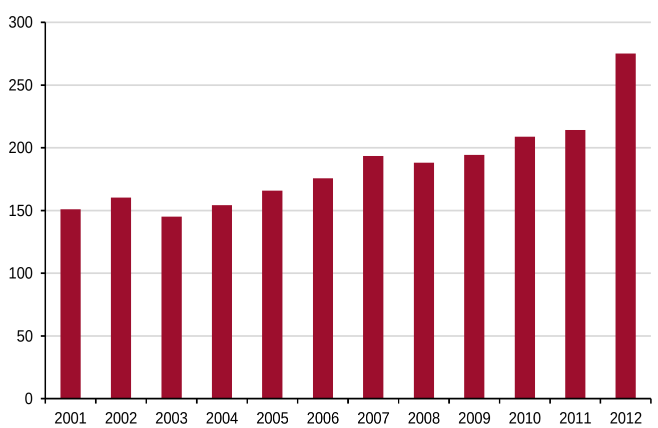
Peakers were typically constructed to have low utilization rates and only be used during those times when loads became too much for the base supply to meet. These units can be switched on and off at low cost, unlike many coal-fired plants, where these changes create maintenance problems. Nuclear plants are unsuited for rapid switching on and off and make up base-load capacity. Additionally, if price permitted and large amounts coal generation was offline, some shoulder-season loads would also be met with natural gas generation.

1H 2012 has altered the way many think about C2G switching: In response to a record mild winter, and still-growing natural gas supplies, the amount of natural gas in storage left the 2011-2012 winter at a level never before seen in the US gas market. Prices responded accordingly, hitting decade lows at sub-$2 prices on numerous occasions.

- We estimate that coal-to-gas switching has allowed for an average of 61 Bcm/y (6 Bcf/d) of year-on-year growth in gas consumption within the power sector, pushing the total percentage of generation output higher than coal for the first time on record.

Exhibit 24: US gas demand for power

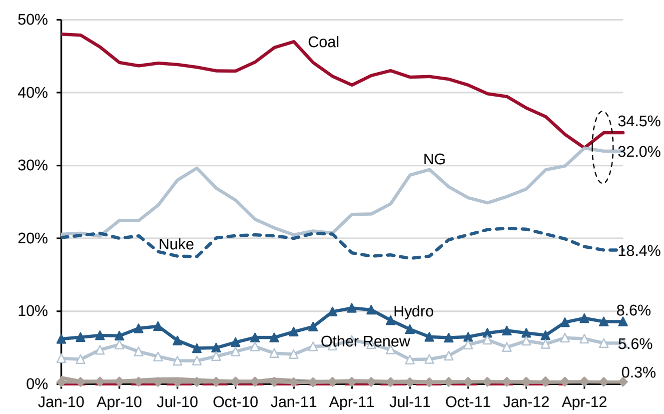
Bcm/y



Source: EIA, Credit Suisse

Exhibit 25: Total generation met by fuel type

% of total generation all industries

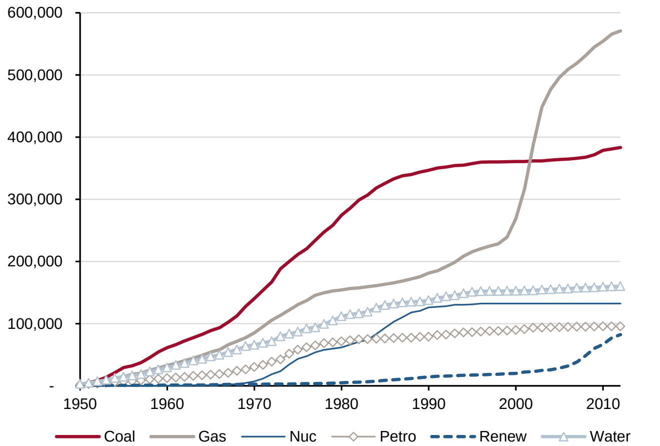


Source: EIA, Credit Suisse

The build-out of generation capacity and EPA policies are setting the stage for a permanent move to gas power in the US. As shown in Exhibits 26 and 27 , it is clear that the ramp-up in generation capacity since the 2000s has favored natural gas at the expense of coal and other fossil fuel sources. Meanwhile, major EPA policies, such as the Mercury and Air Toxics Standards (MATS), aim to make coal generation even more costly and place close to 60 GW of coal generation at risk of retirement by 2025, according to Credit Suisse Equity Research utilities analyst, Dan Eggers – likely increasing gas demand further still (see Utilities for further details).

Exhibit 26: Historical capacity additions by source

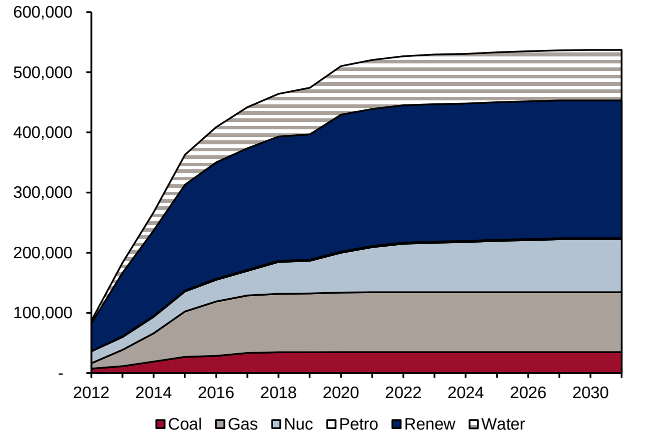
MW



Source: Credit Suisse, Energy Velocity

Exhibit 27: Planned capacity additions by fuel

MW



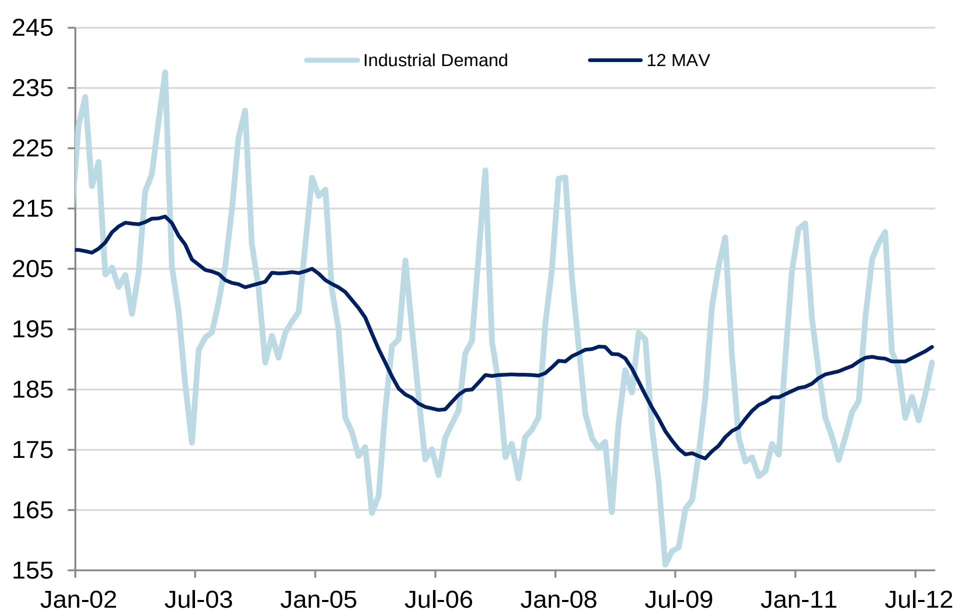
Source: Credit Suisse, Energy Velocity

Industrial demand for gas also rising

US consumption of natural gas for industrial purposes fell 20%, or 33.1 Bcm/y (3.2 Bcf/d), from 2001 to 2009. Since reaching these lows, industrial gas demand has staged a decent recovery, reaching near pre-recession levels in 2011 and 2012 (Exhibit 28). Low North American gas prices have attracted investments in gas-powered industrial capacity and aid in our outlook for a steady growth through the end of the decade.

Exhibit 28: US Industrial gas demand

Bcm/y



Source: EIA, Credit Suisse

LNG markets: will the US emerge as a major gas exporter?

Low prices relative to global benchmarks have turned attention toward LNG exports but there are many impediments to overcome, and the emergence of large-scale trade in gas from the US will take many years. In turn, the LNG's industry structure will probably result in a retention of pricing and contract mechanisms that protect large investments in new supply through the next decade.

Exhibit 29: Credit Suisse view of market-ready and speculative US LNG to target APAC

Mt/y (From tons per year the conversion to Bcf/d is: MT/y x 0.1334, e.g. 40.3MT in 2020 equals 5.7Bcf/d)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Market ready / near to market ready									
Sabine Pass phase 1	0	0	0	0	1	2	2	2	2
BG Sabine Pass sourced				3.5	4.5	5.5	5.5	5.5	5.5
BG Lake Charles	0	0	0	0	0	0	15	15	15
Conoco Freeport LNG	0	0	0	0	0	10	10	10	10
Cove Point	0	0	0	0	0	0	7.8	7.8	7.8
Sempra / Mitsubishi/ Mitsui/ GDF Suez Cameron	0	0	0	0	0	12	12	12	12
Total	*0*	*0*	*0*	*3.5*	*5.5*	*17.5*	*40.3*	*40.3*	*40.3*
speculative									
Sabine Pass expansion						9	9	9	9
Cheniere Corpus Christi	0	0	0	0	0	0	13.5	13.5	13.5
Total (market ready + speculative)	0	0	0	3.5	5.5	26.5	62.8	62.8	62.8

Source: Credit Suisse

How much LNG will the US really allow to be exported?

In an early 2012 EIA study, 6 Bcf/d (46 Mt/y) and 12 Bcf/d (90 MT/y) LNG export hurdles were used when identifying the effect on domestic US gas prices. The result was an assumed increase of US$0.52/MMBtu and $1.39/MMbtu against the EIA reference case in the worst-case 6 Bcf/d and 12 Bcf/d scenarios, respectively.

Following the first report, political opposition to scaled-up LNG exports appears to be mounting; Congressman Markey (D-Mass.) has proposed a bill to stop any further exports of US gas (the bill is named the Keep American Natural Gas Here Act). We would expect manufacturers of chemicals, fertilizers, agriculture, etc. – all of which benefit from low-cost feedstock – to be particularly worried about the knock-on effect of rising domestic prices that a surge in LNG exports would bring. This points to at least a cap on export volumes for some years.

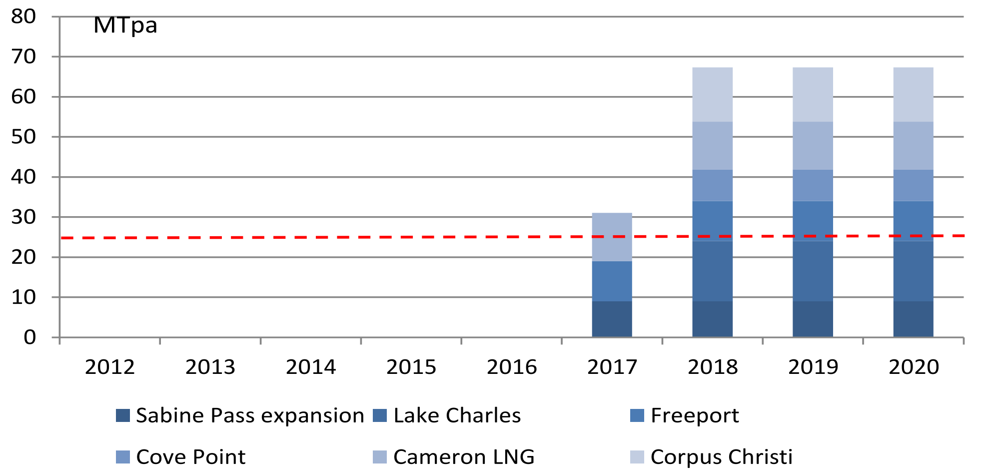
DOE study cites economic benefits of US LNG exports

In late March, the DoE began delaying further decisions on non-FTA exports (outside of the approval for Sabine Pass), pending the completion of a second report assessing the macroeconomic impacts of LNG exports. The findings of the DoE LNG export report, released on 5 December, are constructive for additional LNG export approvals, stating "for every one of the market scenarios examined, net economic benefits increased as the level of LNG exports increased."

The report does, however, expect a rise in US natural gas prices with US LNG exports, citing a possible $0.33 (2010 $/MMbtu) increase when exports initially begin and a potential increase to $1.11/MMbtu after five additional years of exports. Overall, the report states that the limit on how high US natural gas prices ultimately rise will be determined by the global market because importers will not purchase above and beyond the cost of competing supplies. The study does not see natural gas prices becoming linked to oil prices in any case examined.

Exhibit 30: Potential US non-FTA LNG capacity vs. assumed capacity hurdle

Mt/y



Source: Credit Suisse

Exhibit 31: Key APAC marketing considerations for US LNG projects

	HH price link	JCC price link	Avoid US political risk	'Portfolio' / reserves certainty	Interruptable	Capacity (MTpa)	Brown/ greenfield
Cheniere Sabine Pass	Yes	No	No	No	Yes	18	Brown field
Cheniere SP expansion	?	?	No	No	Yes	9	Brown field
Cheniere Corpus Christi	Yes	No	No	No	Yes	13.5	Green field
BG Lake Charles	No	Yes	Yes	Yes	likely	15	Brown field
BG Sabine Pass	No	Yes	Yes	Yes	likely	5.5	Brown field
Conoco Freeport	No	Yes	If 'portfolio'	If 'portfolio'	likely	10	Brown field
Dominion Cove Point	Yes	?	No	No	Yes	7.8	Brown field
Sempra Cameron	Yes	?	No	No	likely	12	Brown field

Source: Credit Suisse

We assume that a further 27 Mt/y/3.6 Bcf/d *could* be (non-FTA) approved in the US.[6] We look back to the great re-gas race in the early 2000s, when more than 60 re-gas terminals were proposed, but in the end, fewer than five were constructed. Given the building political backlash to gas exports and the lack of maturity of a number of the project proposals, we assume that the 6 Bcf/d ceiling is set, suggesting that a further 27 Mt/y could be approved following Cheniere's Sabine Pass project.[7]

APAC pricing conclusions: don't write off the JCC link yet

APAC pricing: short term (2013-2016) – no downward price pressure. Contract crude price correlations are likely to remain high, with spot prices occasionally higher than contract prices. Feeding in Credit Suisse Commodities Research's Brent crude price forecast suggests a Japan DES (Delivered Ex Ship) average landed price of US$16.8/MMBtu in 2013, falling to US$16.3/MMBtu in 2014 before falling back (as our long-term crude price does) to US$14.9/MMBtu in 2015. For further details, please see our recent global LNG report *Global Gas - From tight to loose by 2016E*.

6 Credit Suisse Fixed Income Commodities Research

7 Cheniere's Sabine Pass Phase 1 has already been almost entirely sold (16 Mt/y out of 18 Mt/y). Sempra Cameron has signed initial agreements for full capacity, and Cove Point has signed for an initial 2.3 Mt/y of its 7.8 Mt/y (see exhibit above).

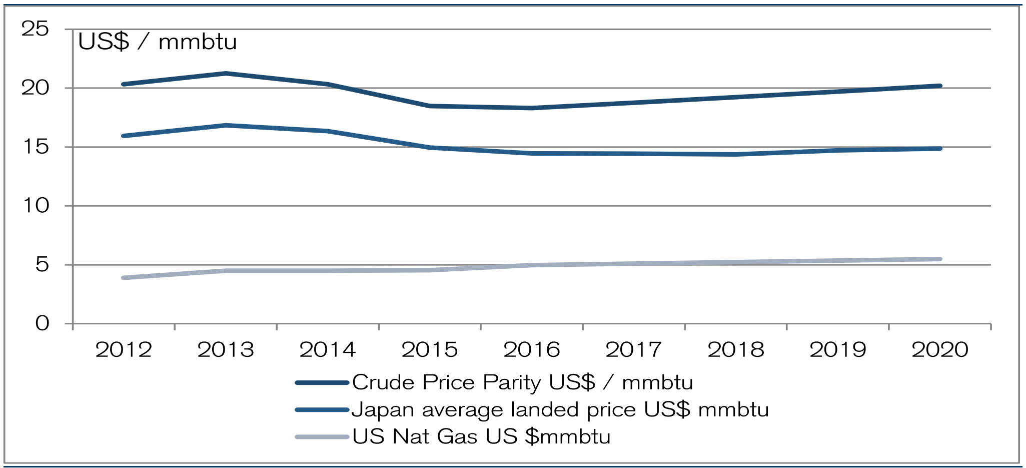
Exhibit 32: Credit Suisse Equity Research's Japan LNG landed price forecasts, 2012-2015

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Brent - US$ / bbl	110.0	115.0	110.0	100.0	99.0	101.5	104.0	106.6	109.3
JCC - US$ / bbl	107.8	112.7	107.8	98.0	97.0	99.5	101.9	104.5	107.1
Average correlation	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7
Price in US$ / boe - FOB basis	80.9	85.7	83.0	75.5	72.8	72.6	72.4	74.2	75.0
Price in US$ / mmbtu - FOB basis	14.9	15.8	15.3	13.9	13.5	13.4	13.4	13.7	13.9
Price in US$ / mmbtu - DES basis	**15.9**	**16.8**	**16.3**	**14.9**	**14.5**	**14.4**	**14.4**	**14.7**	**14.9**

Source: Credit Suisse estimates

Pricing long term – JCC link continues but softens slightly: We still forecast a 70% crude price correlation by 2020. Japan will buy from the US at HH-linked pricing, but only to the degree that it can then use that price signal to try and "soften" the JCC linkage in existing LNG supply contracts from Asian suppliers. We believe that in the next contract cycle for un-contracted demand (2017-2020), traditional LNG suppliers will look to use increased flexibility provisions (Asian LNG is traditionally 100% ToP) to thwart downward price pressure from HH-based contracts. Hence, in nominal terms, we forecast a circa US$15/MMBtu headline Asian price realization by 2020 (nominal $s).

Exhibit 33: Credit Suisse Equity Research's Japan LNG landed price forecasts, 2012-2020



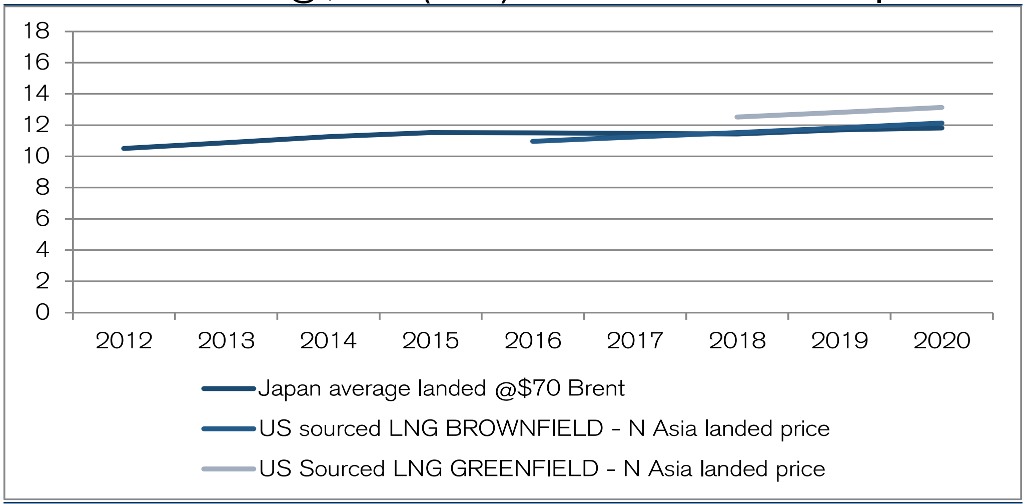
Source: Credit Suisse estimates

HH versus Asian landed LNG prices tends to produce "sticker shock": Exhibit 33, which shows our Commodity Research team's forecasts for US natural gas versus our Equity Research team's forecast for landed Asian LNG prices, with a US$12/MMBtu gap in 2013 falling to US$9.4/MMBtu in 2020, tends to draw the eye.

The gap narrows, accounting for liquefaction and transportation: We assume a US$3/MMBtu liquefaction cost for brownfield US locations (such as Sabine Pass), $4/MMBtu for proposed greenfield locations (such as Cheniere's Corpus Christi) and US$3/MMBtu transportation via the Panama Canal.[8] With these assumptions, the gaps narrows to US$3.5/MMBtu in 2016 to US$2.7/MMBtu for brown-field supply points and to only US$1.8/MMBtu from 2018 for Greenfield proposed supply points. **Therefore, if Brent met our Commodities Research team's forecast but HH rose by $2/MMBtu in the latter part of the decade, there would be no price advantage for Asian buyers of US-sourced greenfield projects**, an uncomfortably narrow margin (we suspect) to take on both a lean gas supply and a disaggregated value chain (not to mention the political risk of a change in appetite to continue exports over a 20-year time horizon).

8 Credit Suisse Equity Research Oil & Gas team estimates

Exhibit 34: Asian LNG @ $70/bbl (Brent) vs. US-sourced LNG landed price



Source: Credit Suisse estimates

Now, imagine a US$70/bbl (Brent) world and Credit Suisse Commodities Research's US natural gas forecasts prevail: our Commodities Research teams is not forecasting the decline in Brent but is forecasting no change in US natural gas prices. If that scenario were to eventuate, this would completely remove the price arbitrage in a US brownfield supply **and would make greenfield-sourced supply circa US$1/MMBtu MORE EXPENSIVE than traditional Asian LNG-based price formulas** – with our base-case correlation to crude.

Economic Impact

US "unconventional energy" macro perspectives

ECONOMICS RESEARCH

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In this section, we assess the broader economic implications of the transition to unconventional energy sources. Although the impact on energy markets is striking, shale's impact on the aggregate US economy is unlikely to be transformative in the near future.

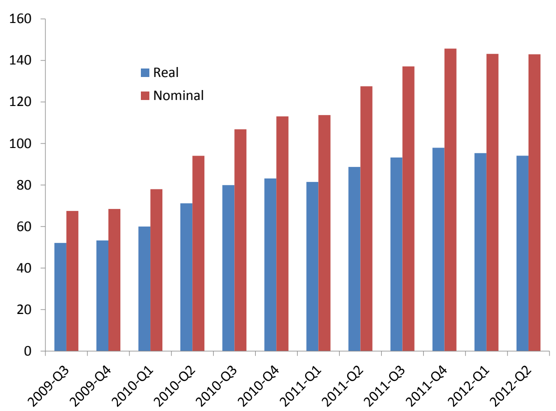
Energy booms are exciting – in some countries, in some moments in time, even transformative. The US experienced such transformations in the 20th century. The US is now a very big and diversified economy (despite the well-advertised fiscal and growth deficiencies of the moment).

Natural gas and petroleum exploration now account for a relatively small portion of the economy today – slightly less than 1% of GDP – despite the onset of the "unconventional energy" boom that began in the middle of the last decade. But the sector has punched above its weight in the GDP over the last few years, **accounting for 5% of the growth in real GDP since the Great Recession ended in mid-2009**.

The sector now accounts for 9% of total business fixed investment, four times what it was in the 1990s. About 17% of the growth in real business fixed investment since 2009 has come from oil and gas exploration.

Exhibit 35: Oil and gas exploration during the recovery period

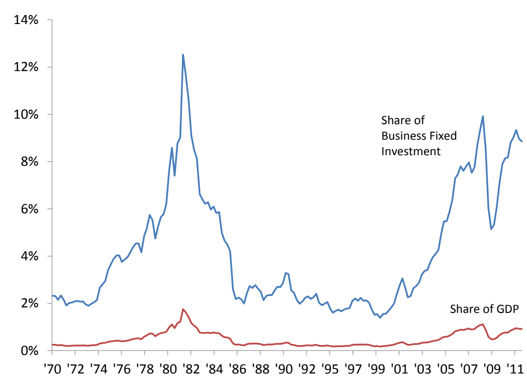
$bn, seasonally adjusted annual rates



Source: Bureau of Economic Analysis, Credit Suisse

Exhibit 36: Oil and gas well exploration share of business investment and GDP

%

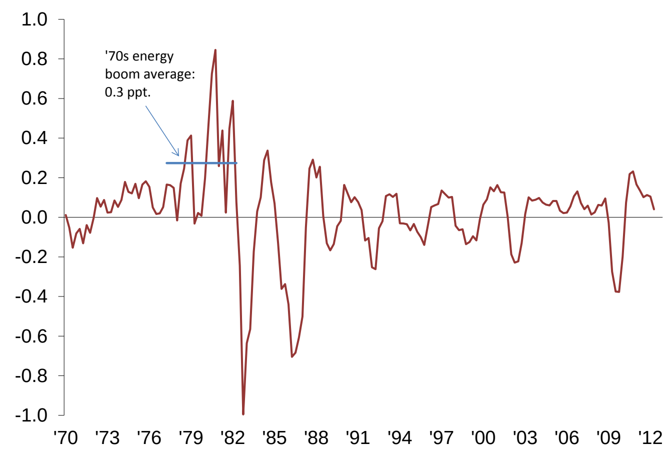


Source: Bureau of Economic Analysis, Credit Suisse

The future of unconventional extraction growth and its impact on GDP is highly uncertain. But if the 1970s energy boom is any guide, oil and gas exploration contributed 0.3 percentage points of GDP growth on average during the headiest years, with a brief period late in the decade surpassing 0.8 percentage points of annual growth (Exhibit 37).

Exhibit 37: Oil and gas contribution to real GDP growth

Ppt. contribution to real GDP, year over year

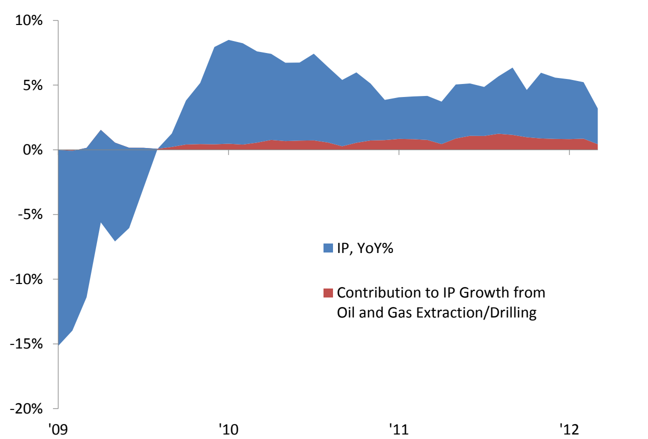


Source: Bureau of Economic Analysis, Credit Suisse

While the oil and gas sector's weight within GDP is relatively small, the sector's influence on industrial production growth is perhaps underappreciated. Its weight within IP is slightly more than 9%, almost triple where it was a decade ago. By comparison, domestic auto and parts production accounts for 6% of IP; tech hardware production, just 3%. In the most recent period, oil and gas output growth peaked in January 2012; at the time, it was contributing 1.2 percentage points to annual IP growth, or roughly 28% of total growth. Oil/gas output tapered off more recently, partly due to refining disruptions triggered by summer storms.

Exhibit 38: Oil and gas exploration and IP

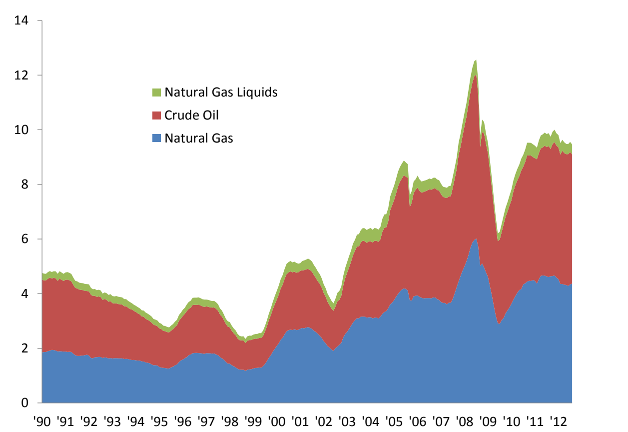
year over year %



Source: Bureau of Economic Analysis, Credit Suisse

Exhibit 39: Energy extraction shares of IP

%

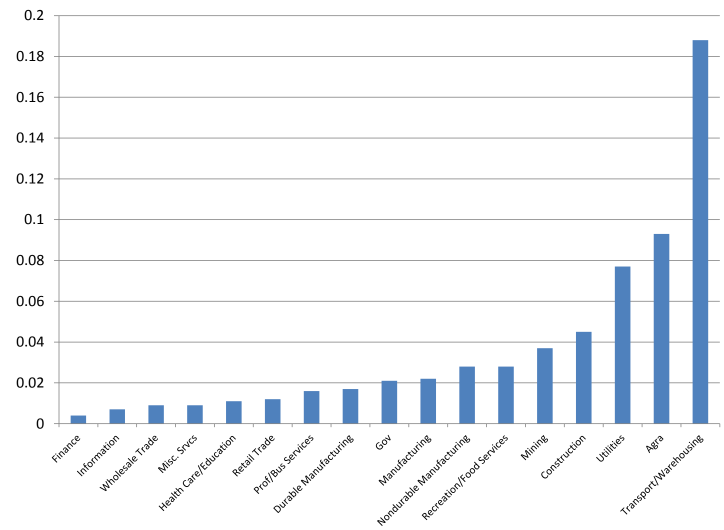


Source: Bureau of Economic Analysis, Credit Suisse

Which sectors would tend to benefit the most from cheaper energy? The exhibit below shows the energy input share by industry, as recorded in the GDP industry data. The transportation sector figures to benefit the most, followed by agriculture, utilities, construction and mining. Manufacturing, which is often mentioned as a prime beneficiary, is somewhere in the middle of the pack (please see the Stock picks and industry section for implications from our Equity Research analysts).

Exhibit 40: Energy inputs as a share of gross output by industry

%

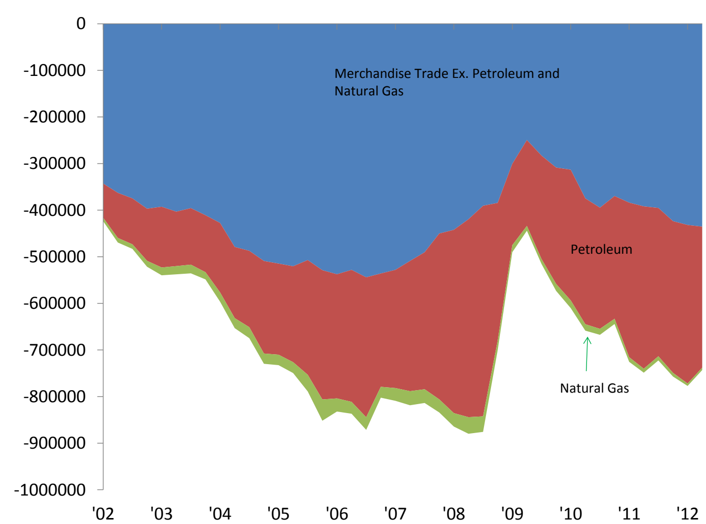


Source: Bureau of Economic Analysis, Credit Suisse

The US achieved a trade surplus in refined fuels last year but still has a huge trade deficit in total energy goods, due mainly to the deficit in crude oil. About 41% of the overall US merchandise trade deficit is in petroleum.

Exhibit 41: Merchandise trade deficit – energy and non-energy

$ millions

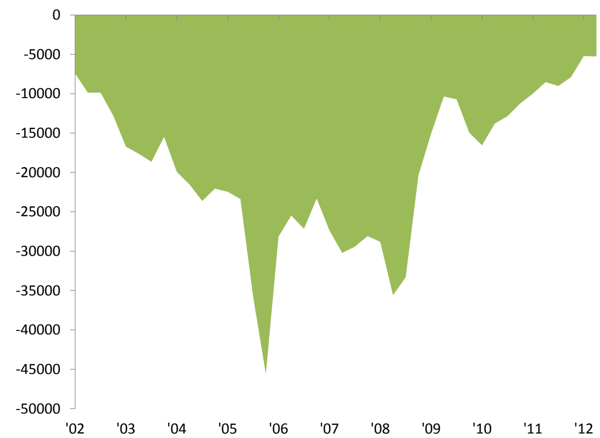


Source: Bureau of Economic Analysis, Credit Suisse

While much smaller in scale relative to petroleum, the trade deficit in natural gas shrunk dramatically in recent years as imports have been displaced by domestic discoveries. **At the current pace, the US will be a natural gas net exporter in roughly a year's time. Still, given the heavy reliance on crude, the US doesn't seem destined to become a total energy net exporter any time soon.**

Exhibit 42: Natural gas trade balance

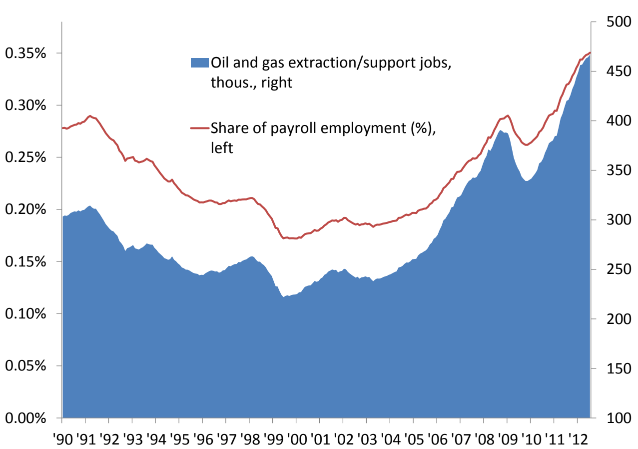
$ millions



Source: Bureau of Economic Analysis, Credit Suisse

The energy sector has relatively high labor productivity. Employment in the industry can be locally intense (think of Houston in the 1970s or North Dakota now), but overall employment is relatively small in the scheme of things. Headcount in oil and gas extraction, including "support" sectors for these activities, accounted for 467K total jobs as of September 2012, or 0.35% of total payroll jobs. Since its low point in the fall of 2009, 128K net new jobs have been added in these sectors. Over the last two years of solid gains, jobs are being generated at a +52K annual pace. Job creation in these sectors would lower the national unemployment rate (all else equal) by about 0.03% per year – not large enough to make a significant dent.

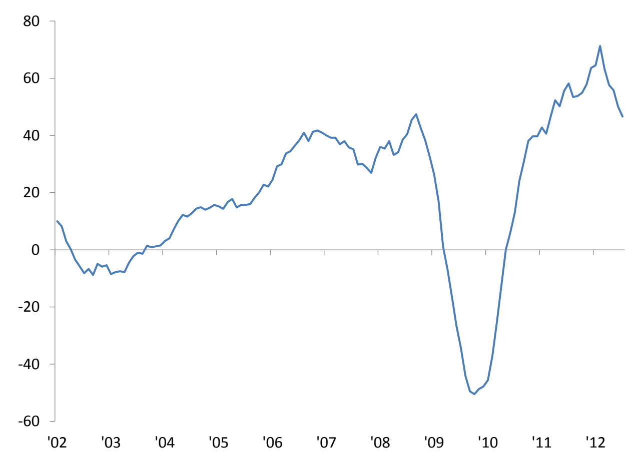
Exhibit 43: Employment level and share of the workforce, oil and gas extraction/support sectors



Source: Bureau of Labor Statistics, Credit Suisse

Exhibit 44: Employment growth, oil and gas extraction/support sectors

Annual change, thousand

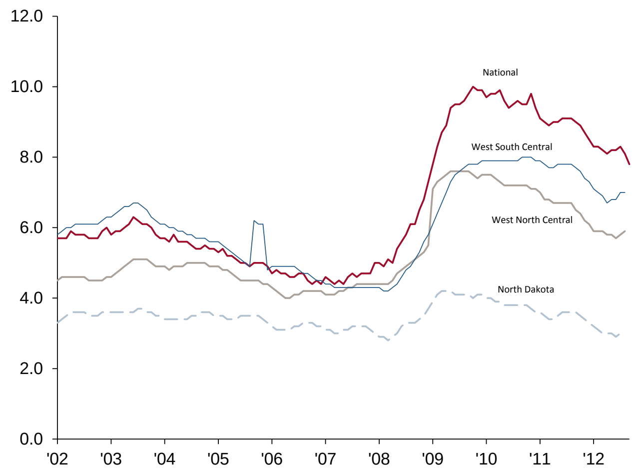


Source: Bureau of Labor Statistics, Credit Suisse

The effect on the labor market is more visible at a regional or state level. For example, North Dakota – lush in "tight oil" unconventional shale deposits – has a 3.0% unemployment rate. States that make up the upper Midwest ("West North Central" in the Census Bureau's categorization) have a combined 5.9% unemployment rate. The traditional "oil patch" West South Central region (Texas, Oklahoma, Louisiana and Arkansas) has a 7.0% unemployment rate, well below the 7.8% national average.

Exhibit 45: Exploration surge most visible in regional and state unemployment rates

%

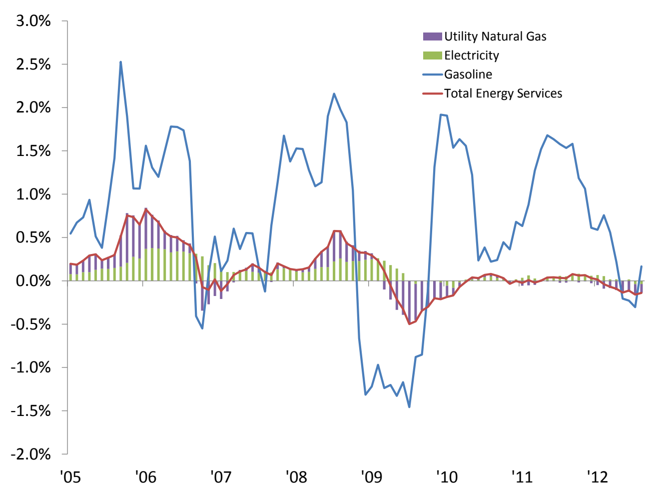


Source: Bureau of Labor Statistics, Credit Suisse

The surge in unconventional gas production (and more recently, one of the warmest winters in history) caused natural gas prices to plunge. But the impact on inflation has been minor. Exhibit 46 plots the contribution to the CPI from both electricity and utility natural gas ("energy services") and compares that to gasoline. The weight of utility gas spending in the CPI is quite small – just 0.9%. The 11% plunge over the last year has subtracted a mere 0.1 percentage point from headline CPI over the last year.

Exhibit 46: Energy component contributions to inflation

Ppt. contributions to CPI, year over year



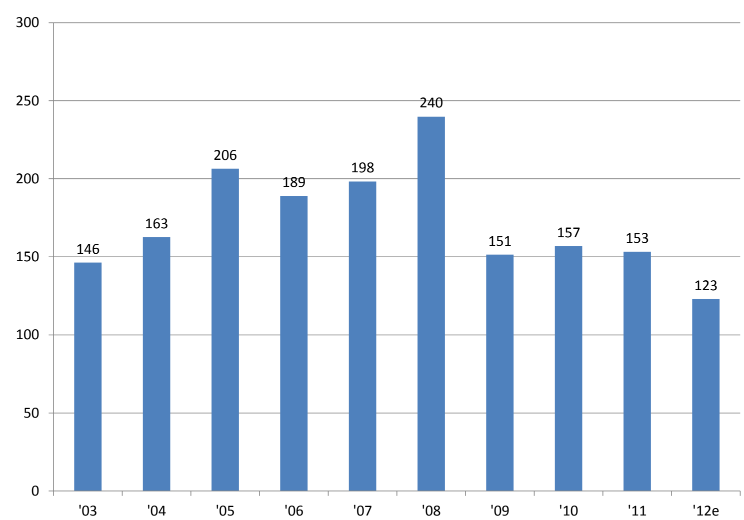
Source: Bureau of Labor Statistics, Credit Suisse

The picture is not materially altered by including the effect of electricity prices, which would capture second-round effects of cheaper natural gas (in addition to the impact from other fuel inputs used by power generators). Within the energy complex, changes in gasoline prices (a function of crude oil) tend to overwhelm changes in natural gas and electricity prices for the overall inflation arithmetic. The short-run relief from cheaper natural gas is welcome news at the margin but isn't large enough to be a game-changer for the inflation picture or household purchasing power. Cheaper natural gas might matter more in certain commercial applications than in the household sector at large.

The exhibit below shows our estimate of total end-user natural gas demand from detailed EIA data – which includes not only residential usage but also commercial, industrial and electric power. **The total natural gas "fuel bill" for the economy is estimated at $123bn for 2012, $30 billion lower than last year as well as the average for the prior three years.** Much of this is due to price declines and favorable weather. Think of this as a $30 billion tax cut for the economy. (For perspective, that's about one-quarter the size of the Social Security payroll tax cut, the potential reversal of which looms so large in our concerns about the fiscal cliff).

Exhibit 47: Total end-user natural gas spending

$ billion

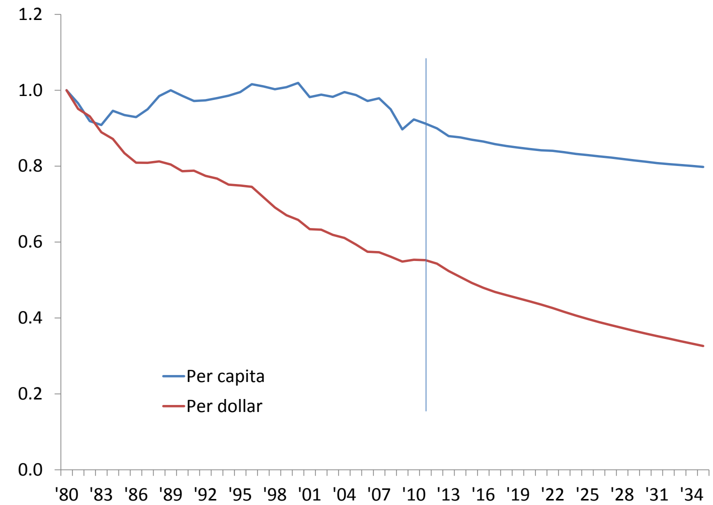


Source: EIA, Credit Suisse

A more efficient mix of energy inputs is projected to reduce the energy intensity of the economy in the coming decade or two, continuing the trend of the last few decades. Although long-run forecasts can be hazardous, the current baseline looks encouraging. Energy Information Administration (EIA) projections show energy consumption per capita declining by an average of 0.6% per year through 2035. The energy intensity of the GDP declines by an average of 2.1% per year.

Exhibit 48: Energy intensity of the US economy

Energy costs per capita, and BTU per dollar of US GDP in 2005 dollars



Source: EIA, Credit Suisse

All in all, more abundant and cheaper natural gas is a good thing to have and is perhaps transformative for the energy sector and certain state and local economies. But it doesn't seem likely to be transformative for the aggregate American economy over a three- to five-year horizon.

Global Impact: China Shale = Security of Supply

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In this section, we analyze the potential for the exploitation of shale resources globally, focus on the geological infrastructure, regulatory and environmental factors at work. We focus in detail on China specifically, a key focus for the shale debate.

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 on gas, especially as China is thought to have twice the recoverable shale reserves estimated in the US and the vestiges of a command economy capable of accelerating national priority projects.

China has set ambitious production targets for the end of the decade: 60-100 Bcm (5.8-9.7Bcf/d), which our initial math suggests is not the ridiculous basis the US experiences. The key question will be when China reaches the production inflection point, as the US did in 2006. At Credit Suisse's recent China Energy Conference, the consensus view was that China may hit these ambitious volume targets but a few years later than advertised.

Time and technology are the two major current challenges for Chinese shale: time, as China has drilled less than 100 shale gas wells (versus over 150K in the US), so China is still at the start of the learning curve, and technology, with the need to find the commercial pathway to shale production under different geological challenges than North America faces. In this section, we also look at other challenges, including water, rig and horsepower availability as well as pipeline reach/access.

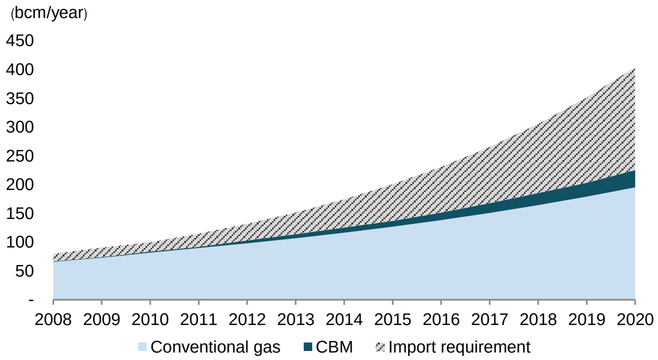
The starting gun for Chinese shale was almost fired on 25 October, the day on which the Ministry of Land and Resources announced that 19 of the 20 shale gas blocks had received the necessary three bids from which the MLR would shortly award the blocks. We expect the Chinese super-majors to dominate the bid round. Once awarded, the work will start in earnest as successful bidders prepare exploration campaigns for their respective blocks, which in turn should lead to order book strength for the service sector focused on shale. Rig manufacturer Honghua (196:HK – Not Rated), pressure pumper Yentai Jerah (002353.SZ – Not Rated) and service players Anton Oil (3337.HK – Not Rated) and SPT Energy (1251.HK – Not Rated) are all competing in this space.

Recent news: China has confirmed that a RMB0.4 per m3 subsidy will be paid for shale gas production: The government announced on the 5 November that it will provide the subsidy at least until 2015 to support and stimulate shale gas exploration and production.

Why China is focusing on shale

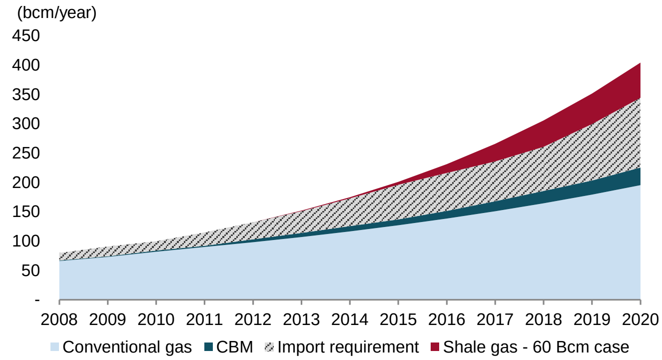
Energy security is at the heart of China's push into shale: China is set to be the world's largest importer of oil – potentially having to import 10 million barrels per day by 2020, 10% of estimated global production. While gas plays only a minor role in primary energy use (currently 4%), China wants to increase gas' share in the total mix, for both environmental reasons and overall growth factors. What China does not want to do is end up with a gas supply as dependent on foreign sources as it is for oil.

Exhibit 49: Potential imports without shale



Source: Credit Suisse estimates

Exhibit 50: Potential imports with 60Bcm shale



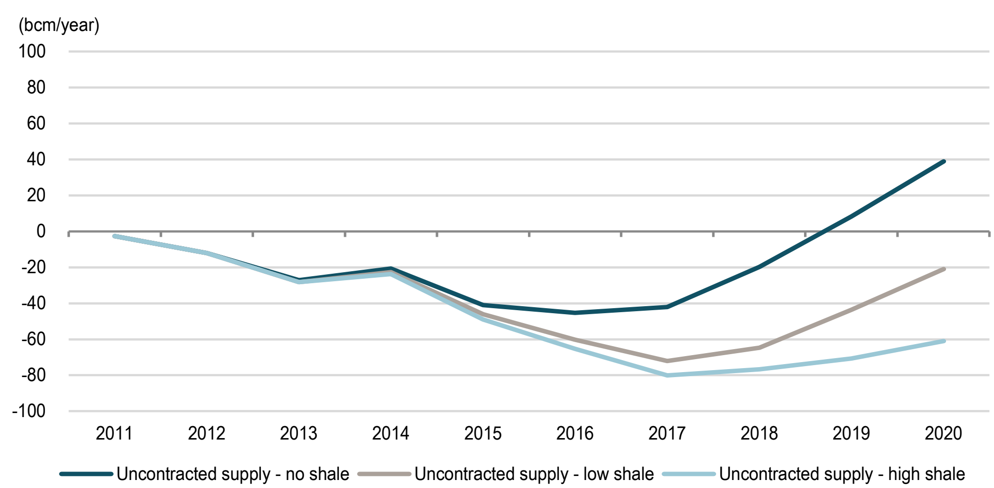
Source: Credit Suisse estimates

Without shale production, China could be 50% dependent on imported gas by 2020: If we assume that conventional domestic production attains a 9% 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 decline to 20%-30% if shale "succeeds": The government has a quoted target of shale gas production between 60 Bcm (6bcfd) and 100 Bcm/year (10bcfd) by 2020 (and 6.5 Bcm in 2015) – if this is achievable, it would significantly reduce the need for further gas imports beyond those already committed to.

With China long gas until 2018, the shale ramp-up would extend that "comfort zone": We include the recently announced additional 35 Bcm/year of Turkmenistan gas in our base case, and when added to the other firm sources of gas supply, China is long gas until 2018 (see Exhibit 51), 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 be long gas at the end of the decade and significantly long gas if it were to hit the yet more ambitious 100 Bcm/y target in 2020.

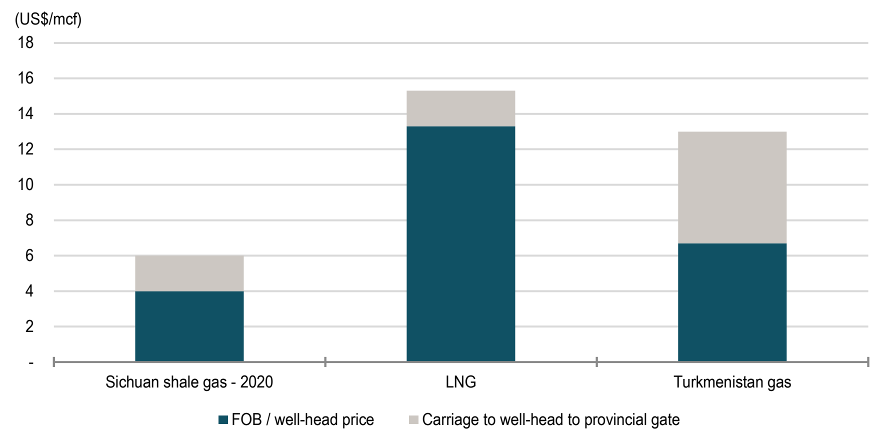
Exhibit 51: China's un-contracted gas import requirements (including Turkmenistan II gas) – three scenarios



Source: Credit Suisse estimates

Gas cost also drives the focus on shale: Credit Suisse Equity Research is not a believer in global LNG price convergence and expects APAC LNG prices to continue to be significantly correlated to crude oil through the remainder of the decade and into the next (see our recent global LNG sector update report, *Global Gas - From tight to loose by 2016E*, 8 June 2012). We estimate a 40% correlation to crude for the Turkmenistan gas, at the country border, with a further US$2.3/mcf as the transportation fee through Kazakhstan/Uzbekistan – hence at US$100/bbl, this suggests a price at China's western boundary of US$9/mcf – and a provincial gate cost to supply of US$13-13.5/mcf for eastern seaboard provinces.

Exhibit 52: China's shale gas supply cost vs. LNG/Central Asia imported gas

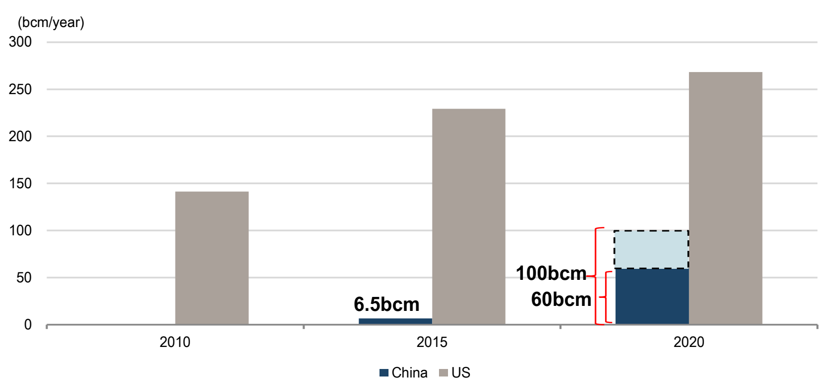


Source: Credit Suisse estimates

Domestic shale should be far cheaper than LNG: For LNG, we expect landed prices in North Asia to be in the US$18-19/MMBtu range until the middle of the decade, then fall back to circa US$14/MMBtu as crude moves back into an "equilibrium" pricing range (we would add US$1/MMBtu as a placeholder for re-gas cost to convert DES LNG prices to a provincial gate price). If shale is produced in Sichuan and it has a scale/unit cost to produce that is broadly similar to US shale gas at circa US$4/mcf (well-head), we estimate a provincial gate supply cost (including a return to the upstream) of circa US$6/mcf in the Eastern Seaboard provinces.

Ambitious production targets – US analogue?

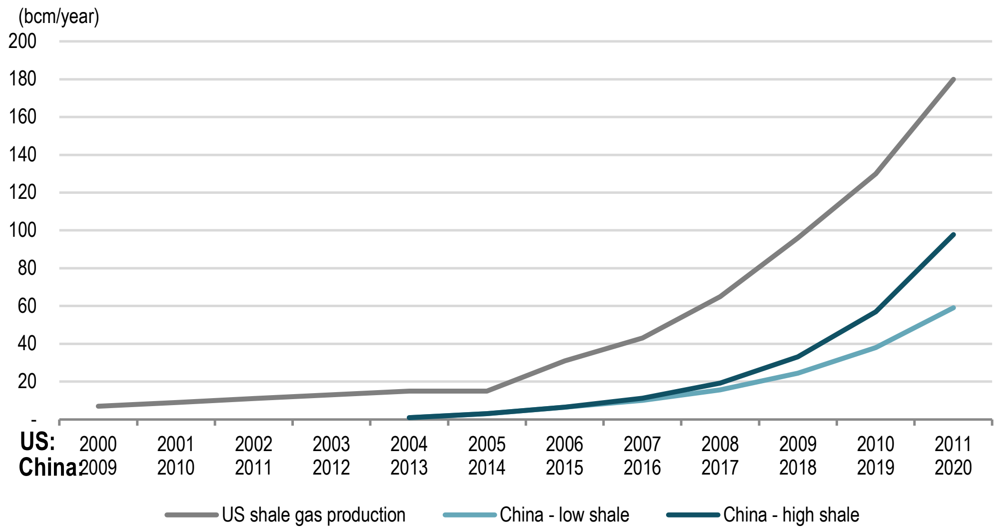
Exhibit 53: China NDRC's shale gas production target range



Source: NDRC, US EIA

China production target: 6.5 Bcm by 2015, 60-100 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 to an aggressive production ramp-up in the 2016-2020 plan period – hence the target of 6.5 Bcm/year by 2015 and a broad target range of 60-100 Bcm/year by 2020.

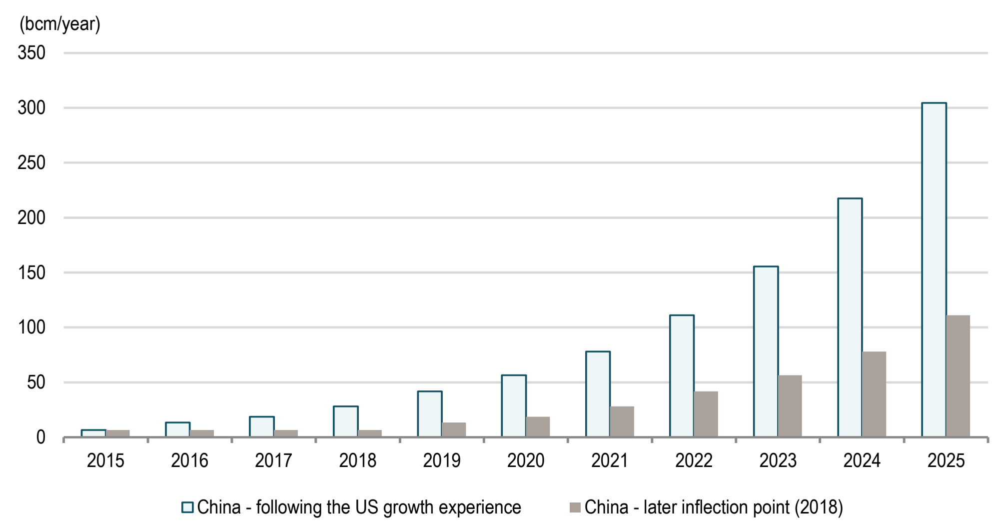
Exhibit 54: US actual vs. Credit Suisse Equity Research China shale gas production scenarios (time sequenced)



Note: For demonstration purposes we show the first inflection point year for the US (2006) as 2015 for China – purely for comparison purposes
Source: US EIA, NDRC, Credit Suisse Equity Research estimates

Is China hoping that 2015 is "US 2006"? The US recorded a very pedestrian rate of shale production growth during 2000-2005, but it 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% year over year), 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 2016 and follows the US production growth trajectory (2006 forward), it would hit 56 Bcm in 2020 and 110 Bcm by 2022.

Exhibit 55: China – extrapolated US growth to 2023



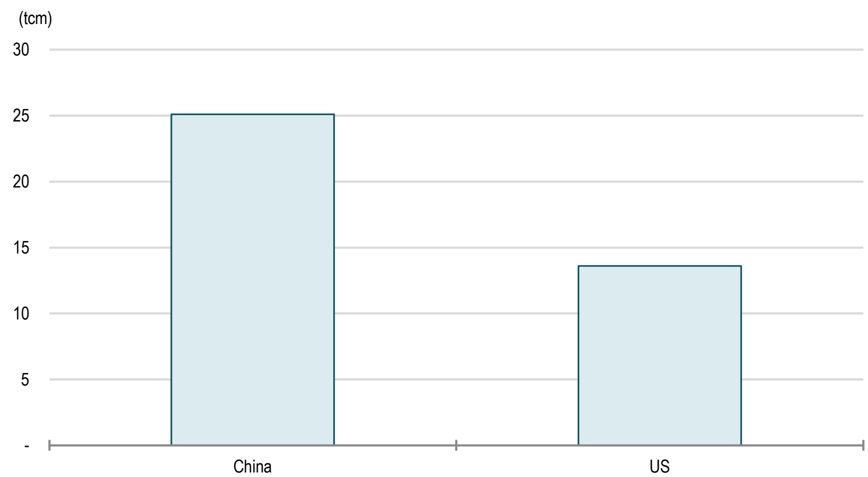
Source: Credit Suisse estimates

Is 2023 a more realistic target for to hitting the 60 Bcm target? Using 2015 as the inflection point seems very optimistic given the lack of wells drilled to date (fewer than 100 wells), so we ran another scenario, assuming 2018 as the inflection point. In this delayed scenario, China would hit 60Bcm in 2023 and 100 Bcm in 2025.

China – the story so far

Prospectivity – twice as large as in the US: The Sichuan and Tarim basins are deemed to be the most prospective at this point, with deposits also in the Ordos, Junggar, Tuha and Bohai basins. The most recent forecast of recoverable shale resources in China is 25 Tcm (EIA – 2012 estimate) **–** similar to the US. Chinese estimates vary for in-place and recoverable resources, but we conclude that about 70% of the total shale gas in-place is in three marine shale areas **–** namely, South China, North China and the Tarim basin.

Exhibit 56: China vs. US – recoverable shale gas resource estimates



Source: EIA

Two shale gas blocks formally awarded thus far: The MLR (Ministry of Land and Resources) offered four shale gas blocks in 2011 to six qualified bidders, of which two were eventually taken up **–** one by Sinopec (Nanchuan block) and the other by Henan Provincial Coal Gas Dev't & Utilisation Co (Henan CBM – the Xuishan block); both blocks are in Chongqing. The bid requires a minimum US$3,000 spend/km p.a.

Strong interest for the 2nd shale bid round: The second round of bidding has been delayed since late 2011, likely partially as a result of the disappointing response in the first round and a focus on which type of entities should be eligible to bid. Initially, the plan was for only Chinese SOEs to be involved in the bids, but this appears to have since been extended to both Chinese independents and foreign companies in a JV with a suitable local partner. On 25 October, the MLR (Ministry of Land & Resources) announced that it received 152 bids from 83 pre-qualified companies for 20 blocks and that 19 of the 20 blocks received at least the minimum required 3 bids for the award to go forward. We assume that the bid awards will be announced in the next three months, which should lead to initial capex commitments in the second half of 2013.

63 test wells drilled to April 2012: Of these 63 wells, 58 are shale gas and 5 shale oil wells, with 15 of these being horizontal. In 2011, 18 shale wells were drilled in China, of which 16 were vertical and 2 horizontal. Industry sources suggest that vertical frac wells cost an average of US$250,000 per well, while horizontal fracs cost an average US$600,000/well.

Multiple "trial" initiatives between Chinese and foreign entities: PetroChina is working with Shell and is now in the process of converting its trial agreement with Shell into a Production Sharing Contract (PSC) for the Fushun-Yongchuan shale gas play in Sichuan (awaiting final approval). It has also signed a trial agreement with Henan CBM for the Xuishan block. Apart from PetroChina, CNOOC apparently is also working with Shell in Anhui; the two have signed a joint study agreement (JSA) that will commit Shell to providing technical assistance for CNOOC to explore shale gas.

BP is working with Sinopec, while Total also recently signed a pact to work on shale with Sinopec. Chevron has announced that it is working in the Qianna basin and is starting seismic data capture in July. Exxon is also working with Sinopec, in a study signed in mid-2011 in Sichuan. Statoil is reportedly in talks with Shenhua. PetroChina is also reportedly working with Conoco on shale gas exploration.

Shell likely ahead at this point: Converting its trial agreement into a PSC is a major step forward for Shell/CNPC PetroChina. So far, 15 shale wells have reportedly been drilled, with Yang 101 + 102 each producing an average of 100,000m^3/day (3.5 million cubic feet/day) on the 3,500 km^2 Fushan block. Shell is talking about a drill-up program of 500-1,000 wells. It has already purchased three shale gas rigs from Honghua (0196.HK – Not Rated) and stated that its plans to use 30 frac units in the drill-up of the Fushan block (Source: *Upstream* publication). The same article indicated that Shell has committed to spend US$1 billion/year over the next five years on shale in China. The next phase is the bid and award of a Front End Engineering and Design (FEED) contract for the development of the block. Worley Parsons, Fluor and AMEC are all reportedly interested in participating, although a local partner is thought to be required for these companies to be eligible to bid.

Running the numbers

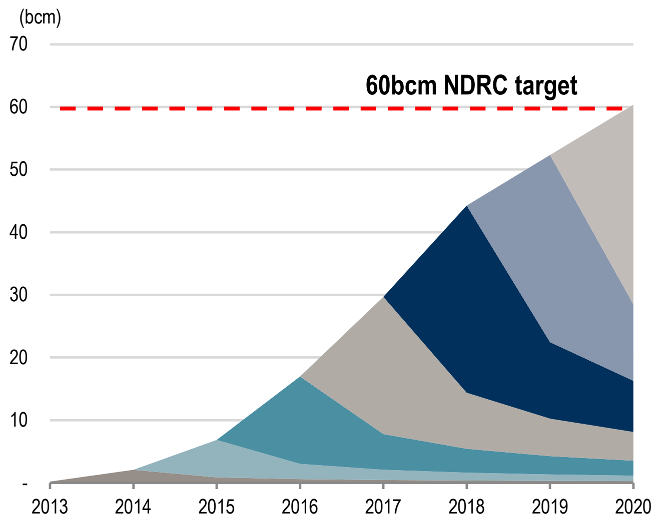
Shale gas production declines rapidly in the first few years of a well cycle. Unlike conventional oil and gas production wells, shale wells typically decline rapidly in the early part of a well cycle and then decline more slowly toward the middle and latter part. In our typical shale gas well, we have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

We assume an initial production (IP) rate of 4 mmcfd in our base-case scenario. And we 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 that China needs to drill 6,800 wells by 2020 to get to the bottom end of the NDRC production target. To reach the NDRC's 6.5 Bcm target by 2015, we estimate that 410 wells will 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/year until 2018. In essence, we estimate that 6,400 wells will be drilled in the latter part of the decade.

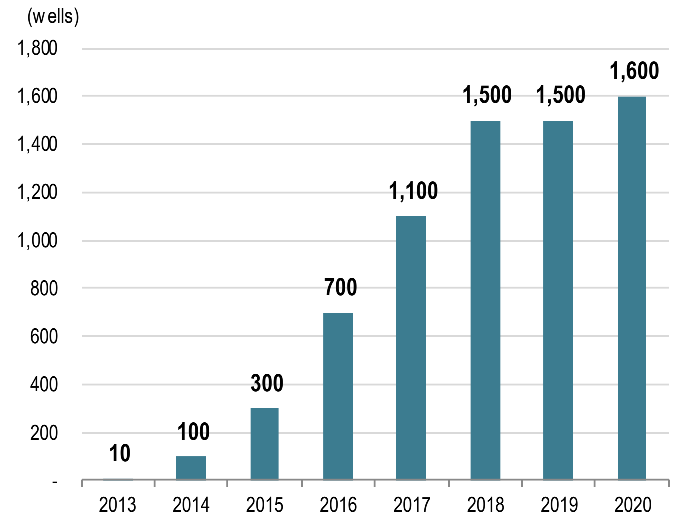
It is worth noting that Exhibit 57 is simply an illustrative example of China's shale gas production profile to achieve the 60 Bcm target. We did not carry on with the drillings post 2020 in our exercise – hence the sharp decline in production once China hits the 2020 target.

Exhibit 57: China 60 Bcm shale gas production scenario – Credit Suisse base case



Source: Credit Suisse Equity Research estimates

Exhibit 58: Number of shale gas wells assumed under Credit Suisse base case



Source: Credit Suisse Equity Research estimates

We estimate that China therefore needs 10,000 wells by 2020 to achieve the 100 Bcm production target. We assume an even more significant ramp-up in drilling activities starting in 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 US$5 million and US$10 million per well. Based on our US Equity Research E&P team's estimates, a horizontal well in the US could cost anywhere from US$5 million to US$10 million. In the Eagle Ford, with depths of 3,000-3,600 meters (10,000-12,000 feet) and laterals roughly 1.6 km long, well costs range from US$6.5 million to US$8.5 million on average. In the Bakken reserve, with comparable depths and longer lateral of 3 km, well costs can be closer to US$10 million. Vertical well costs on average are closer to US$2-3 million, but they are obviously depth dependent.

Current (initial pilot) drilling costs in China are high… Our understanding from industry players is that the first few horizontal wells drilled in China cost two to three times those in the US. Currently, a single horizontal well could cost around US$15 million in China.

…but are expected to come down with higher economies of scale. Upstream players plan to bring costs down to a level comparable to those in the US as production ramps up in China – for example, Shell JV targets US$4 million per well in the long run.

Land access

The remit of the Ministry of Land and Resources (MLR): The MLR controls the allocation of land use rights, both on and below the ground in China. Therefore, 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 re-apply 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

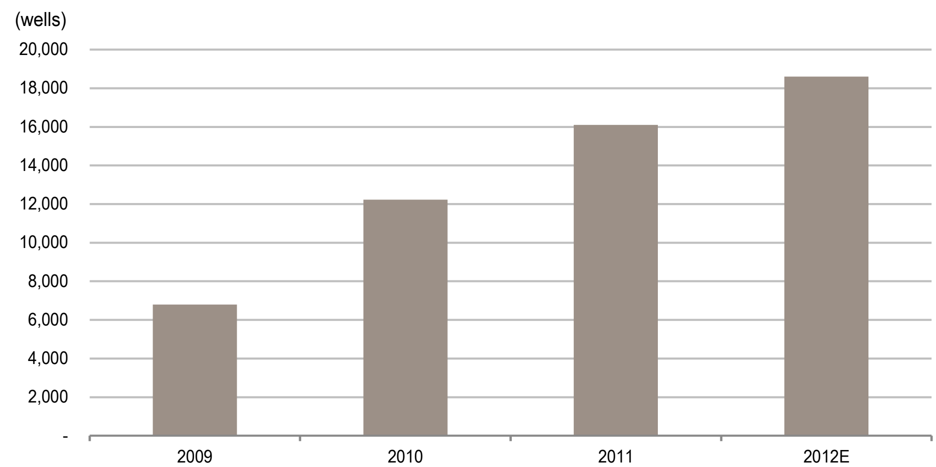
China is "rig rich" but will still need considerable additional rigs to drill up its shale production target. From our interactions with industry consultants and operators, we understand that there is no official land rig count in China. Based on our knowledge, we estimate that China has around 1,500 land rigs on the ground. However, hardly any of them are tailored for shale gas drilling. Honghua last year sold three land rigs to Shell's JV in China with shale drilling specifications.

We estimate that 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% utilization 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 onward.

Horizontal wells

We understand that China had drilled 63 wells to April 2012. Of that, 58 were shale gas and 5 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 2 horizontal. This compares to 16,100 horizontal wells drilled in the US in 2011, according to Spears & Associates (Exhibit 59).

Exhibit 59: US horizontal wells drilled



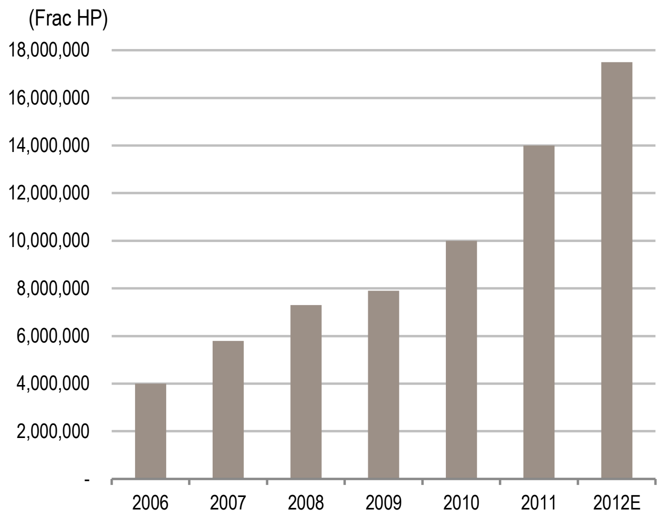
Source: Spears & Associates

Pressure pumps

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

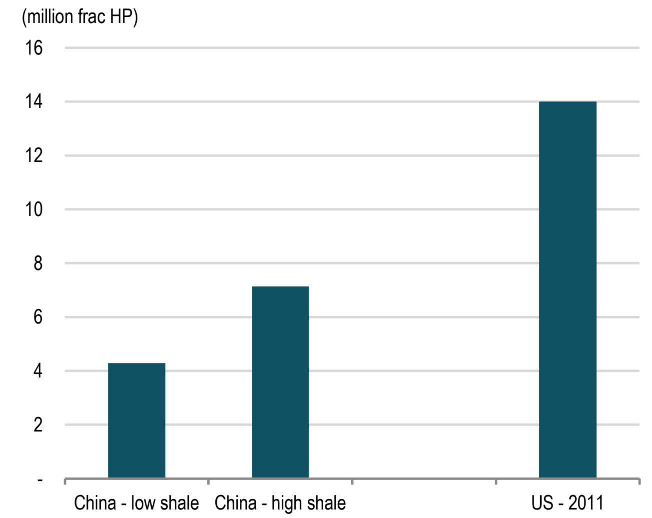
We estimate that China will need 4.2 million additional HP to reach the low end of the target. By using data in the US, we calculate that roughly 12,000 cm (340 cf) of shale gas is produced per horsepower. Applying this to China's production target in 2020, and assuming that the current 1 million HP capacity is taken up for other unconventional gas drillings, we estimate that China will need 4.2 million additional HP to achieve 60 Bcm and 7.1 million HP to achieve 100 Bcm.

Exhibit 60: US fracturing horsepower (HP) capacity



Source: Spears & Associates

Exhibit 61: Fracturing horsepower (HP) capacity in China vs. US 2011 frac capacity

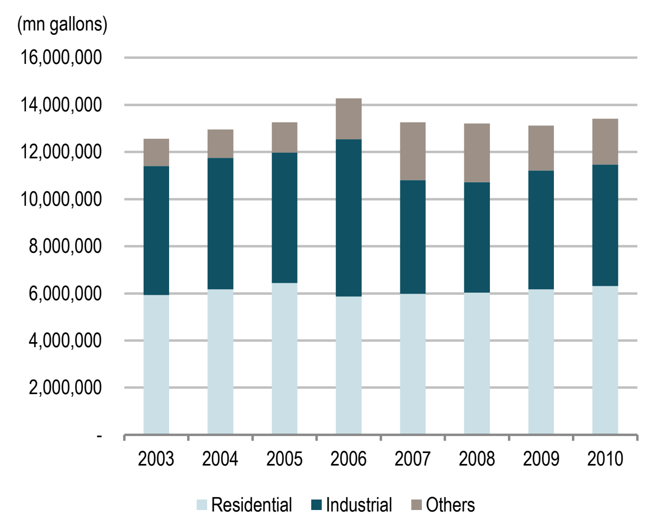


Source: Spears & Associates, Credit Suisse estimates

Water

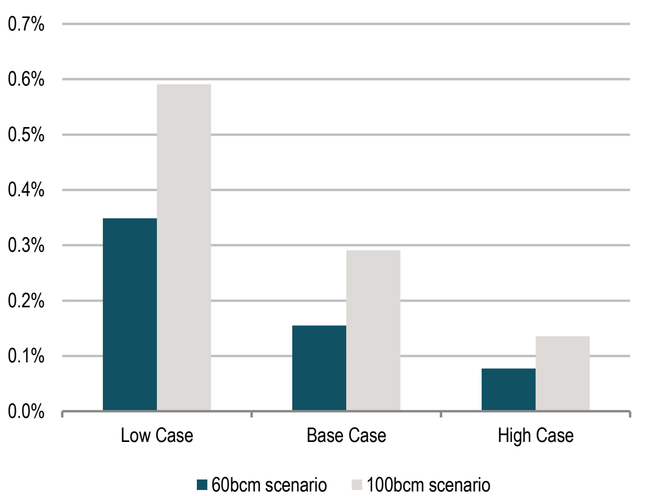
A multi-stage horizontal well requires 4-5 million gallons of water. This water consumption amount is consistent between China and the US, based on our conversation with industry experts and our US Equity Research E&P team.

Exhibit 62: China water usage by segment



Source: CEIC, Credit Suisse estimates

Exhibit 63: Total water consumption under our production scenarios, as a % of 2010 China industrial water supply



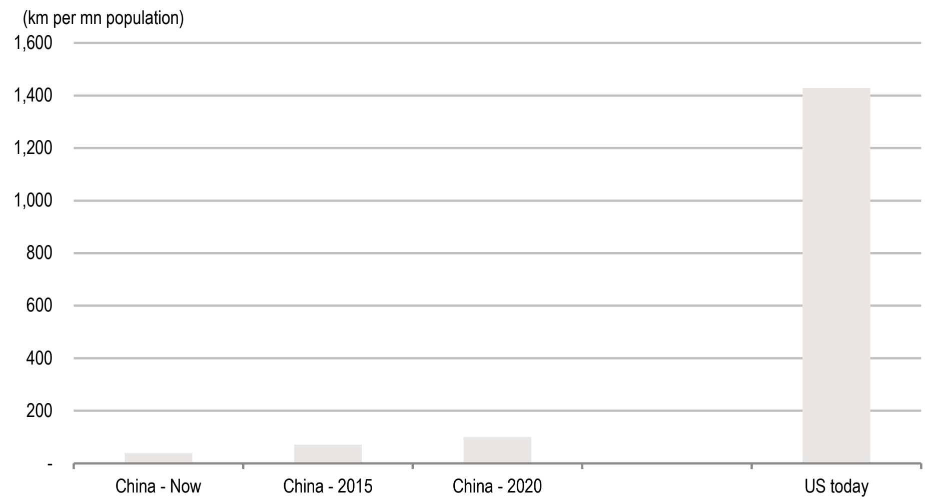
Source: CEIC, Credit Suisse estimates

It appears that water consumption from fracking takes up only a small portion of China water supply. We compare estimated water consumption by 2020, by applying a 5 million gallons-per-well assumption. It appears that by then, shale will account for less than 1% of industrial water supply.

Globally social/environmental concerns about 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 a major public concern about 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 regarding 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 as well as CO_2 emissions are 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

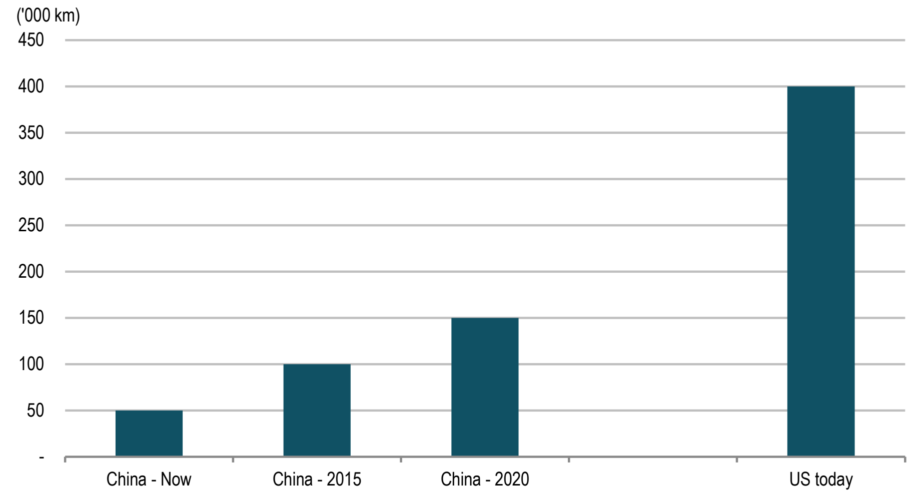
Exhibit 64: China vs. US gas kilometer per million population



Source: Credit Suisse

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

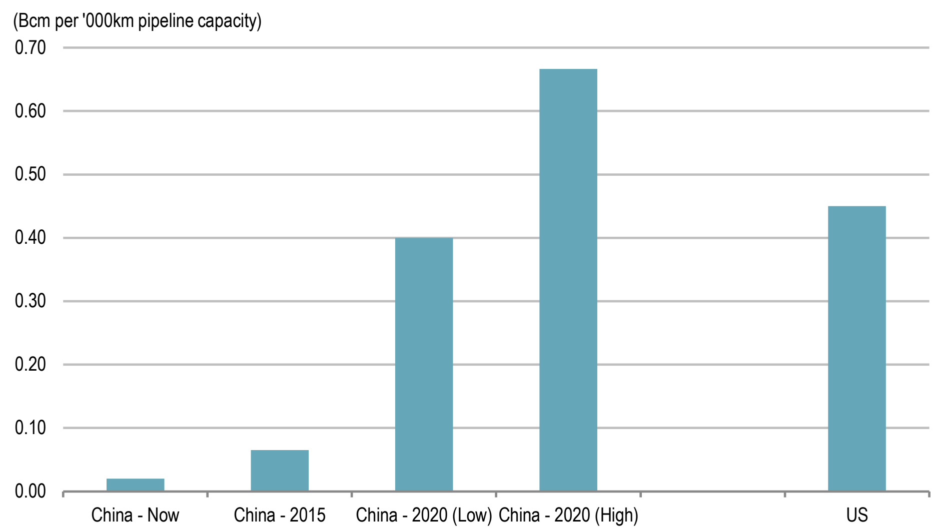
Exhibit 65: China vs. US gas pipeline reach



Source: Credit Suisse

Chinese Bcm per kilometer of pipeline could exceed that in the US. At the moment, the implied amount of shale gas to be carried per 1,000 kilometers 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 kilometers as the US currently does but would exceed the US by 50% if the 100 Bcm upper target is achieved that year.

Exhibit 66: China vs. the US – Bcm carried per 1,000 km pipeline capacity



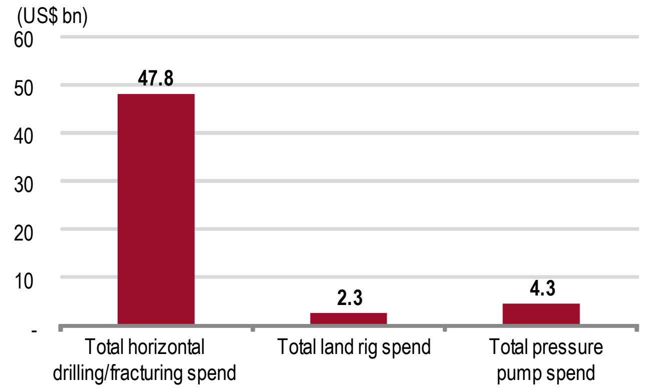
Source: Credit Suisse

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

The "to-buy" list

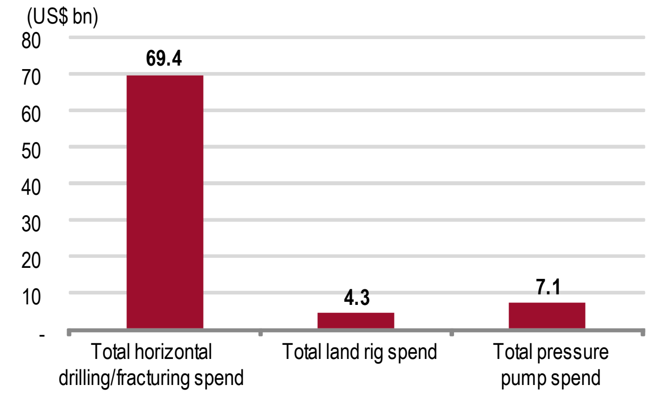
To summarize, we estimate that to achieve the low end of China's shale gas production target of 60 Bcm, China would need to drill 6,800 wells in aggregate or 1,600 wells per annum by 2020. China would need to buy 280 rigs under our base-case assumption (4 mmcfd IP rate) and 1.6 million HP of pressure pump. This compares to fewer than 10 shale-specific rigs and 1 million HP currently.

Exhibit 67: China's total shale OFS spend under the 60 Bcm scenario, using our base-case assumption



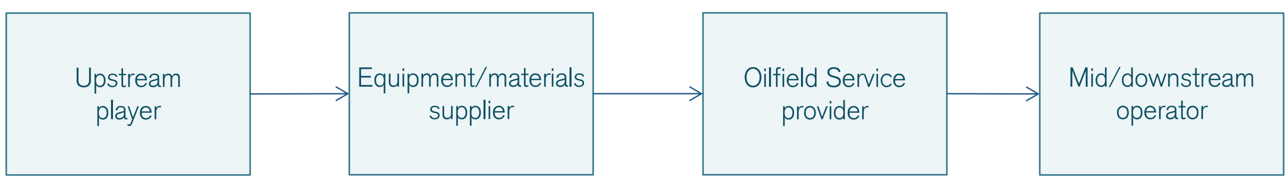
Source: Credit Suisse Equity Research estimates

Exhibit 68: China's total shale OFS spend under the 100 Bcm scenario, using our base-case assumption



Source: Credit Suisse Equity Research estimates

Exhibit 69: China's shale gas value chain



Upstream player:
- PetroChina (857 HK)
- Sinopec (386 HK)
- CNOOC (883 HK)
- Shell (RDSa.L)
- Chevron (CVX)

Equipment/materials supplier:

Land rigs:
- Honghua (196 HK)
- BOMCO (not listed)
- Lanzhou Lanshi (not listed)
- RG Petro Machinery (not listed)

Pressure pumps:
- Yantai Jereh (002353 SZ)

Proppants:
- Carbo (CRR US)
- Saint-Gobain (SGO FP)
- Yixing Orient Petroleum Proppant (not listed)
- ENTI (not listed)

Oilfield Service provider:
- Anton Oil (3337 HK)
- SPT Energy (1251 HK)
- Hilong (1623 HK)
- COSL (2883 HK)
- Sinopec Engineering (not listed)
- Orion Energy (not listed)

Mid/downstream operator:

Water purification:
- Aegis (not listed)

CNG/LNG transportation:
- CIMC Enric (3899 HK)

NGV:
- Weichai-Westport (not listed)
- Kunlun Energy (135 HK)

Source: Credit Suisse

Impact Across Commodities

Oil's Shale Shake-Up

US energy independence and global tension

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Growth in US shale oil production and 100 years of natural gas resources are driving hopes for complete energy independence for the US and fears of a correction in medium-term oil prices. Here we present a summary of the views expressed by our US Securities Research team in a comprehensive report entitled US Oil Production Outlook, which examined the prospects for a boom in oil extraction from shale, building on lessons learned from the shale gas experience in the USA. As with any new technology, our assumptions could prove optimistic or conservative – time will tell.

We disagree with the currently fashionable point of view that the US 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 US 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 US will still need to import about one-sixth of its oil (compared to one-half today).

Equally important, the price of oil will probably still find a relatively high floor. We think that this floor will be near US$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 US) from out of the ground at a profit or buying it from the world's main sovereign exporters.[9] While full-cycle upstream costs in the US 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 US 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 US, 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 US 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 to determine 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 six to eight years. But this also assumes relatively high prices:

9 Credit Suisse Fixed Income Commodities Research estimates

– To fund around US$150 billion of required annual industry capex would require oil prices equivalent to Brent US$95 this year and next. As cash flows grow, the price of Brent oil could fall to around US$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.

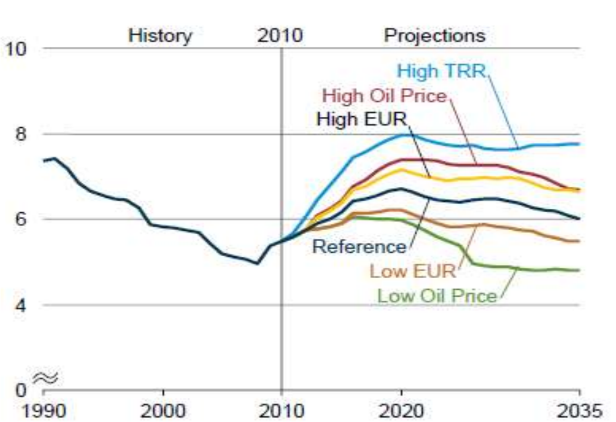
In addition, our model shows that production from shale oil reservoirs will reach a plateau and a maximum sustainable rate that falls well short of trajectories widely advertised by others. Recent much-publicized studies by the International Energy Agency (IEA), for instance, project not only higher but also continually rising output from shale in the US well into the 2030s. As the share of shale oil in US oil supplies grows from less than 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 be 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 that of oil wells, which suggests that 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.

Exhibit 70: Projected oil production in the US, according to the IEA

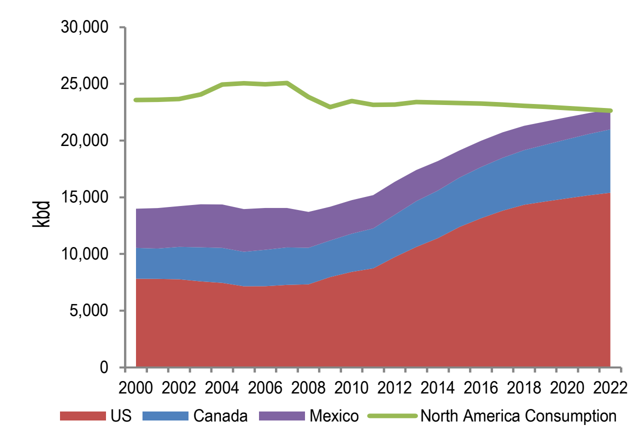
Mbbl/d



Source: EIA (2012 Outlook)

Exhibit 71: Crude oil and liquids production and consumption in North America

Thousand bbl/d



Source: Credit Suisse

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.

Oil prices have global drivers, so 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.

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 Mbbl/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. Key shale plays to watch include the Eagle Ford, Bakken and Permian. After recent exploration success, the offshore Gulf of Mexico and potentially Alaska should contribute some growth also.

What oil price is required to fund this growth?

Single well economics suggest break-evens in the US$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 $95/bbl Brent near term to fund the capital expenditure required to deliver this growth, based on self-generated cash flow alone.[10]

This could be lowered by external funding, but we are already seeing some companies reduce capex when WTI recently fell through $90/bbl. As US oil production volumes rise, this breakeven could fall toward $80/bbl. It is important to note that the average recovery of a gas well is three to five 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:

- **Shale oil wells are less productive than gas**: Each individual shale oil well is less productive than gas wells from the Haynesville/Marcellus that have lowered the cost of natural gas.
- **Terminal decline rates are unknown**: We do not know yet the terminal decline rates from new oil shale plays (given the limited history). Physics suggests that oil decline could be higher than natural gas shale decline. This decline treadmill is likely to lead to a plateau in

[10] Credit Suisse Equity Research Oil & Gas team estimates

US production. We forecast a 10 Mbbl/d plateau for US oil production by 2020-2022. At that time, we would need to add 1-1.5 current Bakken's 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-over-year oil growth from the US 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 that WTI-LLS 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 is likely to be overwhelmed, with light sweet crude requiring shipments to the US and Canadian East Coast or even exports (if policy allows). It would be better for consumers if US light sweet crude is refined in Europe, where refineries are less complex, than 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 Equity Research team's 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 America oil shale potential and rising gas demand should require substantial investment, people and services activity.

US energy independence – 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 (US, 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 higher cost of oil shale extraction and Canadian oil sands recovery. Natural gas appears to be the best low-cost energy policy hope.

And if there is another recession?

In the event of a double-dip recession, with industry balance sheets unable to absorb further deterioration in revenues, we would expect a contraction in oil activity. We flex our model to show that US production could be lower by 1.5 Mbbl/d in 2017. This would also ease congestion on WTI markets, although Canadian oil production growth would still need new pipelines to reach markets, making refiners in the north mid-continental region more defensive.

Implications for global oil shale potential?

North America shale success is leading a wave of entrepreneurial animal spirits. Thus far, we are most impressed with shale results in Argentina and Germany, but above-ground 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 some excitement exists over Australian potential. Shale hydrocarbon potential globally 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 US and Canada is visibly growing. However, outside North America, non-OPEC supply growth has been 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 2004-2008 time frame of rapid oil price increases. **It would take away a prop under fundamentals and allow prices to gravitate down toward more sustainable long-run levels nearer $90/bbl.** Moreover, without relatively high prices ($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 2015-2020 time frame 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.

Exhibit 72: Our 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 $80-90/b (real, 2011) through 2020.

Million barrels per day (mb/d)

Demand	2011	2012E	2013E	2014E	2015E	202E
Global	89.6	90.7	92.2	93.2	94.2	98.0
YoY Growth, %	1.1%	1.2%	1.6%	1.1%	1.1%	
OECD	46.6	46.3	46.3	45.9	45.4	
YoY Growth, %	-0.8%	-0.5%	-0.1%	-0.8%	-1.1%	
Non-OECD	43.0	44.4	45.9	47.3	48.8	
YoY Growth, %	3.3%	3.1%	3.4%	3.1%	3.2%	
Supply	**2011**	**2012E**	**2013E**	**2014E**	**2015E**	
Global	88.6	90.4	91.9	93.2	94.2	102.0
YoY Growth, net mb/d	0.8	1.8	1.5	1.3	1.0	
Non OPEC	50.5	50.8	51.5	53.1	54.6	
YoY Growth, net mb/d	0.1	0.2	0.7	1.6	1.5	
North America	15.5	16.5	17.4	18.3	19.2	22.5
YoY Growth, net mb/d	0.5	1.1	0.8	0.9	0.9	
Non OPEC less NA	35.0	34.2	34.1	34.8	35.4	
YoY Growth, net mb/d	-0.5	-0.8	-0.1	0.7	0.6	
Processing gain	2.4	2.5	2.5	2.6	2.6	
OPEC	35.7	37.2	37.9	37.6	37.0	
YoY Growth, net mb/d	0.6	1.5	0.7	-0.3	-0.6	
Opec Crude Oil	30.3	31.6	32.3	31.9	31.4	
YoY Growth, net mb/d	0.3	1.3	0.7	-0.4	-0.6	
Balance, stocks						
Implied inventory change	-1.0	-0.2	-0.3	0.0	0.0	
Spare Capacity						
(All Saudi Arabia)	2.4	1.9	1.9	2.5	2.9	4.0
% of total supply	2.7%	2.2%	2.1%	2.7%	3.1%	4.0%

Source: Credit Suisse

All in all, while we cannot any longer maintain that demand growth will be curtailed by constraints on supply, we do believe that high oil supply growth requires hefty investment. What's more, in our base case, sovereign producers retain the ability to manage supply. **We therefore expect that even as price trends begin to roll in coming years, that decline will be quite muted and moderated**.

Coal – The Biggest Loser?

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

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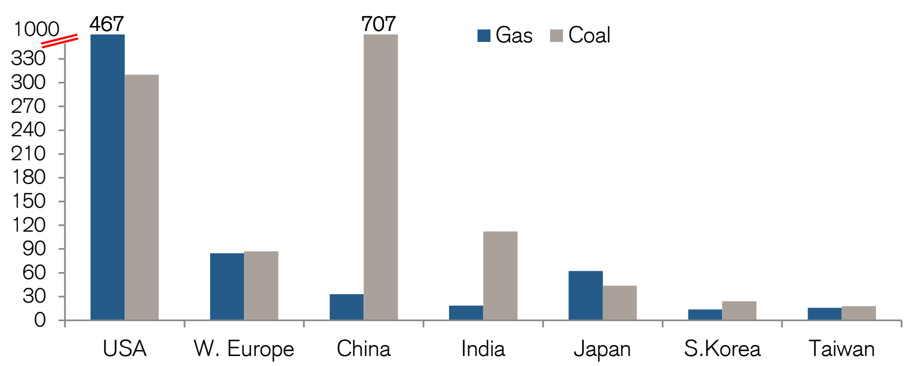
The revolution in US gas supply has already begun to have an impact on other energy sources, with the most obvious to date in the global thermal coal market, where cheap US gas has seen substantial switching from coal to gas among electricity producers. This has driven a dramatic change in the US's involvement 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 US has been a key factor depressing coal prices over the past year. This section focuses on the transition away from coal in global energy markets and hypothesizes its future (reduced) role.

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 substitution limited. In time, however, most nations will also reduce their call on coal; however, the biggest impact is unlikely to be felt until the 2020s and beyond, with the key swing variable China's ability to follow the US's lead and effectively utilize its large-scale shale gas resources.

Exhibit 73: Installed generating capacity in major coal consuming regions – room for coal to gas switching?

GW



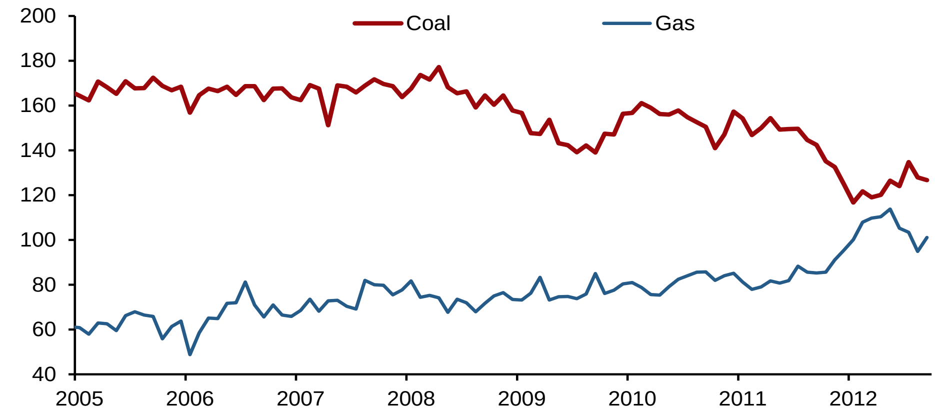
Source: Credit Suisse, EIA, CEIC, CEA, Eurostat, Taiwan BoE, Company data, Japan FEP

The US – 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.

Exhibit 74: US electricity generation by source

TWh, Monthly, SA

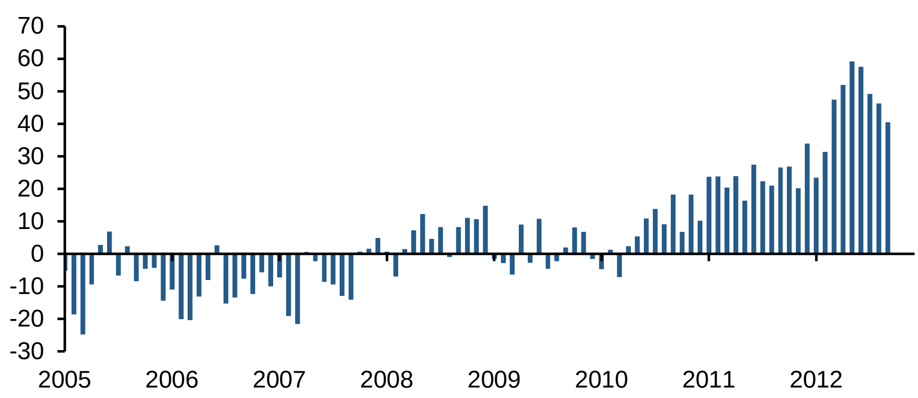


Source: Credit Suisse, US EIA, the BLOOMBERG PROFESSIONAL™ service

The follow-on from weaker domestic coal demand has been a dramatic shift in the US's net coal exports (Exhibit 75). 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.

Exhibit 75: The US has become a substantial net exporter of thermal coal

Mt, Monthly, SAAR



Source: Credit Suisse, Customs Data

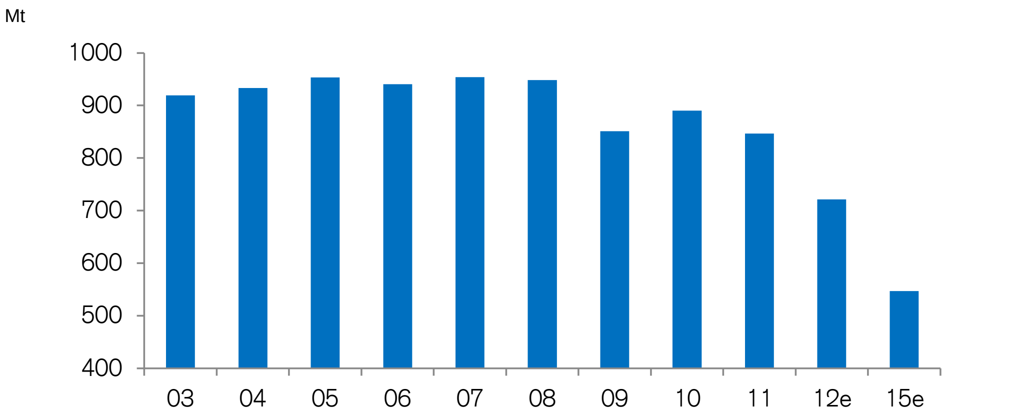
US coal consumption in a structural decline?

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, with the absolute level since then on a clear downward trend (Exhibit 76).

The Credit Suisse US Equity Research utilities 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, 28 GW has been earmarked for retirement and a further 22 GW of retirements are expected to be announced by 2017. This equates to a roughly 20% reduction in coal-generating capacity.
  - We note that the net impact on coal consumption should be somewhat offset by an expected 4.7 GW of capacity additions, from already under construction projects and coal capacity utilization of to 50%.
  - Moreover, the recent recovery in Henry Hub prices suggests that coal-to-gas switching is also likely to be less pronounced in 2013 than it has been in 2012 – Henry Hub prices have moved back above key coal-to-gas switching levels of $2.50-$2.75 (PRB coal is substituted for gas) and $3.25-$3.50 (Illinois basin is substituted).
  - This could create the potential for slightly higher utility coal consumption in 2013 over 2012 levels, but we view the capacity closures as more telling in terms of the long-run picture.

Exhibit 76: US power plant thermal coal consumption



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

For illustrative purposes, if installed capacity declines by around 55 GW through 2015, and utilization were to run at 50%, it would imply power plant thermal coal demand of around 550 Mt, 300 Mt below 2011's level of consumption.

Freeing up more material to export

As domestic consumption continues to fall, we expect net exports to remain high, with the likelihood that they will increase further in coming years, after potentially moderating a little in 2013, on the back of the recent increase in gas prices.

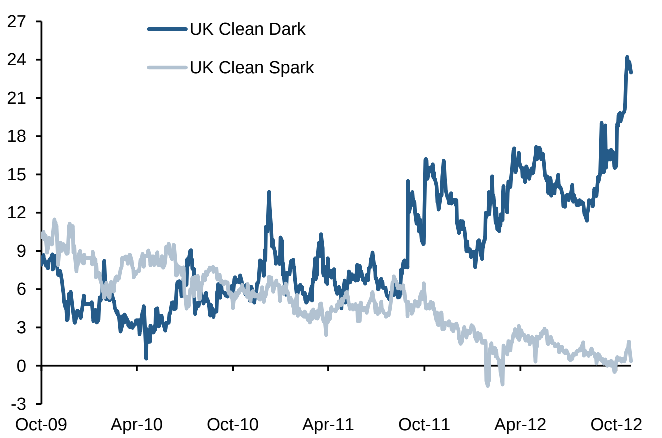
- Our US Equity Research Mining and Metals team highlights current plans to add a further 95 Mt/y to export infrastructure capacity by 2017 through the expansion of existing facilities and construction of greenfield projects.
- This, along with the continued decline in domestic consumption, suggests that US export capacity could rise to over 200 Mt/y by the latter years of this decade.

Europe – a very different picture

In contrast to the US, coal consumption has increased over the past year, as coal prices have fallen while gas has remained relatively expensive, given continued oil-linked formulae in continental gas prices.

Exhibit 77: UK clean spark vs. dark spreads

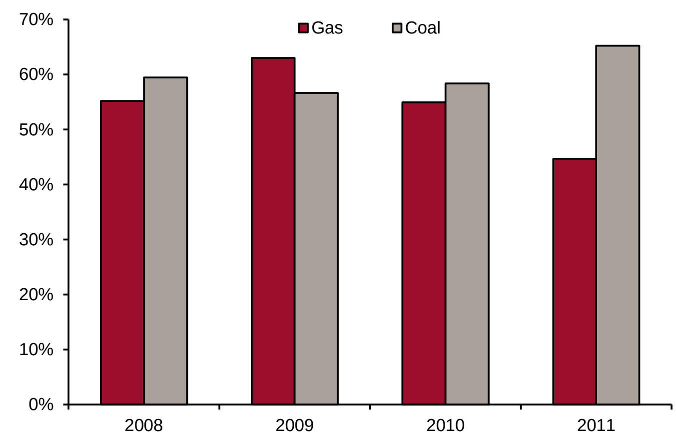
GBP/MWh, front month contract



Source: Credit Suisse, the BLOOMBERG PROFESSIONAL™ service

Exhibit 78: German power plant load factors

Utilization, Percentage



Source: Credit Suisse, ENTSOE, Eurostat

Taking the UK and Germany as illustrative of these dynamics, we note that the incentive to burn coal rather than gas has been a key theme for power utilities over the last year and one on which they have acted. In the UK, implied clean spark spreads – which also include carbon emissions permits – are effectively zero, while dark spreads from coal are deeply in the money (Exhibit 77). The German power market has exhibited a similar trait through 2011-2012 – with coal plants' utilization consequently running at 65%, in contrast to gas plants' 45% (Exhibit 78).

Gas nevertheless still runs, partly to earn peaking rather than base-load power prices but also as a result of the existence of take-or-pay agreements and the inability of the rest of the power mix to satisfy total demand independently. **The current European power dynamics have therefore been near diametrically opposed to those experienced in the US.** Given Europe's relatively high share of installed gas capacity (Exhibit 73) and current low utilization, if the spark versus dark spread economics were to shift, there is considerable potential for coal-to-gas switching even before considering future changes to installed capacity.

Unconventional gas does not look like a potential trigger for change. As noted in the earlier outlook for the development of unconventional European resources, political and regulatory headwinds put significant supply-side additions outside of any time frame we can currently forecast.

Nevertheless, we do expect gas to take back a certain degree of market share from coal in coming years as the impact of the large combustion plant directive, the introduction of a UK carbon floor and political intervention in the European emissions trading scheme all shift utilities' incentives. Consequently, over the period from 2012 to 2015, we estimate that EU27 thermal coal imports will decline by nearly 20Mt, but this is without feeling any direct effects of the shale gas revolution being experienced in other regions.

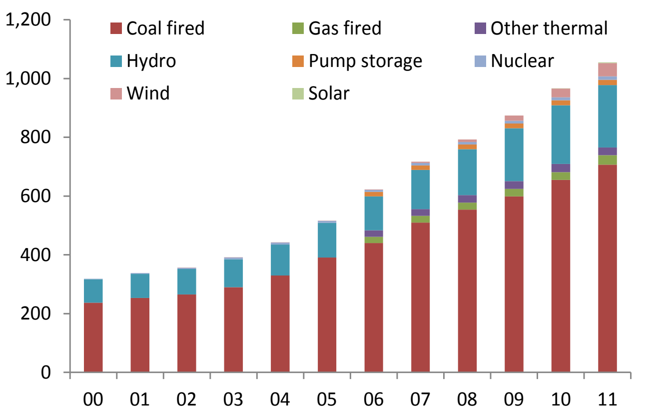
Beyond this, the development of significant US LNG exports – detailed later in this section – should compound this move to greater gas usage, but that is something that should play out more in the 2020s than the current decade.

China – coal remains the energy bedrock, for now

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

Exhibit 79: Installed generating capacity by source

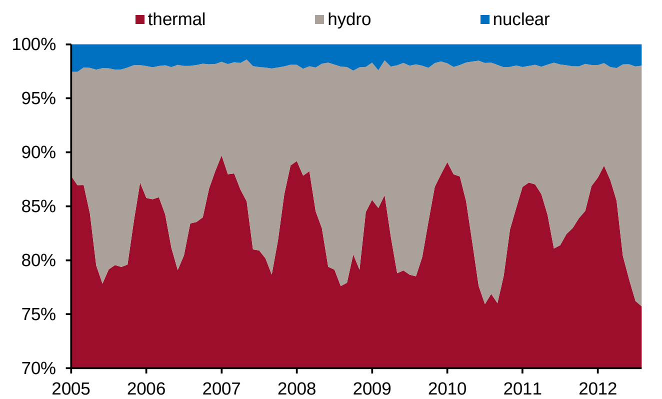
GW



Source: Credit Suisse, China NBS

Exhibit 80: Monthly share of electricity output

Percent, monthly

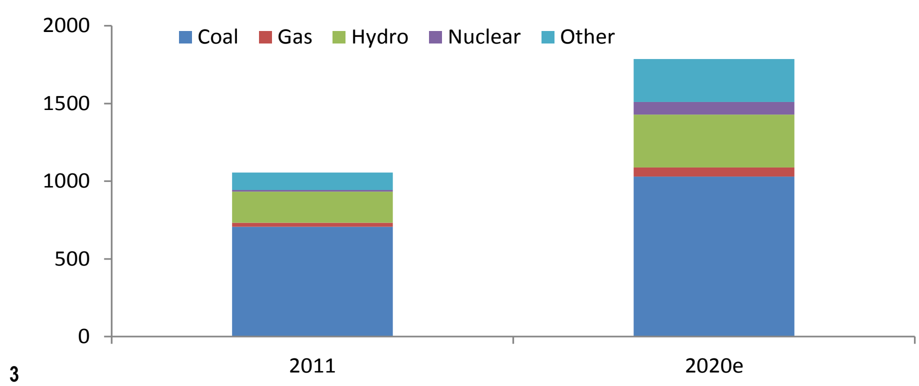


Source: Credit Suisse, China NBS

Therefore, within 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-over-year volatility exhibited by hydro make it a considerably less dependable power source (Exhibit 81).

Exhibit 81: 2011 vs. estimated 2020 installed capacity

GW



Source: Credit Suisse, China NBS, CEC

Any question of a major switch away from coal is therefore some way off. More relevant though is the potential for other power sources to cannibalize coal's demand growth, gradually taking a greater market share. To this end, the CEC's outline of capacity additions sees total generation rising to 1,786 GW by 2020, with coal's market share falling back to 58%. Hydro capacity, on this road map, is expected 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 59 GW, a modest growth in market share.

The extent to which capacity additions follow this path has already been affected by a slowdown in additions of nuclear capacity in the wake of the Fukushima Daiichi disaster, and the plan for gas could also shift. Almost certainly, gas will eventually make greater inroads into supplying peak-load power, especially in China's developed cities, where pollution abatement has become a much more important quest. For the time being, however, it is worth noting that gas is prohibited from use in base-load generation, and even if it were not, there is currently no incentive to use it for such a purpose.

Domestic supply growth

A key driver of any energy policy shift will be the success of efforts to promote the domestic shale gas industry, with a current target for production to reach 60-100 Bcm by 2020. As detailed in the China supply section, on current projections, we see the top end of this range as extremely unlikely to have been realized by 2020, but a figure around 60 Bcm is possible.

Within this time horizon, greater gas consumption is therefore much more likely to retard the rate of growth in coal demand than to lead toward any absolute reduction in coal use. In particular, until domestic gas production takes on a more prominent role in gas supply, coal will continue to enjoy primacy over gas from an energy security perspective, with China still over 90% self-sufficient in thermal coal.

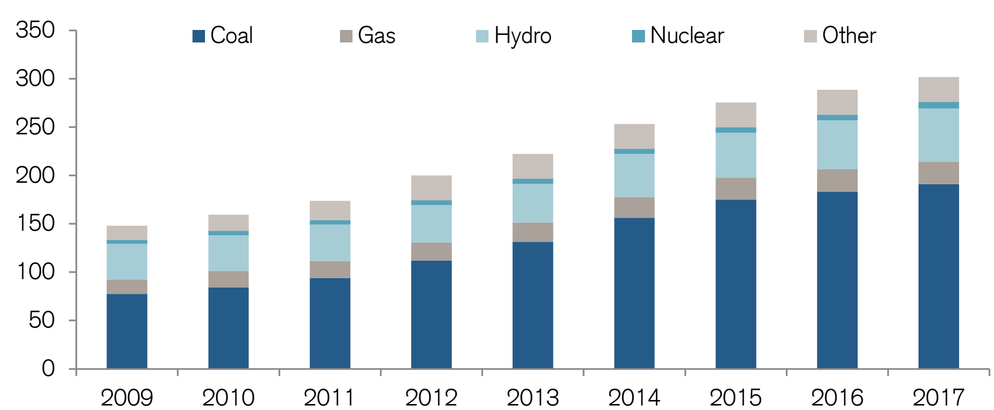
- Consequently, while gas, particularly for some industrial uses, looks set to take some of coal's market share, electricity generation should continue to be dominated by thermal coal until after 2020.
- Moving through the next decade, however, if China is able to replicate the US's explosive shale gas production growth, the days of thermal coal as the energy backbone could be numbered.

India – the once and future "King Coal"?

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 (Exhibit 82). Moreover, according to the India Equity Research 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.

Exhibit 82: Current and forecast Indian installed power generation

GW



Source: Credit Suisse, India CEA

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.**

Again, the scope for gas demand growth should be much more of a direct industrial use than a power generation story. However, industrial users are constructing gas turbines, as well as renewable energy sources to supplement for inadequate grid supplies and costly stand-by diesel generation.

Deeper inroads into the power sector will only come with major power sector reforms and the emergence of peaking power price mechanisms. At current relative prices, imported gas is far too uncompetitive, with cheaper domestic coal and even imported coal. However, India seems far from tackling some of the key problems associated with its crippled power sector, namely the following:

- Anomalies in coal and electricity pricing
- A financially impoverished distribution sector and severe “losses” of electricity and revenues
- Environmental and other land access barriers to boosting domestic coal mine supply
- Inadequate domestic gas supply at affordable prices to make inroads into peaking power use

Beyond the potential for opening up unconventional sources of gas supply (which might well face some resistance from rural communities), gas penetration in power is likely to rely more on the supply of LNG at competitive prices.

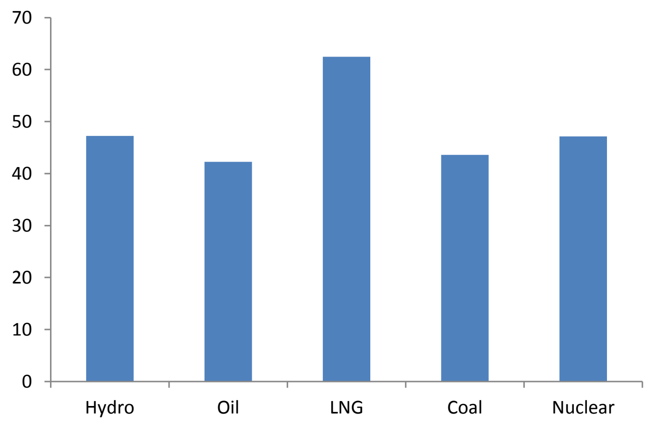
Japan – searching for a nuclear alternative

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 our base case does remain on the table.

The means by which Japan would replace this lost generating capacity, though there is clearly a heavy bias toward renewables, does therefore remain extremely unclear. This is evidently something that needs to be addressed, as before the Great Tohoku Earthquake, installed nuclear capacity of 47.1 GW accounted for 19% of generating capabilities. Moreover, because nuclear power was key to meeting base-load requirements, utilization rates have been historically high, other than for periodic maintenance inspections following previous tectonic disturbances. This downtime has meant that Japan has never consistently achieved the utilization rates of a number of European countries, but despite this, nuclear still accounted for above 25% of total electricity generated.

Exhibit 83: Installed Japanese capacity by source

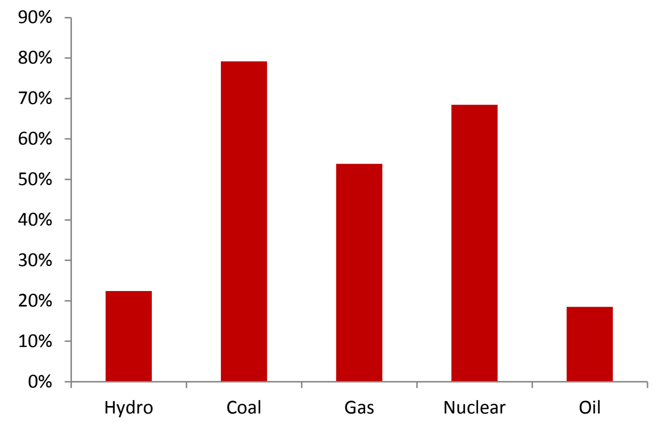
GW, 2010



Source: Credit Suisse, Japan FEP

Exhibit 84: Utilization of installed Japanese capacity

Percent, 2010



Source: Credit Suisse, Japan FEP

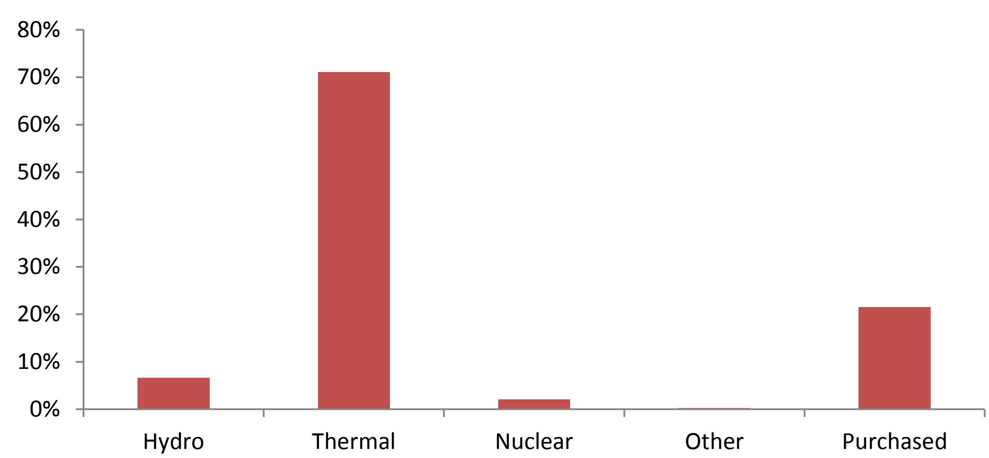
Consequently, while there had previously been some scope for coal-to-gas switching, the chances of this being recreated within the short term are now extremely slim. Looking at the current generation breakdown for August, we note that 71% of power was provided by thermal generation, comprising coal, gas and fuel oil capacity. With the implied utilization for this capacity, on aggregate generation of 61TWh, therefore standing at 55%, the overall burden being carried by thermal generation leaves little or no room for inter-fuel substitution.

While restart of some nuclear generation should offer a degree of respite, we still do not expect any significant switching in the power mix.

At present, the combination of Japan's nuclear shutdowns and this year's relatively high oil prices has seen seaborne LNG outperform thermal coal in dramatic fashion (Exhibit 85), making the economics of coal-to-gas switching particularly unattractive for most consumers.

Exhibit 85: Current power generation in Japan

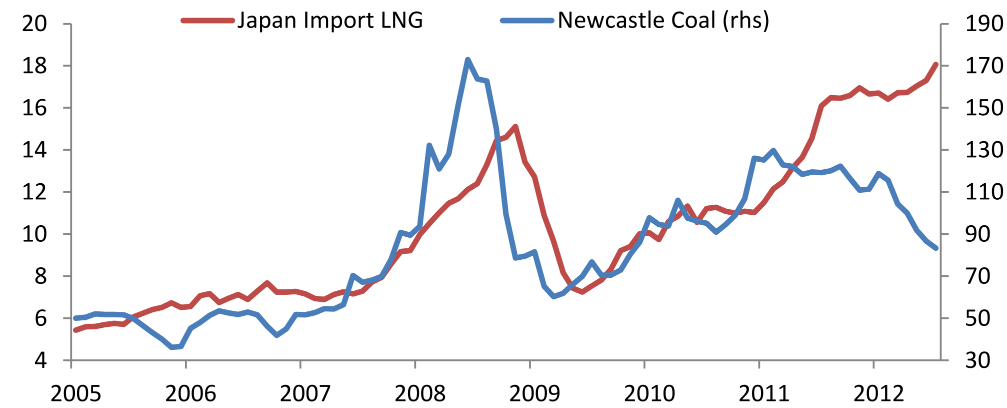
Percent of power generated, August 2012



Source: Credit Suisse, FEPC

Exhibit 86: Japan import LNG vs. Newcastle thermal coal FOB

US$/MMBtu (lhs), US$/t (rhs)



Source: Credit Suisse, the BLOOMBERG PROFESSIONAL™ service

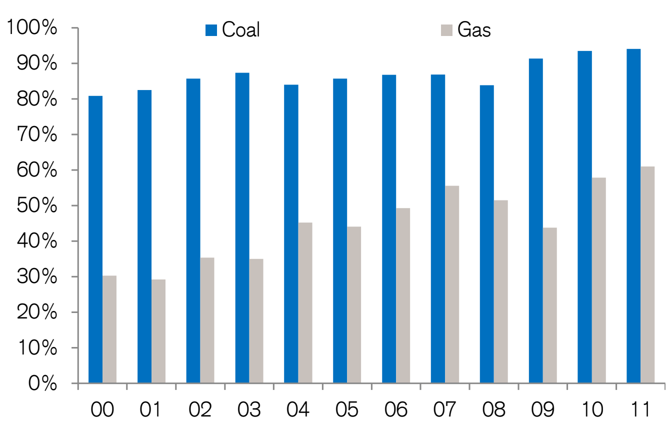
Further out, our global gas colleagues (*Global Gas - From tight to loose by 2016E*) have made the case that global gas prices are unlikely to converge and that APAC LNG should stay close to US$18/MMBtu into the middle of this decade before falling back toward $14/MMBtu. Primarily this is because consumers will continue to depend on oil-linked seaborne prices and do not currently stand to benefit from the cheaper "stranded" shale gas elsewhere. Consequently, absent a rally in seaborne coal prices that is far beyond our current price expectations for a gradual improvement (see *The Best of Times; The Worst of Times*), Japanese coal demand should remain fairly robust through the current forecast period into the 2020s.

South Korea – unfulfilled potential

As Exhibit 73 demonstrates, 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, however, consistently run at higher utilization levels than gas capacity given its role in base-load generation (Exhibit 87) and, as a consequence, has accounted for a considerably greater share of electricity output (Exhibit 88). **The country does, therefore, in theory, have some scope for a switch away from thermal coal, toward natural gas.**

Exhibit 87: Coal and gas capacity utilization

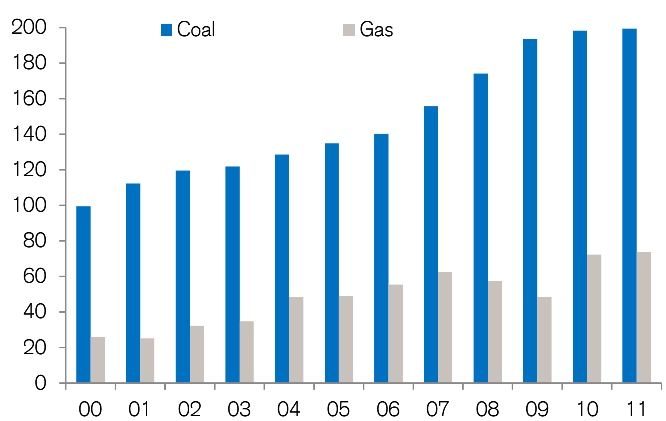
Utilization, percentage



Source: Credit Suisse, Company data

Exhibit 88: Power generation by source

TWh



Source: Credit Suisse, Company data

In 2011, South Korea imported 107 Mt of thermal coal, and year-to-date run rates suggest a similar total for 2012. Though some of this coal is used directly for industrial processes, the bulk is used for power demand, and for simplicity, we assume that, were coal to be substituted away from in the power mix, industry would demonstrate a similar trend.

This 107 Mt of coal was used to generate 200 TWh of electricity at a coal utilization rate of 94.1%. Essentially, 1 Mt of thermal coal equated to 1.86 TWh of power. If, for illustrative purposes with all other things being equal, gas utilization were to rise from 61% to 70%, this would equate to an additional 10.9 TWh of gas-generated electricity and a reduction of 5.8 Mt in coal demand.

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. The reason is 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.

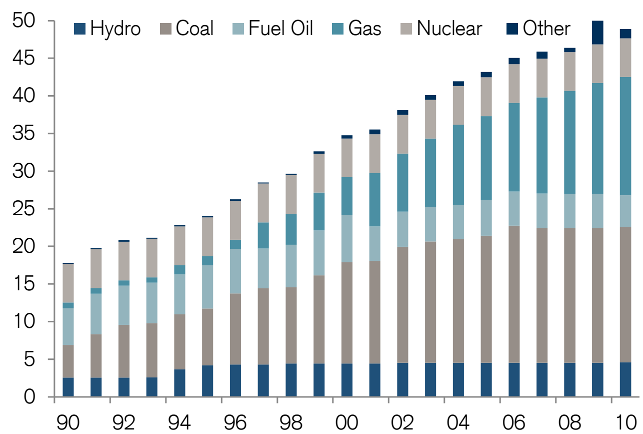
Taiwan – just like its neighbor

Taiwan currently demonstrates an extremely similar story to that of South Korea. While gas generation has grown to around a third of installed capacity, its output accounts for only roughly one-quarter of electricity production. Consequently, like South Korea, there is considerable scope for coal-to-gas switching – an increase in utilization from 44% to 60% would displace an estimated 11Mt of thermal coal demand (equivalent to 18% of coal demand) – but the economic incentive is currently lacking and, on existing price expectations, is unlikely to emerge for some years yet.

It is thus a very similar story to that being witnessed in South Korea. **Taiwan should be one of the first countries to switch away from coal when the opportunity arises, but that opportunity remains some years away**.

Exhibit 89: Taiwan's installed capacity by source

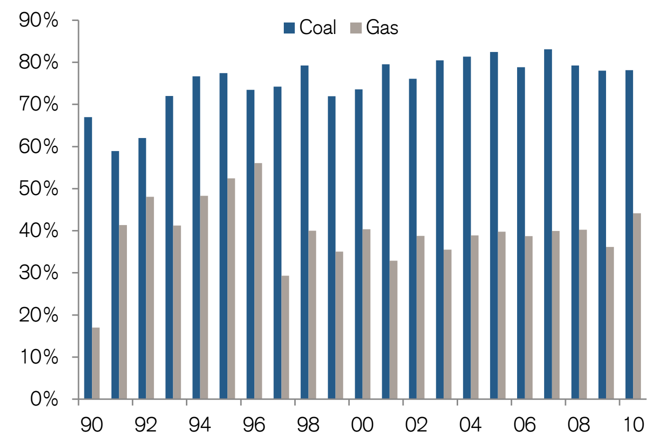
GW



Source: Credit Suisse, Taiwan BoE

Exhibit 90: Coal and gas capacity utilization

utilization, %



Source: Credit Suisse, Taiwan BoE

Seaborne coal – the fat lady's not singing yet

We believe that coal will eventually be displaced by natural gas, as its environmental credentials, bar a dramatic CCS breakthrough, place it at an inherent disadvantage – gas emits roughly 60% less carbon dioxide per kWh of electricity generated. **That said, the speed with which this initial displacement has occurred in the US does not appear to be replicable in any other geography.**

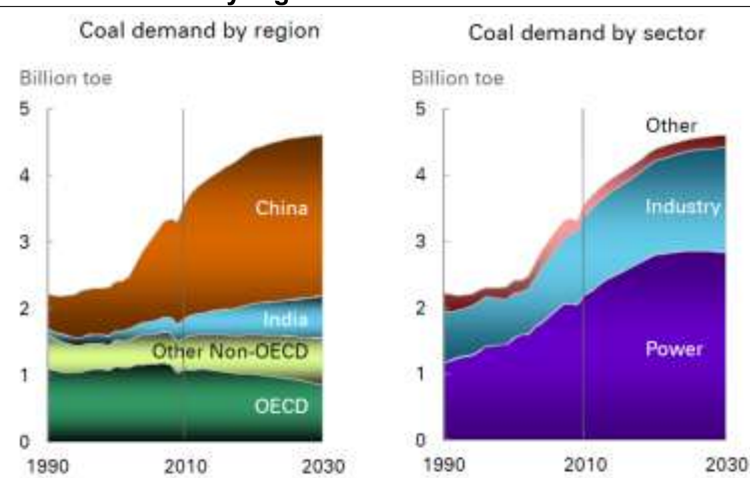
Broadly speaking, the obstacles to replication can be broken into supply- and demand-side constraints. From our analysis, no other region will match the magnitude of US supply growth within this decade, and the US, despite becoming an LNG exporter, is likely to keep much of its gas at home. Consequently,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

Moreover, outside of Europe, South Korea and Taiwan, the other major seaborne coal consumers – crucially including China and India – do not currently have sufficient flexibility within their generating mix to materially switch from coal to gas, even if cheap gas were to become readily available. Other than in India, where current projections suggest that gas' share of the power mix will fall through to 2017, this situation should slowly change. However, with gas plants requiring three to four years for construction, after all plans and permitting have been finalized, even if gas supply growth were to surprise dramatically on the upside, none of these countries could immediately follow the US lead.

The transition from coal to gas should, therefore, be a rather more drawn-out process than some have assumed through their assessment of the US alone. In general, gas demand growth is more likely to retard the rate of coal demand growth – particularly in direct industrial applications – than reduce coal demand in terms of absolute tons at least until the end of this decade.

Forecasting beyond the next small number of years carries inherent risks, so no date can confidently be placed on gas' usurping of old "King Coal." Current probabilities do, however, point to it being well into the next decade, by which time the degree of substitution could become substantial if China is able to replicate the US's rapid increase in shale gas production.

Exhibit 91: Coal demand by region and sector



Source: Credit Suisse, OECD

Equity Research

Sector Implications and Stock Recommendations

Key stock picks

The following section sets out the implications of the shale revolution on specific equity sectors. We highlight key stocks that are poised to benefit from growth in the shale space, as chosen by our equity research analysts.

Exhibit 92: Key global stock picks

Name	Country	Symbol	Market Cap (bil) Local	GICS Group	GICS Industry	Sens-itivity	CS	Investment Thesis
ANADARKO PETROLEUM	USA	APC	37.62	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Dominant position in the Wattenberg play - growing at 20% CAGR & providing some of the highest returns in US E&P
ARKEMA GROUP	FRA	AKE	4.99	Materials	Electrical Equipment	High	Outperform	Elevated propylene prices in the US could support higher derivatives prices globally.
AURORA OIL & GAS LIMITED	AUS	AUT	1.39	Energy	Oil, Gas & Cons. Fuels	High	Outperform	High growth, high margin, liquids rich Eagle Ford shale producer.
CHINA OILFIELD SERVICES	HKG	2883	73.72	Energy	Energy Equip. & Services	High	Outperform	To benefit from shale drilling onshore China in the future.
CNOOC LIMITED	HKG	883	751.17	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Drilled initial positive shale wells in AU.
DOW CHEMICAL	USA	DOW	37.24	Materials	Chemicals	High	Outperform	Could benefit from a cost advantage from shale gas at least until 2015.16.
FLOWSERVE CORP	USA	FLS	7.15	Cap Goods	Machinery	High	Outperform	Could benefit from increased demand in centrifugal pumps which are used around the well to transport water
GARDNER DENVER INC	USA	GDI	3.41	Cap Goods	Machinery	High	Outperform	Could benefit from increased demand in pressure pump manufacturing.
GENERAL ELECTRIC CO	USA	GE	225.56	Cap Goods	Industrial Conglomerates	High	Outperform	#1 in gas turbines globally, and it is refreshing its product suite.
HALLIBURTON CO	USA	HAL	31.54	Energy	Energy Equip. & Services	High	Outperform	As the largest provider of hydraulic fracturing services worldwide, is a likely beneficiary of the shale gas revolution
KANSAS CITY SOUTHERN	USA	KSU	8.89	Transport ation	Road & Rail	High	Outperform	Benefit from 'crude-by-rail'. Involved in bringing materials into and out of shale plays.
KUNLUN ENERGY COMPANY	HKG	135	129.42	Utilities	Gas Utilities	High	Outperform	Is developing LNG transportation business.
LYONDELLBASELL	USA	LYB	31.09	Materials	Chemicals	High	Outperform	Could benefit from a cost advantage from shale gas at least until 2015.16.
MARATHON OIL CORP	USA	MRO	21.33	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Low cost way to play growing high return production in the Eagle Ford Shale with exploration optionality on top.
MARATHON PETROLEUM CORF	USA	MPC	20.82	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Benefiting from low refining/chemical costs and growth potential in logistics
NOBLE ENERGY INC	USA	NBL	18.09	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Dominant position in the Wattenberg play - growing at 20% CAGR & providing some of the highest returns in US E&P
PDC ENERGY INC	USA	PDCE	1.01	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Our play for exposure to emerging Utica play
PERUSAHAAN GAS NEGARA	IDN	PGAS	111,502.44	Utilities	Gas Utilities	High	Outperform	Will benefit for abundant and cheap shale gas in the future, to support the expansion in the LNG regasification capacity
PETROCHINA CO LTD	HKG	857	1,954.66	Energy	Oil, Gas & Cons. Fuels	High	Neutral	Dominant acreage holder and closed access pipeline network in China.
PHILLIPS 66	USA	PSX	36.47	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Benefiting from low refining/chemical costs and growth potential in logistics
ROTORK P.L.C.	GBR	ROR	2.16	Cap Goods	Machinery	High	Outperform	May benefit growth of gas infrastructure as their valve actuators are used in pipelines and processing plants.
SIEMENS AG	DEU	SIEGn	71.69	Cap Goods	Industrial Conglomerates	High	Outperform	Is a gas turbine manufacturer so could benefit from the move towards gas-fired power generation.
TRANSCANADA CORP	CAN	TRP.	32.26	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Could benefit from growth in the pipeline industry in North America.
UNION PACIFIC	USA	UNP	58.23	Transport ation	Road & Rail	High	Outperform	Benefit from 'crude-by-rail'. Involved in bringing materials into and out of shale plays.
VALLOUREC	FRA	VLLP	4.85	Cap Goods	Machinery	High	Neutral	Could benefit from the increased demand of steel pipes used in casing of wells and extraction of gas.
WEIR GROUP PLC	GBR	WEIR	3.89	Cap Goods	Machinery	High	Neutral	Could benefit from increased demand in pressure pumps / fluid ends / service as a result of shale boom.

Source: MSCI, Credit Suisse research.

North America Energy

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Many of the key conclusions regarding shale implications can be found in our regular research reports, notably the U.S. E&P PlayBook, US Natural Gas Reservoir, theme pieces such as U.S. Energy Independence Day, our recent U.S. Oilfield Services initiation Wait 'Til You See the Whites of their Eyes or for the refiners 10 Steps to Refiner Heaven, Mid-Con Heaven and A Decade of Free Cash Flow.

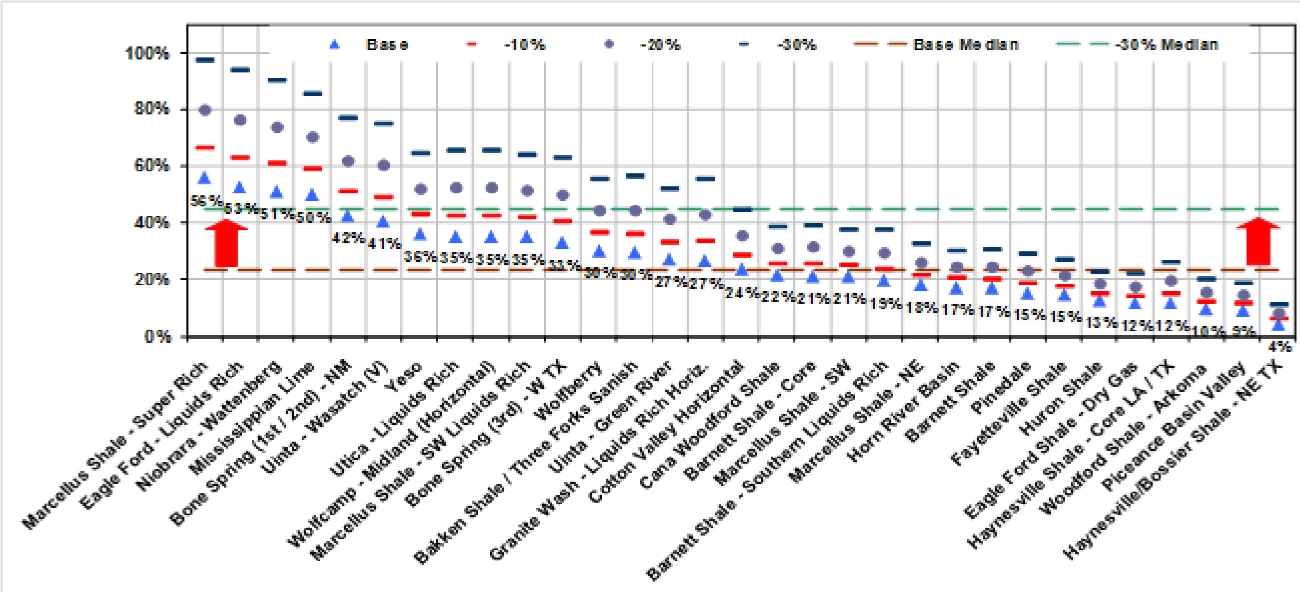
Our current views can be summarized as follows:

- **E&P**: Well-positioned E&P companies with existing liquids rich shale acreage are benefiting currently from falling costs (both efficiency gains and service cost deflation) and the potential for improved domestic oil realizations as infrastructure is built out. We also expect consolidation by larger players.
- **Services**: Unfortunately, the counter-seasonal decline in drilling activity is causing another pricing step down for North American services that pushes the recovery back a quarter or two and should result in missed 2H12 results and lowered forward guidance.
- **Refiners**: The refiner universe still offers value and operates at the low end of the global cost curve. Shale has reduced the US refiners feedstock costs and energy costs. Shale also creates opportunities to grow the Refiners' logistics businesses. There could be some near-term headwinds as margins transition from "supernormal" to normal and as WTI-LLS crude spreads compress. However, Refiner shares are not pricing in midcycle free cash generation, and management can force valuations higher through the return of cash via dividends or through the creation of logistics (and even refining) MLPs.
- **Best shale plays in the US**: Within US E&P, the greatest growth in oil production is coming from the Eagleford and Permian plays in Texas. Not surprisingly, some of the best performers have been from these regions. Our larger-cap picks have exposure to the Eagleford (MRO, ROSE), the Wattenberg, another much improved play (NBL, APC, PDCE), the emerging Utica play in Ohio (PDCE), and rising North American gas and NGL prices from a low base (DVN, RRC). The Marcellus (RRC) remains the lowest-cost natural gas shale basin in the United States.
- Overall our top producer picks levered to the shale theme include APC, NBL, RRC, MRO, PDCE and ROSE. In US services, we remain cautious owing to falling domestic pricing.

Improving E&P cost structure

Given falling service pricing and improved efficiency, cost structure will be a key theme through 2H12 and into 2013. Some E&P companies have spoken to reduced costs in the Eagleford and in the Bakken. Given the stretched balance sheets across the Independent E&P sector, any sign of costs easing would be a key positive catalyst for the group, particularly if macro confidence improved also.

Exhibit 93: Improvement in returns across the play with well cost reductions



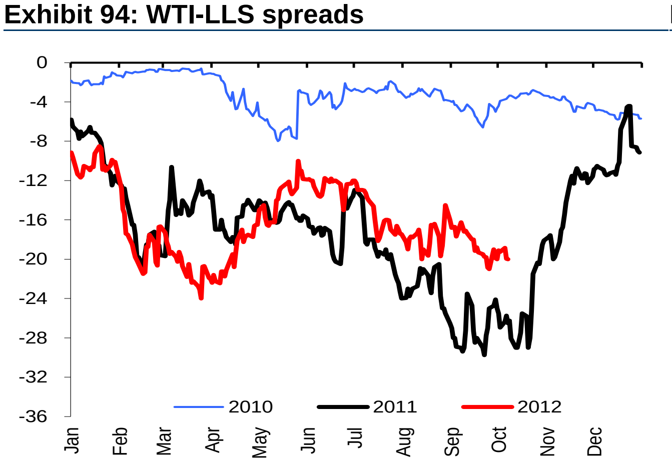
Year:	1	2	3	4	5	6	7	8+
WTI Oil:	$93.31	$93.92	$92.19	$89.89	$88.36	$87.57	$87.57	$87.57
NYMEX Gas:	$3.42	$3.93	$4.23	$4.41	$4.58	$4.77	$4.77	$4.77

Source: Company data.

Improving domestic E&P realizations

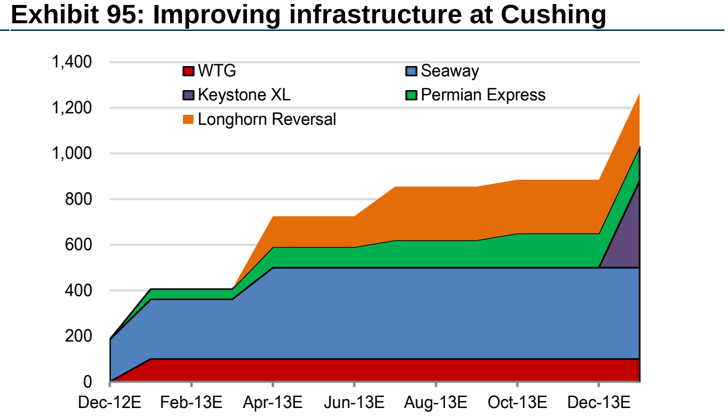
We expect WTI-Brent spreads to peak in 4Q12. There is substantial pipe infrastructure to bring mid-continent crude to market in 2013. This should have a narrowing influence on WTI (Cushing)-LLS (Louisiana) crude price spreads. Rail infrastructure should also help narrow Bakken discounts to $13-16/bbl relative to coastal Brent related prices. Although WTI-LLS could narrow considerably, there is a concern that the Gulf Coast market would become oversupplied with light sweet crude, given strong growth in the Permian, Eagleford, Mississippian and recent offshore discoveries. Investors who have lost faith in WTI question LLS pricing versus Brent also. We believe Texas refineries will be oversupplied in 2014 and Louisiana by 2016. However, there are relatively low cost export opportunities from the Gulf to Eastern Canada at just $2/bbl for 500kbd. Beyond Canada, Jones Act compliant shipping to 1.2MBD of East Coast refining capacity would cost around $4.5/bbl. LLS prices should fall versus Brent but it may not be as bad as the WTI dislocation.

Exhibit 94: WTI-LLS spreads



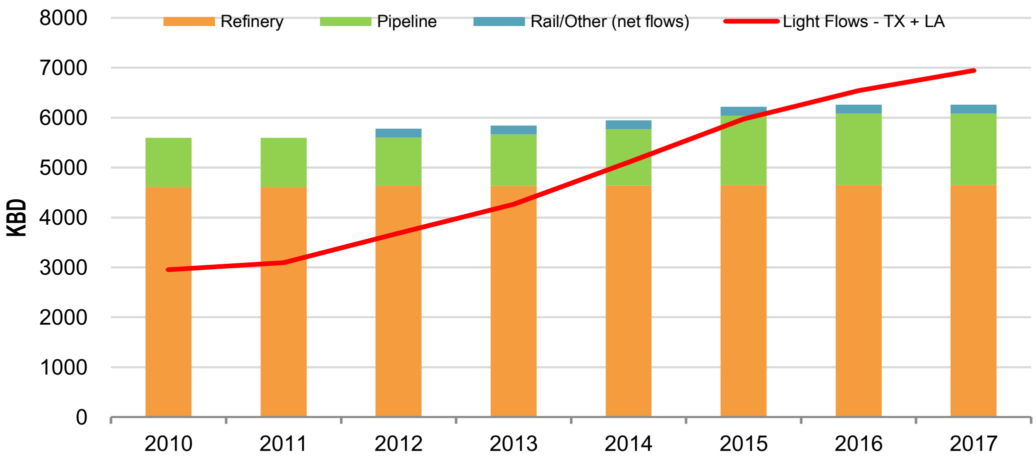
Source: the BLOOMBERG PROFESSIONAL™ service.

Exhibit 95: Improving infrastructure at Cushing



Source: the BLOOMBERG PROFESSIONAL™ service.

Exhibit 96: Light crude supply in the Gulf versus capacity

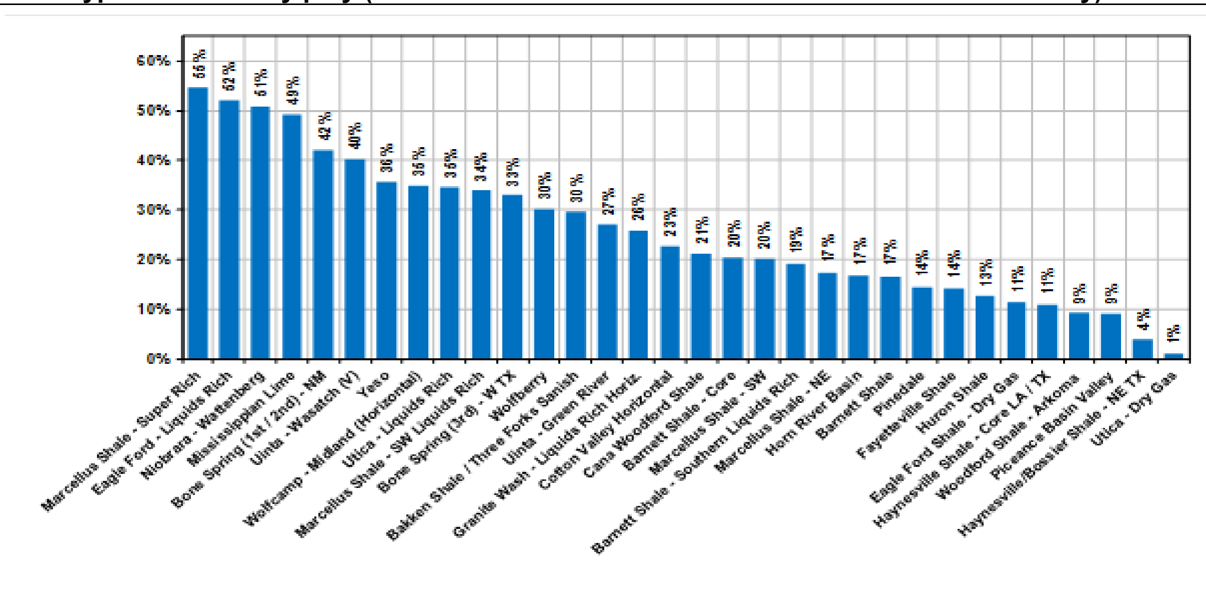


Source: The BLOOMBERG PROFESSIONAL™ service, Credit Suisse.

Eagleford, Niobrara, Mississippian and Permian continue to lead the play board. Utica is emerging.

As we assess the returns from typical single wells in each play, the super-rich Marcellus, Eagleford, Niobrara, Mississippian, and Permian horizontal plays stand out. Our stock picks include exposure to each of these key plays. From an emerging play perspective, we would highlight the Utica liquids rich window in Ohio. The other key industry trend is downspacing which allows companies to drill more wells in their acreage and extend production growth/boost NAV.

Exhibit 97: Typical returns by play (note that actual well results exhibit substantial variability)



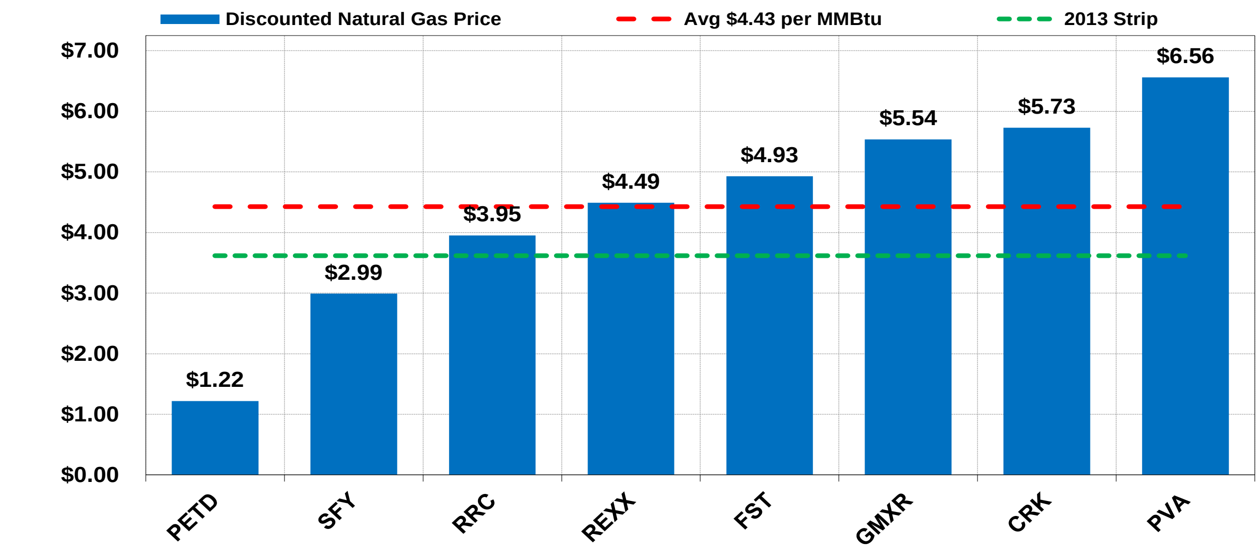
Year:	1	2	3	4	5	6	7	8+
WTI Oil:	$93.26	$93.71	$91.78	$89.35	$87.74	$86.87	$86.87	$86.87
NYMEX Gas:	$3.33	$3.85	$4.18	$4.37	$4.55	$4.74	$4.74	$4.74

Source: Company data.

Play rising US gas demand in the hybrid producers

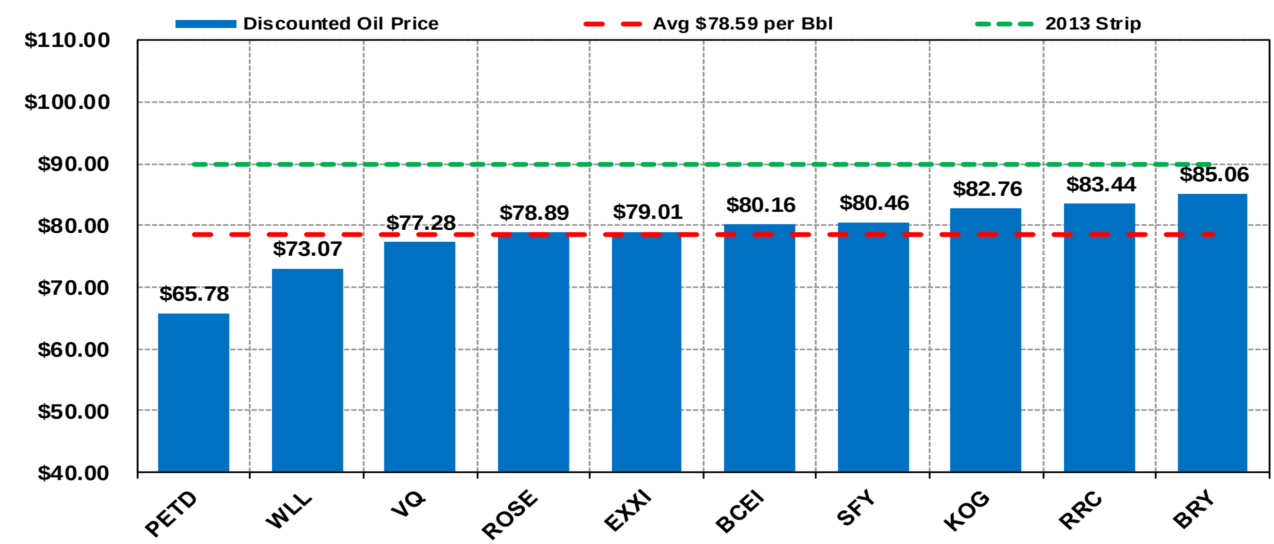
Focusing on the smaller end of the universe, we can gauge embedded commodity prices. We estimate the gas-focused E&Ps under coverage currently imbed $4.43/MMBtu long term, and the market appears apprehensive in recognizing value in the oil-focused group, which we estimate imbeds ~$79/bbl long-term WTI.

Exhibit 98: Equity prices discounting $4.43 per MMBtu natural gas price – *at the Oil Futures Strip*



Source: Credit Suisse estimates. *Note: Futures Strip as of 7/23/12.

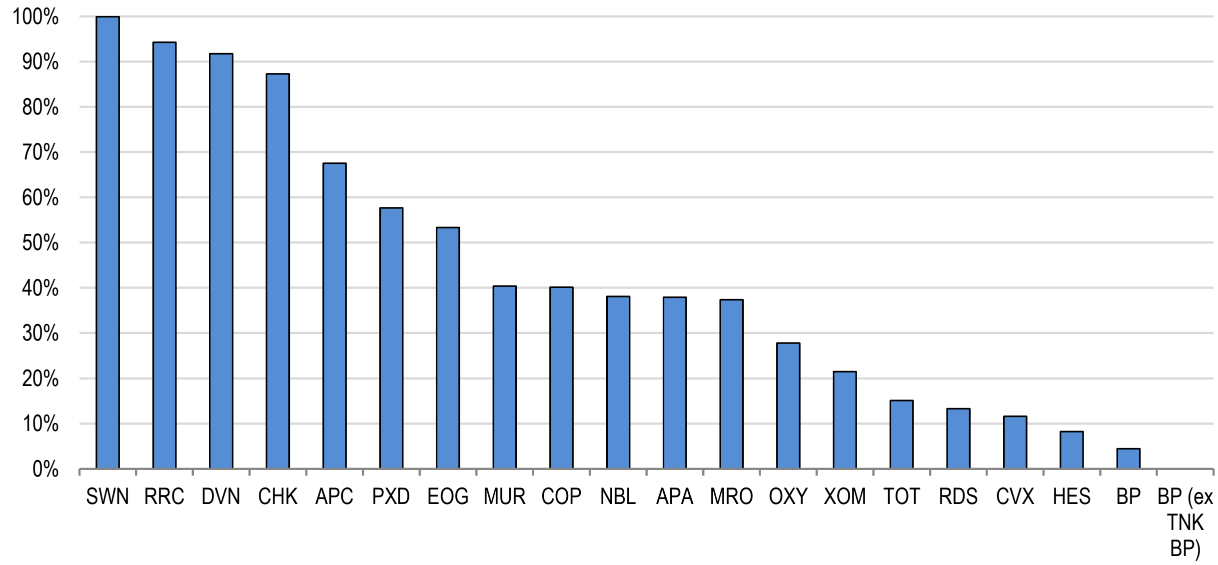
Exhibit 99: Equity prices discounting $78.59 per Bbl Oil Price – *at the Natural Gas Futures Strip*



Source: Credit Suisse estimates. *Note: Futures Strip as of 7/23/12.

Among the purer gas-focused plays, we prefer DVN and RRC, but it may also make sense to focus on those companies that are not pure plays on gas but have substantial leverage nonetheless. The following exhibit shows the share of production that was “underearning” in 2Q12 – i.e., US natural gas and NGL production. APC, EOG, NBL, and MRO are hybrid producers with significant gas leverage that trade on lower-than-average multiples.

Exhibit 100: "Share of under-earnings" production in the hybrid producers, 2Q12

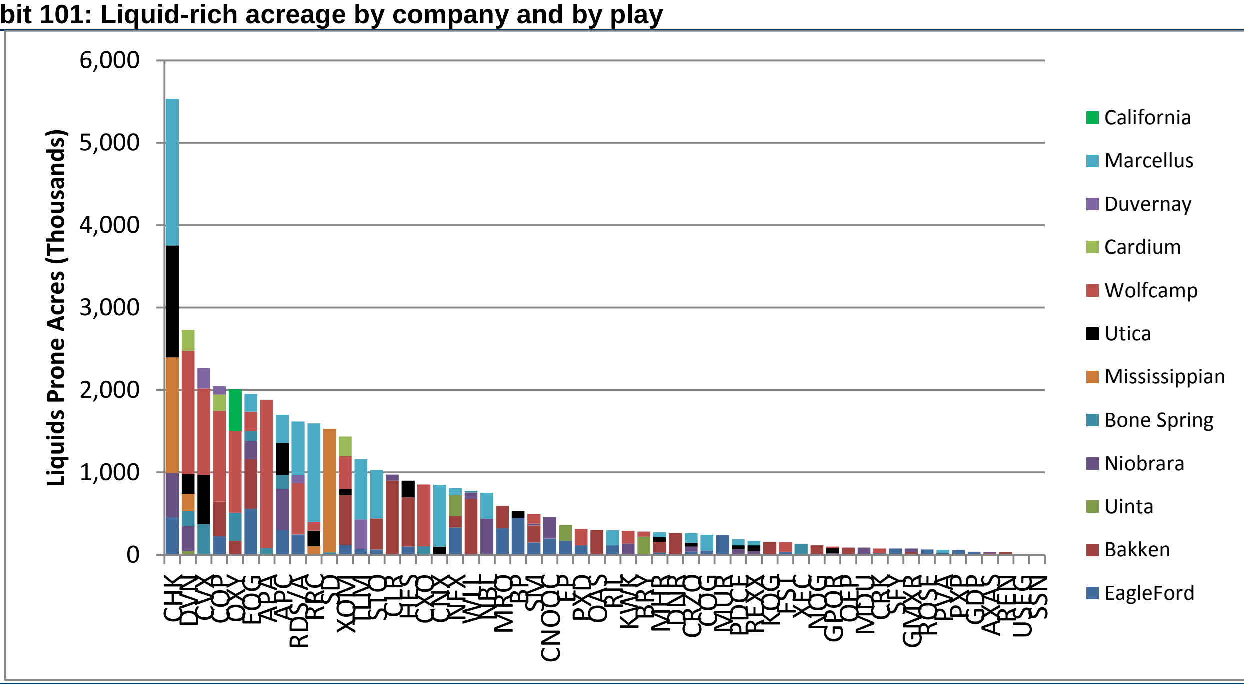


Source: Credit Suisse estimates.

Consolidation

It still makes sense that consolidation will remain a theme, given the returns available in select North American shales (e.g., Permian, Eagleford, Niobrara), the capital constraints of the Independents, the manufacturing and technology approach the larger companies can bring to the table, and the low-cost rocks for producing relatively clean natural gas in the Marcellus. We show in the chart below a simple proxy – liquid acres per company – that could act as a rough screen to identify companies that have substantial shale acreage in the United States.

Exhibit 101: Liquid-rich acreage by company and by play



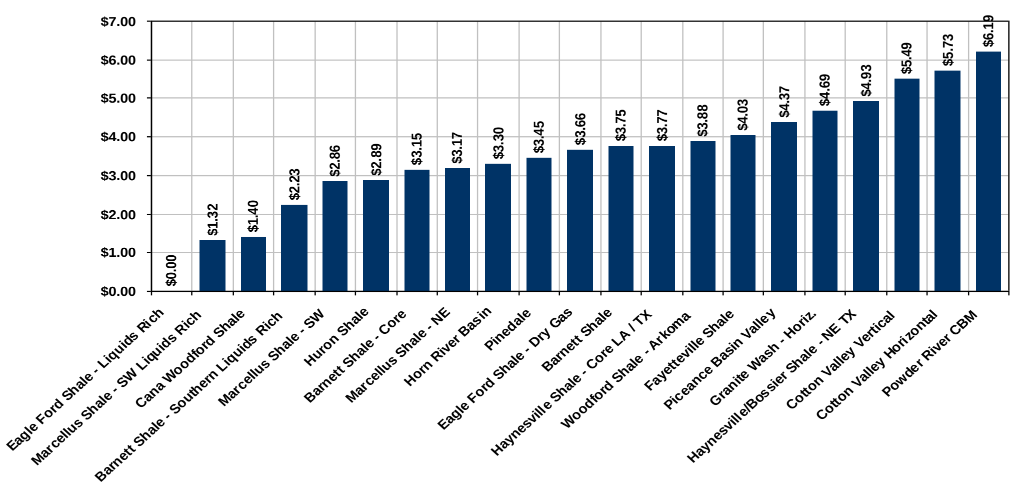
Source: the BLOOMBERG PROFESSIONAL™ service.

There will be losers

Shale is disrupting the cost curve of the natural gas industry (and oil to a lesser extent) and this means there will be losers. Although individual shale wells breakeven at low prices, it takes a lot of upfront capital to secure attractive acreage, to do the science well, to delineate the best parts of the acreage, and then to build a material source of cash flow. Companies with high cost gas acreage may struggle in this transition. Investors are more willing to focus on short cycle projects exposed to the front end of the oil curve than to take a chance on longer-term projects, mostly in the offshore..

Exhibit 102: With sufficient demand growth, gas prices would need to rise. We forecast $4.5/MMBtu longer term

NYMEX breakeven price for 10% after-tax ROR



Source: Credit Suisse.

Infrastructure

Canadian energy infrastructure and US MLPs

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There is a significant infrastructure requirement associated with the transition to unconventional energy sources, giving rise to unique investment opportunities. We find the infrastructure opportunity has likely been underestimated by industry sources and suggest several ways to play the ongoing trend.

North America's energy infrastructure related to the 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. Exhibit 103 shows the location of US shale plays.

Therefore, these companies are extremely well positioned for future growth from the ongoing rise of North American shale plays. With this backdrop, we briefly discuss three areas:

- Natural gas shale related infrastructure;
- Crude oil shale related infrastructure; and,
- Power pricing implications.
- Each of these areas is addressed below.

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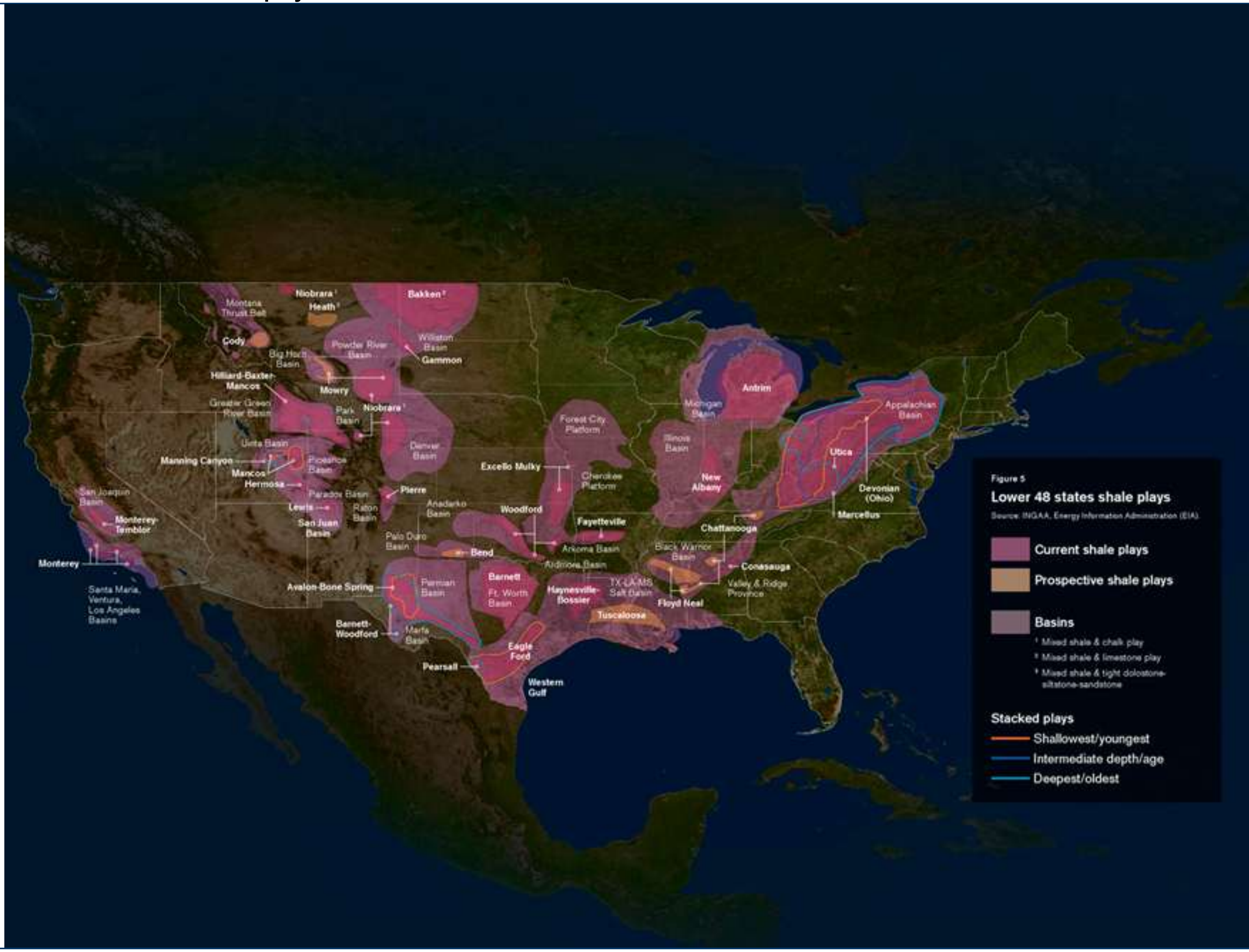
Exhibit 103: Lower 48 states shale plays



Source: INGAA, Energy Information Administration (EIA).

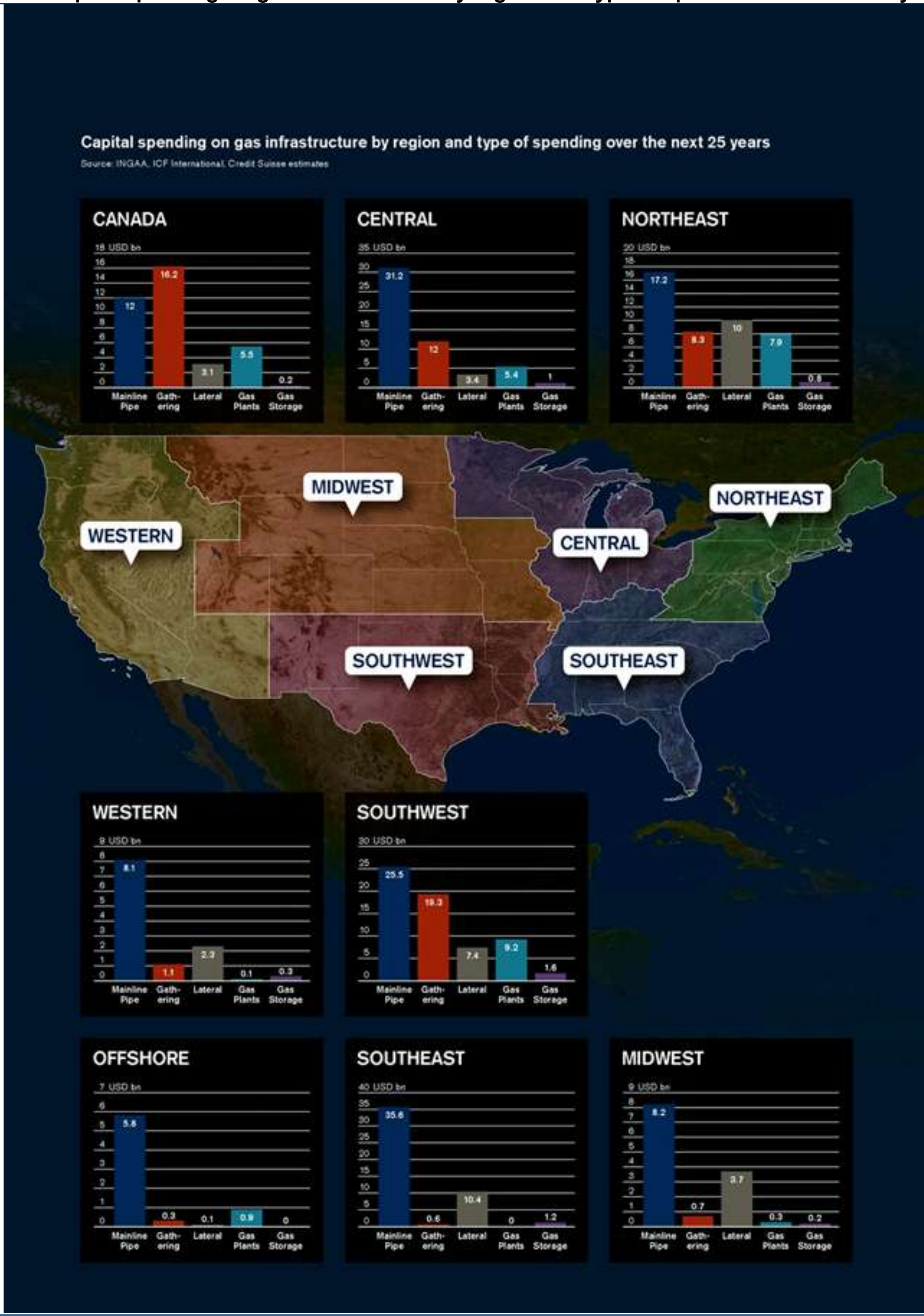
Ample infrastructure investment opportunities

Many shale plays require significant infrastructure development. The shale revolution looks to provide infrastructure companies and the US Master Limited Partnerships with ongoing opportunities for capital allocation. With a relatively modest rise in price outlook for natural gas ($4.38/MMBTU in 2010 rising to $5.59/MMBTU in 2020 and $7.15/MMBTU in 2035 and oil at $80/bbl in 2010$), INGAA's 2011 study concluded $338B of infrastructure would be required in nominal $US from 2011 to 2035. A trend of coal to natural gas switching underpinned some of INGAA's views along with incremental generation from natural gas. INGAA's breakdown consists of:

- ~US$132 billion for large-diameter natural gas mainline pipeline;
- ~US$59 billion for small-diameter gas gathering pipeline;
- ~US$41 billion for small-diameter gas lateral pipeline;
- ~US$29 billion for natural gas processing plants;
- ~US$60 billion for NGL and oil pipeline; and,
- Remainder is for pipeline compression and storage facilities.

Note in Exhibit 104, the largest increase in mainline pipe is expected for the SE United States where we expect a significant amount of new generation and/or coal to gas switching to take place based on economics as well as population growth. The other areas of significant growth are in the Central and S/W United States where there are significant amounts of gas associated with crude and liquids production. The N/E is also strong not just from shale production but also in replacing aging infrastructure. One gas utility in the N/E has indicated a $30 billion program over the next 10-15 years for refurbishing aging gas transmission, gathering, and distribution infrastructure. Taking the nominal dollar figures translates to roughly $275 billion over the period including laterals, gas processing plants, and gas storage.

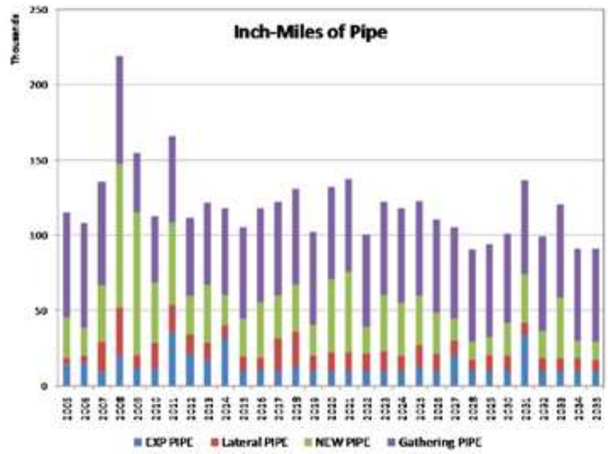
Exhibit 104: Capital spending on gas infrastructure by region and type of spend over the next 25 years



Source: INGAA, ICF International, Credit-Suisse estimates.

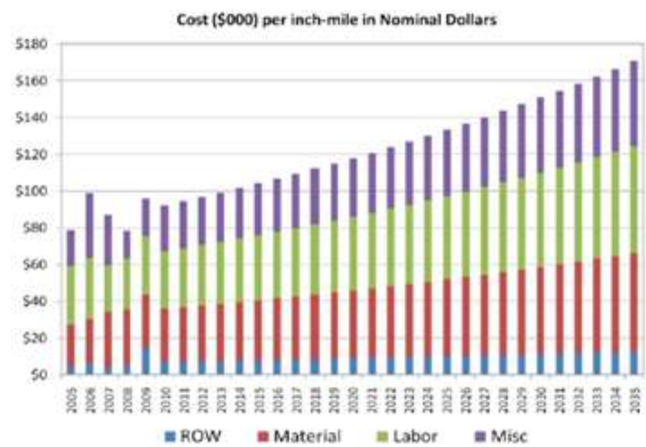
We believe the study likely underestimates the infrastructure opportunity. Given the 110,000 inch-miles added each year and approximately $100,000 per inch mile estimated for 2013 would translate to approximately $275 billion in total just from pipe – setting aside storage and gas processing (Exhibits 105 and 106).

Exhibit 105: Approximately 110,000 inch miles/year expected over the 2010-2035 time frame



Source: INGAA, ICF.

Exhibit 106: Gas pipeline costs expected to average approximately $100,000/inch mile in 2013

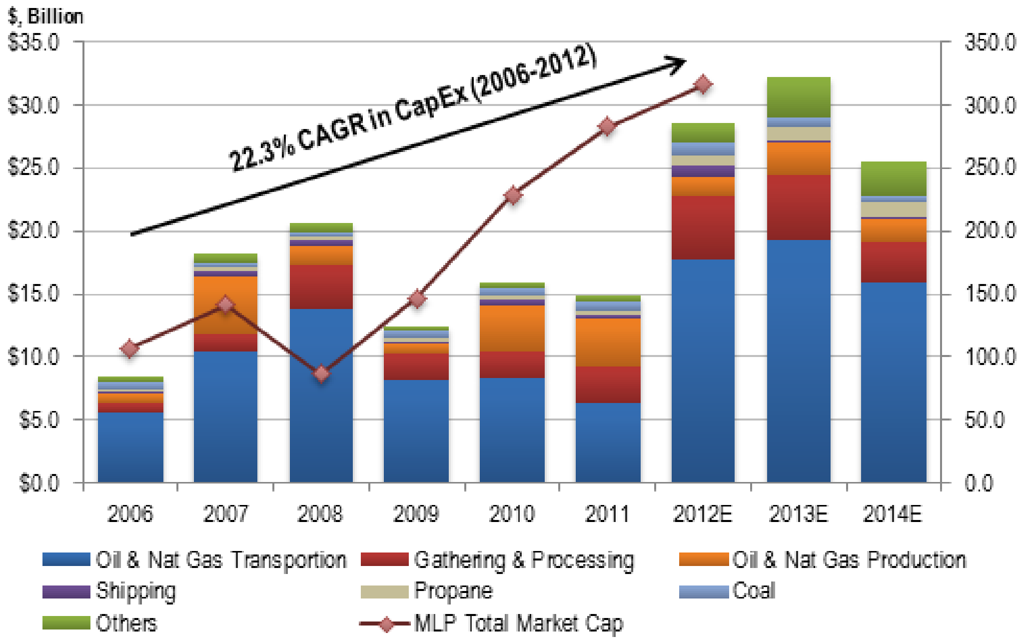


Source: INGAA, ICF International, Credit Suisse research.

Underscoring the capital investment opportunity unleashed by the shale revolution, capital spending in the MLP sector has increased rapidly over the past six years, rising over 22% per year compounded, and is expected to exceed $75 billion for 2012-2014. A notable positive for this growing capex profile has been the significant investor demand for yield oriented product offered by long-dated pipeline assets. Historically, low interest rates make a rather compelling argument for the cash flow predictability, duration, and unique growth offered by infrastructure companies. The shale revolution is likely to drive demand for infrastructure at least through the end of the decade. Consequently, we are not overly concerned about the growing capex figures under the current environment.

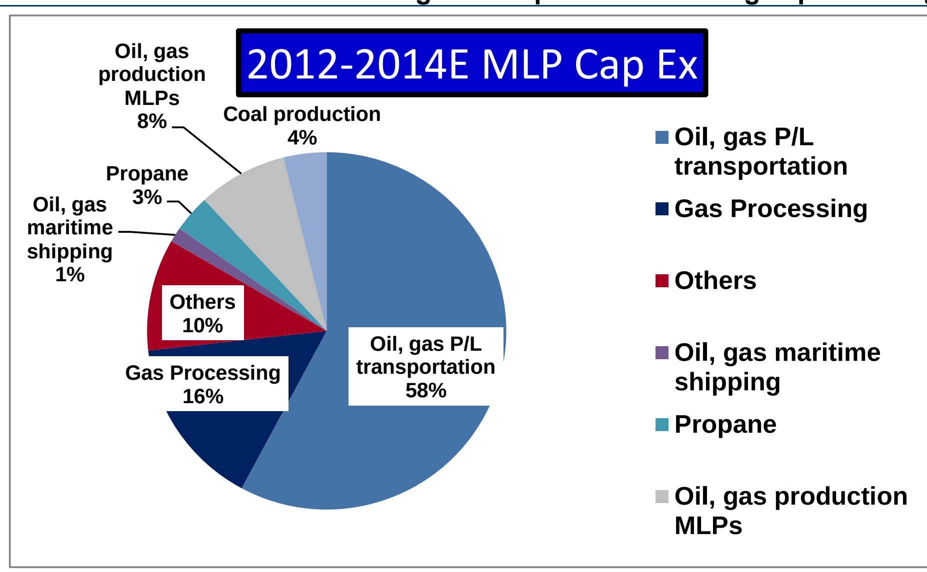
The changing sources of natural gas supply from relatively new shale plays have altered transportation patterns. Those changes provide investment opportunities, but can also significantly alter natural gas basis differentials at various geographic locations. Wide basis differentials provide a signal for incremental infrastructure investment; whereas, relatively flat basis differentials signal that pipeline capacity is adequately supplied and can raise questions regarding the underlying value of existing assets owing to renewal risks on 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, 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 build.

Exhibit 107: Capital spending has increased at a CAGR of over 22% since 2006 and is expected to reach an aggregate of $124 billion by the end of 2012



Source: Credit Suisse research.

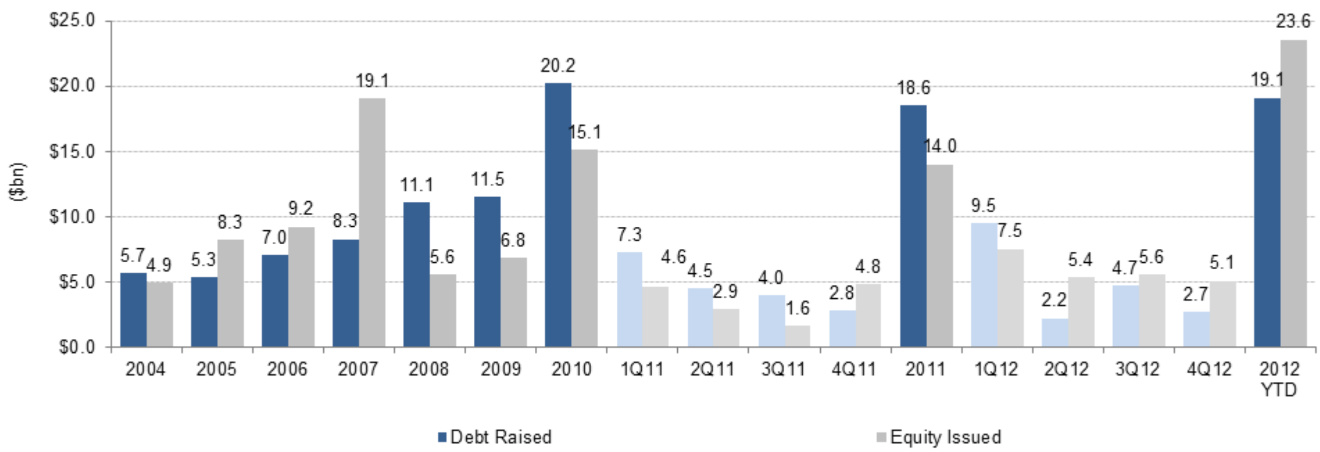
Exhibit 108: Approximately three-quarters of the estimated $75 billion of capex in 2012-2-14E is concentrated in oil/gas transport and natural gas processing



Source: Credit Suisse research.

To accommodate the demands of large amounts of capital spending that is expected to reach a cumulative total of $124 billion by the end of 2012, MLPs have been active in capital markets Exhibit 109.

Exhibit 109: $104 billion of equity and $105 billion of debt raised since 2004



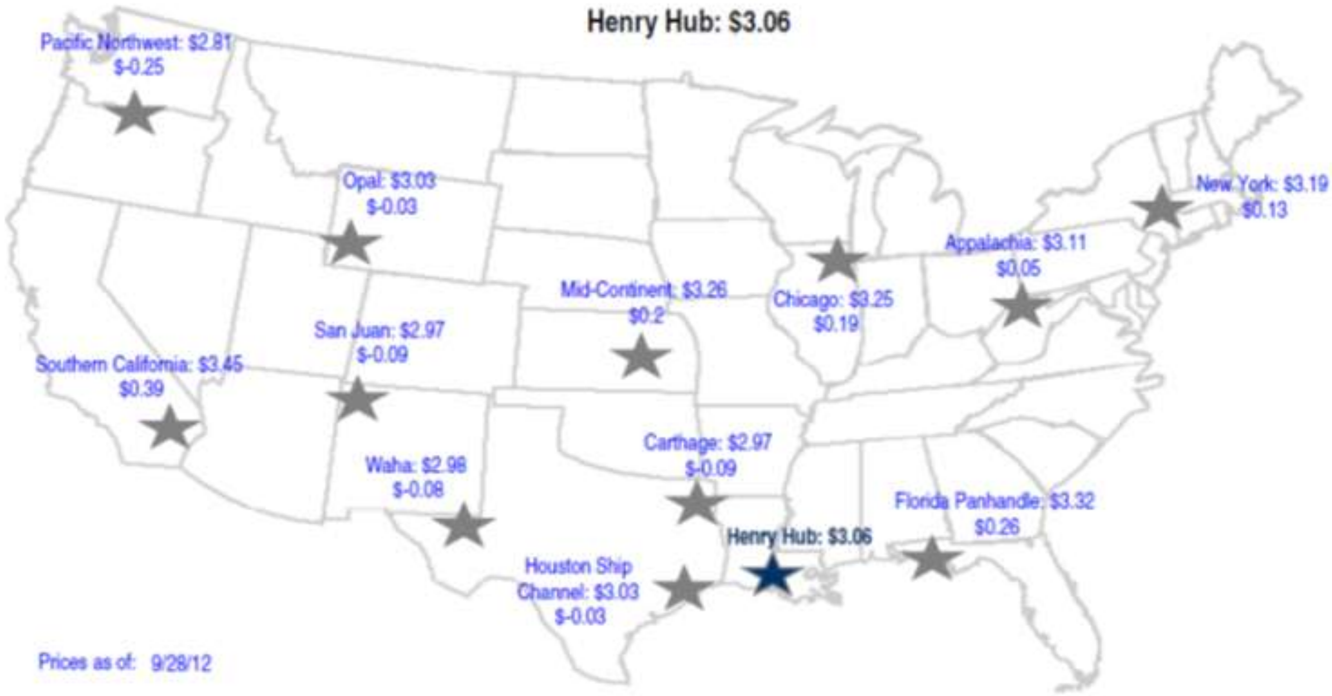
Source: Credit Suisse research.

A considerable amount of the MLP activities are focused in terms of geography. Yet, collectively all of these activities add up to a considerable amount of capital and new asset development. These regional opportunities help create considerable potential value for the MLPs; however, they can be viewed as significant threats for many of the often corporately owned long-haul pipeline assets.

Shale plays both an opportunity and threat for infrastructure companies

The EIA's *Annual Energy Outlook for 2011* projected the total remaining resource base of natural gas to be 2,552 Tcf, which is below that of INGAA's projection of 3,105 Tcf. At current US natural gas consumption, INGAA's figure represents 140 years of supply. The most important part of this supply source is the growth of the relatively new shale plays and the need for increased infrastructure and redirected infrastructure to support new fields. These dramatic changes to the traditional locations of production have played a degree of havoc with natural gas basis differentials as appears in Exhibit 110 below.

Exhibit 110: Natural gas hub prices and basis differentials to Henry Hub ($/MMBtu)



Source: the BLOOMBERG PROFESSIONAL™ service, Credit Suisse research.

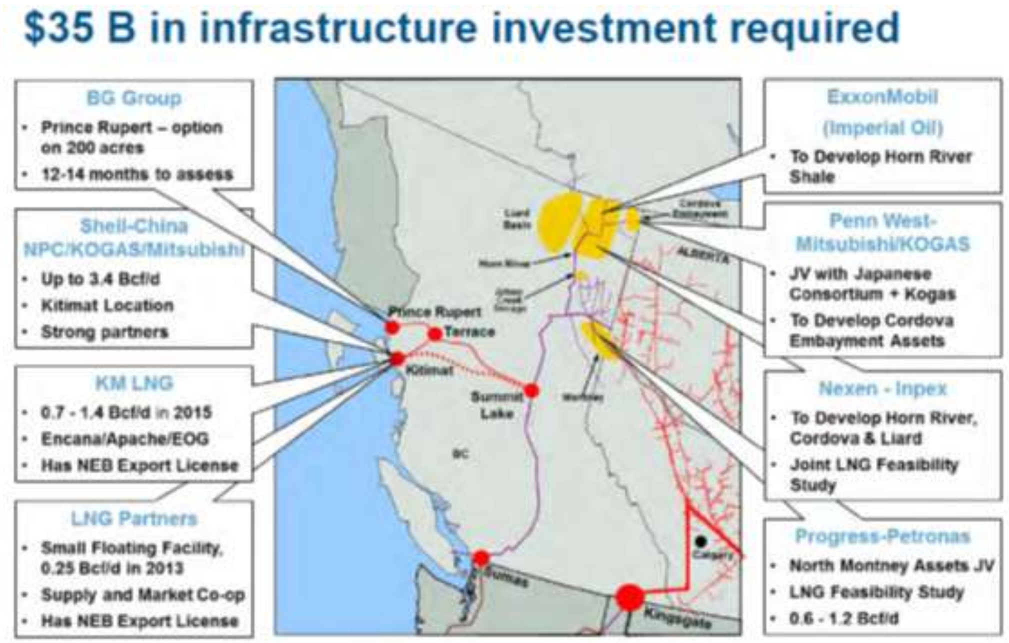
Over a longer period, basis differentials should allow a reasonable return on capital for the infrastructure assets and for the producers. Very wide basis differentials provide an interesting signal for incremental infrastructure investment; whereas, relatively flat basis differentials question the underlying value of existing assets. 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. Clearly, the changes to natural gas flows provide considerable opportunities for greater infrastructure build.

From a strictly Canadian perspective, we believe the infrastructure opportunity to the west coast servicing planned LNG facilities is significant. Some major proposed pipelines include:

- TransCanada's Coastal GasLink project for Shell and partners "to design, build, own and operate" a proposed pipeline transporting Montney region natural gas to a future LNG facility in Kitimat, BC. This proposed C$4bn pipeline would flow more than 1.7 BCF/d of natural gas and be online "toward the end of the decade" after a three-year construction period.
- Spectra Energy's Project Development Agreement with BG Group to jointly develop a new natural gas transportation system with capacity up to 4.2 Bcf/d connecting Northeast BC with a proposed LNG facility in Prince Rupert.

A recent AltaGas presentation provided an interesting perspective on the infrastructure potential in British Colombia appearing in Exhibit 111 below.

Exhibit 111: Investments required in the province of British Columbia



Source: Company data, Credit Suisse research.

In our coverage universe, both Enbridge and TransCanada remain among the largest pipeline companies in North America. From our view, these companies among others like Enbridge Income Fund Holdings are extremely well positioned to capture a percentage of the growth in this asset class over the next decade.

Crude oil shale-related infrastructure

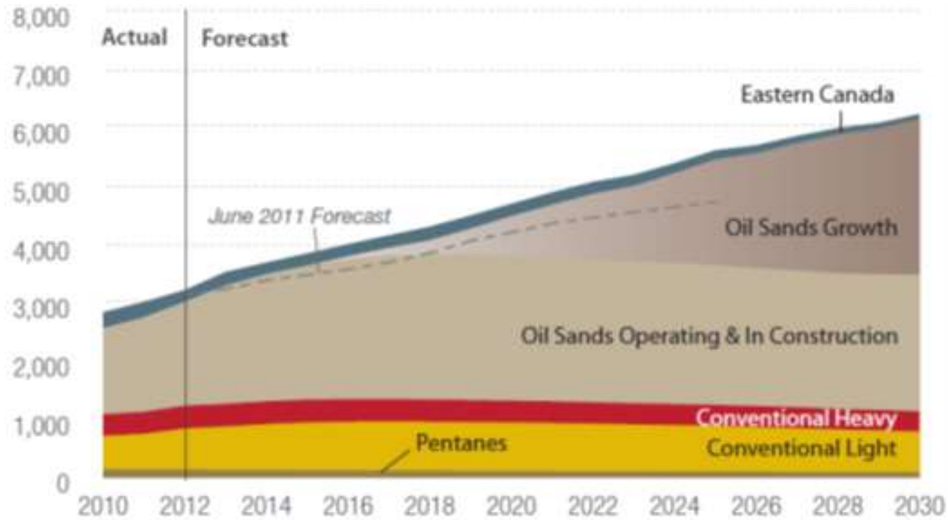
Share oil and oil sands production growth translates into a need for increased infrastructure.

Increased shale development benefits natural gas pipelines along with crude oil pipelines and related infrastructure. Shale oil development and the ongoing development of the Canadian oil sands create a need for more infrastructure assets. For context, unlocking some natural gas shale plays with new technology also benefitted oil-dominated shale developments. The EIA estimated roughly 23.9 billion barrels of shale oil resources are located in the onshore lower 48 states. The three largest shale oil formations include the Monterey field in southern California, Bakken in North Dakota and Eagle Ford.

In our coverage universe, Enbridge and TransCanada are the two main companies for oil infrastructure exposure. A considerable part of the North American crude oil story revolves around Canadian oil sand and basins like the Bakken. An industry forecast from the Canadian Association of Petroleum Producers (CAPP) in the annual *Crude Oil Forecast, Markets & Pipeline* provides an interesting perspective in Exhibit 112.

Exhibit 112: Canadian oil sands and conventional production

Thousand barrels per day



Source: Canadian Association of Petroleum Producers (CAPP).

With the growing production of crude oil from oil sands development as well as new discoveries such as the Bakken, pipeline infrastructure growth can be seen in Exhibit 113, which shows current and expansion projects. A number of projects aim to transport crude to western Canada, eastern Canada and to the Gulf coast.

Exhibit 113: Canadian and US crude oil pipelines

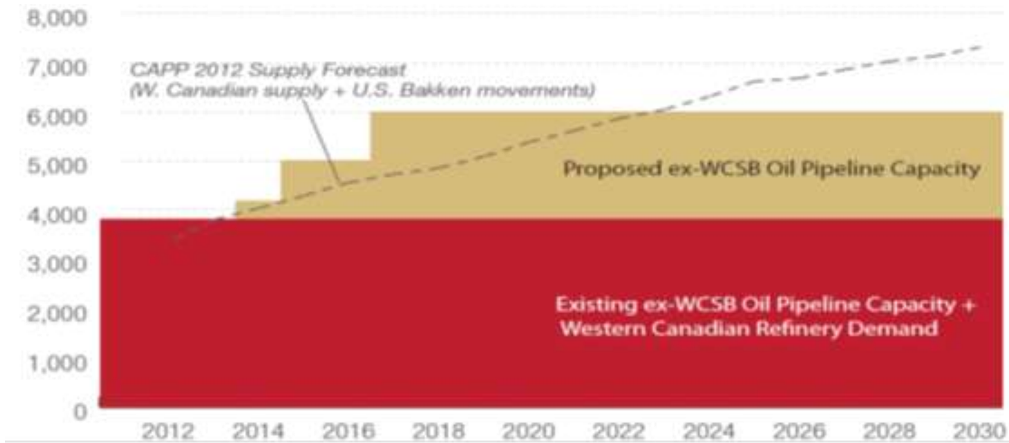
Source: CAPP.

Exhibit 114 illustrates the need for new western Canadian export pipelines by 2014. If currently proposed pipelines are built, additional pipeline based on the 2012 CAPP production forecast won't be needed until 2020.

New pipelines are needed, but delays are problematic

Exhibit 114: WCSB take-away capacity versus supply forecast

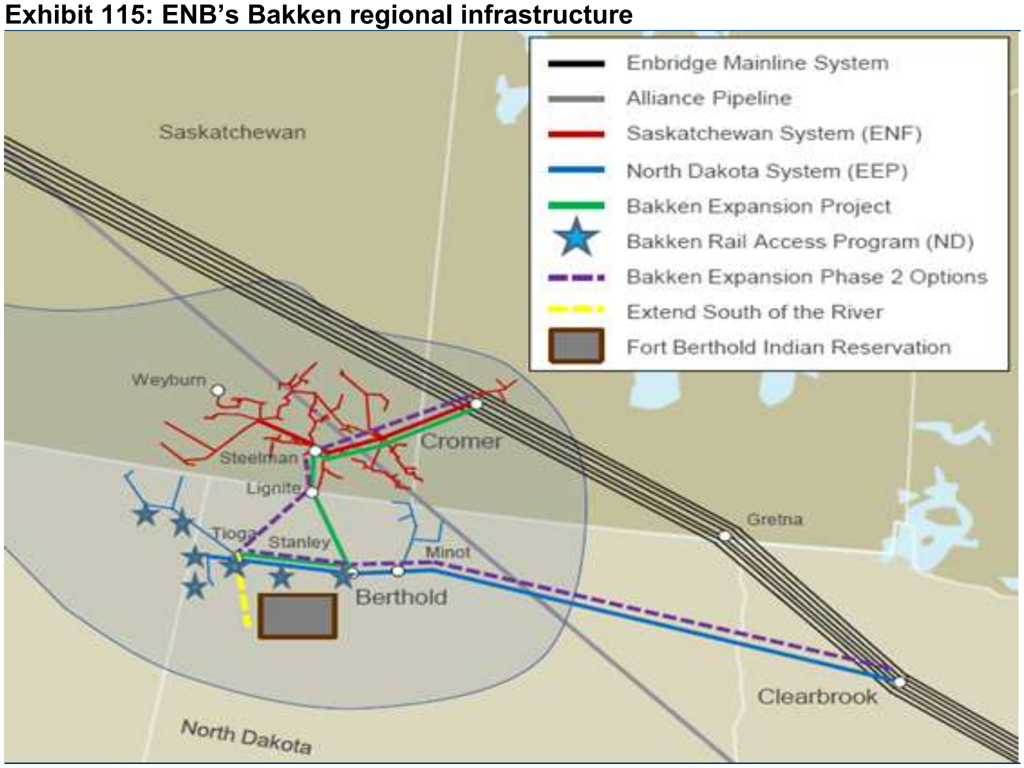
Thousand barrels per day



Source: CAPP.

One of the largest oil shale developments is the Bakken formation. The Enbridge Group of companies and TransCanada are participating in the build out of infrastructure in that area. ENB's Bakken regional pipeline system is located on the fast-growing Bakken shale region of southeast Saskatchewan and Northwest North Dakota. The pipeline network transports crude oil from producing fields to Enbridge's mainline pipeline. Enbridge's Bakken regional pipeline system can be seen below.

Exhibit 115: ENB's Bakken regional infrastructure



Source: Enbridge.

For some perspective on the growth from this basin, on 24 August 2010, Enbridge Income Fund and Enbridge Energy Partners (EEP) made a joint announcement for a joint venture to further expand crude oil pipeline capacity in the Bakken and Three Forks formations. This expansion will cost US$370m for EEP and C$190m for Enbridge Income Fund and will increase take-away capacity by roughly 145,000 bpd. Capacity can be easily expanded to 325,000 bpd at low cost to EEP and Enbridge Income Fund.

Exhibit 116: Expansion projects on the Saskatchewan system

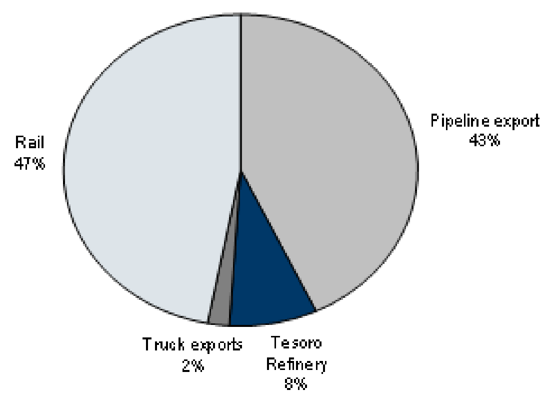
Project	Capacity Increase (bpd)	Capital Costs	In-service
Phase 1	98,000	36	2007
Phase 2	125,000	158	2010
Bakken Expansion Program	145,000 (max 325,000)	190	2013

Source: Enbridge, Company data.

We believe that the continued production growth in the Bakken shale play, regardless if it is in Saskatchewan or North Dakota, will create ongoing opportunities for the Enbridge Group to expand its crude oil pipeline in the region. An example of this would be the current Bakken Expansion Project, which is to take crude oil from Berthold, North Dakota, to Cromer, Manitoba (ENB terminal that connects to Enbridge Inc.'s mainline).

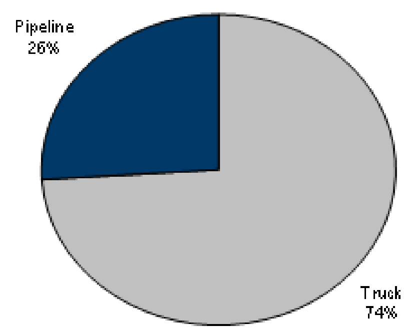
Exhibit 117 and Exhibit 118 illustrate potential opportunities within the North Dakota Bakken shale for pipeline to take market share away from other forms of crude oil transportation. The most economical method of transporting crude over long distances remains through pipeline.

Exhibit 117: Williston Basin oil transport (as of July '12)



Source: North Dakota Pipeline Authority and Credit Suisse.

Exhibit 118: North Dakota crude gathering (as of Feb '12)



Source: North Dakota Pipeline Authority.

Some of the infrastructure trends in the Bakken are somewhat similar to those occurring in other shale basins.

Power pricing implications

In relation to power, an abundance of shale natural gas tends to impact marginal prices. The Canadian market is a bit different than some other jurisdictions for several reasons, including (1) an abundance of hydroelectric generation; (2) the dominance of government owned generation; and, (3) significantly regulated markets. The major Independent Power Producers in Canada have both domestic and international exposure and include: Brookfield Renewable Energy Partners; Capital Power Corporation; and, TransAlta. In our view, relatively low natural gas prices may have a longer-term impact on rather lackluster power prices as portions of less emission friendly generation (largely coal) is transitioned to natural gas generation.

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 overall creating helpful bill reductions for customers. In this section, we analyze the potential impact of shale gas developments on power prices and stock implications for utilities companies across the US, Europe, and Japan.

US switching: still room but gas price dependent

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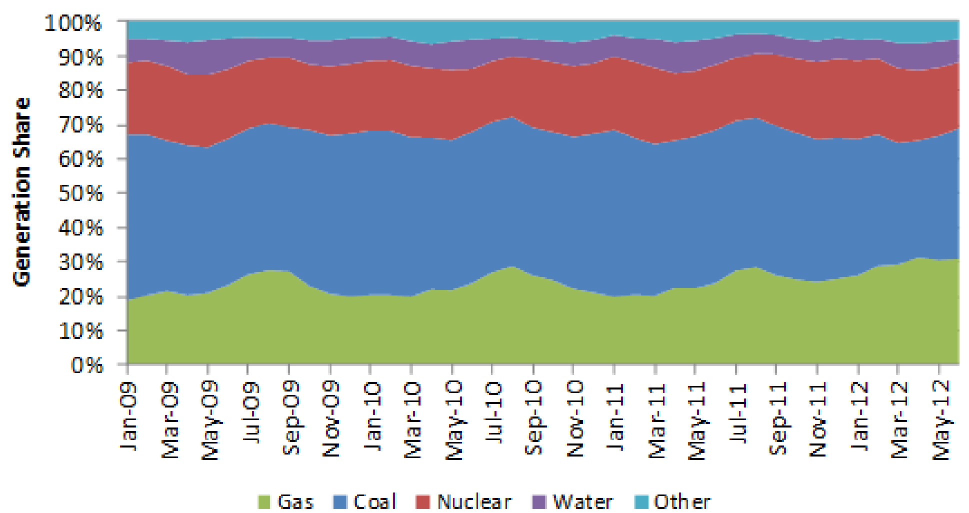
Gas generation attractiveness versus coal

A significant change in power markets over recent years – particularly with the recent weakness in spot natural gas prices – has been the transition to natural gas from coal generation as a competitive, low cost source of power generation. In Exhibit 119, we see the growing market share of gas generation going from 22% in 2009 to ~30% today, mostly at the expense of coal that has fallen to ~35% from ~45%. As we have discussed in other reports, we think this transition will be structurally durable with gas generation remaining a cost competitive resource in power markets into the future.

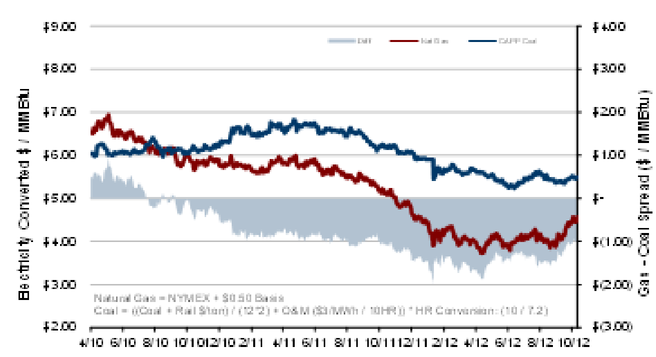
Exhibit 119: Historical US generation market share distribution



Source: EIA data.

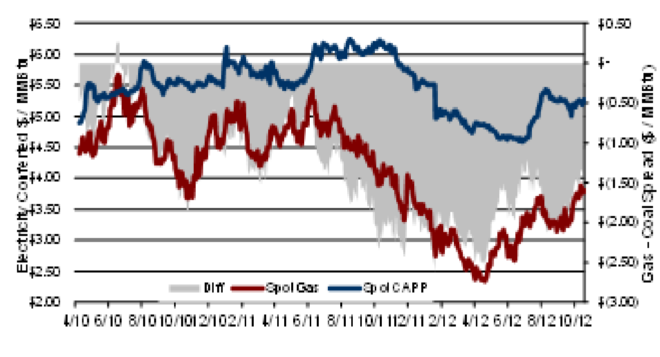
To help put the structural opportunity in context, Exhibit 120 shows the electricity equivalent price of natural gas relative to Central Appalachian coal using 2013 forwards. After natural gas transitioned from being expensive relative to coal to cheap relative to coal in in mid-2010, the spread between natural gas and coal has pushed out to near all-time wides. Looking at Exhibit 121 we show the same math using spot market prices where the spreads have been even more dramatic with the prompt natural gas price weakness.

Exhibit 120: 2013 CAPP coal/NYMEX natural gas parity



Source: the BLOOMBERG PROFESSIONAL™ service.

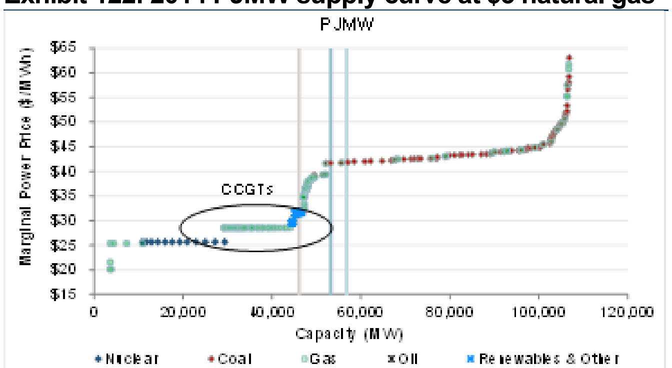
Exhibit 121: Spot CAPP coal/NYMEX natural gas parity



Source: the BLOOMBERG PROFESSIONAL™ service.

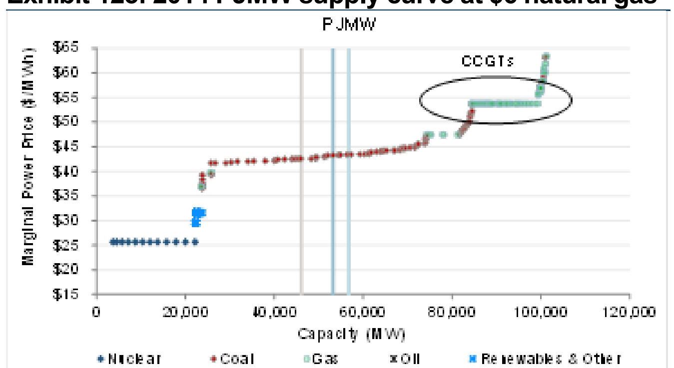
The comparable cheapness of natural gas on an electricity equivalent basis has in turn led to a reorganization of the economic dispatch curves. Looking at our unit by unit build-up of the supply curve in PJM, we see dramatically different dispatch with natural gas at today's ~$3 / mcf (Exhibit 122) versus the curve at $6 / mcf (Exhibit 123). With coal plants represented by the red dots and gas plants by the green dots, gas dispatches ahead of coal at today's prices but shifts to the back of the supply curve if we assume $6 / mcf natural gas.

Exhibit 122: 2014 PJMW supply curve at $3 natural gas



Source: EnergyVelocity

Exhibit 123: 2014 PJMW supply curve at $6 natural gas

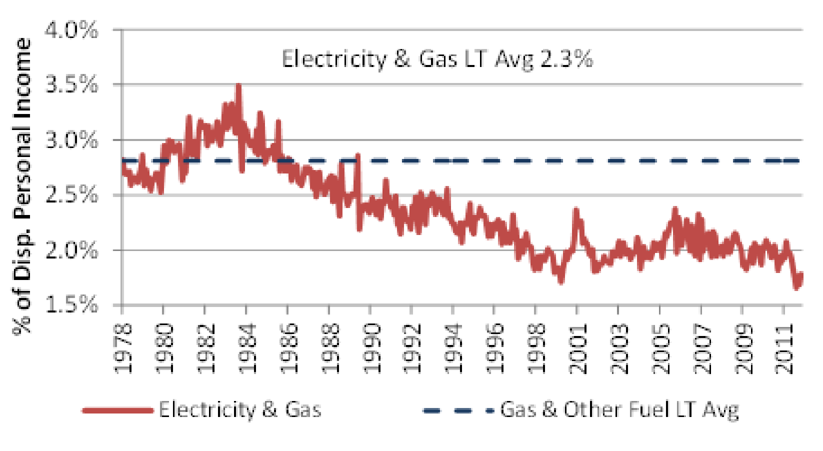


Source: EnergyVelocity

Utilities are benefitting from cheap bills

Spending on utility bills as a percentage of disposable income (a measure of affordability) is currently at historically low levels (Exhibit 124) owing in part to low fuel costs. Low bills have afforded regulators more latitude to maintain healthy allowed ROEs in a lower interest rate environment. However, upward sloping commodity curves for both coal and gas could pressure utility fuel costs and, in turn, customer bills after a wave of fuel cost compression. This coupled with the low interest rate environment could pressure regulated utilities' allowed ROEs.

Exhibit 124: Spending on utility bills as a % of personal disposable income

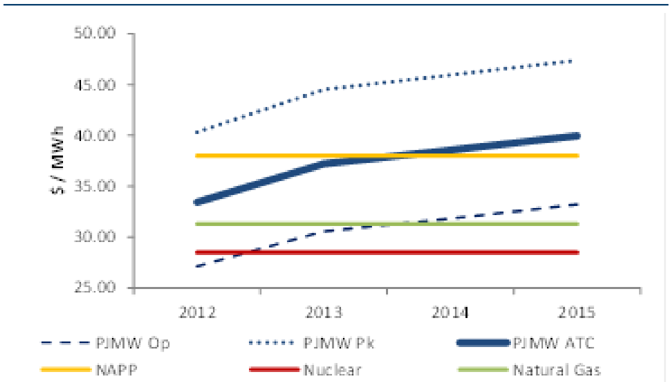


Source: Credit Suisse estimates

But competitive generator economics are challenged

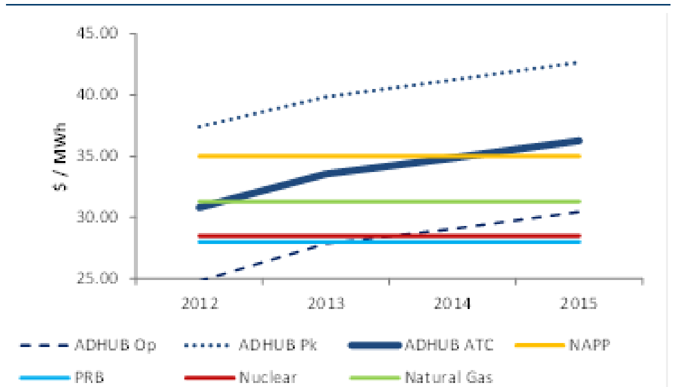
The low fuel cost environment is not helping regulators as low natural gas prices and weak demand have put pressure on power prices. Current forward curves for many markets and hours are not offering positive energy margins (pre-capacity payments) for plants that must run to serve load. In Exhibits 125-127, we show the current forward power price curves for three major competitive power markets with unit operating costs (fuel plus O&M) for different types of power plants captured in the horizontal lines. Looking at the PJM markets we see Appalachian coal plants and even nuclear / PRB burning coal plants capturing negative margins in the off-peak hours with some seeing negative margins on a blended around-the-clock pricing basis (NAPP in AD-Hub and even PJM-W).

Exhibit 125: PJMW power prices and plant economics



Source: the BLOOMBERG PROFESSIONAL™ service.

Exhibit 126: ADHUB power prices and plant economics



Source: the BLOOMBERG PROFESSIONAL™ service.

Exhibit 127: ERCOT Power prices and plant economics

Source: the BLOOMBERG PROFESSIONAL™ service.

European Utilities

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European shale gas and power generation

In 2011, Europe used c381 bcm of gas, c31% of which was used in power generation. Of the c401bcm total volume supplied in 2011A, only c32% came from indigenous production, with the rest supplied through LNG or pipelines. (Total consumption = Total supply + change in inventory.) Russian pipeline accounts for c20% of the supply and the high share of oil-linked contract with Russian suppliers (e.g., Gazprom) means the effective gas input price has been prohibitively high for many European utilities, squeezing their gross margin (we have seen negative Clean Spark Spread for the past year and expect it to continue). The introduction of cheaper sources of supply (i.e., shale gas) could have a noticeable effect on utilities earnings.

The key question is, where would the cost of production be in the merit order? Given the various geological and economical differences Europe faces compared to the situation in the US, we highlight the uncertainties around the cost structure and price of European shale gas. We thus assume in our analysis that shale gas will be sold at a level that encourages coal-gas switching and focus on sensitivity analysis.

Coal – gas switching

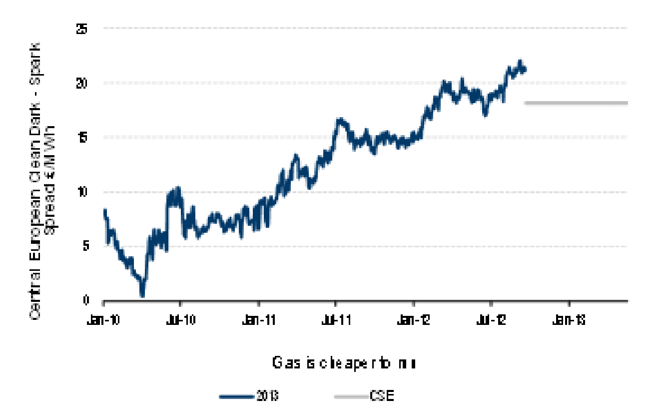
Europe is currently experiencing the “Coal King” phenomenon owing to low coal and carbon prices in Europe. Coal-gas switching will happen if the gas price falls to €18/MWh, which is our base assumption in this analysis.

Exhibit 128 shows the difference between Clean Dark Spread (theoretical gross margin a coal plant can generate) and Clean Spark Spread (theoretical gross margin a gas generator makes) under the current commodity environment and CSE assumptions for 2013E. Currently CDS is c€20/MWh higher than CSS.

We analyze how far gas price needs to fall to cause a coal-gas switch in Exhibit 129. All analysis done under assumptions for CCGT: thermal efficiency = 55%, carbon intensity = 0.38t/MWh. For coal plants: thermal efficiency = 47%, carbon intensity = 0.92t/MWh.

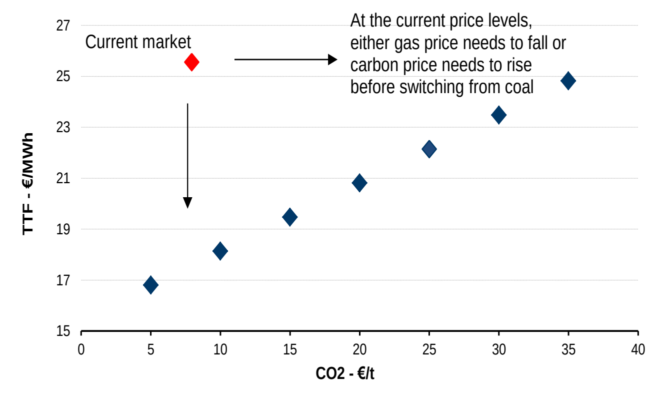
If we assume carbon price stays at the c€8/t level, TTF gas price needs to fall to below €[11]18/MWh before switching starts – we use €18/MWh as a base assumption in the following analysis.

Exhibit 128: Coal King



Source: the BLOOMBERG PROFESSIONAL™ service; Credit Suisse estimates.

Exhibit 129: What it takes to cause switching (2015E)



Source: Credit Suisse estimates.

Impact on demand? Should European shale gas help spot gas price to achieve such low levels, we see a potential 29bcm increase (c25% on 2011A level) in gas demand from European generators.

We arrive at this figure assuming:

- All existing gas plants will be running at a 10% higher load factor versus 2011.
- All existing coal plants will be running at a 10% lower load factor versus 2011.
- No new build decisions are changed.

Implication on carbon

Interplay between commodity (coal / gas) and carbon prices is highly complex. But assuming everything else remains equal, a lower gas price can lead to a lower carbon price

Another key factor in the coal-gas switching equation is the cost of carbon. As a reminder, the low EU ETS cost has been one of the key reasons why CDS has been so appealing in recent months (Exhibit 130) – and the Credit Suisse utilities team expects this to remain suppressed for the foreseeable future.

In our model, given the current forward commodity prices (i.e., without the introduction of European shale gas), carbon prices need to quadruple from the current level to encourage coal-gas switching (Exhibit 131).

However, if we assume European shale gas can drive the gas price down below the coal-gas switching level – i.e., making gas the cheaper method of production (we assume flat €18/MWh in real terms in our calculation), there will be a significant fall in carbon break-even price. This is because the dirty coal generation needs a much lower CO_2 price to equalize the cost of production by gas plants.

We note however, analysis in Exhibit 131 aims to show more of a direction than a precise figure, as our calculation is done on the assumption that everything else remains equal. In reality, this is a highly complex interplay of coal, gas and carbon prices:

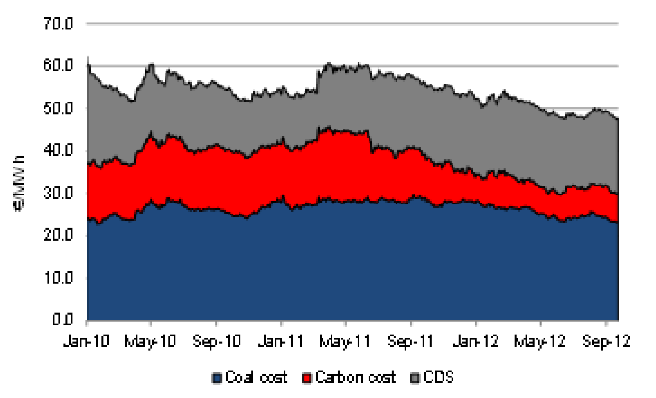
- As gas generation becomes more profitable, demand for gas for power generation will increase while that for coal will fall, leading to a change in gas and coal prices;

[11] According to ENTSOE (European network operators' associate) data.

- The prospect of the abundant supply of cheap shale gas may encourage companies to build more CCGT plants instead of coal plants. With a lower average carbon intensity in the market, carbon price may be very low, which could then benefit dirtier (coal) generators. There is no clear-cut conclusion whether CDS will be below CSS under such circumstance.

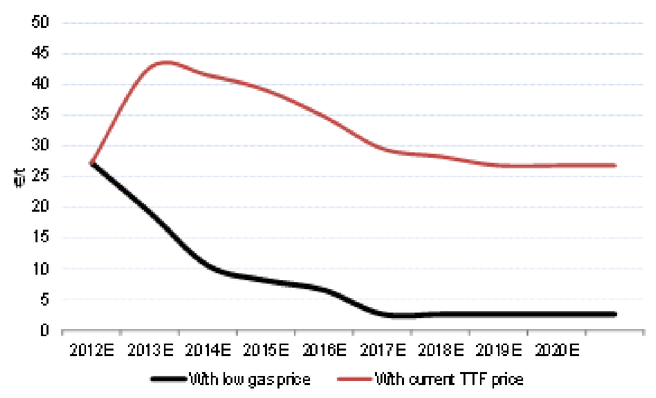
For more details on the implications for carbon, please see Carbon.

Exhibit 130: Falling carbon cost for coal generation



Source: the BLOOMBERG PROFESSIONAL™ service; CS estimates.

Exhibit 131: Breakeven CO_2 price (€/t)

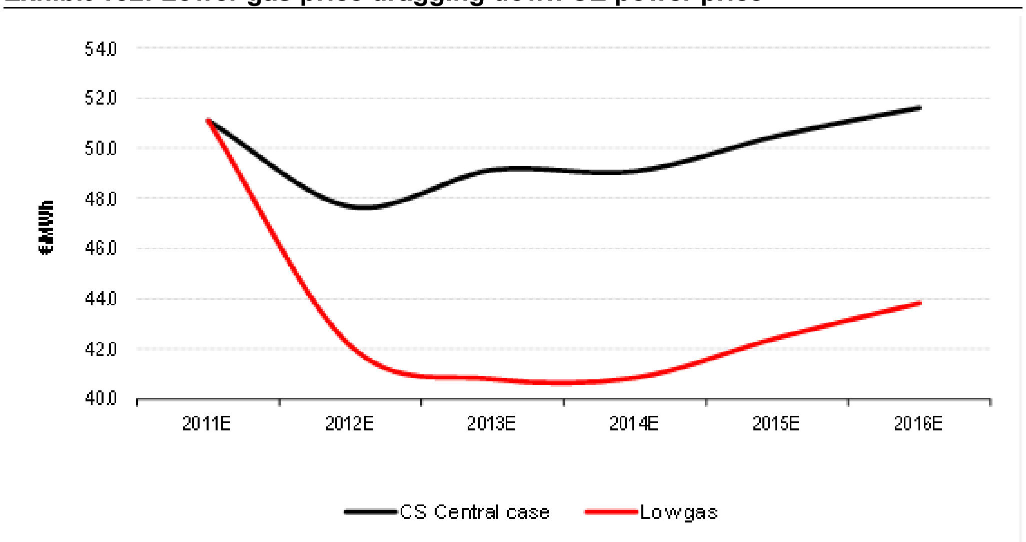


Source: Credit Suisse estimates.

Implication on Central European power price

If we assume the development of European shale gas leads to a low gas price (e.g., the current theoretical coal-gas switching price €18/MWh), this is the implication on power prices – assuming everything else remains the same. Lower gas price could drive down marginal cost of production and thus power price in Central Europe:

Exhibit 132: Lower gas price dragging down CE power price



Source: Credit Suisse estimates.

Exhibit 133 shows Central European power price sensitivity to commodity price movements.

Exhibit 133: Central European power price sensitivities

(Nominal)	2012E	Chge in %	2016E	Chge in %
+/- €1/MWh gas TTF	+/- €1.0/ MWh	*+/- 2.1%*	+/- €1.1/ MWh	*+/- 2.1%*
+/- $5/bbl oil Brent	+/- €0.2/ MWh	*+/- 0.3%*	+/- €0.0/ MWh	*+/- 0.0%*
+/- $5/t coal ARA	+/- €0.4/ MWh	*+/- 0.9%*	+/- €0.5/ MWh	*+/- 1.0%*
+/- €1/t CO2	+/- €0.7/ MWh	*+/- 1.4%*	+/- €0.7/ MWh	*+/- 1.3%*

Source: Credit Suisse estimates.

Implication on European Utilities

The above movements in gas, carbon and power prices will have implications on the gross margins European utilities could make too. Exhibit 134 shows the thermal spreads' sensitivity:

Exhibit 134: Thermal spread sensitivities

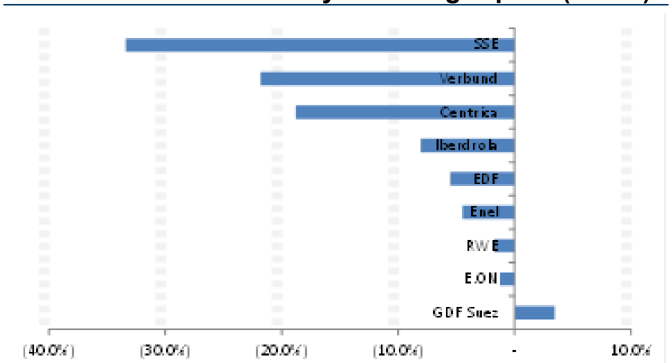
Spreads sensitivities (Real)	Clean Dark Spread (coal)	Clean Spark Spread (gas)	Clean Brown Spread (lignite)
2016E			
+/- €1/MWh gas TTF	+ €1.0/MWh	- €1.0/MWh	+ €1.0/MWh
+/- $5/bbl oil Brent	+ €0.0/MWh	+ €0.0/MWh	+ €0.0/MWh
+/- $5/t coal ARA	- €0.9/MWh	+ €0.5/MWh	+ €0.5/MWh
+/- €1/t CO2	- €0.1/MWh	+ €0.3/MWh	- €0.6/MWh

Source: Credit Suisse estimates.

Given the power prices and gas price assumptions (€18/MWh) from above, we show the stock implications in Exhibit 135 and Exhibit 136.

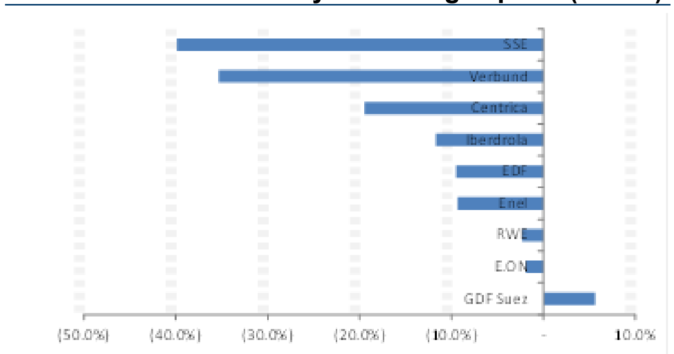
Note that we only take into account the impact on the generation part of the business (i.e., we ignore the impact of a lower gas price on European Utilities' midstream gas business).

Exhibit 135: EBIT sensitivity to lower gas price (2013E)



Source: Credit Suisse estimates.

Exhibit 136: NI sensitivity to lower gas price (2013E)



Source: Credit Suisse estimates.

- The impact of a lower gas price is higher for the UK than Central Europe – mainly because UK is largely a market where gas sets the margin;
- Clean generators (SSE, Verbund) are more sensitive to lower gas prices because they only see the negative impact from lower power prices (and no offsetting lower cost of production).

Clean Technologies

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The abundance of natural gas in the United States (and persistent low prices) is transformative for the clean technology and alternative energy sectors. We see significant implications for alternative transportation given favorable economics behind Natural Gas Vehicles.

We see the following impacts and opportunities:

- **Opportunities increase for biochemical companies**: Chemical markets will continue to see a structural shift towards cracking lighter gases, away from heavy oil, resulting in shortages of C3 and C4-derived chemicals such as butanediol (BDO) and acrylics. Companies have invested in bio-based in technologies that can convert alternative feedstocks, mainly sugars, into these high-value chemicals. Please refer to Chemicals for additional information on the structural shift that is occurring**.** Over the next five years we expect there to be numerous companies that successfully commercialize, at scale, biobased chemicals.

- **The economics of fuel cells continue to improve**: Fuel cells convert natural gas into electricity and are more efficient than traditional generation, while also emitting up to 75% less CO_2. The elevated cost of natural gas and early stages of technology development limited the adoption of distributed fuel cell power plants, but that is likely to change. Technologies are now commercially developed and offer attractive economics for commercial & industrial customers, especially with state subsidies and for customers in elevated retail power price areas (e.g., California) in addition to federal Investment Tax Credits (ITC).

- **Policy response likely to favor natural gas as a potential alternative fuel**: US politicians (and elsewhere over time as resources are developed) are more likely to view natural gas as a potential transportation fuel, or feedstock for fuels, and may adopt favorable policies to encourage its use. In the US, for example, Senator Inhofe (R-OK) introduced a bill to support Natural Gas Vehicles, potentially granting them preferential treatment in the calculation of CAFE standards for automakers. Additionally, legislation has been proposed from Representative Olson (R-Texas) that would allow natural gas-derived ethanol to qualify, at least partially, as a renewable fuel under the Renewable Fuel Standard (RFS) program. While these legislative measures have not resulted in any enacted policy, they do highlight the momentum within the US Congress to favor natural gas.

- **Metering companies and related gas processing companies benefit**: Gas metering companies will continue to benefit from the global gasification trends, providing residential & commercial gas meters to utilities as more gas distribution networks are built. In particular, we highlight Itron (ITRI, Neutral) with 28% of their sales in the gas metrology market. Additionally, Energy Recovery (ERII, Neutral) is in the initial stages of commercializing a device for the gas processing market to reduce the energy costs associated with cleaning sour gas. The product recovers energy that is currently wasted while depressurizing amine fluids in gas processing facilities.

- **Renewable energy (solar, wind, geothermal)**: Price competitiveness of renewable electricity becomes more difficult in the US, absent continued cost declines, as the “grid parity” reference price (typically a gas-fueled power plant) declines. Pricing for utility-scale renewable power likely separates meaningfully from natural-gas sourced power pricing. We believe the separation is sustainable, as long as state-level Renewable Portfolio Standards (RPS) support pricing that is higher than competing fossil-fuel generation. Furthermore, we see the cost declines and efficiency improvements making solar economic over time, especially for distributed generation where high retail rates already make solar cost competitive.

Potential winners

Itron (ITRI, Neutral) is a metering company that should benefit from global gasification trends as more households are connected to gas networks and as more upstream metering equipment is needed for the distribution infrastructure.

Energy Recovery (ERII, Neutral) is currently launching into the gas processing business, their second market. While they do not see any revenues from this venture today, material revenues are to be expected. Energy Recovery is already doing field trials in three continents. Sour gas needs to be cleaned, which is typically done using Amine chemicals, which is very energy intensive. Energy Recovery's product can reduce the energy consumption for gas cleaning by 20-40%; as such, a global boom in natural gas will ultimately benefit them.

Alternative Transportation

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Driving into the oil market

Natural Gas Vehicles are adopted in certain markets based on compelling economics. We believe vehicle fleets will gradually shift to natural gas vehicles in several markets, expanding opportunities for engine technology providers and fueling infrastructure companies in the clean technology sector. The primary driver of the adoption is based on favorable economics of natural gas fuels relative to diesel and, in some cases, gasoline.

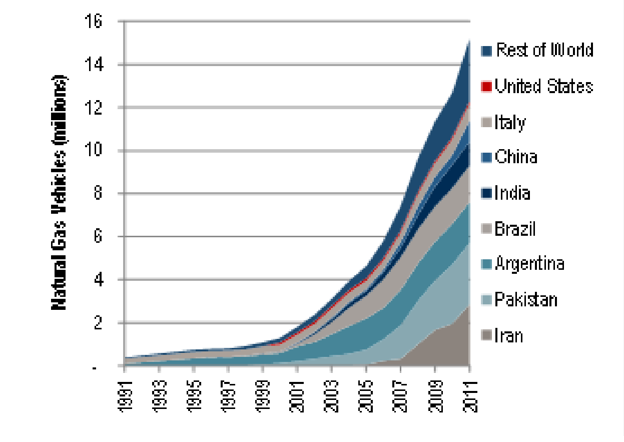
We estimate a two- to four-year payback period for Natural Gas Vehicles (NGV), based on an economic model that varies truck class, annual mileage, and incremental equipment/engine costs. The potential adoption of natural gas vehicles in the United States should not be overlooked – other countries have already made the switch (Pakistan has nearly 2.9 million natural gas vehicles – or 64% of the fleet) and there are already 15.2 million NGVs in use globally according to the industry association NGVA.

Based on our analysis, the US market could gradually adopt Natural Gas vehicles adding to 3.7 bcf/day of natural gas demand (nearly a 6% increase relative to 2011 demand) and offsetting 32 million gallons per day in gasoline and diesel consumption by 2020, driven primarily by only 20% adoption within the heavy-duty trucking segment and 33% adoption in niche markets such as refuse collection. This trend is underway, with more than 120,000 NGV vehicles on US roads today and new natural gas engines being introduced by Westport Innovations (WPRT, not covered). Companies are aggressively investing in both LNG and CNG fueling infrastructure across the country, led by Clean Energy Fuels (CLNE, not covered) and Shell.

Perhaps the most far-reaching break-through in terms of energy use could stem from fuel switching in transport applications. The abundant supply of domestically produced natural gas offers an attractive economic and geopolitical solution to switch transportation fuels for many countries. Globally, there are already 15.2 million NGVs in use according to the industry association NGVA. Pakistan has nearly 2.9 million NGVs which represents 64% of their vehicle fleet.

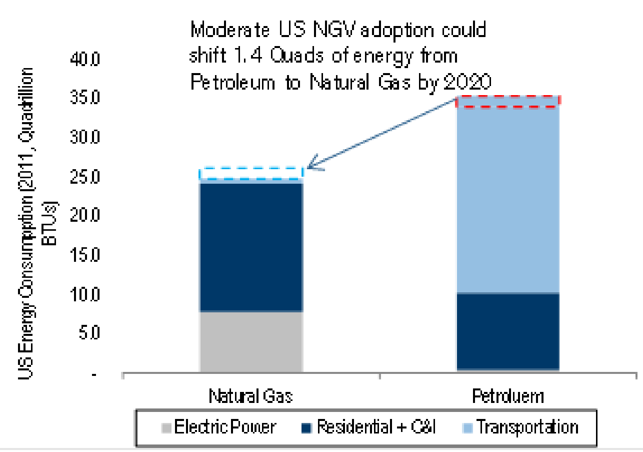
We see the United States as the next market to adopt NGVs for several specific markets, while Europe remains focused on smaller niche markets. China, and Asia broadly, remains a wild card, largely dependent on the ultimate domestic supply of natural gas and government policies.

Exhibit 137: Current global natural gas vehicle penetration



Source: NGV Global, Credit Suisse estimates.

Exhibit 138: A moderate switch in the US could boost natural gas demand 5.5%



Source: EIA, Credit Suisse estimates.

Compelling economics driving adoption in the United States

The US is already a profligate user of gasoline in vehicles, but shifts to natural gas could take place, especially in fleet cars, long-haul trucks, and buses. The primary driver of NGV adoption in the United States is based on favorable economics of natural gas fuels relative to diesel and, in some cases, gasoline.

We estimate a two- to four-year payback for NGVs, based on an economic model that varies truck class, annual mileage, and incremental equipment/engine costs. We do note, however, that the incremental pricing for natural gas engines and onboard storage tanks is still estimated. The economics of low-mileage consumer vehicles are less attractive given the high incremental cost of fuel storage and the engine and are unlikely to switch in the near term.

Exhibit 139: Natural Gas is among the least expensive energy sources…and relatively cleaner

LNG is $3/gallon less expensive than diesel….	$/MMBTU	$/Gallon Diesel Equivalent
Natural Gas (wellhead)	$ 4.50	$ 0.58
+ Pipeline & Delivery Cost	$ 2.50	$ 0.32
+ Liquefaction, Infrastructure, Margin + Tax	$ 1.35	$ 0.18
Total Natural Gas Fuel Costs	**$ 8.35**	**$ 1.08**
Current Retail Diesel Costs		$ 4.08
LNG discount to Diesel - %		(73)%
LNG discount - $/gallon		$ (3.00)

And Natural Gas is relatively cleaner as a fuel….

Emission Reductions:

- Carbon monoxide (CO) by 70%–90%
- Non-methane organic gas (NMOG) by 50%–75%
- Nitrogen oxides (NOx) by 75%–95%
- Carbon dioxide (CO2) by 20%–30%

(source: NGVA, note: Emission reductions relative to in-use vehicle)

Source: Credit Suisse.

Exhibit 140: Compelling economics to switch with less than three-year paybacks in most price environments

Wellhead Natural Gas:	1.65	3.15	4.65	6.15	7.65	9.15
Payback (years) / Diesel Price at Pump ($/gallon) — Total Natural Gas Fuel Costs (fully loaded, LNG) ($/MMBtu)	5.50	7.00	8.50	10.00	11.50	13.00
1.50	12.9	33.8				
2.00	5.4	7.3	11.1	23.9		
2.50	3.4	4.1	5.1	6.7	9.8	18.5
3.00	2.5	2.8	3.3	3.9	4.8	6.2
3.50	2.0	2.2	2.4	2.7	3.1	3.7
4.00	1.6	1.8	1.9	2.1	2.3	2.6
4.50	1.4	1.5	1.6	1.7	1.9	2.1
5.00	1.2	1.3	1.4	1.4	1.6	1.7
5.50	1.1	1.1	1.2	1.3	1.3	1.4

Green shading indicates payback periods of less than 3 years

Payback reflects Class 8 truck with $60k incremental truck cost, 100k miles/yr

Source: Credit Suisse.

US politicians also taking note are more likely to view natural gas as a potential transportation fuel and may adopt favorable policies to encourage its use. For example, Senator Inhofe (R-Oklahoma) introduced a bill to support natural gas vehicles, potentially granting them preferential treatment in the calculation of CAFE standards for automakers. Additionally, legislation has been proposed from Representative Olson (R-Texas) that would allow natural gas-derived ethanol to qualify, at least partially, as a renewable fuel under the Renewable Fuel Standard (RFS) program. While these legislative measures have not resulted in any enacted policy, they do highlight the momentum within the US Congress to favor natural gas transportation.

Infrastructure and engine availability affect timing of US adoption

Public natural gas refueling infrastructure in the United States is still small (<1% of total gas stations in US) in spite of lower natural gas prices due to the classic chicken & egg quandary – what comes first, the vehicles or the fuel infrastructure? In reality, both are being developed in lock step, likely reaching a tipping point by the end of 2013.

- **Engine companies,** mainly Westport Innovations and Cummins, are actively developing natural gas engines for truck manufacturers. Cummins Westport introduced a 8.9 liter engine which was widely adopted by OEMs for refuse trucks. A larger 12 liter is expected to be launched in 2013 for Class 8 trucks. Westport also has a division offering conversion kits and services and has introduced an engine for Ford F250 vehicles with an assembly center that can support 20,000 vehicles/year.
- **Infrastructure companies** are preparing for these customers are in the process of developing a nation-wide fueling infrastructure. There are really two types of infrastructure: Compressed Natural Gas (CNG) which is common for light duty vehicles and municipal busses, for example. The second type is Liquefied Natural Gas (LNG) stations, which will be used for trucking applications given the requirements for longer range. Clean Energy Fuels (CLNE, not covered) is a leader in both, having a large presence for fleet & airport fueling stations while also building LNG stations throughout the United States. Clean Energy Fuels currently has ~300 CNG fueling stations and 22 LNG stations and plans to have 150 LNG stations built by the end of 2013.

Exhibit 141: Natural gas engine availability

NGV Engines & Complete Vehicles	Date
Cummins-Westport - 9L Engine	Available as of 2007/2008 (ideal for refuse trucks)
Westport - 15L Engine	Available as of 2006
Cummins-Westport - 12L engine	Launching 2013
Westport - 13L engine	2014
Cummins-Westport Engine	2015
Chrysler Pickup truck / Ram 2500	4Q 2012
GM Ford F250 Truck	4Q 2012
Mack Trucks	2013

**Excludes all conversion kits & buses, which have been commercially available for 10+ years*

Source: Credit Suisse.

Exhibit 142: Natural gas fueling infrastructure

LNG Infrastructure	Notes
Clean Energy Fuels at Pilot Flying J Stations	22 completed June 2012; 70 by end of 2012 & 150 in total by the end of 2013 (announced Jan 2012)
Shell at TravelCenters of America	100 stations operational in 2013; MOU announced June 2012
CNG Infrastructure	
GE / Chesapeake	CNG Fleet Equipment
Atlanta Gas Light Company	City Gas Station
New Jersey Natural Gas (pilot project)	Fleet Gas Station
Trillium CNG (Integrys Energy Group)	Highway Gas Station
DeBartolo / Chesapeake (pilot project)	Highway Gas Station
Nopetro	City Gas Station

Note: In total, there are 910 CNG fueling stations in the United States according to the Department of Energy (Clean Energy operates ~300+ stations)

Source: Credit Suisse.

- **Transportation companies** in the United States are taking note and are starting to consider Natural Gas Vehicles. We recently met with senior management at FedEx, who said that the company is piloting several LNG-powered tractors in its Freight division (long-haul, over the road, line-haul movements in the LTL business). The company said it was too early to tell what the payback period would be, as the pilot had just started and the price of the tractors would have to be negotiated based on the volume of tractors purchased.

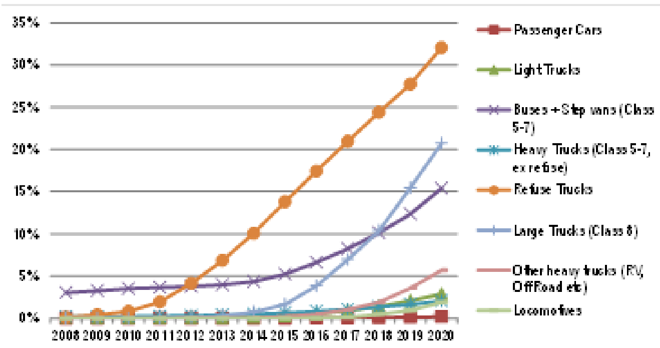
- **Railroad operators** are also open to considering LNG powered locomotives, "when the time is right." On its 3Q12 earnings call, CSX's operating chief said that the company currently is piloting LNG locomotives and remains open and flexible to studying the viability of this alternative fuel. Additionally, Caterpillar recently announced its intention to launch LNG-powered locomotives in 2015.

Central scenario envisions 3.7 bcf demand from US transport by 2020

Based on our analysis, the US market could gradually adopt Natural Gas vehicles adding to 3.7 bcf/day of natural gas demand (nearly a 5.5% increase relative to 2011 demand) and offsetting 32 million gallons per day in gasoline and diesel consumption by 2020, driven primarily by only 20% adoption within the heavy-duty trucking segment and 33% adoption in niche markets such as refuse collection.

Exhibit 143: Gradual adoption in the US is expected over the next decade, mainly from Refuse trucks, large trucks, and buses…

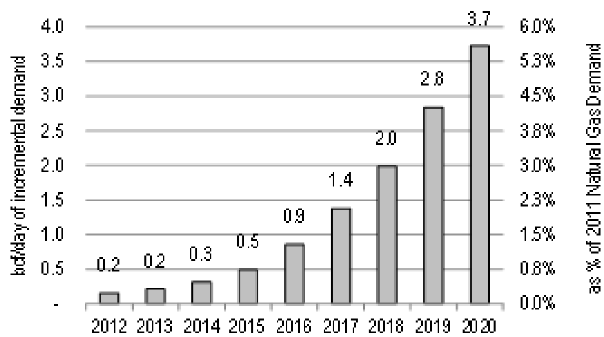
% of vehicle feet converted by transport class



Source: Credit Suisse.

Exhibit 144: …which would result in 3.7 bcf/day of NG demand and displace 32 mgd of gasoline & diesel demand by 2020

% of vehicle feet converted by transport class



Source: Credit Suisse.

Adoption in Europe possible, but less likely, in our view

Wide-scale adoption of Natural Gas Vehicles in Europe is not prevalent today and, in our view, is unlikely to take place in the medium term.

In Europe, we view governments' desires to curtail emissions as the primary driver for supporting any natural gas vehicles. However, there is an absence of legislation at both a national and regional level, whilst infrastructure investment would likely require some government support, at least initially, which we view as unlikely given on-going austerity measures.

Yet there are exceptions. In Italy, NGV's have gained market traction initially as a consequence of government incentives and more recently as consumers look to reduce fuel bills, following increases to tax rates on gasoline/diesel. Meanwhile, in Germany there are estimated to be >900 NGV fuelling stations, following government policy at the beginning of the century, providing a sound infrastructure network; yet less than 1% of the vehicle fleet is estimated to run on natural gas.

While stringent CO2 targets in Europe potentially offer an opportunity for higher NGV penetration going forward, most OEMs are looking to meet these targets through advanced gasoline and diesel engines. Meanwhile, hybrids and electric vehicles seem to be the secondary technologies which OEMs are turning to in their endeavors to bring down weighted fleet emissions averages.

As a result, NGV applications in Europe are largely the preserve of municipal schemes, where cities have introduced fleets and infrastructure to support NGV's including buses and vocational vehicles. In addition, the availability of dual-fuel engines for heavy duty vehicles has proven an attractive option for select operators.

Moderate adoption in China likely

China is also a compelling market for Natural Gas Vehicles, primarily due to government programs and considerable coal-bed methane resources. China has set ambitious goals for Natural Gas Vehicles, including targeting 40-50% of taxis and buses and by establishing programs in a handful of cities. To date, China has more than 1.1 million NGVs and engine manufacturers are targeting heavy-duty markets. For example, Westport Innovations formed a joint venture with Weichai Power to produce and sell natural Gas Engines in China. The facility capacity was doubled this year to support up to 40,000 engines annually.

The main bottleneck, in our view, remains the high upfront capital costs for LNG heavy duty trucks and limited infrastructure, but we would not be surprised to see the market develop over the next five years.

Selective adoption in India

Historically, adoption of NGV in India has been driven mainly by judicial intervention. In its two largest cities, Mumbai and Delhi, the entire public transport infrastructure has been converted to gas. And seeing the benefits in these two cities, more cities have gone the CNG route with over 60 cities currently introducing CNG vehicles for their public transportation. With the rising fuel prices and given the cost conscious nature of the Indian consumers a number of private vehicles have also converted to gas. Maruti, India's largest car manufacturer, has had reasonable success with its NGVs as gasoline prices have increased sharply. Gas adoption in the western part of India, where gas availability is better, has been very good.

With India being a gas deficit country, we believe current adoption of NGVs by more cities in India is restricted by availability of gas. Once gas availability improves the share of NGVs will register a sharp increase. India already has over 1m NGVs and until about 2009 was adding ~0.3m vehicles p.a. Growth in number of NGVs has been very weak in recent years but once gas supply improves NGV growth should definitely pick up again. CNG cylinder manufacturing company, Everest Kanto Cylinders, may benefit from such a pick-up, but this would be very small in nature.

Denso already develops/supplies fuel injection systems for current niche NGV demand, but the business scale should be small. There are only small differences between normal gas injection systems and NGV systems; however, once the OEMs start enrollment of NGVs, current suppliers for NGV systems could also increase volumes.

Steel and Mining

The impact of natural gas in the steel industry could be significant. Meanwhile, within the miners, the US has already endured the pain of a shale gas revolution in their domestic market and, there is now the potential for miners in other regions to see their coal products pushed out by gas. That said, coal to gas switching outside of the US is more a story for 2020 and beyond than a realistic prospect for the next couple of years. As such, while US producers are likely to remain under pressure in their domestic market, export opportunities should continue to offer them some source of solace.

Steel

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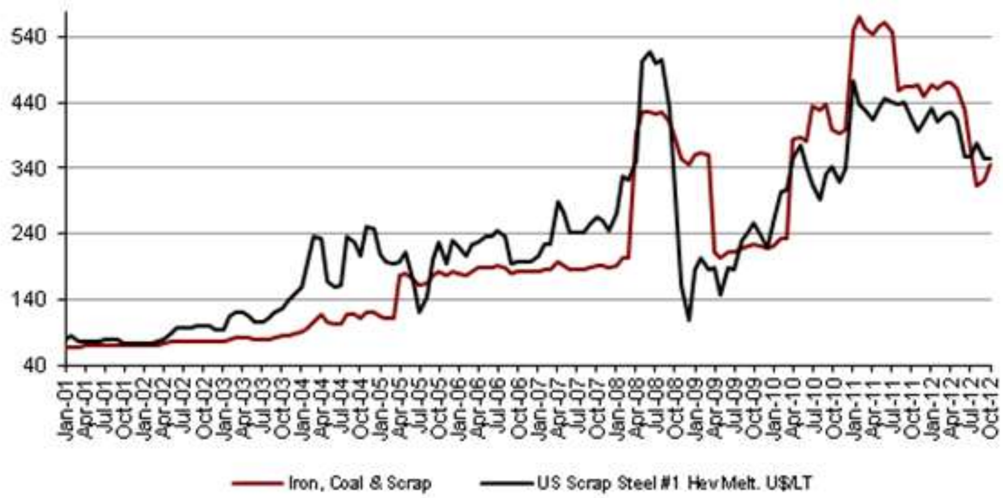
On the demand side steel pipes used in the casings for wells, and extraction of gas continue to be major beneficiaries to the likes of Vallourec and Tenaris.

Exhibit 145: Cost of steel making through scrap route and traditional BoF route



Source: Company data, Credit Suisse estimates.

Benefits are not just limited to the demand side. In effect steel is the reduction of iron using energy – the iron units can come from iron ore or scrap, and the energy units come from

1) Coal in the Blast furnace
2) Electricity (Electric Arc furnace)
3) And (more rarely but perhaps increasingly so in the future) gas, through the direct reduced iron (DRI) route for Arc furnaces and
4) Injection of gas in the blast furnace, which combined with PCI can make a cheaper substitute for coke (a derivative of coking coal)

Currently, the effective input costs (Electric Arc Furnace [scrap] versus Blast furnace [ire plus coal plus scrap]) are broadly similar, so a shift in the dynamic of a "new" route could lead to significant savings

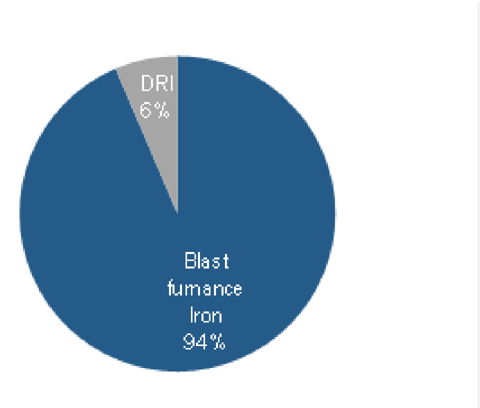
Steel makers can benefit from using "cheap" natural gas in the steel making process with potentially material savings. Key equations are the price of gas plus PCI versus the price of purchased coke, plus of course the capital cost of changing the injection of fuel into the blast furnace. In the arc furnace route, the cost of DRI (gas plus iron ore including the capital cost of a DRI facility) versus scrap is the key equation.

Current landscape – global versus the US

Year to date, DRI production globally (9m to September) was 42mt (according to WSA data) compared with a BOF iron unit production of 841mt and total crude steel output of c1.02bn tonnes – i.e., DRI as of now is a tiny part of the global steel making process.

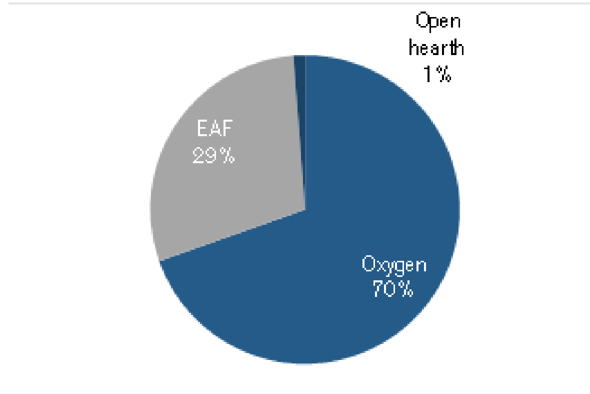
The EAF method of steel output accounted for 29% of the total steel production globally. This is relatively heavily skewed to the US where c55% of output is EAF driven. Perhaps important longer term, China produces steel almost entirely through the blast furnace route. The potential to change over the long term, however, is significant if gas prices remain low in the US and shale gas leads to lower gas prices elsewhere in the world.

Exhibit 146: DRI/BF – global iron ore production (2011)



Source: WSA.

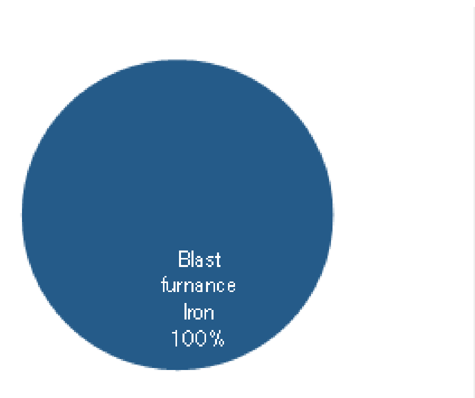
Exhibit 147: Global steel prodn by type (2011)



Source: WSA.

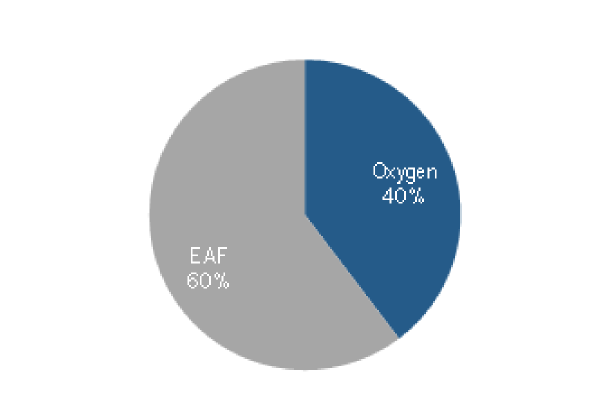
Looking at the US in particular detail DRI production was nil in 2011 versus BOF iron production of 30mt.

Exhibit 148: DRI/BF – US iron ore production (2011)



Source: Company data, Credit Suisse estimates.

Exhibit 149: US steel production by type (2011)



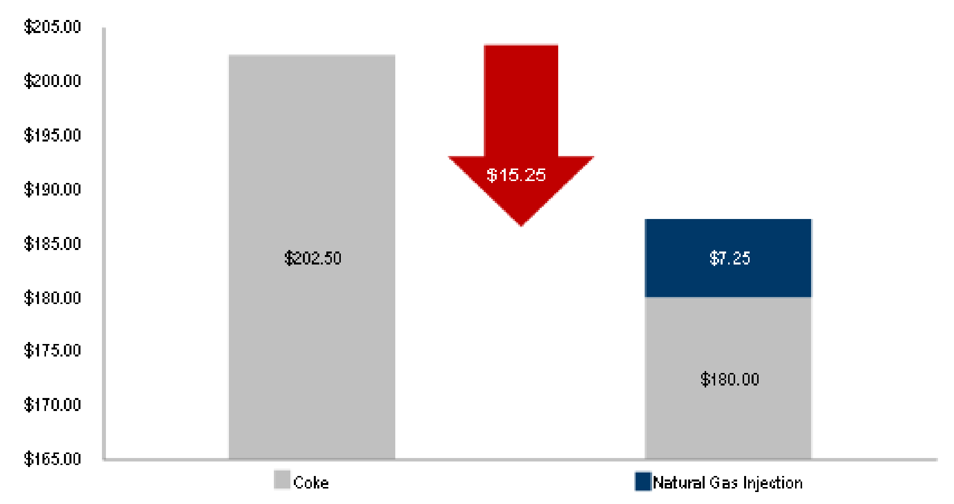
Source: Company data, Credit Suisse estimates.

Both US steel and Nucor have however announced plans to benefit from cheap natural gas, with the latter in the middle of construction of a DRI site by mid-2013.

US Steel (X, Neutral): X has not yet approved any specific projects or timelines to benefit from higher natural gas usage.

According to X, the potential benefit of replacing Coke (up to 100 lb/hot metal) by nat gas could be ~$15/short ton

Exhibit 150: Reduction in blast furnace fuel cost per ton of hot metal



Source: Company data,
*Assumes Coke at $450/ton. Injection Coal at $150/ton, Natural Gas at $4/MMBtu, and 100 pound reduction in Coke used per ton of hot metal.

Nucor (NUE, Outperform): NUE is one of the largest minimill (EAF only) steel producers in the world, and as a result has been at the forefront of pushing forward on utilizing the cost benefits of lower natural gas through the construction of a new DRI facility in Louisiana. Nucor is targeting self-sufficiency of one third of its scrap needs (6-7m tons), which if NUE proceeds with both Phase one and two at Louisiana will get it there.

No stranger to DRI, NUE currently has the most exposure to DRI among the US steel producers, with its recently expanded 2 million ton DRI facility in Trinidad, and its multi-phase DRI project in Louisiana.

Louisiana DRI project is a game changer: NUE is currently in the middle of construction of its new DRI facility in Louisiana, with the first phase to produce 2.5m short tons of iron at a capital cost of $750 million. NUE also has a second phase of the project permitted, allowing for construction of a second DRI plant on the site taking total capacity to 5.0 million short tons). Phase One of the Louisiana DRI plant is expected to be completed by mid-2013, with Phase 2 likely completed by 2014-15 if NUE proceeds soon after Phase One.

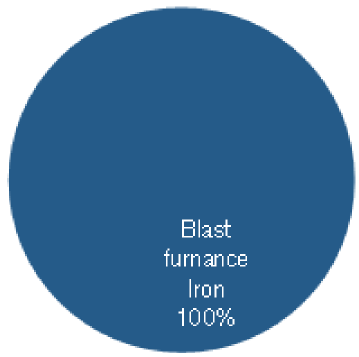
NUE has entered a joint venture agreement with one of the largest natural gas producers in North America (partner not disclosed), which essentially hedges the cost of natural gas needs. The partnership allows NUE to (1) buy at cost plus (the asset is still competitive at current prices) (2) There are no upfront investments needed and (3) the drilling can be terminated if gas prices go lower (i.e., a “pay as you go” capital investment). The capacity will generate sufficient low-cost natural gas to hedge gas usage of Phase One for 20 years.

By our estimates, DRI is a lower cost substitute if scrap prices are above $300/t-$350/t. We estimate that at $100/tonne Iron ore and $3MMBtu nat gas, the estimated saving would be ~$110/s.ton.

China

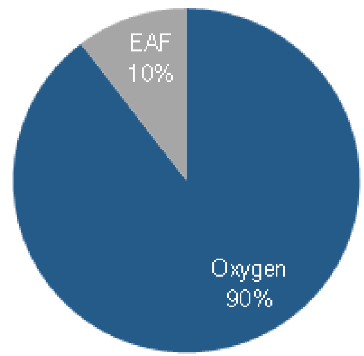
The shale revolution will only ever take off in steel-making if China (the world’s most significant steel producer) goes down this route. Currently, all iron units produced in China are through traditional methods, and there is very limited production of steel via the EAF route. A shale revolution would require significant investment therefore. But this could significantly change the dynamic, especially for the use of metallurgical coal in the steel making process relative to natural gas.

Exhibit 151: DRI/BF – China iron ore production (2011)



Source: Company data, Credit Suisse estimates.

Exhibit 152: China steel production by type (2011)



Source: Company data, Credit Suisse estimates.

The operating cost savings

Below, we show data from Nucor estimating that the saving in producing an iron unit through the DRI route is c $152/s.ton versus. traditional BoF in North America. However, adjusting for other savings and use of Natural gas alongside PCI to substitute for 40% of coke usage, the saving is $82/s.ton.

Exhibit 153: Worked example – BOF versus DRI

$/ton	Blast Furnace	DRI
Iron Ore (62% FE, FOB Brazil)	$100	$100
Pellet Premium	$30	$30
Iron Premium (BF = 65% Fe & DRI = 68% Fe)	$9	$18
Freight	$25	$15
Iron Ore Consumption (BF = 1.6 ton & DRI = 1.5 ton)	$262	$245
Cash Conversion Costs	$70	$35
BF Reductant (100% coke)	$144	
DRI Reductant (11 mmbtus @ $4)		$44
Iron Unit Cost	$476	$324
BF with sinter plant cost savings	$30	
BF Cost Savings By Substituting 40% of coke usage with PCI & natural gas	$26	
BF Higher "Value-In-Use" Benefit	$15	
"Adjusted" BF Iron Unit Cost	$406	

Source: Company data, Credit Suisse estimates.

Capital costs: is it worth it?

In concept, using the above math is compelling. Constructing a 2.5mt DRI facility costing US$750m to construct would save an annual US$380m – in effect a two-year payback. That said the issue then becomes the longer-term structural dynamic of how ore, scrap coal move in relation to changing uses in steel making. Also of equal importance is the potential capital cost of the front end steel capacity. Nucor is an EAF producer of steel, so the switch makes sense in terms of DRI versus scrap. But an existing BoF producer or a new entrant would require the capital cost of a new EAF also.

In principle, if more gas and iron ore are used in the steel making process, then all things equal:

1) Iron ore prices should rise
2) Scrap prices should fall
3) Met coal prices should fall
4) And as such the traditional blast furnace route of making steel (Ore plus coal plus scrap) should in principal become lower cost thanks to the fall in coal and scrap prices.

That said the savings look so compelling that it is hard not to believe capital is likely to be increasingly invested in DRI capacity in regions where cheap natural gas and iron ore are plentiful.

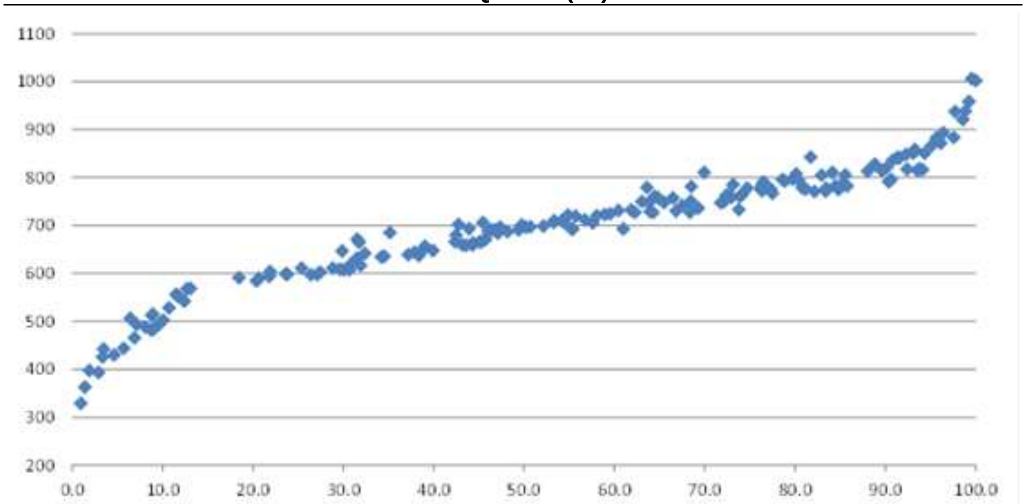
It is worth noting also that the capital cost of a DRI and EAF facility combined (we estimate at around US$750/t for an EAF and US$300/t for a DRI facility or just over US$1000/t in total) remains substantially lower than the capital cost of a Blast furnace (c US$1500/t) so for new entrants with access to natural gas the equation makes a lot of sense.

While there are unlikely to be any new entrants into the US market (it is a very mature steel market arguably in structural decline), China and the emerging markets are likely to go through an on-going period of capacity growth and a significant period of upgrading of obsolete and inefficient facilities so again the shale gas revolution long-term is most likely to change the dynamic of the cost curve and raw materials over a much longer term.

Can savings be kept?

The above analysis is all contingent on savings being able to be kept. If savings cannot be kept (i.e., the whole global cost curve falls as cos switch to nat gas), there remains little incentive to try and cut costs and to that extent, shale gas may not be the revolution that it could be for US steel producers.

Exhibit 154: Global steel cost curve HRC Q4 2011($/t)



Source: MBR.

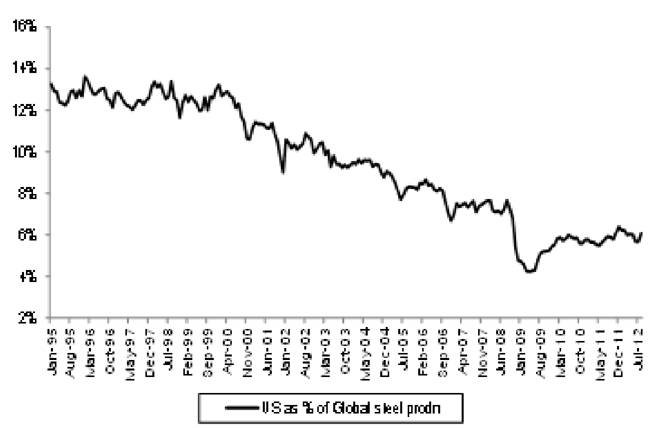
The global steel cost curve for HRC is relatively flat – with the steeper lower end dominated by backward integrated producers with raw materials. The change on raw material pricing (long-term contracts to quarterly to spot) had a significant effect on flattening out the curve, as all buyers in effect moved to the same methodology for purchasing raw materials.

In Q4 2011 the 75th percentile (roughly global utilization in that period) saw an operating cost of HRC of around US$750/t. Since then, steel costs have fallen by some US$160/t as ore and coal prices have dropped, leading to a 75th percentile operating cost of cUS$600/t, which is broadly where the global steel price is trading right now.

A revolution for the US industry?

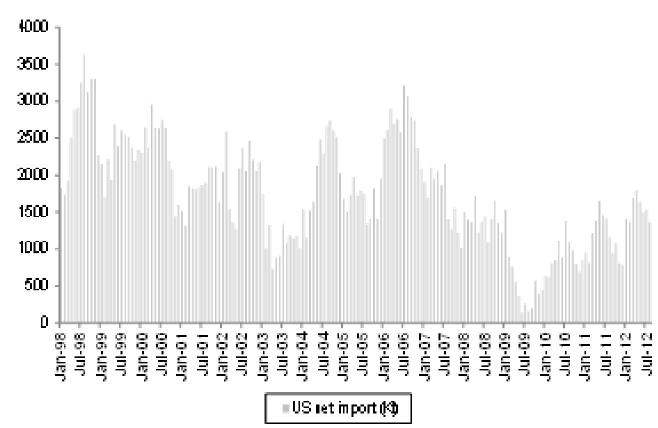
Savings from using natural gas for US producers should be able to be kept to some degree since the US represents only a small proportion of global steel production (and is a net importer) and to that extent has little impact on the global steel price. In fact the irrelevance of the US market and the abundance of cheap natural gas there could see certain US producers simply move way down the cost curve.

Exhibit 155: US as % of global steel production



Source: WSA.

Exhibit 156: US net imports (Kt)



Source: the BLOOMBERG PROFESSIONAL™ service, USGS.

Once regions such as China adopt shale and benefit similarly to the US, it is likely that there could be a massive shift in the shape of the global cost curve and as such a real winners /losers scenario could emerge but this may be 10 or 20 years away.

Potential winners

US steel producers should be the medium-term winners from Shale gas. And Nucor appears to be the leader in terms of investing in the relevant technology. As a c20 mt producer in a 1.5bn tonne industry, Nucor could in principle change its own cost dynamic significantly whilst having no net long term impact on the global cost curve.

We believe the economics of building DRI plants versus BOF stack up and given the US remains a relatively small market, we believe that US producers should be able to keep savings. Longer-term the outlook is very much dependent on China. If China adopts shale, the steel price could genuinely move the MC of producing steel lower and therefore move the global price lower. The losers in such an environment would be the European producers who would struggle to cover fixed costs. Eastern European producers, who are slowly losing their cost curve advantages as raw materials prices structurally move lower (as supply of IO for example exceeds demand) would also be longer term losers.

In Indonesia, Perusahaan Gas Negara distributors would be best placed to benefit from shale growth. In terms of gas supply, which has been its major constraint, this is likely to come at a much cheaper price. Losing out would be the coal companies: Adaro, Harum, Indika, ABM, and Bukit Asam. They may remain profitable being among the lower cost coal producers; however, volume growth could be constrained. Bukit Asam may not be as badly affected as other coal exporters, as it is selling most of its coal to the domestic market.

Mining

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Low-cost producers with Pacific exposure to outperform

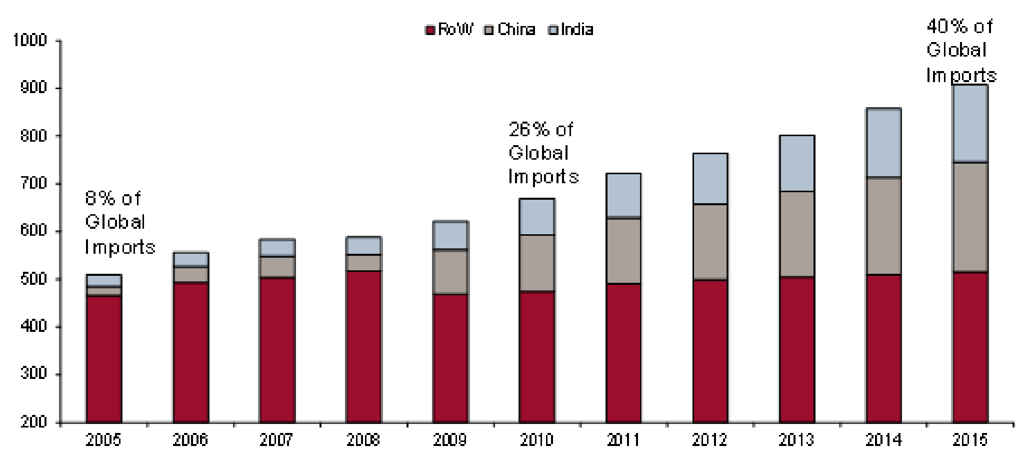
US coal miners have already endured the pain of a shale gas revolution in their domestic market and, as outlined in the coal section of this report, there is now the potential for miners in other regions to see their coal products pushed out by gas.

That said, coal to gas switching outside of the US is more a story for 2020 and beyond than a realistic prospect for the next couple of years. As such, while US producers are likely to remain under pressure in their domestic market, export opportunities should continue to offer them some source of solace.

As detailed in our recent forecast update – *The Best of Times, The Worst of Times* – continued Pacific demand growth, led by Chinese and Indian imports (Exhibit 157), will, in our view, remain the seaborne market's key demand driver. Consequently, we believe miners who can exploit this growth will be better placed than those reliant on a comparatively stagnant Atlantic basin.

Exhibit 157: China and India should account for the lion's share of market growth

Mt/y, China + India % share of seaborne imports



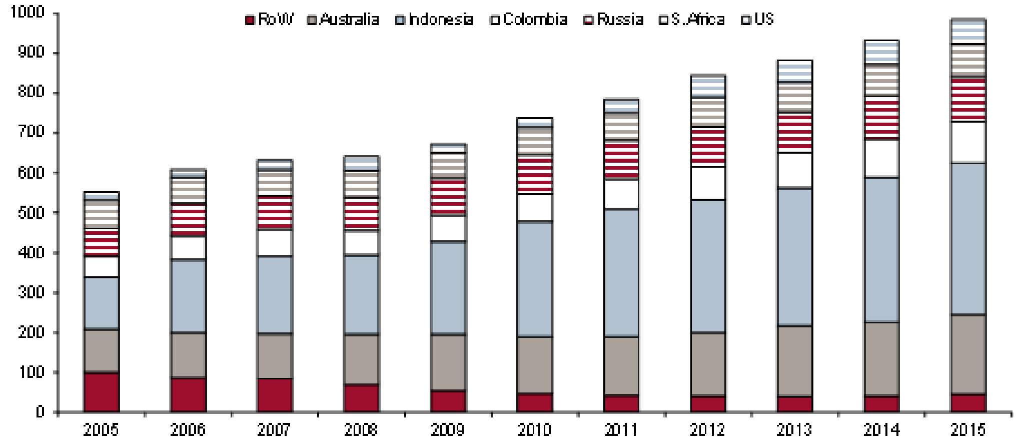
Source: Credit Suisse, customs data, company data.

Consequently, though we think that in aggregate companies' supply growth guidance is overly optimistic, there should still be significant room for supply-side expansions in coming years. This will, however, need to be at a slower pace than that recently achieved, if the market is to return to balance from its current state of excess supply.

In particular, Indonesian and Australian thermal miners should be well placed to continue expanding their output through to 2015. Further out in this decade, with significant additions to US infrastructure capacity and the likely slowdown in seaborne demand growth – as gas begins to take greater market share, particularly for direct industrial applications – the opportunities for supply-side growth are, however, likely to recede.

Exhibit 158: Indonesia and Australia should continue to dominate export volumes

Mt/y

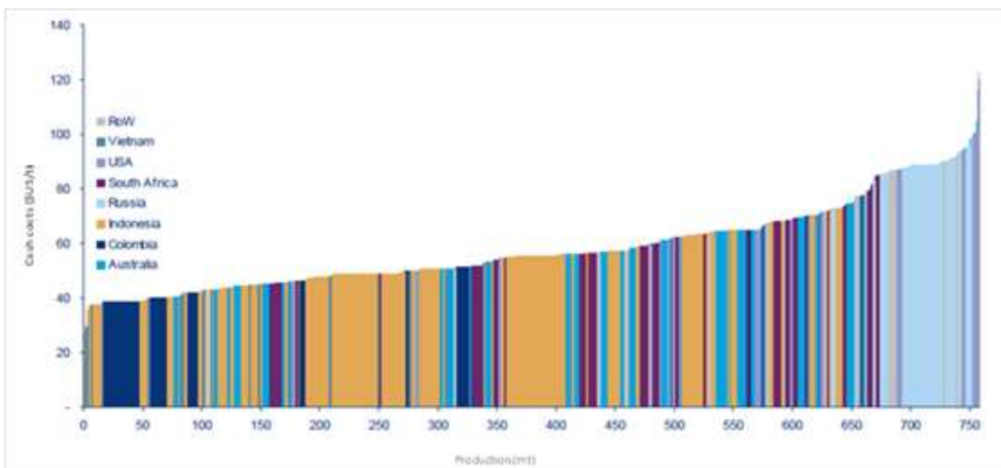


Source: Credit Suisse, customs data, company data.

Though already extremely relevant in the currently depressed pricing environment, the importance of being a relatively low cost producer should then also come into sharper focus.

Exhibit 159: Global thermal coal cost curve

Cash cost of production, US$/t



Source: Wood Mackenzie, Whitehaven company presentation.

Australia

Because of the strength in the Australian dollar in recent years, the competitive positioning of the Australian producers has been hurt, with many producers now finding themselves at the top of the cost curve on an FOB basis. However, Australia remains well positioned versus global peers to supply into the higher growth Asian markets.

Most producers, from majors to juniors, have scaled back project growth plans due to the current weak state of the thermal coal market and early signs of high cost mine shut-downs are beginning to filter through. We expect unapproved projects, particularly greenfield, capex intensive projects, to remain on hold for the foreseeable future until there is a sustained recovery in global thermal coal prices (which we expect from late 2013/2014 onwards). If thermal markets recover gradually, as we expect over the next two years, there is a strong chance at least some of these projects are reactivated. We would expect producers sitting on major greenfield projects to seek “strategic partners” to help de-risk the projects, monetize part of the asset value upfront and to provide funding and off-take.

As it currently stands, our supply/demand modeling for coal has Australia supplying 25% (40mt) of the growth is seaborne thermal coal supply over the next three years. This reflects our view that US$ prices will improve and the AUD will weaken providing a lift in A$ thermal coal prices from today’s A$78/t levels to ~A$130/t. If coal prices stay low and AUD strength persists then the majority of this 40mt of expansion tonnes will be deferred. This would lead to an inevitable tightening of coal fundamentals and higher prices – albeit over a longer timeframe than currently forecast.

US

US-based coal producers have over the past two years experienced the impact of the Shale Gas revolution, and investor expectations over future growth and returns are already very low. While additional coal to gas switching is unlikely in 2013 (with some potential reversal at +$3.50/nat gas already occurring, i.e., gas to coal switching), US demand remains in structural decline longer term, which should continue to result in a continued push by US miners to increase exports. While each of the regions in the US (Appalachia, Illinois Basin, West (PRB, Colorado/Utah)) has some ability to export, current rail access and export terminal capacity is greatest on the East Coast and the Gulf, with limited terminal capacity in the West. However, this is expected to change dramatically over the next 5 years, with significant terminal capacity expansion plans in the works in the West, which would open up PRB tonnage for export to Asia and cause a ripple through global markets.

As mentioned earlier, our US mining and metals team estimates 2012 export capacity to stand at 129Mt/y, with roughly 64Mt/y of expansion plans slated for the East Coast and Gulf over the next 2-5 years. Furthermore, there are also plans for a number of large West Coast ports going through the approval and permitting process, although there has been significant opposition from local communities and environmental groups which may continue to extend/delay the eventual construction/impact of these ports on global markets. If approved, the team estimates anywhere from 33Mt to 73Mt/y of additional West Coast capacity growth over the next decade, versus current Western port capacity of 11Mt/y.

If some or all of the proposed ports are approved and constructed, the impact of new Western port capacity would be a game changer for PRB coal producers such as Peabody Energy (BTU), Arch Coal (ACI) and Cloud Peak (CLD), as it finally provides them access to the Asia Pacific Basin which they have had limited ability to supply, given the lack of terminal capacity. While actual capacity is unlikely to be completed and operational until late 2015/2016 at the earliest, we believe that the implications for global trade flows are significant, and could inevitably result in another competitor (i.e., the United States) for tons in an already competitive market.

For the Eastern coal producers Alpha Natural Resources (ANR) and Consol Energy (CNX), we expect the additional rail and port expansions to foster continued export growth from Appalachia, which will not be a positive for global trade flows but is inevitable given the secular trends expected for domestic thermal coal consumption over the next decade. Additionally, for the Eastern miners in particular, as they are at the high end of the cost curve, this growth in US exports should have a negative impact on margins as it is likely to contribute to lower seaborne prices.

Indonesia

Indonesian coal producers are the losers in the situation. Most of the listed coal companies exports their thermal coal output into seaborne market with export accounting for 46%-90% of their sales volume. The oversupply situation has put pressure on prices though Indonesian players still maintain their competitiveness through location proximity to growing demand in China and India. Falling prices have resulted in production cuts by non-listed, smaller, inefficient mines. Listed players have delayed their expansion plans. If coal prices continue to stay at the current level, Indonesian cement producers are expected to feel more pain as realized ASP start to roll over (no more carried over contracts from 2011) and high costs are persistent (high fuel prices to operate their open-pit mines). In the medium to long term, even with coal prices start to improve, we see logistical challenges and regulatory risks as the key factors restricting export growth. In the medium term, we prefer companies with lower exposure to export markets (Bukit Asam) or companies with strong balance sheets and dividend payments (ITMG and HRUM).

Colombia

Although Colombia is exposed to the weaker Atlantic markets producers benefit from low cash costs and stronger operating margins.

South Africa

Producers in South Africa have struggled to increase exports in recent years due to infrastructure bottlenecks (port and rail). Producers will continue to benefit from proximity to India which has recently over-taken Europe as the main destination for export volumes. Success in developing infrastructure and domestic plans to increase energy capacity will be far more important drivers for the producers over the next five years.

Russia

Sitting almost at the top of the global thermal coal cost curve on FOB basis Russian thermal coal exporters are struggling now. Although being low cost miners (cUS$25-35/t at mine cash cost for export grade thermal coal) they suffer from rail transportation costs as distances from mines to sea ports are 4000-5000km. With rail transportation costs at cUS$40/t and port reloading fees at cUS$15/t the overall FOB cash costs are as high as US$80-90/t.

Although Russia has huge shale gas reserves, reserves are currently not the issue for Russian thermal coal producers. We believe that in the medium term Russia will continue to concentrate on production of conventional gas, and thus rail transportation costs are a much bigger issue. In recent years in Russia rail transportation tariffs growth has been matching inflation of 6-7% per year. In our view, if thermal coal prices on export markets remain low, coal producers may manage to persuade state owned monopoly Russian Railways to temporary reduce tariff growth to c2-3% per year. At the same time, if/when prices recover the link of Russian rail transportation tariffs to local inflation will, in our view, be quickly restored.

Materials

Within Materials, the shale revolution is having a meaningful impact on the Chemical and Fertilizer industries. The growing supply of nat-gas derived liquids, a key input to petrochemical production has placed US producers at a significant cost advantage that is expected to continue. Nitrogen producers in the US have undergone a similar experience.

Chemicals

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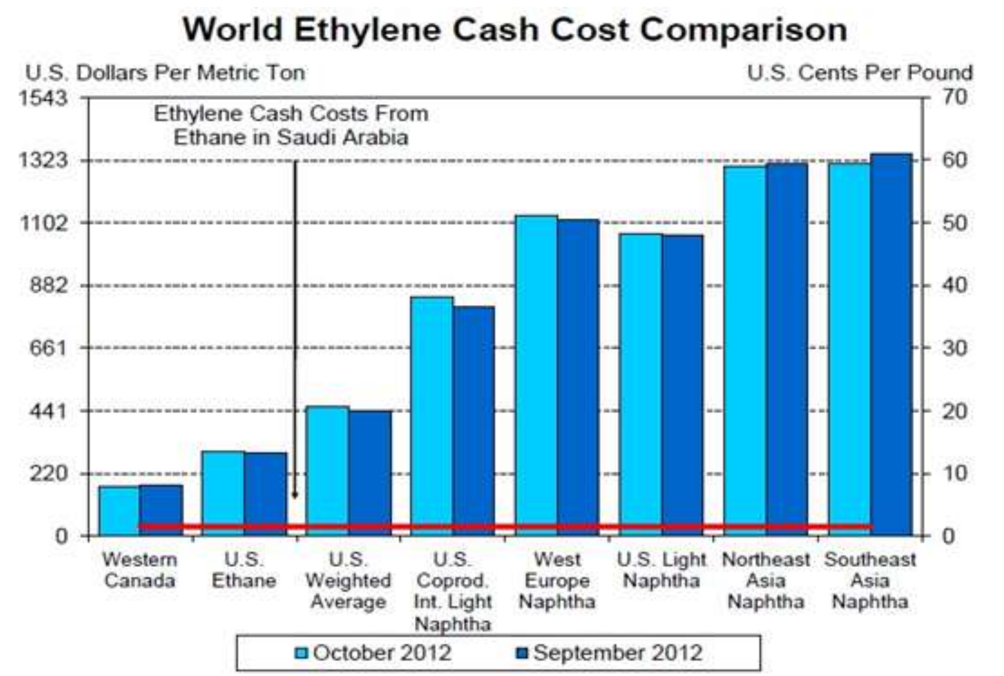
The shale revolution is having a meaningful impact on the chemical industry. This is being driven by the significant growth in US gas production, and owing to the "wetness" (or higher content of nat-gas derived liquids – NGLs) of many reserves, the supply of these NGLs has rapidly expanded. Because NGLs are a key input for petrochemical production, this has resulted in the US producers enjoying a favorable cost position for the production of key basic petrochemicals (mainly ethylene).

US producers enjoy cost advantage; attractive for future capacity expansions

Based on ethylene industry cost structures on a global basis, US producers that have the ability to process NGLs (mainly ethane) have seen a surge in profitability, lowering them to the bottom quartile of the global cost curve only above some Canadian producers and subsidized Middle Eastern producers (Exhibit 160).

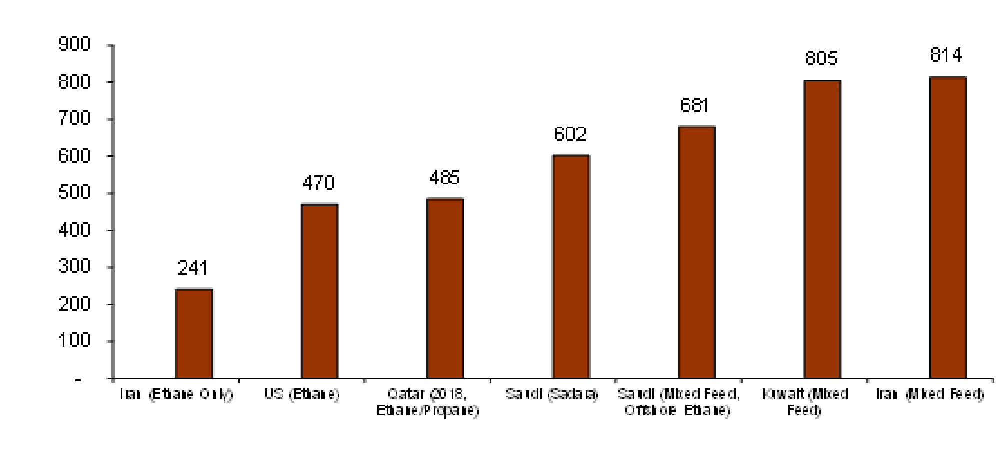
Exhibit 160: Current ethylene production cost per ton (including coproduct credits)



Source: IHS, Credit Suisse estimates.

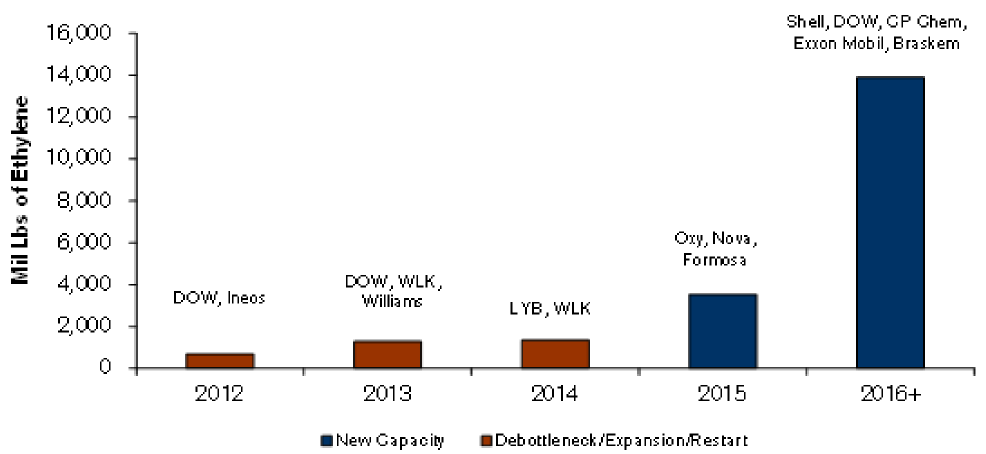
Looking ahead, we believe the US is also the most cost advantaged for new capital deployment (Exhibit 161), particularly with the Middle East being less flush with cheap nat gas owing to higher production costs, less excess supply and/or regional moratoriums on drilling (and in the case of Iran, although Iran appear to be lower-cost than the US, Iran faces issues with UN sanctions limiting their ability to get the equipment needed to produce from their reserves). This supports the numerous new projects/capacity expansion announcements in the US (Exhibit 162).

Exhibit 161: Ethylene production cost per ton for future crackers (including coproduct credits)



Note: Assumes normalized input and co-product pricing (at mid-decade levels).
Source: Company data, Credit Suisse estimates.

Exhibit 162: US capacity addition announcements



Source: Company data, Credit Suisse estimates.

We believe the key beneficiaries of this shale-driven boost in profitability (shown in Exhibit 162) in the United States are LYB (Outperform, TP $60), DOW (Outperform, TP $34) and WLK (as well as the chemical assets of PSX, XOM, EMN, Shell, and Ineos). These names should continue to benefit from the cost advantage until at least 2015-16. At that point, we expect a slew of domestic capacity to come online which will likely put some downward pressure on profitability as it tightens up the supply/demand balance for ethane (unless there are further ramps in the supply of ethane and other NGLs to support all these expansions).

Exhibit 163: Expansion of ethylene production margins driven by advantaged ethane

Source: HIS.

It is important to consider that the shift toward greater NGL-based ethylene production also has an impact on other chemical products given by-product production. Petrochemicals are derived from cracking (heating over a catalyst) either NGLs or crude oil-based naphtha. Both routes produce ethylene (C2 – light derivative) and key "heavier" by-products including propylene (C3), butadiene and related chemicals (C4s) and heavier aromatics (all of which are key to the industry). However, the cracking of NGLs produces a higher proportion of ethylene and less of the heavier by-products compared to cracking naphtha – these by-products account for over 30% of the total product slate when cracking naphtha, but only ~5% when cracking ethane. Thus, while the move to cracking NGLs (particularly ethane) is resulting in a favorable cost position for US producers, it is also lowering the availability of C3, C4, and aromatic derivatives (and accordingly, placing upward pricing pressure for these products).

We are seeing two key resulting trends from this: (1) increasingly attractive returns on projects to directly synthesize the heavier cracking derivatives (notably propane-to-propylene, with butadiene also being evaluated); and (2) the international Chemical industry being supported by these higher prices that are helping to somewhat offset lower relative profitability to produce ethylene.

Impact of US shale gas on the European Chemical sector

European petrochemicals production, as previously illustrated, is at the high end of the global ethylene cost curve. This is predominantly due to its high feedstock cost (mainly based on crude-based naphtha). The European production cost disadvantage is further accentuated by North America's access to cheap shale gas. As a result, we believe European ethylene (C2) production (and derivatives) are likely to generate poor returns. However, as described above, North America's shift towards lighter gas feedstocks also creates shortages (and therefore sustainable above average prices) in the C3 (propylene), C4 (butadiene) and aromatics (benzene, toluene, etc.) co-products.

Overall, we believe the impact on the European Chemicals sector is likely to be a net positive. This is a function of:

- **European listed Chemical companies have largely divested their ethylene exposures over the past 10-15 years.** We note BASF is only the eighth largest producer of ethylene in Europe (versus the largest specialty chemicals company globally). The only other material ethylene exposure among European specialty chemical names is Solvay (largest European PVC producer).
- **European chemical companies may benefit from rising C3, C4, and aromatics prices in the United States**, as globally traded derivatives pricing pushes higher and Europe retains its C3/C4 and aromatic production from naphtha cracking. Medium term, we believe in sustained higher butadiene/aromatic derivative product prices globally.
- **European chemical companies have 15-20% of operations in North America.** We believe companies are likely to allocate resources to benefit from the cheap shale gas feedstock/associated industries.

Strategically, the European Chemicals sector is likely to adapt to cheap shale gas via targeting a larger proportion of growth from North American markets. Importantly, this could also restrict capacity additions in European chemical production. We believe this is likely to keep the European Chemicals supply/demand balance tighter – even without a significant improvement from the demand side. Medium term, this supports greater supply side pricing discipline, and ultimately higher returns on capital throughout the cycle.

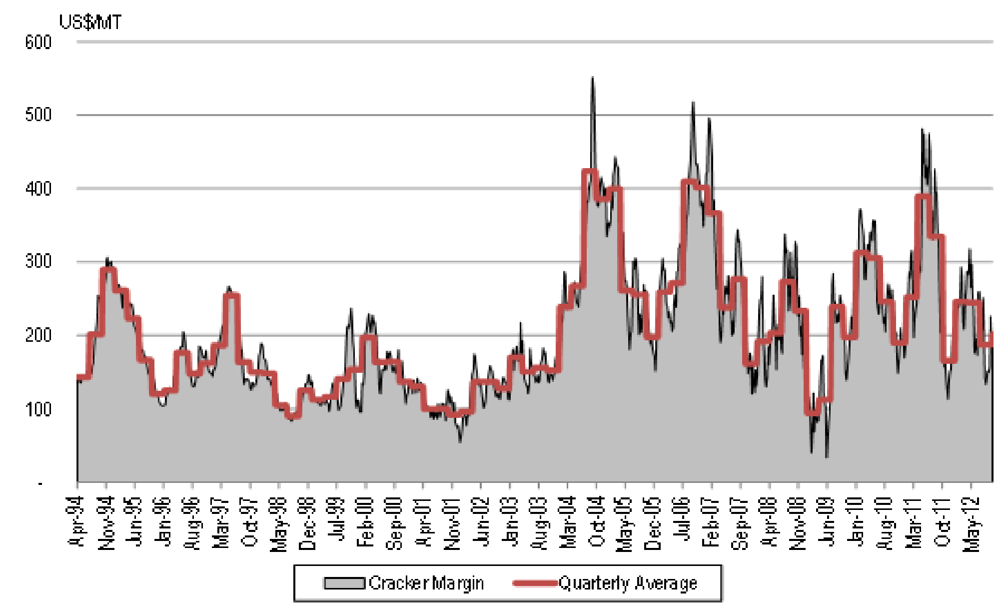
Potential winners

- We believe the key beneficiary of shale gas within European chemicals will be Arkema (O/P, TP €80). We estimate that Arkema has the greatest European exposure to propylene chemistry (mainly through its acrylics chain), therefore elevated propylene prices in the US should support higher derivatives prices globally. In addition, increasingly difficult to access propylene supplies create an additional barrier to entry and a more favorable supply/demand outlook. We believe this should support mid-cycle acrylics margins with risk to the upside longer term.
- We believe Solvay (Outperform, TP €105) remains most disadvantaged by the move to shale cracking in the US We estimate that Solvay has the highest exposure to ethylene chemistry – mostly through their PVC operations. Solvay's European/Latin American PVC operations sit at the higher end of the global cost curve, this is due to the relatively higher cost of ethylene outside of the US Average European producers are currently operating close to breakeven, we estimate Solvay's 2013 EBITDA margin at 6%. We believe the PVC market will remain structurally challenged longer term with increasing exports from the US, oversupply globally, and no material recovery in European demand. However, we highlight that Solvay's PVC operations remain lowest cost in Europe and contribute only c7% to group earnings and (on our 3.5 x multiple) only c4% to our SOTP valuation.

Asian petrochemicals also directly affected

On headline, Asia consumes 45% of total global ethylene and has 33% of total capacity. While there are pockets of low-cost nat gas-based supply (detailed further below), a large portion of Asian ethylene production is crude-oil (naphtha) based, and is therefore at the higher end of the cost curve. In addition, most manufacturers are commoditized and have little specialized applications in the portfolio. The resurgence in US ethylene supply, combined with earlier large increases in low-cost Middle East production, has a direct impact on Asian naphtha cracker profitability.

Exhibit 164: Asian cracker profitability has been weakening



Source: Thompson Reuters, Credit Suisse estimates.

Unable to compete with low cost supplies, most cracker operators in the region are likely to have little choice but to take run cuts during periods of weak demand. Longer term, we think higher cost naphtha crackers in Asia (such as those in Japan) may restructure capacity or close.

China imports ~50% of its ethylene consumption. Chinese companies have plans to build large capacity using the Coal-to-Olefins (CTO) technologies. This, while still more expensive than natural gas (US and Middle East), can have a material cost advantage over naphtha crackers. The first few plants on this technology are already up and are producing on-spec PE, we understand from our industry consultants. Current industry forecasts suggest Chinese companies can produce up to 4.6 MT of ethylene from coal by 2016. This technology, however, requires large amounts of water, which may be unavailable for some Chinese plants. Effective Chinese CTO additions may therefore be less than headline.

Increasing US supplies combined with further CTO additions in China mean Asian naphtha cracker profitability may be impaired materially in the long term. Asian naphtha crackers are therefore likely to be Beta trades on global petrochemical demand growth.

In Taiwan, Formosa Petrochemical Group (6505.TT), naphtha-based producers, would be negatively affected by the emergence of low cost shale gas. We highlight this as one of the risks for the group in the long term, alongside Nanya Plastics (1303.TT), and Formosa Chemical and Fibers (1326.TT) also suffering.

Exhibit 165: Chinese CTO additions – KTA

Company	Location	2010	2011	2012	2013	2014	2015	2016
Zhongyuan PC	Puyang, Henan		25	100	100	100	100	100
Jiutai Energy (IM)	Erdos, Inner Mongolia					75	300	300
Baotou Shenhua	Baotou, Inner Mongolia	113	300	300	300	300	300	300
Nanjing Wison	Nanjing, Jiangsu				100	100	100	100
Ningbo Heyuan	Ningbo, Zhejiang					300	300	300
PuCheng Clean Energy	Pucheng, Shaanxi				75	300	300	300
Qinghai Salt	Golmud, Qinghai					120	160	160
Shaanxi Yanchang	Yan'an, Shaanxi					225	450	450
Shanghai PC	Jinshan, Shanghai					300	300	300
Shanxi Coking Corp.	Hongtong, Shanxi					75	300	300
Sinopec Zhijin	Guizhou, Guizhou					75	300	300
Yankuang Guohong	Zoucheng, Shandong							300
Shenhua Xinjiang	Urumqi, Xinjiang							160
CPI/Total	Erdos, Inner Mongolia							200
Baofeng Energy Group	Ningdong, Ningxia						150	300
Shandong Shengda	Tengzhou, Shandong						170	170
Yili Meidianhua	Yili, Xinjiang							300
Yulin Energy & Chem.	Yulin, Shaanxi					300	300	300
	Total	113	325	400	575	2,270	3,530	4,640

Source: IHS, Credit Suisse estimates.

International shale discoveries may present opportunities longer term, but potential appears limited for now

As this report details, the shale revolution is rapidly expanding internationally. For now, it appears that the most likely candidate for meaningful shale-based nat gas supply is China. That said, we believe the impact on the Chemical industry is likely to be limited at least this decade for two key reasons:

1) **Our Commodity team believes that the meaningful extraction of nat gas from Chinese shale is likely a next-decade phenomenon** – thus, although China is planning to bring on a decent amount of incremental petrochemical capacity of its own over the coming years, these will focus on either coal-based or crude-based inputs.

2) **Our industry experts believe that this gas is mostly "dry,"** implying the incremental supply of nat gas-based liquids or NGLs (and accordingly its impact on the Chemical industry) is likely to be limited; depending on the reserve, there may be some pockets of opportunity for NGL extraction, but its widespread expansion like in the US appears unlikely for now.

In addition, while other regions could also gain some traction in the shale craze (Argentina, Australia, as well as certain parts of Europe), as we've detailed above, we believe the US is the clearest winner for the foreseeable future.

Fertilizers

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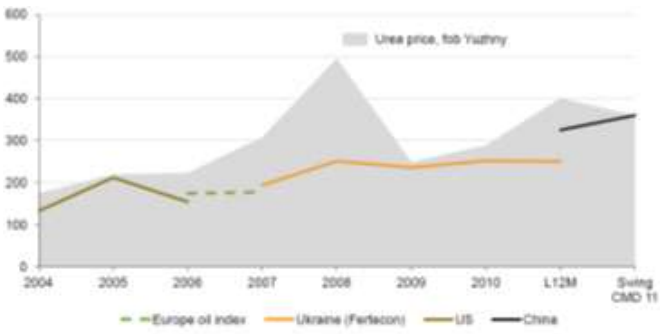
Shale gas has dramatically shifted the North American nitrogen industry down the cost curve. In 2004-06 North American producers were the marginal cost producers. At present they are in the lowest-quartile of production costs.

Exhibit 166: Marginal cost of production and urea price

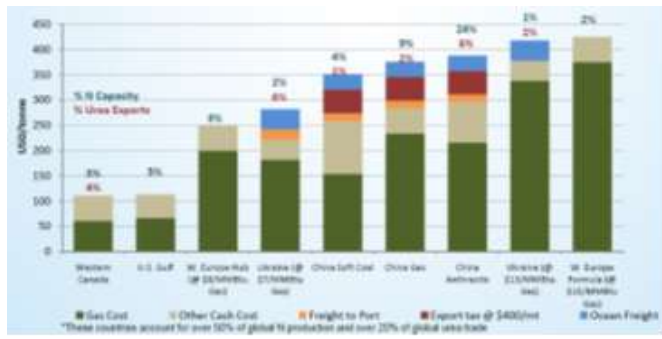
US$/tonne



Source: Fertecon, Yara estimates.

Exhibit 167: Urea cost curve

US$/tonne

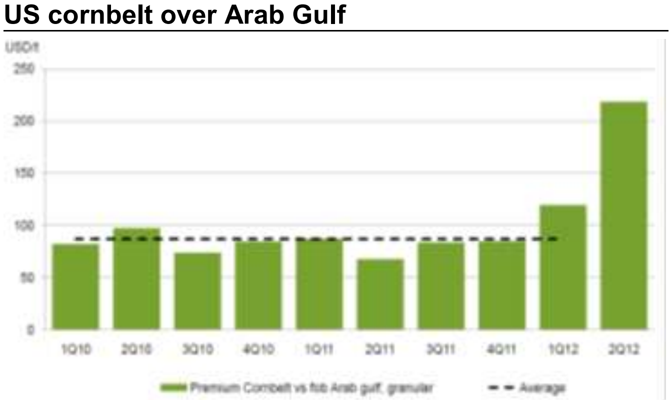


Source: Agrium.

Short to medium term there are no losers from North American low-cost gas, only winners; the North American domestic producers. A price floor has been set by marginal high cost producers in China and the Ukraine around $400/t (Granular Arab gulf fob, $380/t Yuzuhny prilled fob). In comparison, we estimate that granular production costs at a natural gas price of $3/MMBtu are around $115/t. Unsurprisingly, North American producer margins are running at all-time-high. (See Exhibit 169 for CF margins.)

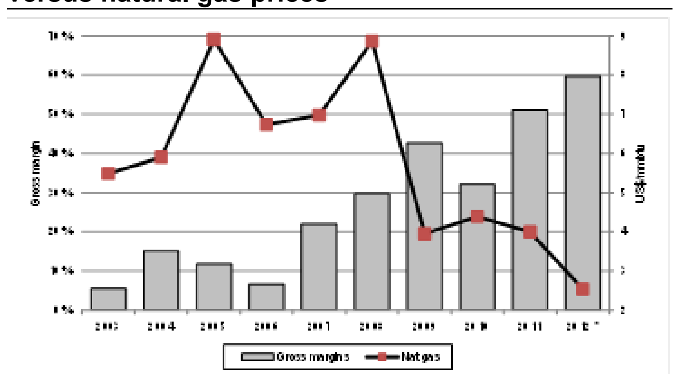
In terms of fertilizers delivered into the US corn belt, North American producers have the best margins globally thanks to a combination of low feedstock costs and a premium price (2y-average premium ~$85/t: import parity price including transport costs from overseas producers (sea freight + domestic transport up to corn belt). Translated into costs, we estimate a $85/t price premium equals a cost benefit of $2.2/MMBtu. The premium price into the US corn belt will persist as long as the North American continent is structurally short nitrogen (~35% of N consumption is imported, 6m tonnes ammonia and 5m tonnes of urea). The spike up in premiums paid in 2Q12 was caused by a combination of insufficient urea imports in the run up to the spring planting season and strong application on account of record corn acreage planted (96m acres).

Exhibit 168: Average granular urea price premium US cornbelt over Arab Gulf



Source: Green markets, ICIS.

Exhibit 169: CF Industries nitrogen gross margins versus natural gas prices



* Jan-June, Source: Company data, Datastream

Unquestionably the strong margins in the North American nitrogen industry are attracting significant investments while new capacity expansions projects in the Middle East have dried up.

So far in 2012 the total of new urea capacity announced or planned in North America for 2016/17 start-up adds up to ~9m tonnes/year. This includes expansions planned by established producers in North America, Agrium, CF, and Koch, as well as proposals from Iowa Fertilizer, Summit Texas, CHS North Dakota. Ohio Valley has also proposed an ammonia/UAN complex and, in Canada, FNA an unspecified nitrogen project. How many of these projects will progress as the rush for cheap shale gas gathers pace remains to be seen.

However, assuming 50% of the announced capacity comes on stream (highly likely, in our view), North America would become largely self-sufficient in terms of its urea requirements, possibly with negative implications for US market price premium. In addition, with the same 50% assumption, reduced import requirements to the US would effectively add c11% to global export supply by 2016/17, displacing capacity at the higher end of the cost curve, and pushing down floor prices with negative implications for global industry profitability.

Potential winners

The winners are CF industries and Agrium, the two largest North American nitrogen producers. Thanks to low-priced shale gas, margins have risen to new highs and competitive feedstock prices offers attractive growth opportunities in the structurally short North American nitrogen market. CF have flagged potential nitrogen capital projects over 2014-16 totaling US$2bn that would add 3.5m tons of combined UAN and urea capacity. In the same time period, Agrium has announced plans to raise its North American urea/UAN capacity by 2.6m.

In the medium term (2016/17) we believe likely significant capacity expansion will result in excess capacity and lower nitrogen prices as high cost marginal cost production is displaced by North American domestic capacity. Overall industry margins are likely to fall.

The relative losers from shale gas are most likely companies with European-based production. High European gas prices are already putting industry profitability under pressure and the likelihood of sustained relatively higher prices in Europe is more likely to lead to capacity closures than growth opportunities.

Capital Goods and Engineering

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Repercussions from the surge in unconventional energy sources are being felt across the Cap Goods space, particularly in select verticals that are closely tied to gas power generation. In some cases, we think this is a theme that will become particularly investable in 2013.

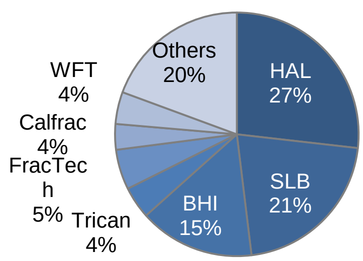
Electrical equipment/multi-industry

Pressure pump manufacturers

The pressure pump manufacturers are the most direct beneficiaries in capital goods of the shale gas revolution, particularly if this extends from the US into other markets such as China; the two global leaders at present are Weir Group and Gardner Denver. Competition is intensifying in this field, with NOV entering the market, but GDI and Weir still have the highest exposure in terms of proportion of sales accruing from this market.

Exhibit 170: US domestic frac revenues – oil services

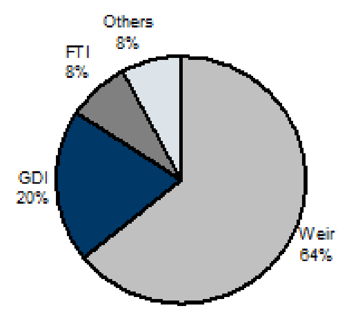
%, unless otherwise stated



Source: Credit Suisse Oilfield Services Research.

Exhibit 171: Frac equipment market share

%, unless otherwise stated



Source: Credit Suisse Oilfield Services Research.

Gas fired power plant plays

Indirectly, we highlight that if the move toward gas-fired power generation is indeed a permanent feature of the power landscape globally, this will help the gas turbine manufacturers such as GE, Siemens, MHI and Alstom. If we see the coal-to-gas switch persist in the US, which is the world's largest market in terms of the installed base of gas turbines, this should benefit GE in particular, given its dominant position in its home market. However, competition is intensifying, and MHI recently shipped its first domestically-manufactured gas turbine, from its new Savannah plant. In China, which is currently the largest gas turbine market in terms of new orders, the equipment is supplied by three main local-foreign partnerships; Dongfang Electric with MHI, Siemens with Shanghai Electric, and GE with Harbin Electric.

Aside from the turbine equipment, companies supplying the process automation control technology for gas-fired power plants would also see orders increase, such as Emerson, ABB and Invensys.

Exhibit 172: Heavy-duty gas turbine market share by volume

USD in millions, unless otherwise stated

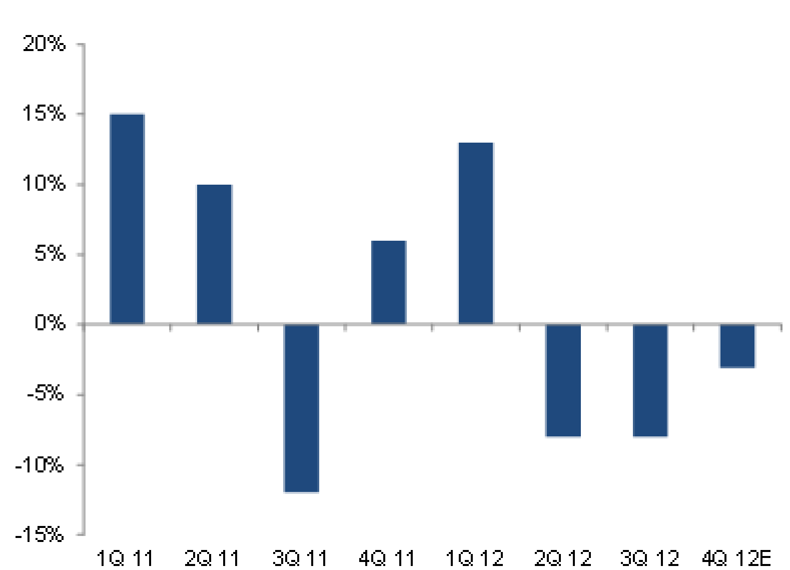
Market Share by Volume														
	General Electric			Siemens			M.H.I.			Alstom			Total Market	
Year	Mwe	Shares	Units	Mwe	Shares	Units	Mwe	Shares	Units	Mwe	Shares	Units	Mwe	Units
2007	33,207	40.4%	395	25,859	31.4%	193	5,741	7.0%	25	8,740	10.6%	40	82,294	874
2008	33,992	47.5%	412	17,192	24.0%	138	8,609	12.0%	37	3,638	5.1%	15	71,531	786
2009	19,002	41.2%	242	17,899	38.8%	115	1,312	2.9%	5	1,820	4.0%	8	46,088	553
2010	21,693	44.2%	295	17,471	35.6%	163	3,456	7.0%	14	1,031	2.1%	4	49,084	626
2011	29,639	42.1%	361	20,947	29.8%	167	9,605	13.7%	33	3,339	4.8%	17	70,336	756
1H11	11,692	31.5%	162	12,954	34.9%	104	2,962	8.0%	11	1,341	3.6%	6	37,101	410
1H12	8,676	38.1%	118	5,724	25.1%	46	2,568	11.3%	8	370	1.6%	2	22,770	224

Source: McCoy, Credit Suisse estimates.

An increased usage of existing gas-fired power plants by electric utilities should also spur rising demand for aftermarket for the installed gas turbine fleet; this could have a meaningful near-term earnings impact on the suppliers of these aftermarket services, as this business tends to be much higher-margin than supplying the OE. Hence, while GE's recent Energy Services order intake has been sluggish, we think this could accelerate in markets such as the United States in 2013.

Exhibit 173: GE energy services order change

%, unless otherwise stated



Source: Company data, Credit Suisse estimates.

Process instrumentation/flow equipment manufacturers

- **Compressors:** GE and Rolls Royce are two of the major players in compressors for gas pipelines. Also, Swiss-based Burckhardt Compression (it demerged a few years ago from Sulzer) is a global leading manufacturer of turbo compressors highly exposed to LNG (for instance contact free piston compressors, hyper compressors and standardized process compressors). Competitors here are Dresser Rand and GE Nuovo Pignione. Key drivers are investments in receiving LNG receiving terminals, LNG storage and desulphurization or polyethylene production.

Exhibit 174: GE positioning in gas overall

%, unless otherwise stated

Source: GE.

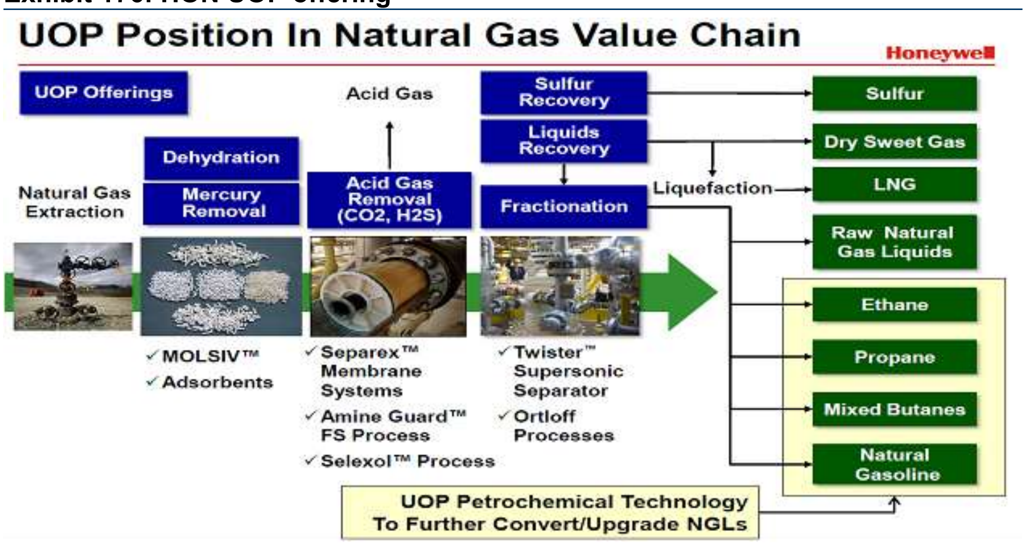
Exhibit 175: GE positioning in shale gas

%, unless otherwise stated

Source: GE.

- **Extraction/cleansing of natural gas:** Honeywell should continue to prosper in its UOP business (part of the PMT operating segment) from its role in helping to extract and cleanse natural gas. The company's recent acquisition of a majority stake in Thomas Russell has increased its expertise in gas recovery.

Exhibit 176: HON UOP offering



Source: Honeywell.

Exhibit 177: Profile of major public automation vendors globally

Region	Company	Company Sales $USD bn	Automation Sales $USD bn	Automation Sales % of total company	Automation Exposure High / Medium / Low	Market Focus Factory / Discrete	Product Focus Controls / Instruments	Key Offerings Products & Solutions
North America	3D Systems Corporation	0.2	0.2	100%	High	Factory	Instruments	3D Printing Systems
	Ametek	3.0	1.8	61%	High	Process	Instruments	Motors, Sensors
	AspenTech	0.2	0.2	100%	High	Factory	Controls	Optimization software
	Autodesk	2.2	2.2	100%	High	Factory	Controls	PLM and CAD software
	Cognex	0.3	0.3	100%	High	Factory	Instruments	Machine vision
	Crane Co	2.5	1.2	45%	Medium	Process	Instruments	Commercial valves and pumps
	Danaher	16.1	1.0	6%	Low	Factory	Instruments	Motion control / motors
	Emerson	24.2	12.3	51%	High	Both	Instruments	DCS, process instrumentation
	Flowserve	4.5	1.5	33%	Medium	Process	Instruments	Valves, pumps, actuators
	GE	147.3	0.8	1%	Low	Both	Instruments	SCADA, control software
	Hardinge	0.3	0.3	100%	High	Factory	Instruments	Milling and grinding machinery
	Honeywell	36.5	3.0	8%	Low	Process	Controls	Process control (DCS)
	Hurco	0.2	0.2	100%	High	Factory	Instruments	Computerized machine tools and control software
	Idex	1.8	0.8	44%	High	Process	Instruments	Pumps, meters, valves & controls
	Kennametal	2.4	2.4	100%	High	Factory	Instruments	Cutting tools
	Newport	0.5	0.5	100%	High	Factory	Instruments	Motion control, industrial lasers
	PTC	1.2	1.2	100%	High	Factory	Controls	PLM Software
	Rockwell Automation	6.0	6.0	100%	High	Factory	Combined	PLCs (technically controller), drives, safety control
	Rofin-Sinar	0.6	0.6	100%	High	Factory	Instruments	Industrial laser sources and solutions
	Romi	0.3	0.2	0%	High	Factory	Instruments	Machine Tools
	Roper	2.8	1.3	45%	Low	Process	Instruments	Meter readers, pumps, valves
	Sensata	1.3	1.3	100%	Low	Factory	Instruments	Sensors and controls
	SPX Corp	4.6	2.0	45%	High	Process	Instruments	Pumps, valves, filters
	Stratasys Inc	0.2	0.2	100%	High	Factory	Instruments	3D Printing Systems
Europe	ABB	38.0	17.1	45%	High	Both	Combined	Robotics, control systems, drives, and sensors
	Alfa Laval	4.0	4.0	100%	High	Process	Instruments	Pumps, valves and heat exchangers
	Dassault Systems	2.4	2.4	100%	High	Factory	Controls	PLM Software
	Gildemeister	2.6	2.2	85%	High	Factory	Instruments	Machine tools
	GEA	7.2	3.9	54%	High	Process	Instruments	Pumps, valves, heat exchangers
	IMI Plc	3.3	2.5	77%	High	Process	Instruments	Valves, actuators, controllers
	Invensys	2.5	1.1	45%	High	Process	Controls	DCS, SCADA
	Krones	3.3	3.3	100%	High	Both	Instruments	Package and bottle machine machine manufacturer
	Kuka	1.9	1.9	100%	High	Factory	Instruments	Robotics
	Metso	8.8	1.0	12%	Low	Process	Combined	Controls, sensors
	Renishaw	0.5	0.5	100%	High	Factory	Instruments	3D Printing Systems, Precision metrology and inspection equip
	Rotork	0.7	0.7	100%	High	Process	Instruments	Valve actuators and control systems
	Sandvik	12.1	3.5	29%	Medium	Factory	Instruments	Cutting tools
	Schneider	29.1	5.8	20%	Low	Factory	Combined	PLCs, switches, motion control, drives
	Schuler	1.3	1.3	100%	High	Factory	Instruments	Stamping, forging, minting machinery
	Siemens	97.5	24.1	25%	Medium	Factory	Combined	PLCs, drives, motors, CNC
	Sulzer	3.4	3.4	100%	High	Process	Instruments	Pumps, controls
	Weir Group	3.5	0.2	7%	Medium	Process	Instruments	Valves and pumps
Asia	Airtac	0.2	0.2	100%	High	Factory	Instruments	Pneumatic cylinders, valves
	Amada	2.2	2.2	100%	Low	Factory	Instruments	Machine tools
	China Automation Group	0.3	0.3	90%	High	Process	Controls	DCS
	Delta	5.7	1.2	21%	Medium	Factory	Controls	HMI, PLC, Sensors, Servo Motors & Drives, Machine Vision
	Doosan	4.0	1.2	31%	Low	Factory	Instruments	Machine tools
	Ebara	4.7	3.8	82%	High	Process	Instruments	Pumps
	Fanuc	6.1	6.1	100%	High	Factory	Combined	Robotics, CNC
	Hiwin	0.5	0.5	100%	High	Factory	Instruments	Linear motion, ball screws, actuators
	Hollysys	0.3	0.1	50%	High	Process	Controls	DCS, SCADA
	Hyundai WIA	5.7	0.2	4%	Low	Factory	Instruments	Automotive parts & Machine Tools
	Kawasaki	14.9	2.0	13%	Low	Factory	Instruments	Pumps, motors, valves, robots
	Keyence	2.3	2.3	100%	High	Factory	Instruments	Sensors, machine vision
	Makino	1.3	1.3	100%	High	Factory	Instruments	Computerized machinery
	Mitsubishi Electric	43.9	5.4	12%	Medium	Factory	Combined	PLC, robots
	Mori Seiki	1.7	1.7	100%	High	Factory	Instruments	CNC
	Nachi	1.9	1.9	100%	Medium	Factory	Instruments	Cutting tools, machine tools, robots
	Nikkiso	1.0	1.0	100%	High	Process	Instruments	LNG Pumps, hemodialysis machines
	Okuma	1.5	1.5	100%	High	Factory	Instruments	Computerized machinery, CNC, CAD
	Omron	7.1	3.1	44%	High	Factory	Combined	PLCs, sensors, relays, machine vision
	OSG	0.9	0.9	100%	High	Factory	Instruments	Cutting tools
	Seiko Epson	10.0	1.9	19%	Low	Factory	Instruments	Robots, digital control, optic devices, sensors
	Siasun	0.1	0.1	100%	High	Factory	Instruments	Robots, Energy Automation Equipment
	SMC	3.9	3.9	100%	High	Factory	Instruments	Actuators, valves, and switches
	Teco	0.9	0.9	100%	High	Factory	Instruments	Industrial motors
	THK	2.2	2.2	100%	High	Factory	Instruments	Electronics, Machine Tools
	Wuhan Huazhong Numerical	0.1	0.1	100%	High	Factory	Instruments	CNC
	Yaskawa	3.5	3.5	100%	High	Factory	Instruments	Motion controls, robotics
	Yokogawa	4.1	3.4	83%	High	Process	Controls	Industrial automation & controls

Source: Credit Suisse. Note: US$ in billions, unless otherwise stated.

- **Process instrumentation/pumps:** Emerson and Endress & Hauser (private) are the two global leaders in process instrumentation. In terms of pure plays focused on process instrumentation, Sulzer is the global #2 for pumping solutions (centrifugal pumps) in O&G upstream, and competes with companies such as Flowserve and Pentair. Exposure to shale gas is low, but centrifugal pumps are used around the well to transport water. Sulzer has currently only 2-4% sales exposure to shale gas but is planning to strengthen its footprint in this space.
- **Machinery:** Rotork as benefitting from the build out of gas infrastructure – its valve actuators are used in pipelines and processing plants and are a material proportion of company sales. Smiths Group's John Crane business should benefit from the build out in gas infrastructure as a supplier of mechanical seals and as well as of spares and service for pressure pumps (examples of customers are Sulzer, Flowserve, Weir). John Crane accounts for 35% of Smiths Group operating profit while the oil & gas segment comprises two-thirds of John Crane business (that is split between 60% downstream, 25% upstream, and 15% midstream).
- **Environmental services:** On this side, we think the biggest beneficiaries from the shale gas revolution would be companies like Heckmann and Waste Connections that have large businesses dedicated to picking up frac fluids and oily solids and disposing off them. Most of the environmental companies that compete on the frac fluid side against Heckmann and Waste Connections are private and do not have the safety record, disposal network & logistical experience, or balance sheets to take market share away as shale gas revolution develops.

What if US manufacturing is spurred by cheap gas?

A lower cost for US manufacturing as a result of lower gas prices could encourage companies to locate a greater share of their manufacturing installed base in the US, rather than abroad. Key beneficiaries of such a trend would be factory automation/ equipment suppliers such as Rockwell Automation, and Emerson Electric. Non-US companies with a significant US presence in this field include Fanuc, ABB and Siemens.

Who benefits if the penetration of Natural Gas Vehicles takes off?

Luxfer manufactures aluminum cylinders which are used in CNG-powered cars, trucks and buses. The company's offering was bolstered recently by its acquisition of Dynetek, which has a leading position in CNG cylinders and alternative fuel systems for buses and heavy-goods vehicles, while its automotive customers include Nissan and Mitsubishi.

Who might lose out?

The losers would be companies who have significant exposure to coal-fired power equipment. Alstom would be one company that we would highlight here, given its #1 position in the steam turbine and boiler market globally (it has entered into a joint venture for boilers with Shanghai Electric), against its #4 position in gas turbines (and it has no local partner in China for this technology). The suppliers of the cooling towers for coal-fired power plants, such as SPX Corp and GEA, will also likely see ongoing soft demand in these businesses (although some of the coal-softness should be offset by better CCGT demand).

US Engineering & Construction

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Exploring the US Energy Renaissance

We believe meaningful spend likely occurs across six major verticals, including Petrochemical, Liquefied Natural Gas, Gas-To-Liquids, Gas New Generation, Emissions Retrofit, and Gas Pipeline.

While the resurgence of energy infrastructure spend in United States is certainly topical, we believe it will become an investable theme in 2013 with catalysts around the corner providing confidence in the cycle. In fact, we think several brownfield ethylene expansions could get announced as early as the third quarter of 2012 and greenfield ethylene plants in 2013. There is also a very high probability that the controversial Keystone gas pipeline project goes forward in early 2013 regardless of the outcome of the Presidential election.

Exhibit 178 provides a cheat sheet of who we think is best positioned by contractor in the US.

Exhibit 178: Who is best positioned in the United States?

					Power	
	Petrochemical	LNG	GTL	Gas Pipeline	Gas New Gen	Emissions
Fluor	●	◔	◔	-	●	●
Jacobs	●	-	-	-	-	-
KBR	●	●	●	-	◔	◔
CBI/Shaw	●	●	◔	-	●	●
Foster Wheeler	◕	●	◔	-	-	◔
McDermott	-	◔	◔	-	-	-
URS Corporation	-	-	-	◑	◑	◑
Willbros	-	-	-	●	◔	-
Quanta	-	-	-	●	◔	-
Babcock & Wilcox	-	-	-	-	-	◔

Source: Company data, Credit Suisse estimates.

We estimate $70 billion in spend heavily weighted toward oil & gas

To be clear, the potential dollars spent could be massive. Taking a pretty substantial haircut to the number of proposed contracts announced already, we believe spend could approach as much as $70 billion across oil & gas and power more broadly.

Exhibit 179 provides our assumptions behind the $70 billion in spend. We do admit that it is a rough estimate and is not perfect and likely over a ten year period. It is also worth noting that the spend in oil & gas could be as much as 2.5 times that of power based on the projects on today's drawing board. We estimate spend in oil & gas spend could be as high as $50 billion which compares to power at approximately $20 billion, assuming CSAPR goes through.

Exhibit 179: Potential spend related to US energy renaissance

Potential Oil & Gas Spend	
4 Ethylene Plants At $4B Each	$16B
Expansions of Ethylene Plants	$2B
1 GTL Plant	$10B
2 LNG Project	$10B
Keystone Pipeline	$7B
Total Oil and Gas	**$50B**
Potential Power Spend	
Emissions Retrofit	$15B
5 Gas Fired Power Plants	$5B
Total Power Spend	**$20B**
Total Spend For US Energy Renaissance	**$70B**

Source: Company data, Credit Suisse estimates.

Who's best positioned?

While all companies within our coverage universe have the potential to benefit, we believe FLR, KBR, CBI, and FWLT are best positioned based on the number of verticals each company can benefit from and taking into consideration the potential for dollars spent. Within the power names, we highlight PWR because they are best positioned to benefit as spend in gas pipeline should be significant, in addition to electric transmission. More important, investor expectations are exceedingly low in gas pipeline given prior performance issues.

Stocks Exposed to the Shale Theme

Exhibit 180: Shale plays by region

Name	Country	Symbol	Market Cap (bil) Local	GICS Group	GICS Industry	Sensitivity	CS recommendation	Explanation
Australias								
AURORA OIL & GAS LIMITED	AUS	AUT	1.39	Energy	Oil, Gas & Cons. Fuels	High	Outperform	High growth, high margin, liquids rich Eagle Ford shale producer.
AWE LIMITED	AUS	AWE	0.65	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Has found both oil and gas from shale.
BEACH ENERGY LIMITED	AUS	BPT	1.88	Energy	Oil, Gas & Cons. Fuels	High	Not Rated	Drilling exploratory shale wells
BURU ENERGY LIMITED	AUS	BRU	0.68	Energy	Oil, Gas & Cons. Fuels	n/a	Not Rated	Drilling unconventional gas exploratory wells
MOLOPO ENERGY LIMITED	AUS	MPO	0.11	Energy	Oil, Gas & Cons. Fuels	High	Not Rated	Shale oil and gas in the Wolfcamp play, Texas
SANTOS LIMITED	AUS	STO	10.45	Energy	Oil, Gas & Cons. Fuels	Moderate	Outperform	Currently in the process of E&P in Australia.
SENEX ENERGY LIMITED	AUS	SXY	0.69	Energy	Oil, Gas & Cons. Fuels	High	Not Rated	Drilling exploration shale wells in the Cooper Basin.
Europe								
ABB LTD	SWE	ABB	305.31	Capital Goods	Electrical Equipment	High	Not Rated	May benefit from lower cost of manufacturing due to lower gas prices.
ALSTOM SA	FRA	ALSO	8.92	Capital Goods	Electrical Equipment	Negative	Neutral	May lose out due to its high exposure to coal-fired power.
AMEC P.L.C.	GBR	AMEC	3.20	Energy	Energy Equip. & Service	Moderate	Outperform	Are reportedly interested in participating in the development of shale block in China.
ARKEMA GROUP	FRA	AKE	4.99	Materials	Electrical Equipment	High	Outperform	Elevated propylene prices in the US could support higher derivatives prices globally.
BP PLC	BP	GBR	81.13	Energy	Oil, Gas & Cons. Fuels	Moderate	Outperform	Exposure to US shale gas but lacks liquids exposure; involved in tight gas in Oman.
BURCKHARDT COMPRESSION	CHE	BCHN	1.04	Cap Goods	Machinery	High	Not Rated	Global leading manufacturer of turbo compressors which are highly exposed to LNG.
ENI	ITA	ENI	65.20	Energy	Oil, Gas & Cons. Fuels	Low	Outperform	They have a license to explore and produce shale in Poland (largest techically recoverable resources in Europe).
GEA GROUP AG	DEU	G1AG	4.63	Cap Goods	Machinery	Negative	Not Rated	May suffer from depressed demand for cooling towers required for coal fired power plants.
INVENSYS PLC	GBR	ISYS	2.61	Cap Goods	Machinery	High	Neutral	Supplier of process automation control technology for gas fired power plants, so would see orders increase.
OMV AKTIENGESELLSCHAFT	AUT	OMVV	9.15	Energy	Oil, Gas & Cons. Fuels	High	Underperform	One of few equity routes to play shale gas.
ROLLS ROYCE HOLDINGS PLC	GBR	RR	16.31	Cap Goods	Aerospace & Defense	High	Neutral	One of 2 major players in compressors for gas pipelines.
ROTORK P.L.C.	GBR	ROR	2.16	Cap Goods	Machinery	High	Outperform	May benefit growth of gas infrastructure as their valve actuators are used in pipelines and processing plants.
ROYAL DUTCH SHELL PLC	GBR	RDSb	135.60	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	Extensive exposure to shale in N. America, China and Ukraine. Benefits from low US gas prices as a chem producer.
SIEMENS AG	DEU	SIEGn	71.69	Cap Goods	Industrial Conglomerates	High	Outperform	Is a gas turbine manufacturer so could benefit from the move towards gas-fired power generation.
SOLVAY SOCIETE ANONYME	BEL	SOLB	8.57	Materials	Chemicals	Negative	Outperform	US oversupply of PVC due to shale cracking in the US will put downward pressure on Solvay's PVC margins.
STATOIL ASA	NOR	STL	441.80	Energy	Oil, Gas & Cons. Fuels	Low	Underperform	Exposure to US shale including 2 liquids-rich plays and low-cost dry gas.
SULZER AG	SUN	CHE	4.83	Capital Goods	Machinery	High	Neutral	Could benefit from increased demand in centrifugal pumps which are used around the well to transport water.
TENARIS S.A.	LUX	TENR	17.48	Energy	Energy Equip. & Service	Moderate	Underperform	Could benefit from the increased demand of steel pipes used in casing of wells and extraction of gas.
TOTAL SA	FRA	TOTF	92.91	Energy	Oil, Gas & Cons. Fuels	Low	Neutral	Exposure to shale in Poland, Argentina and US, and tight gas in China.
VALLOUREC	FRA	VLLP	4.85	Cap Goods	Machinery	High	Neutral	Could benefit from the increased demand of steel pipes used in casing of wells and extraction of gas.
WEIR GROUP PLC (THE)	GBR	WEIR	3.89	Cap Goods	Machinery	High	Neutral	Could benefit from increased demand in pressure pumps / fluid ends / service as a result of shale gas boom.
YARA INTERNATIONAL ASA	NOR	YAR	81.30	Materials	Chemicals	Negative	Outperform	As European nitrogen producers, they will face relatively higher costs due to higher European gas prices.
Americas								
AGRIUM INC	USA	AGU	15.86	Materials	Chemicals	High	Not Rated	Could continue to benefit from increased margins in nitrogen production due to low shale gas pricing.
ALPHA NATURAL RESOURCES	USA	ANR	2.01	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	May benefit from additional rail and port expansions to foster continued export growth from Appalachia.
ALTAGAS LTD	CAN	ALA.	3.50	Energy	Oil, Gas & Cons. Fuels	High	Not Rated	Exposed to processing and other infrastructure in Alberta and British Columbia
ANADARKO PETROLEUM	USA	APC	37.62	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Dominant position in the Wattenberg play - growing at 20% CAGR & providing some of the highest returns in US E&P.
APACHE CORP	USA	APA	29.87	Energy	Oil, Gas & Cons. Fuels	High	Outperform	It has exposure to both NZ and Argentinian shale gas.
ARCH COAL INC	USA	ACI	1.59	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	Western port would offer them access to the Asia Pacific Basin.
BANKERS PETROLEUM LTD	CAN	BNK.	0.72	Energy	Oil, Gas & Cons. Fuels	High	Not Rated	One of few equity routes to play shale gas.
CANADIAN NATIONAL RAILWAY	USA	CNI	39.55	Transportation	Road & Rail	High	Neutral	Benefit from 'crude-by-rail'. Involved in bringing materials into and out of shale plays.
CANADIAN PACIFIC RAILWAYS	USA	CP	17.35	Transportation	Road & Rail	High	Neutral	Benefit from 'crude-by-rail'. Involved in bringing materials into and out of shale plays.
CARRIZO OIL & GAS INC	USA	CRZO	0.84	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	Exposure to Barnett shale gas fields.
CATERPILLAR INC	USA	CAT	57.11	Cap Goods	Machinery	High	Outperform	Intentions to launch LNG powered locomotives.
CF INDUSTRIES HOLDINGS INC	USA	CF	13.97	Materials	Chemicals	High	Not Rated	Could continue to benefit from increased margins in nitrogen production due to low shale gas pricing.
CHEVRON CORP	USA	CVX	210.87	Energy	Oil, Gas & Cons. Fuels	Moderate	Outperform	Exposure to shale in Eastern Europe and in China.
CHICAGO BRIDGE & IRON CO	USA	CBI	4.06	Capital Goods	Construction & Engineer	High	Neutral	One of the best positioned based on the number of verticals the company can benefit from and taking into consideration the potential for dollars spent.
CLEAN ENERGY FUELS CORP	USA	CLNE	1.15	Energy	Oil, Gas & Cons. Fuels	High	Not Rated	Is a leader in CNG and LNG fuelling stations.
CLOUD PEAK ENERGY INC	USA	CLD	1.23	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	Western port would offer them access to the Asia Pacific Basin.
CONOCOPHILLIPS	USA	COP	70.55	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	They have a license to explore and produce shale in Poland.
CONSOL ENERGY INC	USA	CNX	7.70	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	May benefit from additional rail and port expansions to foster continued export growth from Appalachia.
CSX CORP	USA	CSX	20.20	Transportation	Road & Rail	High	Outperform	Could benefit from LNG locomotives.
CUMMINS INC	USA	CMI	19.88	Cap Goods	Machinery	High	Outperform	Are developing natural gas engines for truck manufacturers.
DEVON ENERGY CORP	USA	DVN	21.25	Energy	Oil, Gas & Cons. Fuels	High	Moderate	Large US gas and NGL exposure and emerging liquids portfolio
DOW CHEMICAL	USA	DOW	37.24	Materials	Chemicals	High	Outperform	Could benefit from a cost advantage from shale gas at least until 2015.16.

Source: Credit Suisse Research, Datastream

Exhibit 181: Shale plays by region (continued)

Name	Country	Symbol	Market Cap (bil) Local	GICS Group	GICS Industry	Sensitivity	CS recommendation	Explanation
Americas								
DRESSER-RAND GROUP INC	USA	DRC	4.07	Energy	Energy Equip. & Service	High	Not Rated	Produces turbo compressors which are highly exposed to LNG.
EASTMAN CHEMICAL CO	USA	EMN	9.53	Materials	Chemicals	Moderate	Not Rated	Could benefit from a cost advantage from shale gas.
EMERSON ELECTRIC CO	USA	EMR	37.31	Cap Goods	Electrical Equipment	Moderate	Outperform	Supplier of process automation control technology for gas fired power plants, so would see orders increase.
ENBRIDGE ENERGY PARTNERS	USA	EEP	8.37	Energy	Energy Equip. & Service	High	Outperform	Leading pipeline franchise for oil imports to USA from Canada; assets well positioned for emerging shale play.
ENBRIDGE INC	CAN	ENB.	33.50	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Could benefit from growth in the pipeline industry in North America.
ENBRIDGE INCOME FUND	CAN	ENF	1.14	Energy	Oil, Gas & Cons. Fuels	n/a	Neutral	n/a
ENCANA CORP	USA	ECA	15.50	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	Exposure to Montney shale gas fields.
ENERGY RECOVERY INC	USA	ERII	0.17	Cap Goods	Machinery	High	Neutral	Launching a cost reducing device for gas processing market, so could benefit from a global gas boom.
ENTERPRISE PRODUCTS	USA	EPD	45.00	Energy	Energy Equip. & Service	High	Outperform	Assets placed in virtually every natural gas, NGL, or crude growth basin to take advantage of the shale revolution.
EOG RESOURCES INC	USA	EOG	32.16	Energy	Oil, Gas & Cons. Fuels	High	Neutral	Leading position in the crude oil window of the Eagle Ford Shale.Has strong positions in the Bakken and Permian Basin.
EQT MIDSTREAM LP	USA	EQM	1.06	Energy	Energy Equip. & Service	High	Neutral	Roughly 20-25% of acreage in the Marcellus can potentially be dropped down to EQM from parent EQT.
EXXON MOBIL CORP	USA	XOM	405.74	Energy	Oil, Gas & Cons. Fuels	High	Neutral	Could benefit from a cost advantage from shale gas at least until 2015.16.
FEDEX CORP	USA	FDX	28.35	Transportation	Air Freight & Logistics	High	Neutral	Company is piloting several LNG powered tractors in its Freight division.
FLOWSERVE CORP	USA	FLS	7.15	Cap Goods	Machinery	High	Outperform	Could benefit from increased demand in centrifugal pumps which are used around the well to transport water.
FLUOR CORP	USA	FLR	9.72	Cap Goods	Construction & Engineer	Moderate	Outperform	Are reportedly interested in participating in the development of shale block in China.
FOSTER WHEELER AG	USA	FWLT	2.55	Capital Goods	Construction & Engineer	High	Outperform	One of the best positioned based on the number of verticals the company can benefit from and taking into consideration the potential for dollars spent.
GARDNER DENVER INC	USA	GDI	3.41	Cap Goods	Machinery	High	Outperform	Could benefit from increased demand in pressure pump manufacturing.
GENERAL ELECTRIC CO	USA	GE	225.56	Cap Goods	Industrial Conglomerates	High	Outperform	#1 in gas turbines globally, and it is refreshing its product suite.
GENESIS ENERGY LP	USA	GEL	2.86	Energy	Energy Equip. & Service	High	Outperform	Assets well positioned to take advantage of demands from the large growth in oil and liquids production.
HALLIBURTON CO	USA	HAL	31.54	Energy	Energy Equip. & Service	High	Outperform	As the largest provider of hydraulic fracturing services worldwide, is a likely beneficiary of the shale gas revolution.
HECKMANN CORP	USA	HEK	0.68	Energy	Energy Equip. & Service	High	Outperform	Could see benefits from increased demand in pipeline for shale.
HONEYWELL INTERNATIONAL	USA	HON	48.29	Cap Goods	Aerospace & Defense	High	Neutral	Could see benefits in its UOP business which plays a role in helping to extract and cleanse natural gas.
ITRON INC	USA	ITRI	1.75	Technology	Electronic Equipment	High	Neutral	Should benefit from increased demand in upstream metering equipment for distribution infrastructure.
KANSAS CITY SOUTHERN	USA	KSU	8.89	Transportation	Road & Rail	High	Outperform	Benefit from 'crude-by-rail'. Involved in bringing materials into and out of shale plays.
KBR INC	USA	KBR	4.36	Capital Goods	Construction & Engineer	High	Outperform	One of the best positioned based on the number of verticals the company can benefit from and taking into consideration the potential for dollars spent.
KINDER MORGAN ENERGY	USA	KMP	28.69	Energy	Energy Equip. & Service	High	Outperform	Leading multiline MLP with pipeline access to most active or emerging shale basins.
LYONDELLBASELL INDUSTRIES	USA	LYB	31.09	Materials	Chemicals	High	Outperform	Could benefit from a cost advantage from shale gas at least until 2015.16.
LUXFER GROUP	USA	LXFR	0.29	Cap Goods	Industrial Conglomerates	High	Outperform	A leader in CNG cylinders for cars, trucks and buses.
MAGELLAN MIDSTREAM	USA	MMP	9.82	Energy	Energy Equip. & Service	High	Neutral	Leading refined products pipeline franchise with potential to generate relatively high distribution growth.
MARATHON OIL CORP	USA	MRO	21.33	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Low cost way to play growing high return production in the Eagle Ford Shale with exploration optionality on top.
MARATHON PETROLEUM CORP	USA	MPC	20.82	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Benefiting from low refining/chemical costs and growth potential in logistics
MARKWEST ENERGY PARTNERS	USA	MWE	6.28	Energy	Energy Equip. & Service	High	Outperform	Leading provder of midstream services in the Marcellus and Utica shale plays.
NATIONAL OILWELL VARCO INC	USA	NOV	29.02	Energy	Energy Equip. & Service	High	Not Rated	Beginning to produce pressure pumps used in shale gas E&P.
NEXEN INC	CAN	NXY.	14.07	Energy	Oil, Gas & Cons. Fuels	n/a	Underperform	Not mentioned
NOBLE ENERGY INC	USA	NBL	18.09	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Dominant position in the Wattenberg play - growing at 20% CAGR & providing some of the highest returns in US E&P.
NORFOLK SOUTHERN	USA	NSC	19.45	Transportation	Road & Rail	High	Outperform	Benefit from 'crude-by-rail'. Involved in bringing materials into and out of shale plays.
NUCOR CORP	USA	NUE	13.26	Materials	Metals & Mining	Moderate	Outperform	Could benefit from lower cost natural gas through the construction of a new DRI facility.
ONEOK PARTNERS LP	USA	OKS	61.58	Energy	Energy Equip. & Service	High	Outperform	One of the larger publically traded MLPs with large capacity assets.
ORION ENERGY SYSTEMS INC	USA	OESX	0.03	Cap Goods	Electrical Equipment	High	Not Rated	Offers oilfield services for Chinese shale gas.
PDC ENERGY INC	USA	PDCE	1.01	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Our play for exposure to emerging Utica play
PEABODY ENERGY CORP	USA	BTU	7.35	Energy	Oil, Gas & Cons. Fuels	Moderate	Outperform	Western port would offer them access to the Asia Pacific Basin.
PENN WEST PETROLEUM LTD	CAN	PWT.	5.35	Energy	Oil, Gas & Cons. Fuels	Moderate	Underperform	Exposure to Cordova shale gas fields.
PENTAIR LTD	USA	PNR	10.07	Cap Goods	Machinery	High	Neutral	Could benefit from increased demand in centrifugal pumps which are used around the well to transport water.
PETROBRAS ARGENTINA S.A.	ARG	PER	3.20	Energy	Oil, Gas & Cons. Fuels	Moderate	Not Rated	Exposure to shale in Latin America and New Zealand.
PHILLIPS 66	USA	PSX	36.47	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Benefiting from low refining/chemical costs and growth potential in logistics
PLAINS ALL AMERICAN PIPELINE	USA	PAA	15.39	Energy	Energy Equip. & Service	High	Outperform	Leading operator of oil infrastructure assets - well positioned in nearly every major crude production growth area.
QUANTA SERVICES INC	USA	PWR	5.75	Capital Goods	Construction & Engineer	High	Outperform	Best positioned to benefit as spend in gas pipeline should be significant.
RANGE RESOURCES CORP	USA	RRC	10.51	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Large acreage holder in low cost Marcellus gas play
ROCKWELL AUTOMATION	USA	ROK	11.36	Capital Goods	Electrical Equipment	High	Outperform	May benefit from lower cost of manufacturing due to lower gas prices.
ROSETTA RESOURCES INC	USA	ROSE	2.27	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Eagleford exposure
SCHLUMBERGER LTD	USA	SLB	96.38	Energy	Energy Equip. & Service	High	Neutral	Fraccing crews could benefit from the growing E&P of shale gas.
SM ENERGY CO	USA	SM	3.11	Energy	Oil, Gas & Cons. Fuels	Moderate	Not Rated	Exposure to Eagle Ford shale gas fields.
SPX CORP	USA	SPW	3.15	Cap Goods	Machinery	Negative	Neutral	May suffer from depressed demand for cooling towers required for coal fired power plants.
TAG OIL	CAN	TAO	0.36	Energy	Oil, Gas & Cons. Fuels	High	Outperform	One of 2 biggest players of New Zealand shale oil.
TALISMAN ENERGY INC	CAN	TLM.	11.24	Energy	Oil, Gas & Cons. Fuels	High	Neutral	Have successfully hit shale gas in Poland for the 3rd time.
TRANSALTA CORP	CAN	TA.	3.74	Utilities	Independent Power Proc	Negative	Underperform	May suffer from lower power prices due to increased shift from less emission friendly power sources to natural gas.
TRANSCANADA CORP	CAN	TRP.	32.26	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Could benefit from growth in the pipeline industry in North America.
UNION PACIFIC	USA	UNP	58.23	Transportation	Road & Rail	High	Outperform	Benefit from 'crude-by-rail'. Involved in bringing materials into and out of shale plays.
UNITED STATES STEEL CORP	USA	X	3.23	Materials	Metals & Mining	Moderate	Neutral	Have announced plans to benefit from cheap natural gas.
WASTE CONNECTIONS INC	USA	WCN	4.08	:ial & Professiona	Commercial Services &	High	Outperform	May benefit from increased disposal of frac related materials.
WEATHERFORD INTERNATIONAL	USA	WFT	8.23	Energy	Energy Equip. & Service	High	Neutral	Fraccing crews could benefit from the growing E&P of shale gas.
WESTLAKE CHEMICAL CORP	USA	WLK	5.14	Materials	Chemicals	High	Not Rated	Could benefit from a cost advantage from shale gas at least until 2015.16.
WESTPORT INNOVATIONS INC	CAN	WPT	1.53	Capital Goods	Machinery	High	Not Rated	May benefit from spurred demand in natural gas engines.

Source: Credit Suisse Research, Datastream

Exhibit 182: Shale plays by region (continued)

Name	Country	Symbol	Market Cap (bil) Local	GICS Group	GICS Industry	Sensitivity	CS recommendation	Explanation
Asia								
ADARO ENERGY TERBUKA	IDN	ADRO	45,100.21	Energy	Oil, Gas & Cons. Fuels	Negative	Neutral	They may remain profitable being amongst the low cost coal producers, but volume growth could be constrained.
ANTON OILFIELD SERVICES	HKG	3337	7.19	Energy	Energy Equip. & Service	High	Not Rated	Offer services to Chinese gas blocks, so could benefit from increased Chinese shale gas extraction.
CHINA OILFIELD SERVICES	HKG	2883	73.72	Energy	Energy Equip. & Service	High	Outperform	To benefit from shale drilling onshore China in the future.
CHINA SHENHUA ENERGY	HKG	1088	632.49	Energy	Oil, Gas & Cons. Fuels	High	Outperform	In talks with Statoil to launch E&P of shale oil and gas.
CHUBU ELECTRIC POWER	JPN	9502	788.76	Utilities	Electric Utilities	High	Not Rated	Exposure to potential Canadian shale gas, with prospects that some gas produced could be imported to Japan.
CIMC ENRIC HOLDINGS LIMITED	HKG	3899	5.53	Cap Goods	Machinery	High	Not Rated	Offer CNG and LNG transportation for Chinese shale gas.
CNOOC LIMITED	HKG	883	751.17	Energy	Oil, Gas & Cons. Fuels	High	Outperform	Drilled initial positive shale wells in AU.
DENSO CORPORATION(C)	JPN	6902	2,153.36	utos & Componen	Auto Components	High	Outperform	Could benefit from increased demand in fuel injection systems for NGVs.
DONGFANG ELECTRIC CORP	HKG	1072	29.38	Cap Goods	Electrical Equipment	High	Neutral	Has formed partnership with MHI to supply gas turbine equipment.
EVEREST KANTO CYLINDER LTD	IND	EKCL	3.13	Materials	Containers & Packaging	Moderate	Not Rated	Could benefit from increased demand in CNG cyclinders.
FANUC CORPORATION(C)	JPN	6954	2,787.09	Capital Goods	Machinery	High	Neutral	May benefit from lower cost of manufacturing due to lower gas prices.
FORMOSA CHEMICALS & FIBRE CORPC	TWN	1326	392.03	Materials	Chemicals	Negative	Neutral	Negatively effected by the emergence of low cost shale gas.
FORMOSA PLASTICS	TWN	1301	471.31	Materials	Chemicals	Negative	Outperform	US subsidiary, Formosa USA to build a 0.8mn ton/yr shale gas cracker in Texas by 2016
GAZPROM OAO	RUS	GAZPS	104.10	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	Pipeline gas development plans.
HARBIN ELECRIC CO LTD	HKG	1133	9.20	Cap Goods	Electrical Equipment	High	Outperform	Has formed partnership with GE to supply gas turbine equipment.
HARUM ENERGY TERBUKA	IDN	HRUM	13,770.34	Energy	Oil, Gas & Cons. Fuels	Negative	Outperform	They may remain profitable being amongst the low cost coal producers, but volume growth could be constrained.
HILONG HOLDING LIMITED	HKG	1623	4.12	Energy	Energy Equip. & Service	High	Not Rated	Offers oilfield services for Chinese shale gas.
HONGHUA GROUP LIMITED	HKG	196	6.61	Energy	Energy Equip. & Service	High	Not Rated	The rig maker could benefit from increased Chinese shale gas extraction.
INDIKA ENERGY TBK	IDN	INDY	7,606.88	Energy	Oil, Gas & Cons. Fuels	Negative	Outperform	They may remain profitable being amongst the low cost coal producers, but volume growth could be constrained.
INDO TAMBANGRAYA MEGAH	IDN	ITMG	46,778.90	Energy	Oil, Gas & Cons. Fuels	Moderate	Neutral	Has a strong balance sheet and dividend payment.
INPEX CORPORATION(C)	JPN	1605	1,617.34	Energy	Oil, Gas & Cons. Fuels	High	Not Rated	Has acquired mining concessions in Canada.
KEIHIN CORPORATION(C)	JPN	7251	85.20	utos & Componen	Auto Components	High	Underperform	Could benefit from increased demand in fuel injection systems for NGVs.
KOREA GAS	KOR	036460	5,387.57	Utilities	Gas Utilities	High	Neutral	Is buying gas from Sabine Pass so offering a new source of LNG to Asia.
KUNLUN ENERGY COMPANY	HKG	135	129.42	Utilities	Gas Utilities	High	Outperform	Is developing LNG transportation business.
MARUTI SUZUKI INDIA LTD	IND	MRTI	426.98	utos & Componen	Automobiles	High	Outperform	May benefit from further growth NGVs.
MITSUBISHI CORPORATION(C)	JPN	8058	2,558.85	Cap Goods	Trading Companies & D	High	Not Rated	Is located in Canada where it has exposure to potential LNG.
MITSUI & CO., LTD.(C)	JPN	8031	2,115.11	Capital Goods	Trading Companies & D	High	Not Rated	Is expanding development of Eagle Ford shale and have stakes in Marcellus shale.
NANYA PLASTICS CORPORATION	TWN	1303	410.67	Materials	Chemicals	Negative	Underperform	May be negatively effected by the emergence of low cost shale gas.
OSAKA GAS CO., LTD.(C)	JPN	9532	678.79	Utilities	Gas Utilities	High	Not Rated	Exposure to potential Canadian shale gas, with prospects that some gas produced could be imported to Japan.
PERUSAHAAN GAS NEGARA	IDN	PGAS	111,502.44	Utilities	Gas Utilities	High	Outperform	Will benefit for abundant and cheap shale gas in the future, to support the expansion in the LNG regasification capacity.
PETROCHINA CO LTD	HKG	857	1,954.66	Energy	Oil, Gas & Cons. Fuels	High	Neutral	Is working with Shell, and Conoca on shale gas exploration.
PT ABM INVESTAMA	IDN	ABMM	7,777.69	Energy	Oil, Gas & Cons. Fuels	Negative	Neutral	They may remain profitable being amongst the low cost coal producers, but volume growth could be constrained.
QINGHAI SALT LAKE POTASH	CHN	000792	39.22	Materials	Chemicals	Negative	Not Rated	Plans to build CTO (Coal to Olefins) technologies which is more expensive than natural gas.
SHANGHAI ELECTRIC GROUP	HKG	2727	49.11	Cap Goods	Electrical Equipment	High	Not Rated	Has formed partnership with Siemens to supply gas turbine equipment.
SINOPEC CHINA	HKG	386	756.05	Energy	Oil, Gas & Cons. Fuels	High	Neutral	Has signed deals with BP, Total, Exxon and Chevron to work on shale.
SPT ENERGY GROUP INC	HKG	1251	4.49	Energy	Energy Equip. & Service	High	Not Rated	Offer services to Chinese gas blocks, so could benefit from increased Chinese shale gas extraction.
SUMITOMO CORPORATION(C)	JPN	8053	1,281.53	Capital Goods	Trading Companies & D	High	Not Rated	Exposure to LNG in Maryland.
TAMBANG BATUBARA BUKIT	IDN	PTBA	34,446.77	Energy	Oil, Gas & Cons. Fuels	Negative	Outperform	They may remain profitable being amongst the low cost coal producers, but volume growth could be constrained.
TOKYO GAS CO., LTD	JPN	9531	1,044.18	Utilities	Gas Utilities	High	Not Rated	Exposure to potential Canadian shale gas, with prospects that some gas produced could be imported to Japan.
WEICHAI POWER CO., LTD.	HKG	2338	65.18	Cap Goods	Machinery	High	Not Rated	Are developing natural gas engines.
YANTAI JEREH	CHN	2353	20.97	Energy	Energy Equip. & Service	High	Not Rated	The rig maker will benefit from increased Chinese shale gas extraction.

Source: Credit Suisse Research, Datastream

Impact on Global Gas Markets

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Where and when

We provide a detailed analysis of the shale potential offered by key regions globally. It becomes apparent that significant differences in geology suggest that bringing this onstream may take longer than the market's more bullish forecasts suggest.

We summarize key points below.

- **Canada: Where the game has already changed.** Unconventional extraction technology has been applied with success to select basins (e.g., Horn River, Montney in B.C.) and is spurring exploration in more (e.g., Duvernay in Alberta). However, while Canadian producers have embraced the technology, gas derived cash flows have plummeted due to the spill-over effect of US supply growth and resultant low North American natural gas prices. Canadian gas supply in aggregate has been in steady decline for a number of years. The sector has been particularly hard hit given the basis differential to NYMEX embedded within local AECO prices. Despite declining aggregate supply, B.C. gas production has grown given the emphasis on higher productivity tight/shale gas in the province. In the bigger picture, a more self-sufficient US gas market is forcing Canadian producers and Canadian governments to examine with urgency the prospect of new LNG export markets for Canadian gas supply with implications for the equity ownership of Canadian gas resources.
- **Argentina: very prospective (if you ignore the politics).** The shale opportunity is volumetrically material, supported by in-place infrastructure and with several initial drilling successes under its belt. The primary obstacle at this point appears to be sector confidence in political stability to allow significant capex allocations to the Argentinean shale space.
- **Australia: CBM execution woes; too early to call shale.** The bloom is firmly off the rose for the lucky country's first foray into unconventional gas, with sanctioned CBM to LNG projects struggling with rampant cost escalation and public stakeholder issues, leading us to conclude further CBM to LNG projects are not likely in the near term. With less than 20 shale wells drilled Australia's shale gas story appears to much in its infancy to determine whether it could be a major supply source of shale gas in the future
- **Europe: woe is me.** One would think that Europe would view shale prospectivity as a god- (or in this case Putin) send, but despite resources prospectivity France, Bulgaria, Romania and the Netherlands have banned shale developments, with Germany, & the Czech Republic and Sweden considering a ban. Given severe stakeholder headwinds we suspect shale prospectivity in Europe is low for the foreseeable future. That said a reliance on imports from Russia could drive some political backing for domestic gas supply.
- **New Zealand: early stages but hopeful.** Although not as well known as its shale cousins in North America, there appears to be significant potential in the East Coast basin of New Zealand, where the Waipawa and Whagai shales could hold between 270 billion and 520 billion barrels of oil. Overall, these two shales appear to have potential for shale oil development but still remain in the early exploratory phase.

Canada – shale already a game-changer

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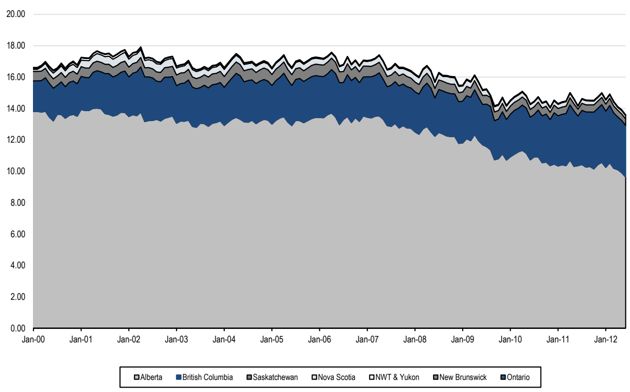
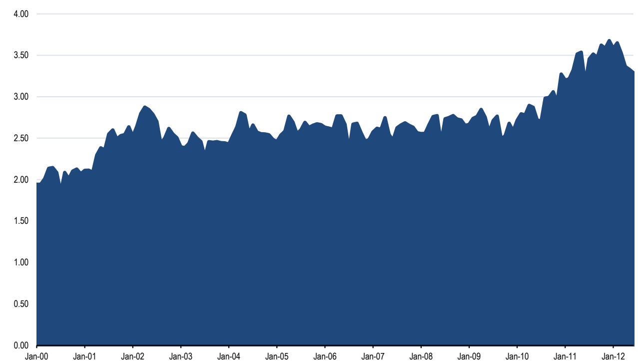
The US "shale gas revolution" has already been a game-changer for Canada. Unconventional extraction technology has been applied with success to select basins (e.g., Horn River, Montney in B.C.) and is spurring exploration in more (e.g., Duvernay in Alberta). However, while Canadian producers have embraced the technology, gas-derived cash flows have plummeted due to the spill-over effect of US supply growth and resultant low North American natural gas prices. As illustrated in Exhibit 183 below, Canadian gas supply in aggregate has been in steady decline for a number of years. The sector has been particularly hard hit given the basis differential to NYMEX embedded within local AECO prices. Despite declining aggregate supply, B.C. gas production has grown given the emphasis on higher productivity tight/shale gas in the province, as shown in Exhibit 184.

Exhibit 183: Canadian gas production (Bcf/d)



Source: NEB

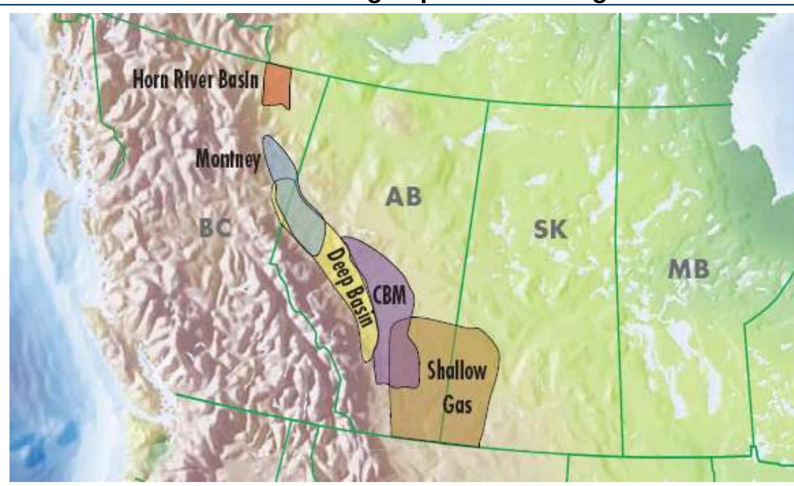
Exhibit 184: B.C. gas production (Bcf/d)



Source: NEB

The impact of shale has been profound on Canadian gas investment flows, with a total shift from low productivity shallow gas and CBM assets in central and south east Alberta to high productivity tight/shale gas assets in northeast B.C. and within the Deep Basin.

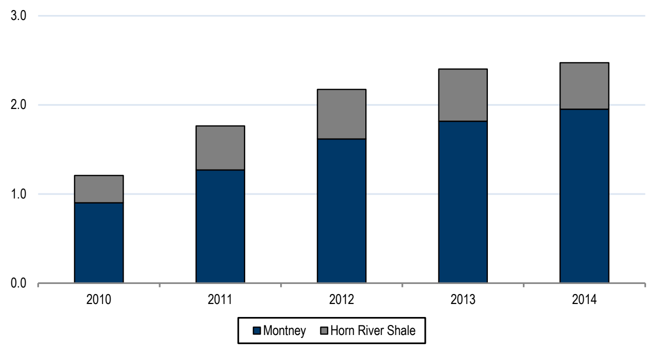
Exhibit 185: Western Canada natural gas production regions



Source: NEB

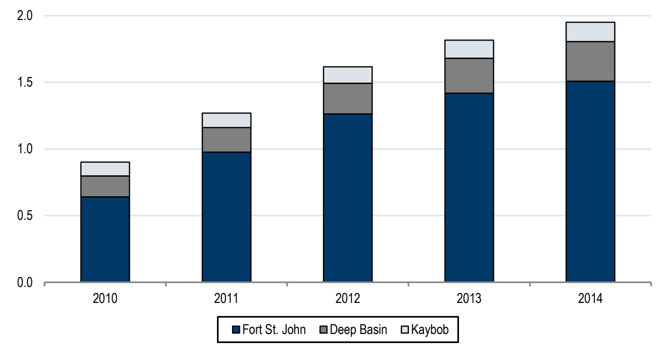
Investment flows have shifted further to favor the lowest cost dry gas (e.g., Montney over Horn River) with a view to developing LNG export capacity, or to liquids-rich gas plays that could be economical for producers at today's gas prices (e.g., Alberta Montney, Duvernay). Even within liquids-rich gas plays, those with a relatively high proportion of high value condensate are being targeted in order to maximize economics.

Exhibit 186: Montney & Horn River outlook (Bcf/d)



Source: NEB (Short Term Gas Delivery report, mid-case gas price)

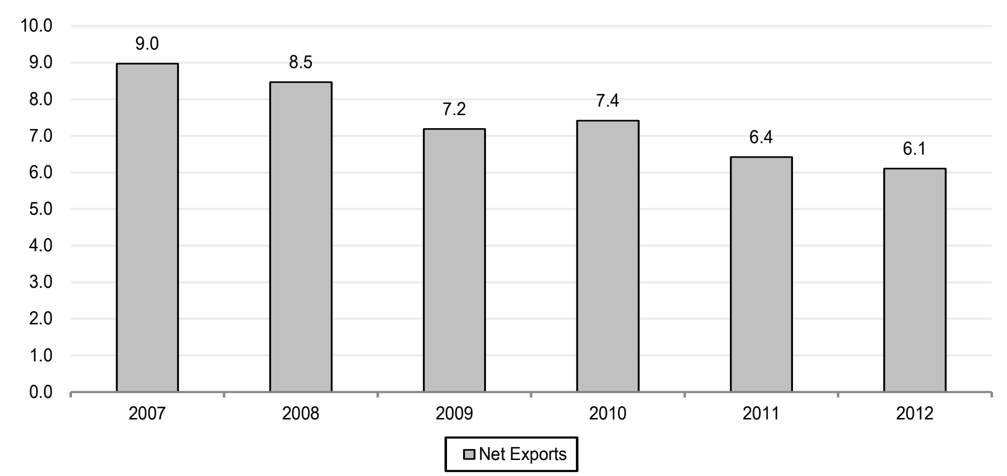
Exhibit 187: Montney outlook, area breakdown (Bcf/d)



Source: NEB (Short Term Gas Delivery report, mid-case gas price)

In the bigger picture, a more self-sufficient US gas market is forcing Canadian producers and Canadian governments to examine with urgency the prospect of new LNG export markets for Canadian gas supply. Already Canadian gas exports to the US (Canada's only current export market) are in decline.

Exhibit 188: Canadian net exports to the US (Jan-July comparison)



Source: GLJ

Given the significant imbalance between capital requirements to exploit Canada's significant tight/shale gas resource and weak producer cash flows, all participants seem to recognize the need for external funding sources. The sector has already seen a number of joint ventures created to stimulate investment in emerging tight/shale gas resources, many with Asian participants. Additional transactions of this nature are likely, in our view, as is consolidation of projects to provide resource certainty for future LNG projects. As shown in Exhibit 189 below, Canada could see the construction of several LNG liquefaction plants on its West Coast toward the end of the decade, positioning the country to participate in global gas markets.

Exhibit 189: Possible Canadian LNG export projects (Bcf/d)

Status	Project	Operator	Partners	Location	Export Capacity	Trains	Export Licence	FID	Indicated Startup
Pre-FID	Kitimat LNG	Apache (40%)	EOG/Encana (30% each)	Kitimat	1.40	2	Y	1Q13	2017+
Feasibility	N/A	BC LNG	Various	Kitimat	0.23	2	Y	N/A	2015+
Feasibility	LNG Canada	Shell (40%)	KOGAS/CNPC/Mitsubishi (20% each)	Kitimat	3.40	4	Filed	N/A	2019+
Feasibility	N/A	BG	N/A	Prince Rupert	N/A	N/A	N	2015	2019+
Feasibility	N/A	PETRONAS (100%)*		Prince Rupert	1.00	2	N	2014	2018+
Feasibility	N/A	N/A	CNOOC/Inpex**	West Coast, BC	N/A	N/A	N	N/A	N/A
Feasibility	N/A	N/A	Imperial/Exxon	West Coast, BC	N/A	N/A	N	N/A	N/A

** assumes closing of the proposed Progress acquisition*
*** assumes closing of the proposed Nexen acquisition*

Source: Company data, Credit Suisse

Argentina

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Renewed interest in Argentina's unconventional resources got traction at the end of 2010 with YPF's 4.5bn tcf tight gas discovery in southern Loma La Lata, followed by an April 2011 report by the EIA which highlighted Argentina as having the third largest shale recoverable reserves globally. YPF has since announced a number of shale oil discoveries in the Vaca Muerta formation in Neuquen and Mendonza, and Ryder Scott has certified over 14bn boe of net resources. There seems to be a number of compelling reasons for the oil industry (and investors) to be upbeat about the unconventional resource opportunity in Argentina. At the same time, there are also a number of challenges that will need to be overcome, such as oil services, macro-politics, and environment (and in YPF's case we would also add financing).

We provide an overview of these factors below. For further details, please refer to our more detailed note *YPF: Why Argentina should not kill Vaca Muerta, April 2012*.

Exhibit 190: Technically recoverable shale gas resources globally (tcf)

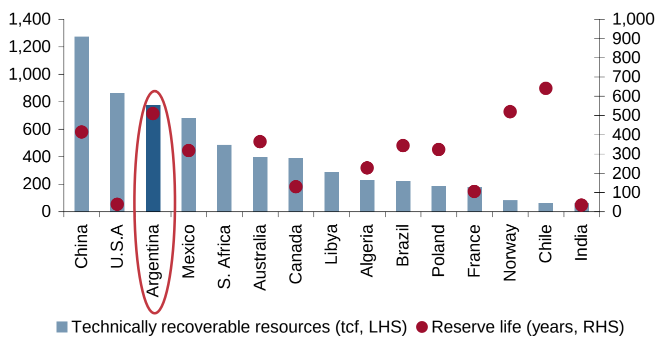
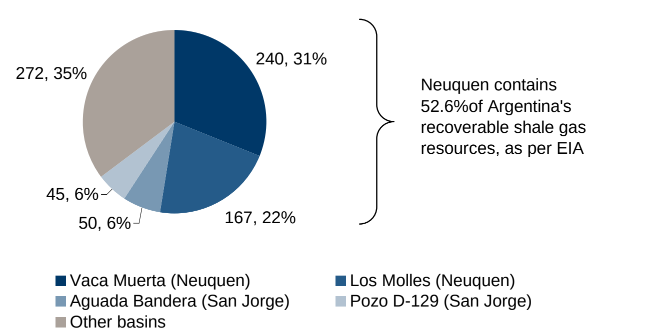


Exhibit 191: Technically recoverable shale gas resources in Argentina (tcf and % of total)



Source: EIA – World Shale Gas Resources: An Initial Assessment, April 2011

The opportunity

Indeed, there seems to be a number of compelling reasons for the industry (and investors) to be upbeat about the opportunity in unconventional Argentina, which so far has focused in the Vaca Muerta formation in the Neuquen province:

- **"World-class resource."** There seems to be growing consensus from industry experts and oil companies on the geological quality of Vaca Muerta. From thickness, to depth, areal extent, organic content, depositional environment, mineralogy, pressure and thermal maturity, a number of geological characteristics seem to make Vaca Muerta a "world-class" resource, including if compared with established shale plays in the US.

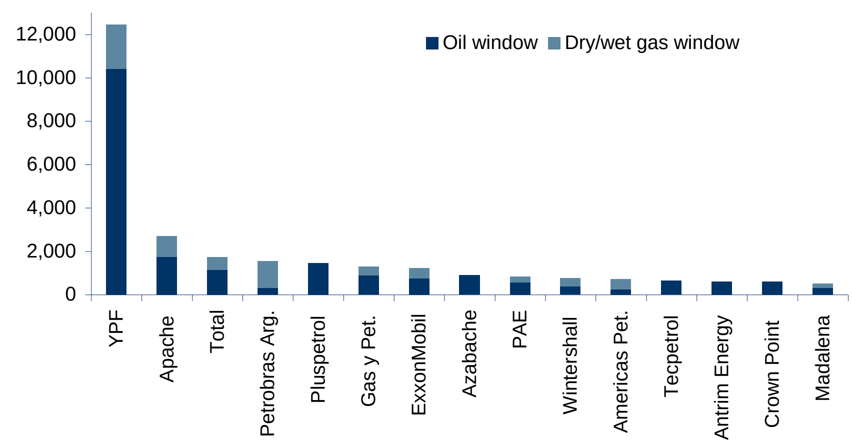
Exhibit 192: Summary comparison of Vaca Muerta and key shales in the United States

		Vaca Muerta	Barnett	Haynesville	Marcellus	Eagle Ford (oil window)	Bakken
TOC	%	6%	5%	2%	12%	4%	12%
Thickness	*meters*	200	91	76	61	61	30
Depth	*meters*	3,000	2,286	3,658	2,057	2,287	1,829
Area	*Km^2*	30,000	16,726	23,310	245,773	5,180	51,800
Reservoir pressure	*psi*	9,000	3,525	10,800	3,375	4,502	4,200
Pressure gradient	*psi/ft*	0.65-1.0	0.5	0.9	0.5	0.6	0.7
STOOIP	*mmbbl*	?	-	-	-	114,000	200,000
STOOIP/km2	*mmbbl/km^2*	33-58	-	-	-	22.0	3.9
OGIP	*bcf*	-	422,337	717	1,499	-	-
OGIP/km2	*bcf/km^2*	-	25.3	30.8	6.1	-	-

Source: YPF, SPE, EIA, WoodMackenzie, UG Harts

- **Industry has stepped in.** Another factor that gives us more confidence on the potential of the opportunity in Argentina unconventional is the stamp of credibility that is being given by the oil industry, with large integrated and E&P companies like Total, ExxonMobil, BP, Petrobras, Apache and EOG already present in the basin, besides YPF (Exhibit 193). And more recently (14 September 14 2012), YPF has signed a MoU with Chevron to study a partnership in both conventional and unconventional assets.

Exhibit 193: Company acreage positioning in unconventional Neuquen (km^2)

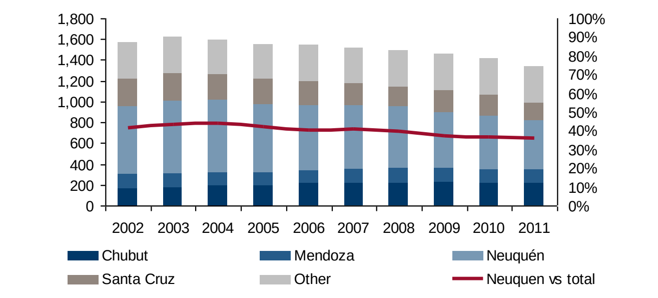


Source: Wood Mackenzie based on YPF delineation of the oil and gas window in Neuquen

- **Encouraging first results from YPF** are providing tangible evidence to Vaca Muerta's potential, both from volumes and productivity standpoint. 2011 had already been an impressive year, with oil potential being in evidence after a 150mmbbls discovery announced in May, a number which increased to 741mmbbls of oil in November with further appraisal. And 2012 has started even better, with a Ryder Scott competent person report mentioning the potential of 14bn boe (net to YPF) in around half of the company's acreage. In March, YPF announced further one billion boe (gross, un-risked) still in the Vaca Muerta formation, but in an 2,000km^2 area not certified by Ryder Scott in the Mendonza province. And in September, YPF announced five new shale discoveries: three in D-129 (San Jorge) and two in the Vaca Muerta gas window.
- **Infrastructure is in place.** Even though the excitement about Neuquen's potential as an unconventional play picked up relatively recently, it is important to highlight that it is the highest producing basin in Argentina, responding for c.50% of the country's total production. This is important because it means that physical and non-physical

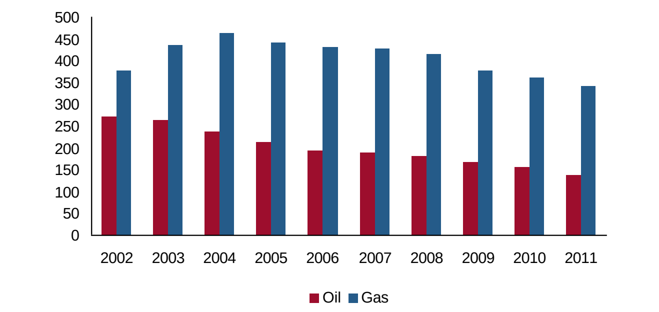
infrastructure related to oil and gas monetization is already in place. Gas y Petroleo Neuquen (the provincial oil company that has regulatory and oversight responsibilities) estimates that the province has enough pipeline capacity to accommodate an increase in unconventional activity for the next five to six years.

Exhibit 194: Argentina's oil and gas production by basin



Source: Secretaria de Energia Argentina. Note: volumes in kboed

Exhibit 195: Neuquen oil and gas production over time



Source: Secretaria de Energia Argentina. Note: Volumes in kboed

- **Beyond Vaca Muerta.** We also make the point that although most of the near-term activity is likely to focus in the Vaca Muerta formation, there are ten other formations spread through Argentina that can hold interesting unconventional potential. Of those, Los Molles and Agrio seem to be the most promising and are also located in Neuquen. Exhibit 196 provides a summary of unconventional potential in Argentina.

Exhibit 196: Unconventional potential in Argentina – Vaca Muerta, Los Molles and Agrio

Unconventional potential	Formation	Province	Thickness	TOC	Comment
	Vaca Muerta	Neuquen	25-450m	3-8%	Extremely prolific, 'world class' source for liquid hydrocarbons
	Los Molles	Neuquen	100-800m	1-5%	Mixed quality for oil and gas. Expanded gas kitchen.
	Agrio	Neuquen	50-400m	2-5%	Dominantly oil prone. Marine deposition.
	D-129	San Jorge	100-2000m	1-3%	Huge thickness in gas window but depth is significant. Lacustrine
	Los Monos	Paleozoic	500-100m	0.5-1%	Mainly gas prone, but poor to mediocre quality. Limited TOC.
	Lower Inoceramus	Austral	50-400m	0.5-2%	Low TOCs, mostly thermally immature. Lacustrine
	Cacheuta	Cuyo	50-400m	3-10%	Low thermal maturity. Lacustrine. Reduced area.
	Pre-Cuyo	Neuquen	50-1,100m	2-11%	Highly variable maturities and thickness. Reduced area
	Tobifera	Austral	-	1-3%	Very scattered rock information. Lacustrine. Variable maturity.
	Neocomiano	San Jorge	500-1,800m	0.5-3%	Mostly on the dry gas window.
	Yacoraite	Cretaceous	5-50m	0.5-6%	Reduced thickness , thermally immature.

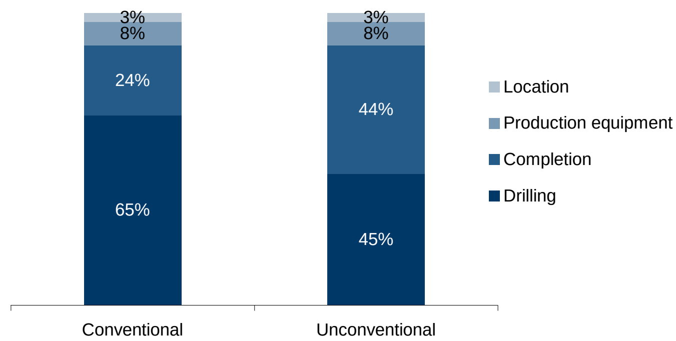
Source: Legarreta and Villar – Geological and Geochemical Keys of the Potential Shales Resoruces, Argentina Basins, 2011.

The challenges

Needless to say, there are a number of challenges to develop any exploration frontier in any region in the world, and this is not different for shale development in Argentina. We broadly label the various challenges we think are relevant in three categories: oil services, macro-politics, and environmental.

- **Oil services challenges.** We have mentioned before that the fact that Neuquen is Argentina's highest producing basin is helpful for the development of shale, as some of the physical and non-physical infrastructure is already in place, including pipelines, roads, rigs, workforce, etc. However, that does not mean that developing the unconventional resource will be easy. In our view, two issues are particularly relevant in this case. (1) Cost structure and critical bottlenecks, of which we highlight drilling rigs, fracturing equipment and crews, and skilled labor. (2) How to incentivize suppliers to come to Argentina will be an important issue given the country is already operating at a tight capacity, meaning that incremental rigs and fracturing equipment will have to come from abroad. Oil services companies likely need long term contracts and adequate pricing to offset the inherent risks of entering a new country.

Exhibit 197: Typical cost breakdown in conventional vs. unconventional wells



Source: Sinopec Argentina

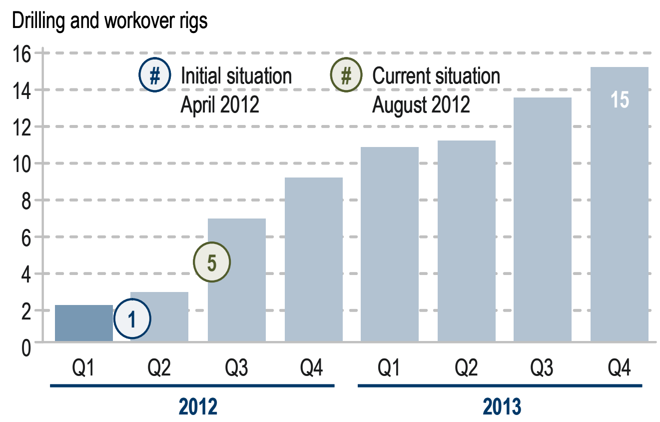
- **Macro-politics** are probably the challenge/impediment most in vogue currently, especially after YPF's nationalization. We think a number of topics are important when looking at the macro and political interference, such as: (1) upstream and downstream pricing policy, with natural gas pricing being the most critical, (2) export tax regime, which effectively forces companies to supply the domestic market by capping the export price at $42-47/bbl, (3) incentives, such as the Gas Plus program, (4) export-related $-repatriation measures and concerns related to dividends, and (5) government intervention, with concerns recently showing up via nationalization for YPF, and provinces (notably Chubut and Santa Cruz) revoking concessions from the company when Repsol was still in control. On the national intervention front, we have had a number of different models that have succeeded and failed in the LatAm oil industry: Venezuela and Bolivia interventionism models so far have not worked (on the contrary), whereas Colombia's more liberalized model has been extremely successful. Brazil is positioned somewhere in the middle, with Petrobras having stellar success on the discovery of pre-salt resources, but challenges becoming more evident now the country is moving towards a 'development reality' phase.
- **Environment and water.** Water is the theme which we find most difficult getting data on or specific regulation in Argentina. YPF believes water is not an issue as the company is already used to dealing with high amounts of water due to 90%+ watercuts in its conventional fields. The company is also comfortable with water supply, with the province of Neuquen providing good water sources from rivers, notably in Loma La Lata. Potential risks on the water/environment subject could come on aquifer contamination from hydraulic fracturing fluids.

Furthermore, we think the industry and investors need to keep in mind how fast Argentinean shale will be able to ramp up and increase efficiency, given the experience with the US shale. In general terms, it took two years for the US to double its unconventional rig-count from around 350 rigs in early 2009, to a 700 rigs level early 2011 that is being sustained until these days. This impressive ramp-up in shale activity carries two side-effects: (1) a beneficial increase in efficiency (in the Bakken, the average time to drill a well decreased from 40 days to around 28 days in the past three years), but also (2) significant cost-inflation (also in Bakken, well costs rose from $7m to $10m in the past year).

Exhibit 198: Oil drilling rigs fleet

Source: YPF

Exhibit 199: Gas drilling rig fleet



Source: YPF

For instance, YPF's business plan assumes that the company will be able to increase the number of oil rigs from 36 today to 55 by end 2013, and from 5 gas rigs to 15 rigs in the same period (Exhibits 198 and 199). If correctly executed, YPF's business plan can indeed be transformational for the company, the shares, and the country, as YPF plans to grow upstream and downstream volumes by 32-37% and create 10,000 jobs by 2017. But to achieve that, the company needs to invest c.$7.5bn per year. So far, we think there are few concrete elements that we can hold on to see how YPF will manage to finance this capex. The company expects financing to be 70% via internally generated cash-flows, 12% via shale partnerships, and 18% via the debt markets. We discuss YPF's business plan later in this report.

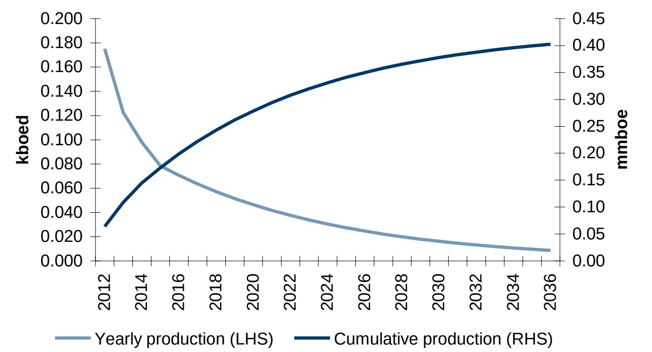
The economics

We take a number of steps to assess the economics of Vaca Muerta shale, and in particular YPF's acreage. We first start out by building individual vertical and horizontal "well-types" models, which enables us to explicitly model YPF's more 'certain' resource base, comprised by certified 3P reserves, contingent resources and resources attached to the recent Mendonza wells. We then move on to less explicit $/boe and $/acre metrics in YPF's remaining acreage, keeping in mind aspects like liquids content, ease of monetization and recent deals in Argentina. We summarize our economic analysis below:

- **Vertical well economics.** We get to an NPV/well of $0.69m, implying in a $1.72/boe, yielding and IRR of 19%. Key assumptions for our base-case vertical well modeling include IP rates of 350boed, 402 thousand boe EUR, 70% oil content, $7m/well cost, 10% USD-inflation on lifting and infrastructure opex, oil prices rising from $72/bbl to $100/bbl in five years, gas prices within the $2-3/MMBtu range.
- **Horizontal well economics.** We get to an NPV/well of $5.29m, implying in a $5.20/boe, yielding and IRR of 35%. Key assumptions for our base-case horizontal well modeling include IP rates of 900boed, one million boe EUR, 70% oil content, $13m/well cost. The remaining assumptions are similar to our vertical well model.
- **Economics of the "certain" resource base.** In this exercise, we assume YPF will develop 1,544mboe of resources (comprised by certified 3P reserves, contingent resources and resources attached to the recent Mendonza wells) on its own. We get to a total project NPV of $1,544m or $4.0 per YPF ADR, yielding a project IRR (unlevered) of 22%. We use a conservative production ramp-up, keeping in mind the oil services challenges that we described in the previous section. We assume YPF will be producing 25mmbbls of oil by 2016, therefore becoming fully integrated with its refining capacity by that period.

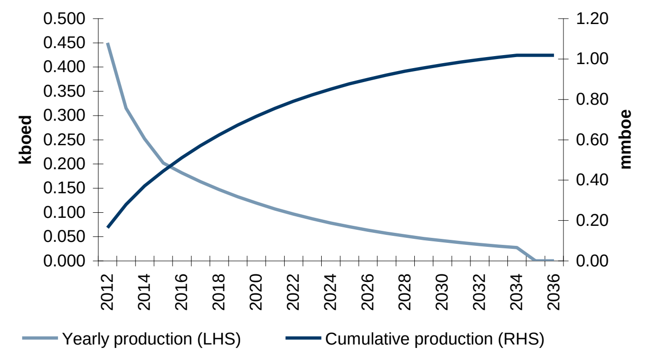
- **Risked prospective resources.** Because so far the liquids content is low (34%), this type of resource base would only be economical in our view with gas prices higher than current levels. Assuming monetization at $5/MMBtu via the Gas Plus program, we would value YPF's prospective net 1,235mmboe at $1.2/boe or $3.8/YPF ADR.
- **Remaining un-appraised, non-certified acreage.** For YPF's remaining, un-appraised, non-certified shale acreage of 1.4 million acres, we use a range of $700-5,000/acre multiples, getting us to a conservative low case of $2.50/ADR up to blue-sky $18/ADR.

Exhibit 200: Vertical well production profile



Source: YPF

Exhibit 201: Horizontal well production profile



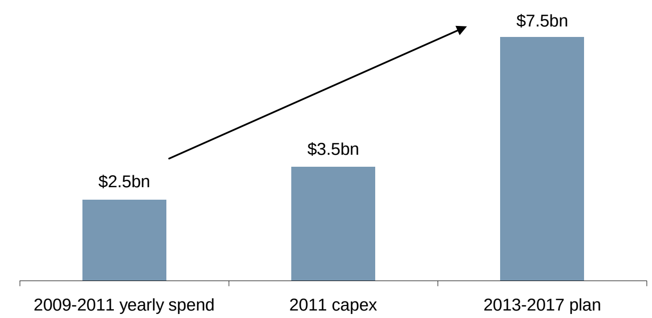
Source: YPF

YPF business plan overview

Because YPF is so far the most relevant oil company in Argentina (and that includes shale), we believe it is useful to provide a brief overview of the company's recently announced business plan, with a focus on Upstream and pricing.

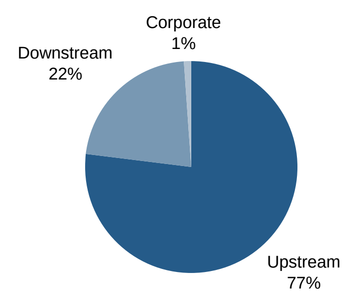
YPF plans to spend $37.2bn over the next five years, representing a significant increase in the spend rate from $1.5-3.5bn/year in 2007-11 to $7.5bn/year in 2013-17.

Exhibit 202: Past yearly spend vs. business plan



Source: YPF

Exhibit 203: 2013-2017 $37.2bn spend split by division

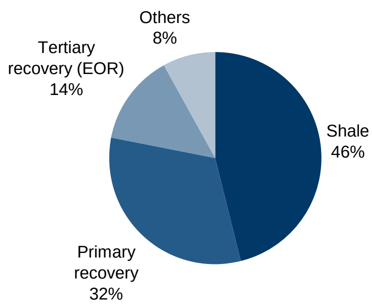


Source: YPF

There is a strong focus in Upstream, which represents 77% of investments, vs. 22% for Downstream. YPF plans to grow oil and gas production by 32% (7% CAGR), increase diesel and gasoline volumes sold by 37% (8% CAGR), and create 10,000 jobs by 2017.

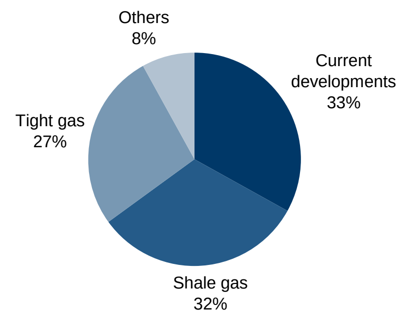
We believe 2012 and 2013 can be seen as transition years in YPF's proposed plan. The company plans to reverse decline rates of 5% p.a in oil and 10% p.a in natural gas. 2013-2017 is a growth period, with average production on average 23-29% higher than current production. Oil-wise, most of the incremental production is expected to come from shale oil (46%), primary recovery (32%), and tertiary recovery EOR (14%). On the gas side, the most important sources of incremental production will be current developments (33%), shale gas (32%) and tight gas (27%).

Exhibit 204: Sources of incremental oil production



Source: YPF.

Exhibit 205: Sources of incremental gas production



Source: YPF.

With regard to pricing, there still exists a significant gap in YPF diesel and gasoline prices both from peers (c.15%) and to import parity (25-30%). Crude oil prices in Argentina are around $65/bbl. The pricing solution for gas is still unclear. There still exists a bifurcation in the market, with industrial users paying $4-6/MMBtu, but residential paying much less, in a way that the average price in Argentina is around $2.7/MMBtu. Gas Plus prices are between $4-7/MMBtu, and YPF is trying to come up with a wider, "modified" Gas Plus program that would allow for faster expedition of projects. YPF expects to announce a new price program "soon."

Australia: already a "mature" unconventional gas province

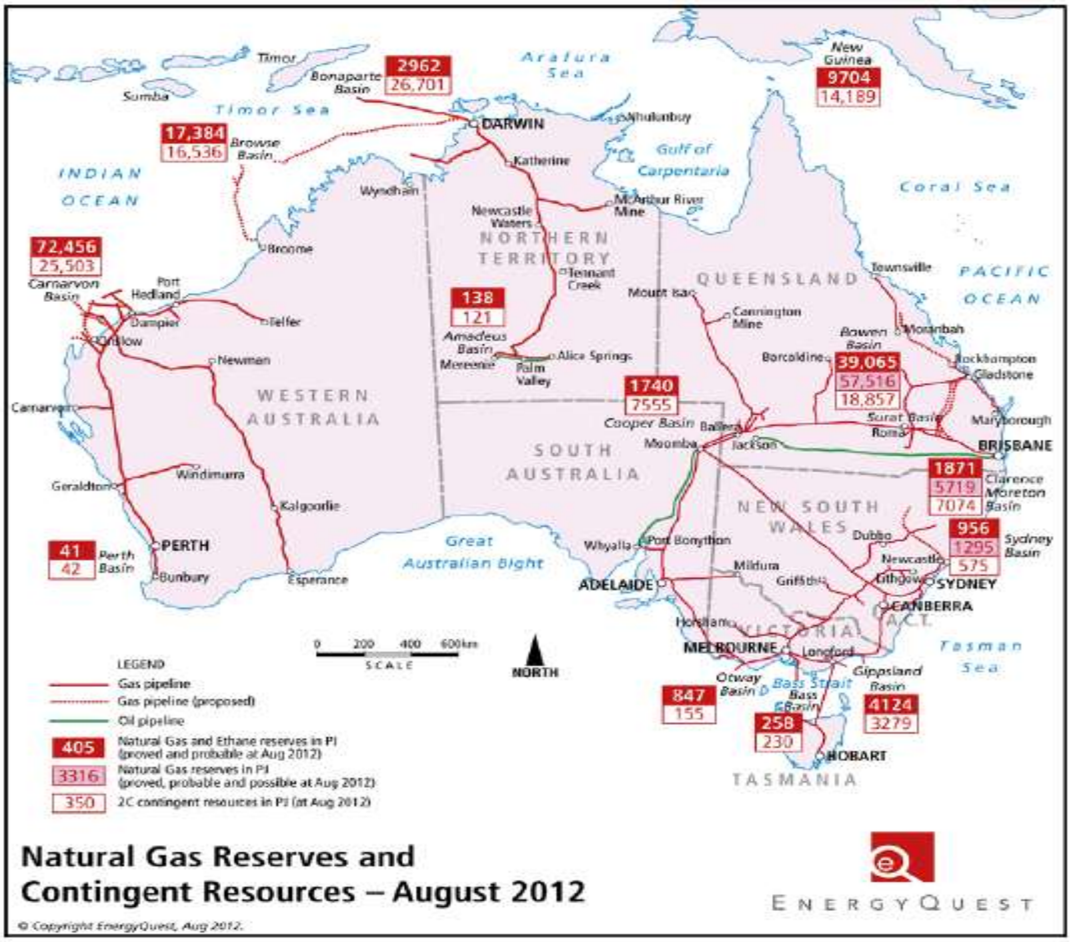
Multiple coal bed methane to LNG projects have been sanctioned and are now in the construction phase. Australia's vast natural gas resources (Exhibit 206) has led to a boom in LNG projects in recent years. In particular, the East Coast's significant coal bed methane resources will provide gas for three LNG projects already in construction, and potentially two more currently in planning

Exhibit 206: East coast CBM LNG projects

Project	Details	Operator/Key Shareholders	FID	Start-up	Capacity	Contracted
QC-LNG	Trains 1/2	BG, CNOOC (5% u/s 10% d/s), Tokyo Gas (1.25% u/s 2.5% d/s)	4Q10	2015	8.5mtpa	CNOOC 3.6mtpa; Singapore 2mtpa; Quintero 1.5mtpa; Tokyo Gas 1.2mtpa
GLNG	Trains 1/2	STO 30%, Petronas 27.5%, Total 27.5%, Kogas 15%	1Q11	2015/16	7.8mtpa	Kogas 3.5mtpa; Petronas 3.5mtpa
APLNG	Trains 1/2	ORG 37.5%, ConocoPhillips 37.5%, Sinopec 25%	3Q11/ 3Q12	2015/16	9.0mtpa	Sinopec 7.6mtpa; Kansai 1.0mtpa
Arrow LNG	Trains 1/2	Shell 50%; PetroChina 50%	2013	2017	8mtpa	***Project considered Speculative
Fisherman's Landing LNG	Train 1	LNG Ltd (100%)	2013	2015	1.9mtpa	***Project considered Speculative

Source: Company data, Credit Suisse

Exhibit 207: Australian natural gas reserves and contingent resources



Source: EnergyQuest

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- **Execution blues: the buildout is being hampered by cost blow outs, community opposition, gas deliverability.** The projects have not been without their challenges, with cost blow outs, strong community opposition to CBM production and gas deliverability major concerns. BG's QCLNG was the first cab off the rank to own up to cost blowouts. The project budget increased 35% from US$15bn at FID to US$20.4bn, with BG citing local market effects, a busy construction environment, increased cost of regulatory compliance and some scope changes as the reason. Next was Santos' GLNG project, choosing to "accelerate" pre-startup capex from US$16bn to US$18.5bn discussed below. APLNG is yet to adjust its capex budget, commenting at its Train 2 FID announcement in July this year that most of the capex blowout seen by QCLNG were already captured in APLNG's guidance of A$23bn, however there was no change to US$ guidance.

Exhibit 208: Comparison of capex/tpa for East Coast CBM to LNG projects

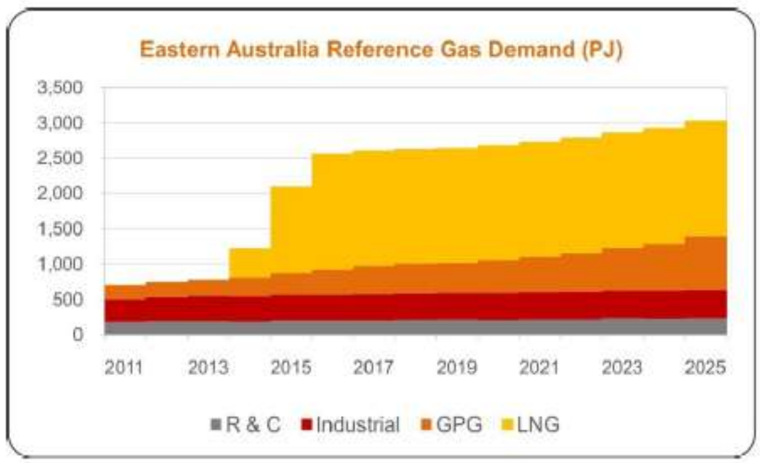
Project	Capex (US$bn)	LNG Output (mtpa)	US$/tpa
QCLNG	20.4	8.5	2,400
GLNG	18.5	7.8	2,372
APLNG	20.0	9.0	2,222

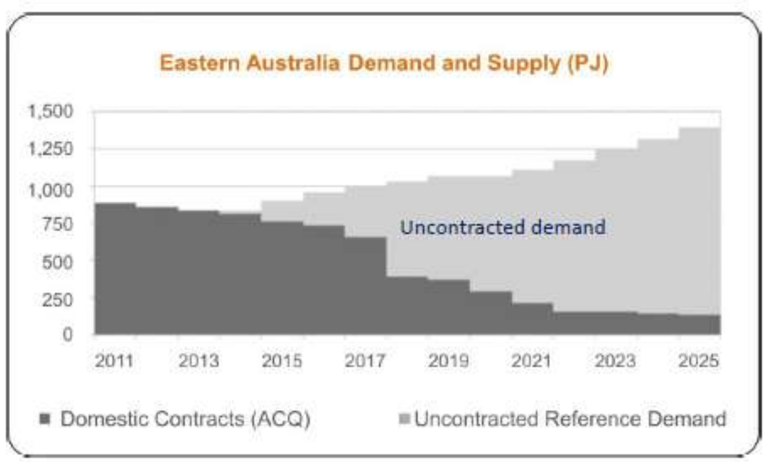
Source: Energy Quest

Investor nerves prompts Santos to provide more detail on GLNG

- **GLNG clarity has been provided, but economics not great…** STO 1H12 result presentation and conference call provided the most detailed update yet on GLNG deliverability noting that Train 2 is expected to begin production 6-9 months after Train 1 and will ramp up over two to three years. While this may be slightly longer than most had expected, we now have visibility on timing. First gas from Train 1 is on track for 2015 and will ramp up over a three- to six-month period. We note that CEO David Knox has remuneration incentive for first gas by 1 July 1 2015. While clarity is great, we wonder what the ramp up profile would have looked like without the accelerated capex and third-party gas deals? As it turns out, the offtake agreements do not require full production until 2019, so there is potential upside from a faster ramp up and additional cargoes. Beyond 2015, STO provided guidance on capex, noting that approximately 300 wells per year are required to sustain production at $2mn/well, equating to $600mn capex/year. STO claims the GLNG project exceeds its weighted average cost of capital. Our revised timing and ongoing capex forecasts equate to an IRR of 11.8%.
- **… but Santos will benefit from rising East Coast gas prices.** The GLNG project, in conjunction with APLNG and QCLNG, will cause a "permanent structural shift in East Coast gas demand" (Exhibit 209), which will have the effect of pushing up prices, re-rating STO's eastern Australia portfolio. STO currently has approximately 10,000PJ of 2P + 2C reserves/resources, including 3,000PJ of 2P of which 50% is currently uncontracted.

Exhibit 209: Eastern Australia gas demand supply forecast





Source: Beach Energy presentation, 30 August 2012.

- **NSW CBM regulatory environment is getting tougher.** The New South Wales government recently increased the area designated as Strategic Agricultural Land (SAL) for protection in the New England North West (Gunnedah Basin) meaning that over half of Santos acreage in the area is now classified as SAL, and will be subject to increased regulatory approval (the Gateway process) to deal with competing land uses. Importantly, the area of focus of STO's CBM (including that acquired from ESG) is to the south of Narrabri. This area is covered by state forests and therefore is not classified as Strategic Agricultural Land. We believe that most (if not all) of STO's current NSW CBM reserves (1,141 PJ) are derived from this acreage, and not materially affected by this updated legislation. The issue for STO is around its other CBM acreage in NSW, particularly north of Narrabri, and its plans for development given the increased regulation imposed on it.

Is shale the next big thing?

- **Too early to tell with only a handful of results to date. The code is not yet cracked.** The Australian shale sector is certainly heating up with an unprecedented level of activity over the past 12 months. Momentum is expected to continue with the first dedicated horizontal shale well expected to be drilled early next year. Focus to date has largely been on the Cooper Basin, South Australia with Santos, Beach and Senex at the forefront, and the Perth Basin in Western Australia where AWE and ORG are focused. The shales targeted have typically produced dry gas; however, AWE's Arrowsmith-2 well flowed both oil and gas to the surface from the Kockatea shale, before being shut in. It is evident that the shale oil and gas service sector is still immature, with only a handful of rigs and 1 frac spread (Exhibit 210) capable of drilling and fracking long horizontal wells currently in Australia. As a result, costs are still high and the gas price is not quite at the level required for economic production.

Exhibit 210: Australian shale wells

Well	Basin	Company	Interval, Fracs	Flow Rates
Moomba 191	Cooper Basin	STO, BPT, ORG	Roseneath, Epsilon, Murteree (REM) Shale - 3 fracs	2.6mmscfd stabilised (3.0mmscfd peak)
Holdfast 1	Cooper Basin	BPT	REM shale, Patchawarra formation - 7 fracs	2.0mmscfd
Encounter 1	Cooper Basin	BPT	REM shale, Patchawarra formation - 6 fracs	2.1mmscfd
Sasanof 1	Cooper Basin	SXY	REM shale, Patchawarra formation - 4 fracs	>0.2mmscfd (peak)
Arrowsmith 2	Perth Basin	AWE, NWE, Bharat	High Cliff Sandstong, Kockatea & Carynginia Shale, Irwin River Coal - 5 fracs	0.78mmscfd
Senecio 1	Perth Basin	AWE, ORG	Dongara and Wagina Sandstone - 2 fracs	1.0mmscfd
Woodada Deep 1	Perth Basin	AWE	Kockatea & Carynginia Shale, Irwin River Coal	Testing
Talaq 1	Cooper Basin	SXY	REM shale, Patchawarra Formation	Awaiting frac
Skipton	Cooper Basin	SXY	REM shale, Patchawarra Formation	Drilling
Marsden 1	Cooper Basin	BPT, STX	Toolachee Formation, REM shale, Patchawarra Formation	Testing
Davenport 1	Cooper Basin	BPT, STX	Toolachee Formation, REM shale, Patchawarra Formation	Testing
Halifax 1	Cooper Basin	ICN, BPT	REM shale, Patchawarra Formation	Drilling
Moonta 1	Cooper Basin	BPT	Toolachee Formation, REM shale, Patchawarra Formation	Testing

Source: EnergyQuest.

- **STO reported "commercial success" from the Moomba-191 vertical shale gas well** in the Cooper Basin. Dry gas flowed at a stabilized rate of 2.6 mmscf/d from the Roseneath, Epilson and Murteree (REM) shale targets. The well will be tied-in to STOs existing gas gathering infrastructure, with sales expected to commence in October, hence the "commercial success" tag. However, in reality the high cost of the well and current gas prices means STO is unlikely to get an economic return on this well.

- **Early days but a step in the right direction.** The Moomba-191 well was drilled with the aim of appraising the gas potential of the REM unconventional gas targets in the Moomba North area, and achieve gas flow to surface. Having successfully done this, the next step will be to prove the economics of large scale development of both vertical and horizontal wells with multi-stage fracs. We expect this will require a reduction in drilling and completion costs and gas prices higher than currently achieved. STO note that considerable cost saving could be achieved through utilizing existing depleted conventional wells and recompleting as shale wells. A dedicated horizontal shale gas well in the Moomba North area is now planned for early next year following the Moomba-191 success.

Exhibit 211: Australian shale service sector immature

Australia's shale oil & gas services sector

		
O&G drill rigs capable of drilling long horizontal shale wells	~1,150	~ 5
O&G drill rigs capable of drilling deep vertical wells	~1,900	< 20
'Frac spreads' capable of fraccing long horizontal shale wells	> 200	~1
'Frac spreads' capable of fraccing shallow coal seam gas wells	> 300	~3

Source: Stike Energy Company Presentation, 5 September 2012.

Unconventional Europe

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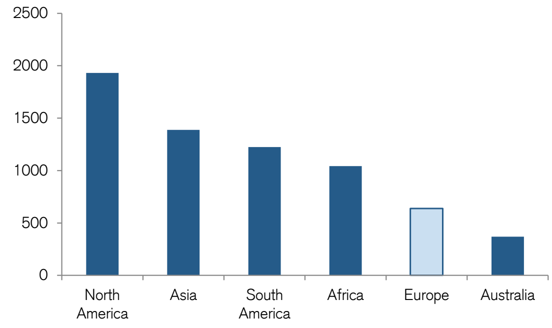
Geological and "above-ground" challenges

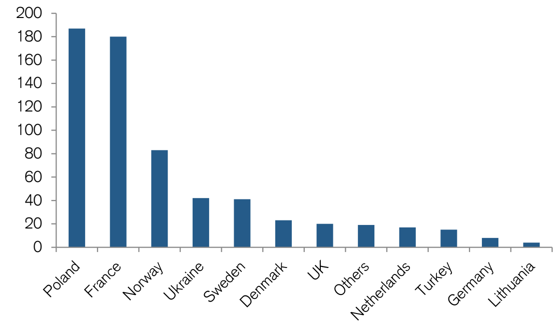
The shale gas revolution in the United States has driven interest among oil companies in Europe, hoping to replicate the success. According to the EIA, Europe has over 600 tcf of technically recoverable shale gas resources, with the majority of these contained within Poland and France. Although shale gas potential does exist, the conversion of this into an energy source is set to be a more challenging task than in the United States owing to more complex geology combined with a vastly different operating environment. One of the main challenges is the limited amount of publicly available research and exploration/production data.

Exhibit 212: World shale gas recoverable reserves (tcf)



Source: EIA

Exhibit 213: European shale recoverable reserves (tcf)



Source: EIA

Slow race to success

Poland has the largest technically recoverable resources (187 tcf according to the EIA), and is currently the European front-runner in terms of awarding licenses and commencing exploration, founded largely on their eagerness to break dependence on Russian imports.

Poland has awarded over 100 licenses to a combination of state firms and IOC's, including Chevron, ConocoPhillips, ENI and Marathon. ExxonMobil acquired 4 licenses in Poland in late 2008, but recently pulled the plug after two gas wells disappointed, concluding that flow rates were not commercial. This reaction by Exxon is very similar to their sharp exit from Hungary in 2009, after initial testing around the Mako Basin produced disappointing results. The remaining companies in Poland are hoping to prove Exxon wrong given that Poland so far has been leading the European shale gas race.

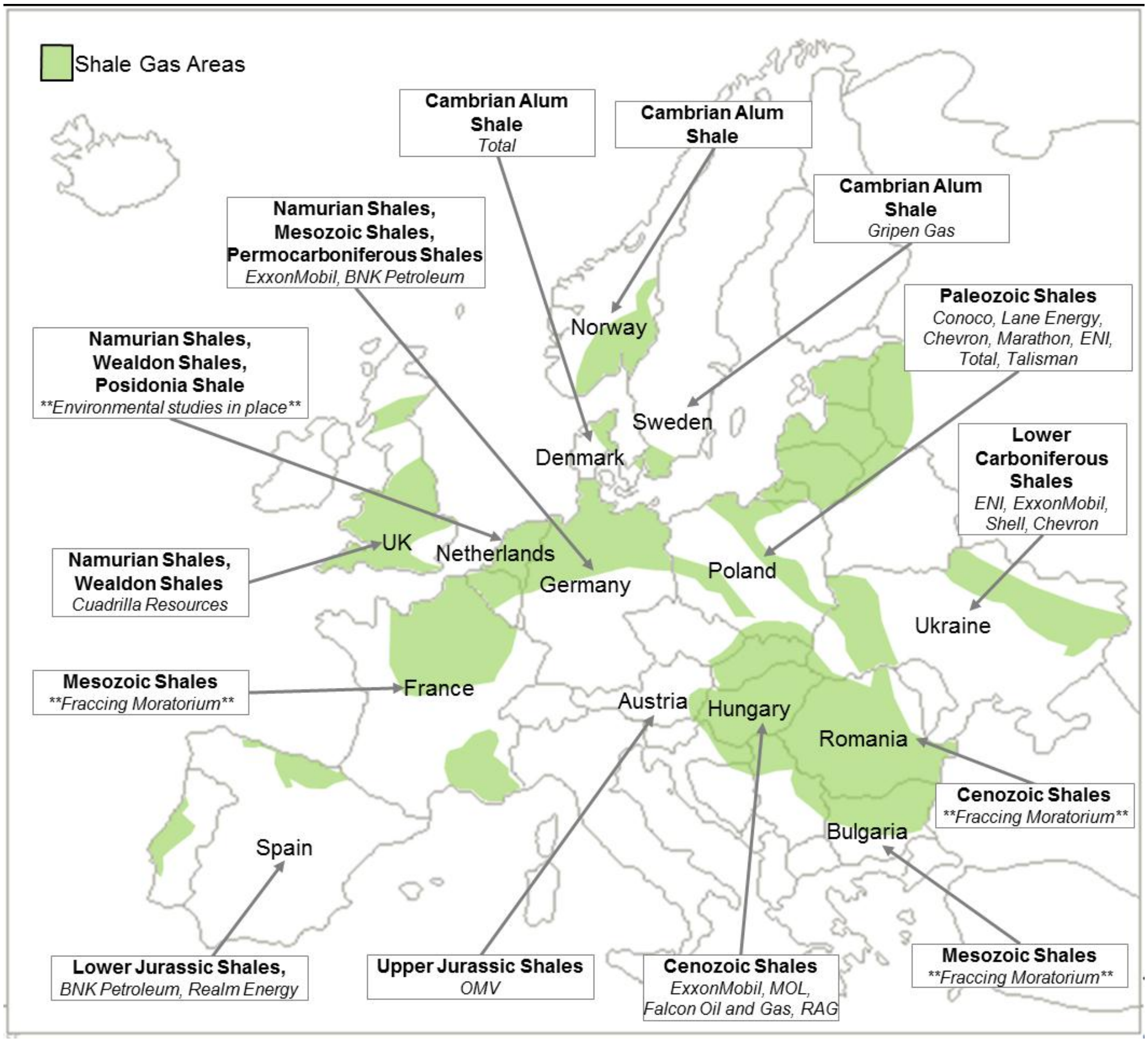
Chevron has drilled two exploratory wells in Poland and are evaluating the results and 3Legs Resources will also continue with operations on the Baltic coast. In July, San Leon announced they had successfully hit shale gas in the Baltic basin in Poland for the third time with partners Talisman. The gas interval is estimated to be over 100m thick in Lower Silurian and Ordovician shales.

Ukraine is also dependent on Russian imports, and has recently awarded licenses to Chevron and Shell. Ukraine has been a less attractive option to foreign investors because of restrictions on the size of exploration areas, which led to Marathon Oil's exit in 2008. A new government has begun to address these problems and has made important headway on change.

Germany has been touted by Exxon as having the most geological potential in Europe (both shale and CBM). A survey concluded earlier this year, "Shale gas reserves in Germany (as estimated in May 2012)," estimated 0.7-2.3 trillion m^3 can be extracted with the application of current technologies. The study concluded that shale gas production is economically feasible and environmentally safe. Exploration will continue up to 2015, although opposition is building amongst German citizens.

Other countries have had far more protests against the establishment of shale gas, with **France** being the first country in July 2011 to impose a shale moratorium. They were joined by **Bulgaria** in January 2012 and **Romania** in May 2012, while the **Netherlands** have put shale gas drilling on hold for a further year while an investigation is carried out into the environmental risks. The **Czech Republic** is also considering the move and opposition is building in **Sweden** and **Germany**.

Exhibit 214: Location of shale gas locations in Europe and company exposure



Source: Credit Suisse

Equity options

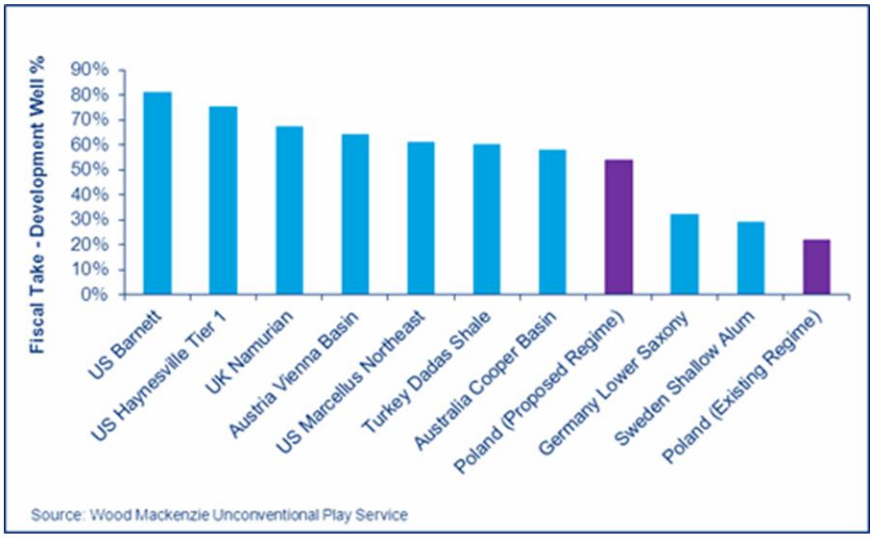
Investors wanting to play shale gas through the equity route are somewhat limited in Europe to BNK Petroleum or the majors (Exxon, Shell, Total, ENI, Chevron, OMV). A number of small private equity companies exist, particularly in the UK (Cuadrilla Resources, Dart Energy), but we do not expect the breadth of E&P names that exist in North America for example to exist until the exploration can be proven to lead to development and government support is in place.

Tax terms

Many of the current tax regimes are based on existing conventional onshore structures. Whilst there is growing demand to change this, governments and industry are aware that it is perhaps more critical to improve understanding of potential through the exploration stage.

On 16 October 2012, the Polish government published proposed changes to its hydrocarbon laws that sees the government increase their stake to 54% from 22%. Estimates from Wood Mackenzie suggest that breakeven prices have increased to $9.55/mcf from a previous $8.14/mcf, reducing Poland's competitive advantage, but providing some certainty at last.

Exhibit 215: Comparison of fiscal take for shale development



Source: Wood Mackenzie

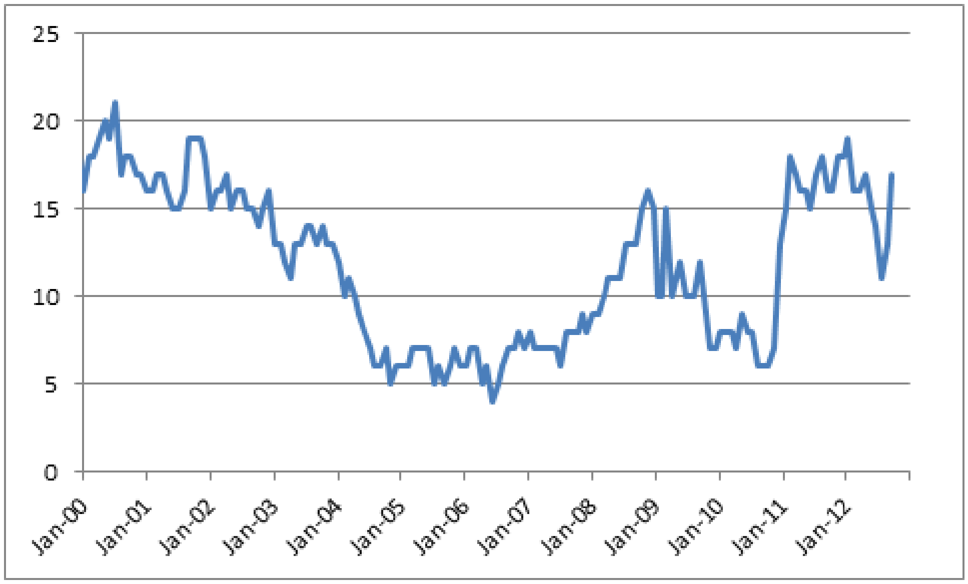
Rig availability

In terms of current activity, we look to the rig count in Poland, Germany, and the UK, which are active in shale gas exploration. While rig count has increased in these countries over the past year, it is by no means large. Poland is hoping to be the first European country with commercial production, but we envisage a bottleneck in the rig situation that could delay rapid production growth.

Wieslaw Prugar, president of Poland-based Orlen Upstream, commented last year that 20-25 rigs may be required in the near term in Poland, compared to 5 at present, and this number could increase up to 50 beyond 2020 if plays are proven. The problem is that drilling contractors are not willing to invest in a market that does not exist yet. In addition, a limited number of the rigs are sufficiently high capacity to drill deep, highly deviated wells, creating a substantial premium on newer rigs but higher costs for operators.

Rigs and frac crews will have to be suitable to the European operating environment, which means common US completion methods such as the "plug and perf" technique may not be suitable. These methods generally require high pump rates and significant amounts of horsepower on location. There are a number of frac crews already in Europe: Poland, for instance, has at least four companies offering crews, including Schlumberger, Halliburton and Weatherford.

Exhibit 216: Total rig count in Poland, Germany and the UK



Source: Baker Hughes.

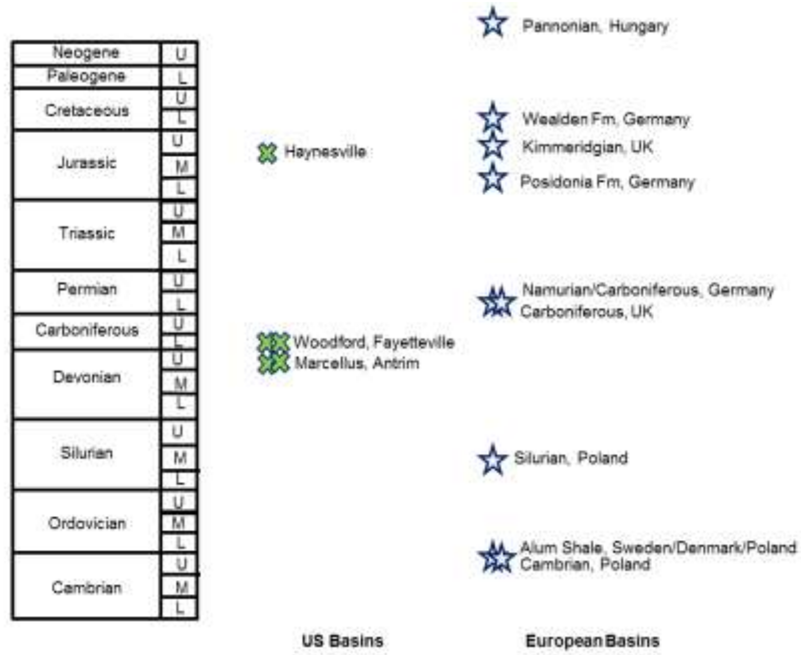
Geological differences

One key difference between the shale basins of the US are their large and shallow nature, that allows easy understanding and production than the deeper and more geologically complex basins in Europe. Deposition of the US shale basins tend to be concentrated over a short time period unlike the wide time frame in which the European basins were deposited. This makes a large difference in the time it takes to understand these basins and commercially, the deeper and more fragmented basins in Europe would be more complex to produce from, requiring further technological advances.

As well as structural differences between the shale basins in the US and Europe, the rock composition also differs. The European shales have a higher clay content than their American counterparts, this will present itself as an issue during the fracking stage of production as clay particles block pores and swell with water and do not allow the flow of water that is needed to produce shale gas.

This difference in reservoir depth and complexity creates a higher general cost for European shale, and a study from the Oxford Institute for Energy Studies (OIES), estimates this to be as much as 2-3 times higher than in the US, with additional water sourcing costs set to also be much more expensive, about 10 times higher than in the United States.

Exhibit 217: Age of shale basins in the US vs. Europe



Source: Credit Suisse

Difficult operating environment

- **Population density**: Beyond the geological difficulties there is the challenging operating environment of Europe too. The population density of Europe is far greater than the US, with the UK now about 260 people per km² versus only 32 people per km² in the US, according to the CIA World Factbook. This means less land available for drilling as well as the chance of greater public opposition.
- **Mineral rights**: In addition, European mineral rights primarily belong to the state rather than the land owners, this is unlike the situation in the US. This difference means that companies must obtain permission to the mineral rights as well as consent to use the land. As land owners will fail to benefit from the production of the gas their permission to land use is likely to be difficult. Furthermore local authorities must grant planning permission but do not receive royalties.
- **US skills transfer and data access**: In order for Europe to make a success out of shale gas, lessons should be learned from the successful US companies. A lot of the US companies are buying up shale gas licenses in Europe and this could benefit the progress of European development. However, unlike the US, Europe has very limited data available and well results are likely to remain confidential to the operator until at least the appraisal stage. This will further delay the timeline of European development and highlights the advantage that new US players have thanks to the need for US well log data to be disclosed.

  In order to overcome this data shortage, Gas Shales in Europe (GASH) was set up in 2009 as an interdisciplinary shale gas research initiative, sponsored by many of the IOC's. The goal of the project is to predict the potential for gas shales in Europe. This is a three year project with the first phase of results expected soon.

Environmental concerns

Environmental concerns have played a big part in the quest to unlock the shale gas potential in Europe. Fraccing moratoriums have been imposed in France (July 2011), Bulgaria (January 2012) and Romania (May 2012), whilst the Netherlands have put shale gas drilling on hold for a further year as an investigation is carried out into the environmental risks.

- **Induced Seismic Activity**: Increased seismicity (the release of energy from the earth caused by rocks breaking and sliding past each other) is one of the biggest concerns from the heavily populated European sites. Cuadrilla Resources were forced to suspend fracking operations in November 2011, after an investigation concluded that two minor earthquakes in the UK were caused from the injection of fluids into shale rocks.

  Although the tremors caused in Lancashire were not big enough to damage buildings, the worry is that this could risk the integrity of the well casings. Where wells have been drilled through natural aquifers, any damage to well-casings could create a serious potential leaking and contamination problem.

- **Contamination of groundwater**: Contamination of groundwater is possible through both well-casing failure and subsurface migration. Groundwater quality in the UK is generally very high and requires little or no treatment. This could cause a serious effect if interfered with and a number of measures need to be put into place to prevent this, further adding to the cost of production.

- **Greenhouse gas emissions**: The main component of natural gas is methane, a gas associated with global warming when released into the atmosphere. During the flowback phase of shale gas, as the fracturing fluid is returned to the surface, it brings along the natural gas released from the shale. Reduced Emission Completion (REC) technologies can now capture the emerging gas at the wellhead and are used increasingly.

- **Water sourcing and disposal**: According to a report by the UK's Tyndall Centre for Climate Change, fracking operations carried out on a 6 well pad would require 54,000 – 174,000 m^3 of water. This presents the problem of water shortage in Europe, particularly parts of central Europe.

  The second water issue if that approximately 10-40% of the fluid will return to the surface bringing with it the natural gas and added chemicals. This is also potentially harmful or environmentally damaging and operators need to provide a clear water management plan before operations can begin.

The Black Sea alternative

A decline in conventional reserves has been used as a key argument for shale gas exploration in Europe. The discovery of a major gas field in Romania's Black Sea in February this year could quash this reasoning.

OMV and ExxonMobil drilled the first deep water exploration well in the Romanian waters of the Black Sea and encountered 70.7m of net gas pay, giving a preliminary estimate of 1.5-3tcf for the accumulation. This was a significant find and has opened up the area.

The discovery has spurred on ExxonMobil and OMV, and in addition other IOC's including Total and Repsol, who are now attempting to prove up resources in the Ukrainian and Bulgarian Black Sea. The downside is the cost that this development will require, given difficulties in rig movements, high well costs ($250m) and subsea challenges. Even if this play works out, timing is not likely before the end of the decade.

The silver lining

Although there has been great objection to the development of shale gas in Europe, many European countries are still very keen to achieve some degree of energy independence. Their reliance on natural gas imports increases exposure to supply and geopolitical risk and gives back more control over local pricing. With dwindling conventional reserves in Europe, and projects in the Black Sea set to be very costly, the shale gas alternative is an attractive option and could help to offset this dependence and tackle growing demand.

Any development of shale gas resources will not only give European countries a higher energy independence but would also lead to an influx of new investment flows, as well as job creation and higher tax revenues.

For countries with a high coal and lignite position in their energy mix (e.g. Germany and Spain) shale gas could be a realistic alternative for allowing for the reduction of CO2 emission. This more positive environmental move will give countries a stronger position in the European Union Emission Trading Scheme (EU ETS), a CO2 allowance system that requires the monitoring and reporting of CO2 emissions.

The key to the success of European shale gas for now however lies firmly in the geological results. Once this is determined, more light will be shed on tax regimes and pricing to determine whether European countries are able reduce their energy independence.

Russia

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Bazhenov shale: too early to estimate

Russia arguably possesses one of the biggest shale gas reserve globally. Located in Western Siberia Bazhenov shale has a territory of about 1 million square kilometers. The shale layer is about 2 km deep but only 20-30 meters thick.

Due to its low permeability and very controversial exploration data the reserve estimates vary wildly, from 2 billion to 140 billion tons.

Despite very high oil density in the shale the recovery is estimated only at 7%, much lower that for the oil produced at traditional fields. At the same time oil of Bazhenov shale is of high quality, its chemical composition is close to the one of Brent with very low sulfur content

So far only Surgutneftegas has drilled about 600 wells (almost all vertical though) and the flow rates varied from 5 to 300 tons per day; 37% of the wells turned dry.

Exhibit 218: Bazhenov shale area

Source: Gazpromneft.

Nevertheless, the Russian government and the Russian state-owned oil companies have expressed keen interest in developing Bazhenov shale which is expected to replace falling domestic conventional oil production from 2020.

Rosneft in co-operation with Exxon and Salym Petroleum Development (SPD), a 50/50 joint venture of Gazpromneft and Shell have recently announced their plans to start active exploration activities in this area from 2013 actively using horizontal drilling with hydro-fracturing and other advanced drilling techniques employed by international majors.

The exploration active phase is expected to last for three years. The first commercial production, according to Gazpromneft, should be expected post 2020. The positive side of the project is that Bazhenov shale is situated in a mature oil producing region with all necessary infrastructure in place.

The project has significant challenges to become economically viable. Due to the capital intensive production, the operating expenses are estimated to be up to four times higher than the ones associated with conventional oil. Lifting costs could be up to $40/bbl which means that without significant tax concessions production of oil from Bazhenov will struggle to be profitable. Even with tax holidays Gazrpomneft estimates it needs min $60-70/bbl of oil price to develop Bazhenov.

The Russian government has already expressed it readiness to waive Mineral Extraction Tax for heavy oil production. Whether the Russian government is also ready to provide a much needed export duty reduction is still under question.

Bazhenov shale is a promising region with potentially significant oil reserves. At the same time it is too early to say whether it will be commercially developed and become economically viable.

New Zealand

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Opportunities on the East Coast

Although not as well known as its shale cousins in North America, there appears to be significant potential in the East Coast basin of New Zealand, where the Waipawa and Whangai shales could hold between 270 billion and 520 billion barrels of oil in place between TAG Oil (TAG) and New Zealand Energy (NZEC). For additional details, please refer to our publication entitled *Initiating Coverage on TSX Listed New Zealand E&P - Down Under Upside*, dated 5 October 2012.

The East Coast basin could contain significant tight oil upside with the Waipawa and Whangai shales

Exhibit 219 shows a stratigraphic chart of the East Coast basin, which has both conventional and unconventional prospects. However, the unconventional shale oil resources in the Waipawa and Whangai black shales are relatively larger in resource size, which we believe is the main focus of both TAG and NZEC here. Both companies have a combined best estimate of roughly between 270 billion and 520 billion barrels of oil in place. Some North American shale oil plays could reach 10% recovery factor, which would imply potentially 27 billion to 52 billion barrels recoverable on TAG's and NZEC's acreage. Both companies look to unlock these large resources by utilizing horizontal drilling and multistage fracturing, and the basin has garnered the interest of other larger operators. Recently, Apache has farmed into TAG's East Coast basin permits and has committed up to C$100 million in exploration and appraisal capital to earn up to a 50% WI. Besides TAG and NZEC, an American company named Westech Energy (subsidiary of Energy Corporation of America) also retains a large land position in this shale trend of which NZEC has recently entered into a joint venture. Furthermore, this shale trend could extend northward toward Petrobras' offshore permit.

The Waipawa and Whangai are comparable to other tight oil and gas plays in North America

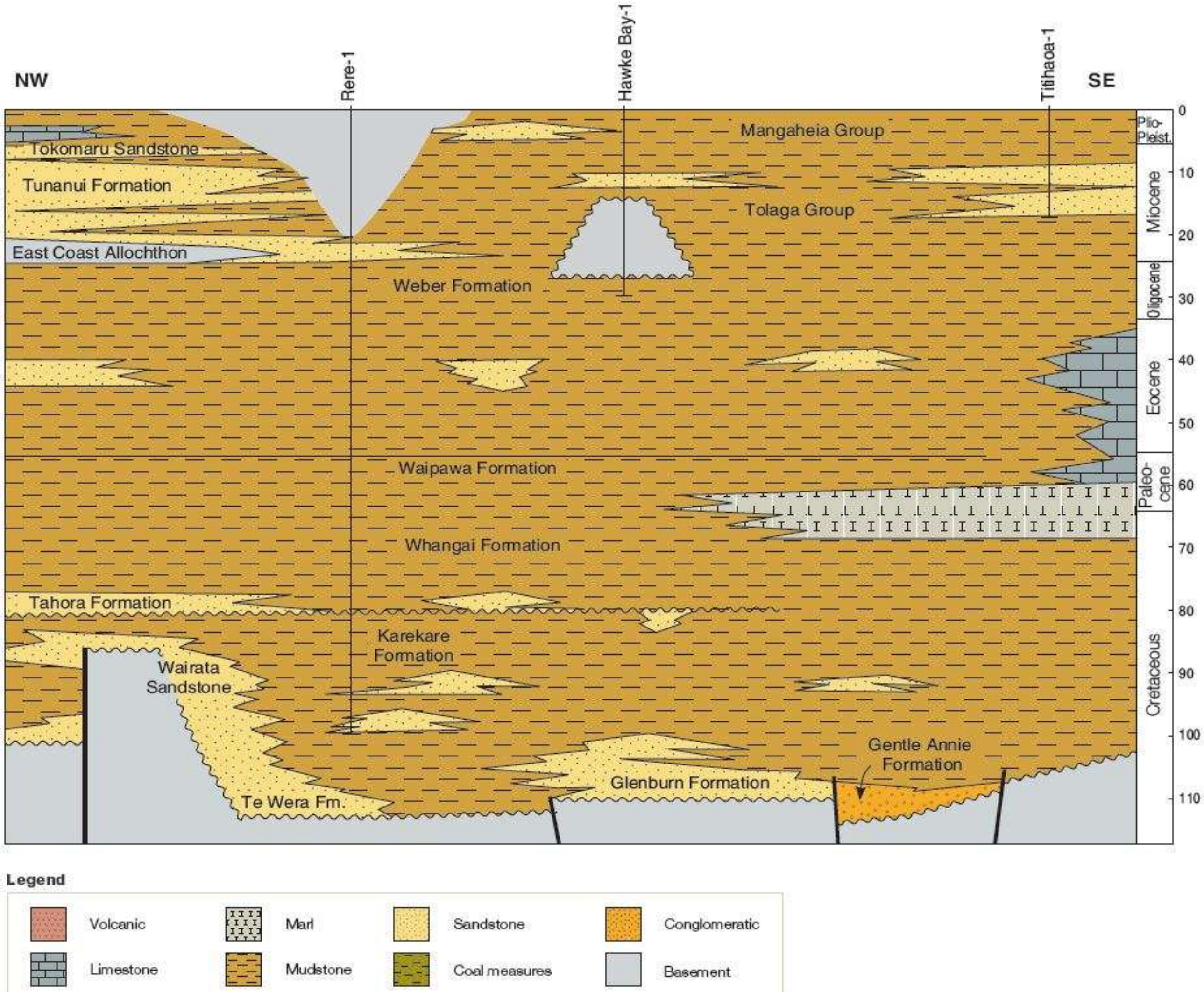
Both the Waipawa and Whangai appear to be comparable to other North American shale oil and gas plays, as shown in Exhibit 220. Through a number of core analyses, the Waipawa and Whangai source rocks appear to have high total organic carbon, ranging from 0.2% in the Whangai to 12% in the Waipawa. The formations have also been observed to be naturally fractured via core sample analysis, which should lend to greater permeability and deliverability (potentially higher production rates). Relative to each other, the underlying Whangai has much greater thickness of between 300 and 600 meters but has a lower total organic carbon content of between 0.2% and 1.7%. This thickness is roughly 6-12 times greater than the Bakken. In terms of brittleness and the ability to fracture stimulate these zones, the high quartz and carbonate content coupled with the apparently low clay content looks to be favorable in both the Waipawa and Whangai.

300 oil and gas seeps in the area have been linked to the Waipawa and Whangai

These shales have also demonstrated hydrocarbon generation with more than 300 oil and gas seeps to surface that have been geochemically linked to these two source rocks.

Overall, the Waipawa and Whangai appear to have the potential for shale oil development but still remain in the early exploratory phase.

Exhibit 219: East Coast Basin stratigraphic chart



Source: Crown Minerals, New Zealand Ministry of Economic Development.

Exhibit 220: Comparison of shale oil plays

Formation Area	Waipawa New Zealand	Whangai New Zealand	Bakken United States/Canada	Eagleford United States	Monterey United States
Depth (m)	0 - 5,000	0 - 5,000	2,700 - 3,500	2,400 - 4,250	2,100 - 4,250
Thickness (m)	10 - 70	300 - 600	10 - 50	60 - 90	10 - 120
Porosity (%)	3 - 8	3 - 8	4 - 12	8 - 12	13 - 29
TOC (%)	3 - 12	0.2 - 1.7	1 - 21	4 - 5	2 - 4.5
Permeability (microdarcies)	10 - 200	10 - 110	5 - 1,000	50 - 1,000	1,000 - 19,000
Quartz (%)	40 - 80	40 - 80	40 - 60	5 - 15	10 - 70
Carbonate (%)	5 - 40	5 - 40	10 - 20	50 - 70	10 - 50
Clay (%)	n.a.	n.a.	5 - 20	10 - 20	5 - 20

Source: AJM Petroleum Consultants, New Zealand Energy data.

Carbon

Oversupply to remain

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Please see more details in the Credit Suisse Utilities team's publication, *Central European power price: lower CO2 leads to lower power prices.*

Summary

- Near-term intervention to EU ETS is probable, but timeline and details are still unclear.
- Fundamental reforms are highly unlikely due to lack of political consensus.
- Oversupply is set to remain, unless structural changes take place.

Chances of a near-term intervention have increased, but there are still too many question marks

In July, we published our analysis on the European carbon market (EU ETS) and arrived to a conclusion that the system suffers from an oversupply of c1.5+ carbon allowances. Most recently, however, the communication from the Directorate Generale for Climate Action has become clearer in terms of the need for a potential "quick-fix" to the system. This has started to manifest in concrete steps. We summarize these below, along with some of the upcoming events relevant for the EU ETS:

- **Mid-November:** The European Commission's review paper on the EU ETS, which might include an action plan on how to deal with the system's oversupply
- **January 1:** Beginning of Phase III of the EU ETS, where the free allocation of carbon allowances will be largely replaced an auctioning system
- **February-March 2013:** EU Parliamentary vote on the European Commission's legal mandate to intervene into the EU ETS

In light of these, we still believe that political discord, opposition of industry groups as well as lack of clarity over the legal mandate of the European Commission for any intervention are likely to hinder all actions. We would except an intervention eventually, but the complexities of the matter suggest it will not happen before Q1/Q2 2013.

Set-aside is probable, but it is no silver bullet

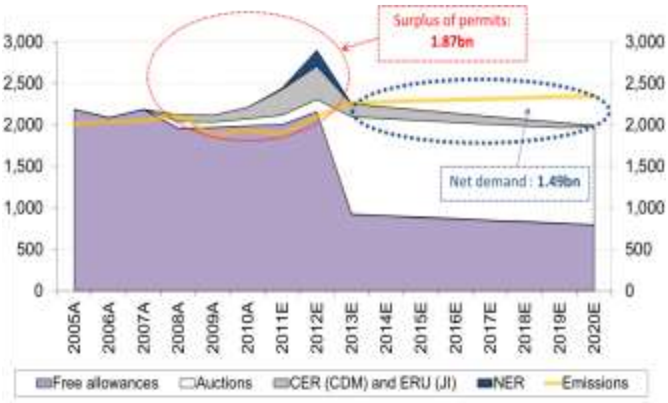
Should a short-term intervention happen, we think the most likely scenario would be a temporary set-aside/delayed auctioning of allowances. This could concern between 400m and 1.2bn allowances (final figure is likely to be closer to the lower end of the range) that would be withdrawn from the system between 2013 and 2016, then returned between 2017 and 2020. On our numbers, however, the oversupply of the system at least c1.5bn permits and therefore a sub-1bn (temporary) cut from the supply side is unlikely to have any lasting impact on the EU ETS. Nevertheless, depending on market perception and the exact conditions of the intervention, some intermittent traction is possible.

Long-term outlook unchanged, structural problems prevail

Once the carbon allowances set aside will have been channeled back to the system, we will be back to the "good old" problem of oversupply. In our view, it is only a more fundamental change to supply-demand dynamics and imbalances that could sufficiently tackle the oversupply. However, we believe there is no political consensus on EU level for this to happen any time soon (the long standing Polish opposition, recent statements from Dutch environment minister and the custom trajectory chosen by the UK to handle the situation around carbon are the best proofs of this). Taking this as well as the unclear future role of international carbon permits (CERs and ERUs) into consideration, we reiterate our views on low carbon prices going into Phase III and expect no significant change to the fundamentals of the EU ETS.

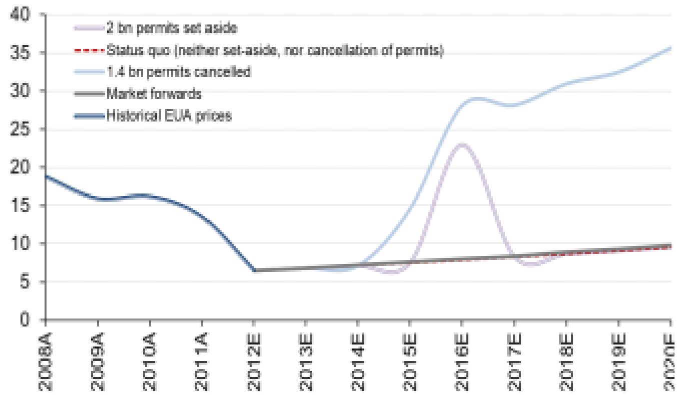
Exhibit 221: Emissions/components of the total cap

(mt)



Source: the BLOOMBERG PROFESSIONAL™ service; Credit Suisse estimates

Exhibit 222: EUA price (€/t) scenario



Source: the BLOOMBERG PROFESSIONAL™ service; Credit Suisse estimates

DISCLOSURE APPENDIX CONTAINS IMPORTANT DISCLOSURES, ANALYST CERTIFICATIONS, INFORMATION ON TRADE ALERTS, ANALYST MODEL PORTFOLIOS AND THE STATUS OF NON-U.S ANALYSTS. US Disclosure: Credit Suisse does and seeks to do business with companies covered in its research reports. As a result, investors should be aware that the Firm may have a conflict of interest that could affect the objectivity of this report. Investors should consider this report as only a single factor in making their investment decision.

Companies Mentioned *(Price as of 10-Dec-2012)*

Doosan (000150.KS, W129,000)
Qinghai Potash (000792.SZ, Rmb24.76)
Hyundai Heavy Industries (009540.KS, W217,000)
Kunlun Energy (0135.HK, HK$16.18)
Honghua Group Ltd (0196.HK, HK$2.13)
SPC (0338.HK, HK$2.35)
Korea Gas Corp (036460.KS, W77,100)
China Petroleum & Chemical Corporation - H (0386.HK, HK$8.62)
CNOOC Ltd (0883.HK, HK$16.78)
Dongfang Electric Corp (1072.HK, HK$14.78)
China Shenhua Energy Company Limited (1088.HK, HK$31.9)
Harbin Power Equipment (1133.HK, HK$6.71)
SPT Energy (1251.HK, HK$3.42)
Formosa Plastics (1301.TW, NT$77.0)
Nan Ya Plastics (1303.TW, NT$52.2)
Formosa Chemical & Fibre (1326.TW, NT$69.5)
Airtac (1590.TW, NT$153.5)
Hilong (1623.HK, HK$2.61)
Hiwin (2049.TW, NT$211.5)
Weichai Power Co. Ltd (2338.HK, HK$32.65)
Shanghai Electric Group Co., Ltd. (2727.HK, HK$3.3)
China Oilfield Services Ltd (2883.HK, HK$16.24)
Taiwan Mobile (3045.TW, NT$107.5)
CIMC Enric (3899.HK, HK$6.47)
PetroChina (601857.SS, Rmb8.73)
Okuma Corporation (6103.T, ¥509)
Amada (6113.T, ¥475)
Makino Milling (6135.T, ¥462)
Mori Seiki (6141.OS, ¥590)
Ebara (6361.T, ¥331)
Nikkiso (6376.T, ¥910)
Nachi-Fujikoshi (6474.T, ¥293)
THK (6481.T, ¥1,420)
Yaskawa Electric Corporation (6506.T, ¥684)
Seiko Epson (6724.T, ¥489)
Yokogawa Elec (6841.T, ¥883)
Keyence (6861.T, ¥23,800)
Denso (6902.T, ¥2,678)
Fanuc (6954.T, ¥14,300)
Nissan Motor (7201.T, ¥770)
Keihin (7251.T, ¥1,139)
ABB (ABB.ST, Skr133.1)
ABM Investama (ABMM.JK, Rp2,925)
Arch Coal, Inc. (ACI.N, $7.44)
PT Adaro Energy Tbk (ADRO.JK, Rp1,390)
Autodesk Inc. (ADSK.OQ, $33.96)
Aegis Group (AEGS.L, 235.5p)
Agrium Inc. (AGU.N, $99.47)
Arkema (AKE.PA, €80.0)
Alfa Laval (ALFA.ST, Skr133.4)
Alstom (ALSO.PA, €29.7)
AMEC (AMEC.L, 1059.0p)
Amedisys Inc. (AMED.OQ, $10.86)
Alpha Natural Resources LLC (ANR.N, $9.1)
Apache Corp. (APA.N, $75.07)
Anadarko Petroleum Corp. (APC.N, $75.8)
Aurora Oil & Gas (AUT.AX, A$3.4)
AWE Ltd (AWE.AX, A$1.24)
Bonanza Creek Energy Inc. (BCEI.N, $25.18)
Bankers Petroleum Ltd. (BNK.TO, C$2.83)
BP (BP.L, 426.1p)
Beach Energy (BPT.AX, A$1.46)
Buru Energy (BRU.AX, A$2.77)
Berry Petroleum Co. (BRY.N, $33.25)
Peabody Energy Corp (BTU.N, $27.3)
Babcock & Wilcox (BWC.N, $25.51)
Caterpillar Inc. (CAT.N, $87.23)
Chicago Bridge & Iron (CBI.N, $41.25)
CF Industries Holding Inc. (CF.N, $213.69)
Chesapeake Energy Corp. (CHK.N, $16.99)
Cloud Peak Energy (CLD.N, $19.76)
Clean Energy (CLNE.OQ, $13.47)
Cummins Inc. (CMI.N, $103.24)

CONSOL Energy Inc. (CNX.N, $33.27)
ConocoPhillips (COP.N, $57.88)
Crane (CR.N, $43.57)
Comstock Resources, Inc. (CRK.N, $15.76)
Carrizo Oil & Gas Inc. (CRZO.OQ, $21.06)
CSX Corporation (CSX.N, $19.93)
Chevron Corp. (CVX.N, $106.96)
Danaher Corporation (DHR.N, $53.41)
Delta (DLTA.L^F10, 184.75p)
Dow Chemical Company (DOW.N, $30.61)
Devon Energy Corp (DVN.N, $52.32)
Encana Corp. (ECA.N, $21.26)
Enbridge Energy Partners, LP (EEP.N, $27.92)
Everest Kanto (EKCL.BO, Rs29.9)
Eastman Chemical (EMN.N, $62.71)
Emerson (EMR.N, $51.23)
Enbridge Inc. (ENB.TO, C$41.66)
Enbridge Income (ENF.TO, C$23.4)
ENI (ENI.MI, €17.83)
EOG Resources (EOG.N, $117.73)
Enterprise Products Partners, LP (EPD.N, $49.87)
EQT Midstream Partners, LP (EQM.N, $29.14)
Energy Recovery Inc. (ERII.OQ, $3.24)
Energy XXI (EXXI.OQ, $32.57)
Ford Motor Co. (F.N, $11.47)
FedEx Corporation (FDX.N, $90.53)
Fluor (FLR.N, $57.52)
Flowserve Corp. (FLS.N, $142.9)
Forest Oil (FST.N, $6.4)
Foster Wheeler (FWLT.OQ, $23.72)
GEA Group (G1AG.DE, €25.01)
Gazprom (GAZP.RTS, $4.53)
Gardner Denver, Inc. (GDI.N, $68.17)
General Electric (GE.N, $21.39)
Genesis Energy, LP (GEL.N, $34.77)
GILDEMEISTER (GILG.DE, €15.11)
General Motors Corp. (GM.N, $25.28)
GMX Resources Inc. (GMXR.N, $0.52)
Gulfport Energy (GPOR.OQ, $37.59)
Halliburton (HAL.N, $33.66)
Hardinge (HDNG.OQ, $9.79)
Heckmann (HEK.N, $4.22)
Hess Corporation (HES.N, $50.02)
Hollysys Automation Technologies (HOLI.OQ, $10.16)
Honeywell International Inc. (HON.N, $61.86)
PT Harum Energy Tbk (HRUM.JK, Rp5,000)
IDEX (IEX.N, $45.9)
IMI Plc (IMI.L, 1092.0p)
PT Indika Energy Tbk (INDY.JK, Rp1,440)
Invensys (ISYS.L, 319.8p)
PT Indo Tambangraya Megah (ITMG.JK, Rp39,400)
Itron (ITRI.OQ, $44.52)
Jacobs Engineering (JEC.N, $42.16)
KBR Inc. (KBR.N, $29.46)
Kinder Morgan Energy Partners, LP (KMP.N, $80.54)
Kennametal Inc. (KMT.N, $39.87)
Kodiak Oil & Gas Corp (KOG.N, $8.93)
Krones (KRNG.DE, €45.195)
Luxfer (LXFR.N, $11.03)
LyondellBasell Industries (LYB.N, $54.37)
McDermott International (MDR.N, $10.6)
Magellan Midstream Partners , LP (MMP.N, $43.03)
Marathon (MPC.N, $62.01)
Molopo Australia (MPO.AX, A$0.435)
Marathon Oil Corp (MRO.N, $30.36)
Maruti Suzuki India Ltd (MRTI.BO, Rs1492.95)
MarkWest Energy Partners, LP (MWE.N, $50.57)
Noble Energy (NBL.N, $100.4)
National Oilwell Varco (NOV.N, $67.89)
Nucor (NUE.N, $40.78)
Nexen Inc. (NXY.TO, C$26.44)
Orion Energy (OESX.A, $1.25)
ONEOK Partners, LP (OKS.N, $55.03)
Occidental Petroleum (OXY.N, $75.35)
Plains All American Pipeline, LP (PAA.N, $45.68)
Petrobras (PBR.N, $19.11)
Petroleum Development Corp. (PDCE.OQ, $34.71)
Perusahaan Gas Negara (PGAS.JK, Rp4,600)
PKN Orlen (PKN.WA, zł46.89)
Pentair, Inc. (PNR.N, $48.17)
Phillips 66 (PSX.N, $53.58)
PT Tambang Batubara Bukit Asam Tbk (PTBA.JK, Rp13,950)

Portugal Telecom (PTC.LS, €3.568)
Penn Virginia Corp (PVA.N, $4.4)
Quanta Services (PWR.N, $26.92)
Penn West Petroleum Ltd. (PWT.TO, C$11.03)
Pioneer Natural Resources (PXD.N, $101.7)
Royal Dutch Shell plc (RDSa.L, 2101.5p)
Rex Energy Corp. (REXX.OQ, $12.23)
Rockwell Automation (ROK.N, $80.43)
Roper Industries (ROP.N, $112.23)
Rotork plc (ROR.L, 2520.0p)
Rosetta Resources Inc. (ROSE.OQ, $43.24)
Rolls Royce (RR.L, 891.5p)
Range Resources (RRC.N, $63.74)
Renishaw (RSW.L, 1852.0p)
Sandvik (SAND.ST, Skr102.0)
Schneider (SCHN.PA, €54.0)
Swift Energy Co. (SFY.N, $15.29)
Saint-Gobain (SGOB.PA, €31.055)
Siemens (SIEGn.DE, €80.82)
Schlumberger (SLB.N, $72.0)
Solvay (SOLB.BR, €105.5)
SPX (SPW.N, $68.32)
Stratasys (SSYS.OQ, $72.31)
Statoil (STL.OL, k138.1)
Santos Ltd (STO.AX, A$11.05)
Sulzer (SUN.VX, SFr143.5)
Southwestern Energy Co. (SWN.N, $33.66)
Senex Energy Limited (SXY.AX, A$0.64)
TransAlta Corporation (TA.TO, C$14.88)
TAG Oil Ltd. (TAO.TO, C$6.05)
TECO Energy (TE.N, $16.86)
Tenaris (TENR.MI, €14.8)
Talisman (TLM.TO, C$10.93)
Total (TOTF.PA, €38.635)
TransCanada Corp. (TRP.TO, C$45.64)
URS Corporation (URS.N, $39.11)
Vallourec (VLLP.PA, €40.0)
Waste Connections (WCN.N, $33.44)
Weir Group (WEIR.L, 1813.0p)
Weatherford International, Inc. (WFT.N, $10.93)
Westlake (WLK.N, $77.21)
Whiting Petroleum Corp. (WLL.N, $42.75)
WorleyParsons (WOR.AX, A$23.01)
Westport (WPT.TO, C$27.52)
United States Steel Group (X.N, $21.85)
ExxonMobil Corporation (XOM.N, $88.41)
Yara International ASA (YAR.OL, k281.0)
YPF Sociedad Anonima (YPF.N, $12.76)

Disclosure Appendix

Important Global Disclosures

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Neutral (N) : The stock's total return is expected to be in line with the relevant benchmark* over the next 12 months.

Underperform (U) : The stock's total return is expected to underperform the relevant benchmark* over the next 12 months.

**Relevant benchmark by region: As of 10th December 2012, Japanese ratings are based on a stock's total return relative to the analyst's coverage universe which consists of all companies covered by the analyst within the relevant sector, with Outperforms representing the most attractive, Neutrals the less attractive, and Underperforms the least attractive investment opportunities. As of 2nd October 2012, U.S. and Canadian as well as European ratings are based on a stock's total return relative to the analyst's coverage universe which consists of all companies covered by the analyst within the relevant sector, with Outperforms representing the most attractive, Neutrals the less attractive, and Underperforms the least attractive investment opportunities. For Latin American and non-Japan Asia stocks, ratings are based on a stock's total return relative to the average total return of the relevant country or regional benchmark; Australia, New Zealand are, and prior to 2nd October 2012 U.S. and Canadian ratings were based on (1) a stock's absolute total return potential to its current share price and (2) the relative attractiveness of a stock's total return potential within an analyst's coverage universe. For Australian and New Zealand stocks, 12-month rolling yield is incorporated in the absolute total return calculation and a 15% and a 7.5% threshold replace the 10-15% level in the Outperform and Underperform stock rating definitions, respectively. The 15% and 7.5% thresholds replace the +10-15% and -10-15% levels in the Neutral stock rating definition, respectively. Prior to 10th December 2012, Japanese ratings were based on a stock's total return relative to the average total return of the relevant country or regional benchmark.*

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Neutral/Hold*	39%	(48% banking clients)
Underperform/Sell*	15%	(44% banking clients)
Restricted	3%	

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Appendices

Models and Forecasts

Exhibit 223: Global oil demand (mb/d, unless otherwise specified)

Demand	2010	Q1-'11	Q2-'11	Q3-'11	Q4-'11	2011	Q1-'12	Q2-'12	Q3-'12E	Q4-'12E	2012E	Q1-'13E	Q2-'13E	Q3-'13E	Q4-'13E	2013E	Q1-'14E	Q2-'14E	Q3-'14E	Q4-'14E	2014E	2015E
Global	**88.6**	89.4	88.6	90.1	90.3	**89.6**	89.7	90.0	91.2	91.8	**90.7**	91.4	91.3	92.6	93.3	**92.2**	92.4	92.4	93.6	94.4	**93.2**	**94.2**
YoY Growth, net mb/d	**3.2**	2.4	0.5	0.8	0.3	**1.0**	0.4	1.4	1.0	1.6	**1.1**	1.7	1.3	1.4	1.4	**1.5**	1.0	1.0	1.0	1.1	**1.0**	**1.0**
YoY Growth, %	**3.7%**	2.7%	0.6%	0.9%	0.4%	**1.1%**	0.4%	1.6%	1.1%	1.8%	**1.2%**	1.9%	1.5%	1.6%	1.6%	**1.6%**	1.1%	1.1%	1.1%	1.2%	**1.1%**	**1.1%**
OECD	**46.9**	**47.1**	**45.4**	**47.0**	**46.8**	**46.6**	**46.3**	**45.6**	**46.4**	**46.9**	**46.3**	**46.6**	**45.5**	**46.3**	**46.8**	**46.3**	**46.2**	**45.1**	**46.0**	**46.4**	**45.9**	**45.4**
YoY Growth, net mb/d	**0.6**	0.4	-0.7	-0.4	-0.8	**-0.4**	-0.8	0.2	-0.6	0.1	**-0.2**	0.2	-0.1	-0.1	-0.1	**0.0**	-0.4	-0.4	-0.4	-0.4	**-0.4**	**-0.5**
YoY Growth, %	**1.3%**	0.9%	-1.5%	-0.9%	-1.6%	**-0.8%**	-1.7%	0.5%	-1.2%	0.3%	**-0.5%**	0.5%	-0.3%	-0.2%	-0.2%	**-0.1%**	-0.8%	-0.8%	-0.8%	-0.8%	**-0.8%**	**-1.1%**
Americas	**24.1**	24.2	23.8	24.2	24.0	**24.1**	23.5	23.8	24.0	24.2	**23.9**	23.9	23.9	24.1	24.3	**24.1**	23.8	23.8	24.0	24.2	**24.0**	**23.5**
YoY Growth, net mb/d	**0.5**	0.5	-0.3	-0.2	-0.2	**-0.1**	-0.8	0.0	-0.2	0.2	**-0.2**	0.4	0.1	0.1	0.1	**0.2**	-0.1	-0.1	-0.1	-0.1	**-0.1**	**-0.5**
YoY Growth, %	**2.0%**	2.1%	-1.2%	-1.0%	-1.0%	**-0.3%**	-3.1%	0.0%	-0.7%	0.8%	**-0.8%**	1.8%	0.4%	0.3%	0.6%	**0.8%**	-0.4%	-0.4%	-0.4%	-0.3%	**-0.4%**	**-1.9%**
Europe	**15.0**	14.5	14.4	15.1	14.4	**14.6**	14.1	14.1	14.5	14.3	**14.3**	13.9	14.0	14.5	14.3	**14.2**	13.6	13.7	14.2	14.0	**13.9**	**13.8**
YoY Growth, net mb/d	**0.0**	-0.1	-0.2	-0.2	-0.7	**-0.3**	-0.5	-0.3	-0.5	-0.1	**-0.4**	-0.2	-0.1	0.0	0.0	**-0.1**	-0.3	-0.3	-0.3	-0.3	**-0.3**	**-0.1**
YoY Growth, %	**-0.1%**	-1.0%	-1.2%	-1.5%	-4.8%	**-2.2%**	-3.2%	-2.2%	-3.6%	-0.7%	**-2.4%**	-1.3%	-0.9%	-0.3%	-0.1%	**-0.6%**	-2.0%	-2.0%	-2.0%	-2.0%	**-2.0%**	**-0.7%**
Asia Pacific	**7.8**	8.3	7.1	7.7	8.3	**7.9**	8.8	7.7	7.8	8.4	**8.2**	8.8	7.6	7.7	8.2	**8.0**	8.8	7.6	7.7	8.2	**8.1**	**8.1**
YoY Growth, net mb/d	**0.1**	0.1	-0.2	0.0	0.2	**0.0**	0.4	0.6	0.2	0.1	**0.3**	0.0	-0.1	-0.1	-0.2	**-0.1**	0.0	0.0	0.0	0.0	**0.0**	**0.0**
YoY Growth, %	**1.6%**	0.7%	-3.4%	0.6%	2.7%	**0.2%**	5.1%	7.8%	2.0%	0.7%	**3.8%**	-0.1%	-1.4%	-1.6%	-2.5%	**-1.5%**	0.0%	0.1%	0.1%	0.1%	**0.1%**	**0.6%**
Non-OECD	**41.7**	**42.2**	**43.2**	**43.2**	**43.5**	**43.0**	**43.4**	**44.4**	**44.7**	**45.0**	**44.4**	**44.8**	**45.8**	**46.3**	**46.5**	**45.9**	**46.2**	**47.2**	**47.7**	**47.9**	**47.3**	**48.8**
YoY Growth, net mb/d	**2.6**	2.0	1.2	1.3	1.1	**1.4**	1.1	1.1	1.6	1.4	**1.3**	1.4	1.5	1.5	1.5	**1.5**	1.4	1.4	1.4	1.4	**1.4**	**1.5**
YoY Growth, %	**6.7%**	4.9%	2.8%	3.0%	2.5%	**3.3%**	2.7%	2.6%	3.6%	3.3%	**3.1%**	3.3%	3.3%	3.4%	3.4%	**3.4%**	3.1%	3.0%	3.0%	3.1%	**3.1%**	**3.2%**
Former Soviet Union	**4.2**	4.2	4.4	4.6	4.1	**4.3**	4.3	4.5	4.7	4.2	**4.4**	4.4	4.6	4.8	4.3	**4.5**	4.5	4.6	4.8	4.4	**4.6**	**4.7**
YoY Growth, net mb/d	**0.1**	0.1	0.3	0.3	-0.1	**0.2**	0.1	0.1	0.1	0.1	**0.1**	0.1	0.1	0.1	0.1	**0.1**	0.1	0.1	0.1	0.1	**0.1**	**0.1**
YoY Growth, %	**3.1%**	3.4%	8.5%	7.5%	-2.7%	**4.1%**	2.9%	2.4%	1.8%	2.2%	**2.3%**	2.1%	2.2%	2.2%	2.2%	**2.2%**	1.4%	1.4%	1.4%	1.4%	**1.4%**	**2.6%**
China	**9.2**	9.6	9.8	9.7	9.9	**9.7**	9.9	9.9	10.1	10.3	**10.0**	10.3	10.4	10.6	10.8	**10.5**	10.9	10.9	11.2	11.4	**11.1**	**11.7**
YoY Growth, net mb/d	**1.0**	0.9	0.4	0.6	0.3	**0.5**	0.3	0.1	0.4	0.5	**0.3**	0.5	0.5	0.5	0.5	**0.5**	0.6	0.6	0.6	0.6	**0.6**	**0.6**
YoY Growth, %	**12.1%**	10.4%	4.3%	6.1%	2.9%	**5.8%**	2.8%	1.2%	4.2%	4.6%	**3.2%**	4.8%	4.9%	5.1%	4.9%	**4.9%**	5.4%	5.4%	5.4%	5.4%	**5.4%**	**5.1%**
Other emerging Asia	**11.0**	11.4	11.6	10.9	11.6	**11.4**	11.7	11.9	11.4	12.0	**11.7**	12.1	12.3	11.8	12.4	**12.1**	12.4	12.6	12.1	12.8	**12.5**	**12.9**
YoY Growth, net mb/d	**0.5**	0.4	0.3	0.3	0.6	**0.4**	0.3	0.3	0.5	0.4	**0.4**	0.4	0.4	0.4	0.4	**0.4**	0.4	0.4	0.4	0.4	**0.4**	**0.4**
YoY Growth, %	**4.8%**	4.0%	2.8%	3.0%	5.1%	**3.7%**	2.7%	2.5%	4.4%	3.4%	**3.2%**	3.4%	3.4%	3.5%	3.5%	**3.4%**	3.1%	3.1%	3.1%	3.1%	**3.1%**	**3.0%**
South America	**6.1**	6.0	6.2	6.5	6.4	**6.3**	6.2	6.4	6.6	6.5	**6.4**	6.2	6.5	6.7	6.6	**6.5**	6.3	6.6	6.9	6.7	**6.6**	**6.8**
YoY Growth, net mb/d	**0.4**	0.2	0.1	0.2	0.2	**0.2**	0.2	0.2	0.1	0.1	**0.1**	0.1	0.1	0.1	0.1	**0.1**	0.1	0.1	0.1	0.1	**0.1**	**0.1**
YoY Growth, %	**6.4%**	3.0%	1.6%	2.4%	2.9%	**2.5%**	3.2%	3.3%	1.8%	1.3%	**2.4%**	1.5%	1.6%	1.8%	1.7%	**1.6%**	1.6%	1.6%	1.6%	1.6%	**1.6%**	**2.0%**
Mideast	**7.1**	6.8	7.2	7.6	7.2	**7.2**	7.0	7.6	7.9	7.6	**7.5**	7.2	7.9	8.2	7.9	**7.8**	7.4	8.1	8.4	8.1	**8.0**	**8.2**
YoY Growth, net mb/d	**0.4**	0.2	0.1	0.1	0.2	**0.2**	0.1	0.3	0.3	0.3	**0.3**	0.3	0.3	0.3	0.3	**0.3**	0.2	0.2	0.2	0.2	**0.2**	**0.2**
YoY Growth, %	**5.8%**	3.3%	1.7%	1.0%	3.3%	**2.3%**	2.0%	4.7%	3.8%	4.3%	**3.7%**	3.9%	3.8%	4.0%	3.9%	**3.9%**	2.7%	2.6%	2.7%	2.9%	**2.7%**	**2.6%**
Africa	**3.5**	3.6	3.4	3.3	3.5	**3.4**	3.7	3.5	3.4	3.6	**3.5**	3.8	3.6	3.5	3.7	**3.6**	3.8	3.7	3.6	3.8	**3.7**	**3.8**
YoY Growth, net mb/d	**0.2**	0.1	-0.1	-0.2	-0.1	**-0.1**	0.1	0.1	0.2	0.1	**0.1**	0.1	0.1	0.1	0.1	**0.1**	0.1	0.1	0.1	0.1	**0.1**	**0.1**
YoY Growth, %	**6.6%**	2.8%	-2.7%	-4.9%	-1.8%	**-1.7%**	2.9%	2.0%	5.9%	3.0%	**3.4%**	2.5%	2.6%	2.6%	2.6%	**2.6%**	2.2%	2.2%	2.1%	2.2%	**2.2%**	**3.2%**

Exhibit 224: Implied and reported inventory changes on "call on OPEC" (mb/d, unless otherwise specified)

Balance, stocks	2010	Q1-'11	Q2-'11	Q3-'11	Q4-'11	2011	Q1-'12	Q2-'12	Q3-'12E	Q4-'12E	2012E	Q1-'13E	Q2-'13E	Q3-'13E	Q4-'13E	2013E	Q1-'14E	Q2-'14E	Q3-'14E	Q4-'14E	2014E	2015E
Implied inventory change	**-0.7**	-0.7	-1.0	-1.9	-0.3	**-1.0**	0.9	0.5	-1.1	-1.2	**-0.2**	0.0	0.4	-0.7	-0.7	**-0.3**	0.2	0.7	-0.4	-0.4	**0.0**	**0.0**
Reported oil inventory:																						
OECD stock change	**0.1**	-0.4	0.5	-0.2	-0.7	**-0.2**	0.4	0.5	0.1	-0.9	**0.0**	0.0	0.2	-0.4	-0.6	**-0.2**						
OECD inventory (billion barrels)	**2.68**	2.64	2.69	2.67	2.61	**2.61**	2.65	2.69	2.70	2.62	**2.62**											
Cover, days demand	**56.9**	58.3	57.2	57.1	56.3	**56.3**	58.1	58.0	57.6	56.3	**56.3**	57.6	56.9	55.6	55.1	**55.1**						
'Call on Opec & stocks"	**30.7**	30.8	30.8	32.1	31.2	**31.2**	30.3	31.3	32.7	33.0	**31.8**	32.0	31.9	33.2	33.3	**32.6**	31.3	31.2	32.5	32.7	**31.9**	**31.3**
YoY Growth, net mb/d	**1.5**	1.3	0.3	0.6	0.0	**0.6**	-0.4	0.4	0.6	1.8	**0.6**	1.7	0.6	0.5	0.3	**0.8**	-0.7	-0.7	-0.7	-0.6	**-0.7**	**-0.6**
YoY Growth, %	**5.1%**	4.5%	1.1%	1.8%	0.1%	**1.9%**	-1.4%	1.4%	1.7%	5.8%	**1.9%**	5.5%	1.8%	1.5%	0.9%	**2.4%**	-2.2%	-2.1%	-2.0%	-1.9%	**-2.1%**	**-1.8%**

Source: IEA, Credit Suisse Fixed Income Commodities Research

Exhibit 225: Global oil supply (mb/d unless otherwise stated)

Supply	2010	Q1-'11	Q2-'11	Q3-'11	Q4-'11	2011	Q1-'12	Q2-'12	Q3-'12E	Q4-'12E	2012E	Q1-'13E	Q2-'13E	Q3-'13E	Q4-'13E	2013E	Q1-'14E	Q2-'14E	Q3-'14E	Q4-'14E	2014E	2015E
Global	**87.9**	88.7	87.6	88.2	89.9	**88.6**	90.6	90.5	90.0	90.6	**90.4**	91.4	91.8	91.9	92.6	**91.9**	92.6	93.0	93.2	94.0	**93.2**	**94.2**
YoY Growth, net mb/d	**2.5**	1.7	0.0	0.2	1.1	**0.8**	1.9	2.9	1.8	0.7	**1.8**	0.8	1.3	1.8	1.9	**1.5**	1.2	1.3	1.4	1.4	**1.3**	**1.0**
YoY Growth, %	**2.9%**	2.0%	0.0%	0.2%	1.3%	**0.9%**	2.2%	3.3%	2.0%	0.8%	**2.1%**	0.9%	1.4%	2.0%	2.1%	**1.6%**	1.3%	1.4%	1.5%	1.5%	**1.4%**	**1.1%**
Non OPEC	**50.5**	50.9	50.0	50.1	51.1	**50.5**	51.4	50.6	50.4	50.7	**50.8**	51.3	51.4	51.3	51.9	**51.5**	52.9	53.0	52.9	53.5	**53.1**	**54.6**
YoY Growth, net mb/d	**1.2**	0.6	-0.3	0.0	0.0	**0.1**	0.5	0.6	0.2	-0.3	**0.2**	0.0	0.8	0.9	1.2	**0.7**	1.6	1.6	1.6	1.6	**1.6**	**1.5**
YoY Growth, %	**2.4%**	1.2%	-0.6%	0.0%	-0.1%	**0.1%**	1.0%	1.2%	0.5%	-0.7%	**0.5%**	-0.1%	1.6%	1.9%	2.3%	**1.4%**	3.1%	3.1%	3.1%	3.1%	**3.1%**	**2.9%**
North America	**14.9**	15.2	15.2	15.4	16.2	**15.5**	16.5	16.4	16.5	16.8	**16.5**	17.2	17.2	17.4	17.7	**17.4**	18.1	18.1	18.3	18.6	**18.3**	**19.2**
YoY Growth, net mb/d	**0.6**	0.5	0.4	0.5	0.9	**0.5**	1.2	1.2	1.1	0.7	**1.1**	0.7	0.9	0.9	0.8	**0.8**	0.9	0.9	0.9	0.9	**0.9**	**0.9**
YoY Growth, %	**4.5%**	3.0%	2.5%	3.3%	5.6%	**3.6%**	8.0%	8.0%	7.4%	4.1%	**6.8%**	4.3%	5.3%	5.3%	5.0%	**5.0%**	5.2%	5.2%	5.2%	5.3%	**5.2%**	**5.1%**
South America	**4.5**	4.6	4.5	4.6	4.7	**4.6**	4.7	4.5	4.5	4.5	**4.5**	4.6	4.7	4.7	4.8	**4.7**	5.0	5.1	5.1	5.2	**5.1**	**5.6**
YoY Growth, net mb/d	**0.2**	0.2	0.0	0.0	0.1	**0.1**	0.1	0.0	-0.1	-0.2	**-0.1**	0.0	0.2	0.2	0.2	**0.2**	0.4	0.4	0.4	0.4	**0.4**	**0.5**
YoY Growth, %	**5.2%**	4.0%	-1.0%	0.0%	2.4%	**1.3%**	1.5%	-0.5%	-1.9%	-3.9%	**-1.2%**	-1.0%	4.9%	4.5%	5.3%	**3.4%**	8.5%	8.7%	8.7%	8.4%	**8.6%**	**10.1%**
Europe	**4.5**	4.4	4.2	4.0	4.2	**4.2**	4.2	4.0	3.6	3.9	**4.0**	4.0	3.8	3.5	3.7	**3.8**	3.8	3.6	3.3	3.6	**3.6**	**3.4**
YoY Growth, net mb/d	**-0.3**	-0.4	-0.4	-0.2	-0.4	**-0.4**	-0.2	-0.1	-0.3	-0.3	**-0.2**	-0.2	-0.2	-0.2	-0.2	**-0.2**	-0.2	-0.2	-0.2	-0.2	**-0.2**	**-0.2**
YoY Growth, %	**-6.8%**	-9.1%	-8.5%	-4.9%	-8.6%	**-7.8%**	-4.2%	-2.5%	-8.3%	-7.1%	**-5.5%**	-5.3%	-5.6%	-4.6%	-4.1%	**-4.9%**	-4.9%	-4.8%	-4.6%	-4.7%	**-4.7%**	**-5.7%**
FSU	**13.6**	13.7	13.7	13.6	13.6	**13.7**	13.8	13.7	13.6	13.6	**13.7**	13.6	13.7	13.8	13.9	**13.8**	14.0	14.2	14.3	14.3	**14.2**	**14.5**
YoY Growth, net mb/d	**0.3**	0.2	0.1	0.1	0.0	**0.1**	0.1	0.1	0.0	0.0	**0.0**	-0.2	0.0	0.2	0.3	**0.1**	0.4	0.4	0.5	0.5	**0.4**	**0.3**
YoY Growth, %	**1.9%**	1.6%	0.7%	0.4%	0.1%	**0.7%**	0.7%	0.4%	0.1%	-0.3%	**0.2%**	-1.4%	0.2%	1.4%	2.0%	**0.5%**	2.9%	3.1%	3.4%	3.4%	**3.2%**	**2.0%**
Russia	**10.5**	10.6	10.6	10.7	10.7	**10.7**	10.8	10.8	10.8	10.8	**10.8**	10.8	10.8	10.7	10.7	**10.8**	10.9	10.9	10.8	10.8	**10.9**	**11.1**
YoY Growth, net mb/d	**0.2**	0.2	0.2	0.2	0.1	**0.2**	0.2	0.1	0.1	0.1	**0.1**	0.0	0.0	-0.1	-0.1	**0.0**	0.1	0.1	0.1	0.1	**0.1**	**0.2**
YoY Growth, %	**2.4%**	1.6%	1.5%	1.8%	1.3%	**1.5%**	1.7%	1.0%	0.9%	0.8%	**1.1%**	0.4%	0.0%	-0.7%	-1.1%	**-0.3%**	1.0%	1.0%	1.0%	1.0%	**1.0%**	**2.0%**
Africa	**2.6**	2.7	2.5	2.6	2.6	**2.6**	2.4	2.2	2.2	2.2	**2.3**	2.3	2.3	2.3	2.3	**2.3**	2.3	2.3	2.3	2.3	**2.3**	**2.3**
YoY Growth, net mb/d	**0.0**	0.0	-0.1	0.0	0.0	**0.0**	-0.2	-0.3	-0.4	-0.4	**-0.3**	-0.2	0.0	0.0	0.1	**0.0**	0.0	0.0	0.0	0.0	**0.0**	**0.0**
YoY Growth, %	**0.5%**	0.6%	-4.2%	0.6%	-1.9%	**-1.2%**	-8.9%	-10.9%	-14.4%	-14.5%	**-12.2%**	-6.8%	0.9%	2.0%	2.3%	**-0.5%**	0.2%	0.4%	0.7%	1.0%	**0.6%**	**1.2%**
Mideast	**1.7**	1.8	1.7	1.7	1.5	**1.6**	1.4	1.4	1.5	1.5	**1.4**	1.5	1.4	1.4	1.4	**1.4**	1.5	1.4	1.4	1.4	**1.4**	**1.4**
YoY Growth, net mb/d	**0.0**	0.0	-0.1	0.0	-0.3	**-0.1**	-0.4	-0.2	-0.2	0.0	**-0.2**	0.1	0.0	0.0	-0.1	**0.0**	0.0	0.0	0.0	0.0	**0.0**	**0.0**
YoY Growth, %	**1.3%**	2.2%	-4.4%	-2.7%	-15.2%	**-5.1%**	-22.0%	-14.4%	-13.0%	0.2%	**-12.8%**	6.7%	2.3%	-2.6%	-4.9%	**0.2%**	-0.9%	-0.7%	-0.5%	-0.2%	**-0.6%**	**0.5%**
Asia	**8.5**	8.5	8.3	8.3	8.3	**8.3**	8.4	8.3	8.4	8.2	**8.3**	8.2	8.2	8.2	8.2	**8.2**	8.2	8.2	8.2	8.2	**8.2**	**8.2**
YoY Growth, net mb/d	**0.3**	0.1	-0.1	-0.3	-0.3	**-0.2**	-0.1	0.0	0.1	-0.1	**0.0**	-0.2	-0.1	-0.2	0.0	**-0.1**	0.0	0.0	0.0	0.0	**0.0**	**0.0**
YoY Growth, %	**4.2%**	1.6%	-1.7%	-3.8%	-3.5%	**-1.9%**	-1.0%	-0.5%	1.4%	-1.3%	**-0.3%**	-2.5%	-1.4%	-2.0%	-0.2%	**-1.5%**	0.3%	0.3%	0.4%	0.5%	**0.4%**	**-0.5%**
Processing gain	**2.3**	2.4	2.4	2.5	2.4	**2.4**	2.4	2.5	2.5	2.5	**2.5**	2.5	2.5	2.6	2.5	**2.5**	2.5	2.6	2.6	2.6	**2.6**	**2.6**
OPEC	**35.1**	35.4	35.2	35.7	36.4	**35.7**	36.8	37.4	37.1	37.4	**37.2**	37.6	37.8	38.0	38.1	**37.9**	37.3	37.5	37.6	37.8	**37.6**	**37.0**
YoY Growth, net mb/d	**1.2**	1.0	0.2	0.1	1.1	**0.6**	1.4	2.2	1.5	1.0	**1.5**	0.8	0.4	0.8	0.7	**0.7**	-0.3	-0.3	-0.3	-0.3	**-0.3**	**-0.6**
YoY Growth, %	**3.6%**	3.0%	0.7%	0.3%	3.0%	**1.8%**	3.9%	6.3%	4.2%	2.8%	**4.3%**	2.2%	1.0%	2.2%	1.9%	**1.8%**	-0.9%	-0.9%	-0.9%	-0.9%	**-0.9%**	**-1.5%**
Opec Crude Oil	**29.9**	30.1	29.9	30.2	30.9	**30.3**	31.2	31.8	31.6	31.8	**31.6**	32.0	32.3	32.4	32.6	**32.3**	31.6	31.9	32.0	32.2	**31.9**	**31.4**
YoY Growth, net mb/d	**0.8**	0.7	-0.1	-0.1	0.9	**0.3**	1.1	1.9	1.3	0.9	**1.3**	0.8	0.5	0.9	0.8	**0.7**	-0.4	-0.4	-0.4	-0.4	**-0.4**	**-0.6**
YoY Growth, %	**2.7%**	2.3%	-0.3%	-0.2%	2.8%	**1.1%**	3.8%	6.5%	4.4%	3.0%	**4.4%**	2.6%	1.5%	2.8%	2.5%	**2.3%**	-1.2%	-1.2%	-1.2%	-1.2%	**-1.2%**	**-1.8%**
Opec 11	**27.5**	27.4	27.0	27.4	28.1	**27.5**	28.5	28.7	28.3	28.5	**28.5**	28.7	28.9	29.0	29.1	**28.9**	28.2	28.4	28.5	28.6	**28.4**	**27.6**
YoY Growth, net mb/d	**0.8**	0.4	-0.5	-0.5	0.6	**0.0**	1.1	1.7	0.9	0.4	**1.0**	0.2	0.2	0.7	0.6	**0.4**	-0.5	-0.5	-0.5	-0.5	**-0.5**	**-0.8**
YoY Growth, %	**2.8%**	1.6%	-2.0%	-1.8%	2.1%	**0.0%**	4.0%	6.4%	3.1%	1.5%	**3.7%**	0.8%	0.6%	2.4%	2.1%	**1.5%**	-1.8%	-1.8%	-1.8%	-1.8%	**-1.8%**	**-2.8%**
Opec non-crude	**5.1**	5.3	5.4	5.4	5.5	**5.4**	5.6	5.6	5.6	5.6	**5.6**	5.6	5.6	5.5	5.5	**5.6**	5.6	5.6	5.6	5.6	**5.6**	**5.6**
YoY Growth, net mb/d	**0.4**	0.4	0.3	0.2	0.2	**0.3**	0.2	0.3	0.2	0.1	**0.2**	0.0	-0.1	0.0	-0.1	**-0.1**	0.1	0.1	0.1	0.1	**0.1**	**0.0**
YoY Growth, %	**9.4%**	7.5%	6.9%	3.4%	4.2%	**5.4%**	4.5%	5.4%	2.9%	1.3%	**3.5%**	0.1%	-1.5%	-0.7%	-1.4%	**-0.9%**	1.1%	1.1%	1.1%	1.1%	**1.1%**	**0.3%**

Source: IEA, Credit Suisse Fixed Income Commodities Research

Exhibit 226: Total US production by state

	Location	2006	2007	2008	2009	2010	2011	2012E	2013E	2014E	2015E	2016E	2017E	2018E	2019E	2020E
U.S. Field Production of Crude Oil (Thousand Barrels)	**US**	**5102**	**5064**	**4964**	**5361**	**5482**	**5676**	**6358**	**7134**	**7767**	**8587**	**9184**	**9676**	**10040**	**10253**	**10452**
East Coast (PADD 1) Field Production of Crude Oil (Thousand Barrels)	**PADD 1**	**22**	**21**	**21**	**18**	**20**	**22**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**	**24**
Florida Field Production of Crude Oil (Thousand Barrels)	Florida	6	6	5	2	5	6	6	6	6	6	6	6	6	6	6
New York Field Production of Crude Oil (Thousand Barrels)	New York	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pennsylvania Field Production of Crude Oil (Thousand Barrels)	Pennsylvania	10	10	10	10	10	10	12	12	12	12	12	12	12	12	12
Virginia Field Production of Crude Oil (Thousand Barrels)	Virginia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
West Virginia Field Production of Crude Oil (Thousand Barrels)	West Virginia	5	4	4	5	4	5	5	5	5	5	5	5	5	5	5
Midwest (PADD 2) Field Production of Crude Oil (Thousand Barrels)	**PADD 2**	**458**	**470**	**539**	**591**	**686**	**817**	**1109**	**1375**	**1601**	**1717**	**1754**	**1779**	**1829**	**1885**	**1942**
Illinois Field Production of Crude Oil (Thousand Barrels)	Illinois	28	26	26	25	25	25	27	28	29	30	31	32	32	32	32
Indiana Field Production of Crude Oil (Thousand Barrels)	Indiana	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Kansas Field Production of Crude Oil (Thousand Barrels)	Kansas	98	100	108	108	111	114	124	133	139	142	131	119	112	107	103
Kentucky Field Production of Crude Oil (Thousand Barrels)	Kentucky	6	7	7	7	7	6	6	6	6	6	6	6	6	6	6
Michigan Field Production of Crude Oil (Thousand Barrels)	Michigan	14	14	17	16	19	18	18	18	18	18	18	18	18	18	18
Missouri Field Production of Crude Oil (Thousand Barrels)	Missouri	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nebraska Field Production of Crude Oil (Thousand Barrels)	Nebraska	6	6	7	6	6	7	7	7	7	7	7	7	7	7	7
North Dakota Field Production of Crude Oil (Thousand Barrels)	North Dakota	109	123	172	218	310	419	657	887	1061	1131	1148	1133	1142	1162	1188
Ohio Field Production of Crude Oil (Thousand Barrels)	Ohio	15	15	16	16	13	13	19	39	68	104	146	195	233	265	294
Oklahoma Field Production of Crude Oil (Thousand Barrels)	Oklahoma	172	167	176	184	186	204	240	246	262	268	255	258	268	277	284
South Dakota Field Production of Crude Oil (Thousand Barrels)	South Dakota	4	5	5	5	4	4	4	4	4	4	4	4	4	4	4
Tennessee Field Production of Crude Oil (Thousand Barrels)	Tennessee	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Gulf Coast (PADD 3) Field Production of Crude Oil (Thousand Barrels)	**PADD 3**	**2838**	**2828**	**2706**	**3121**	**3190**	**3277**	**3713**	**4177**	**4522**	**5176**	**5692**	**6136**	**6435**	**6584**	**6720**
Alabama Field Production of Crude Oil (Thousand Barrels)	Alabama	21	20	21	20	19	23	25	30	35	40	45	50	55	60	65
Arkansas Field Production of Crude Oil (Thousand Barrels)	Arkansas	17	17	17	16	16	16	19	24	29	34	39	44	49	54	59
Louisiana Field Production of Crude Oil (Thousand Barrels)	Louisiana	202	210	200	189	185	189	184	189	198	231	289	429	508	561	600
Mississippi Field Production of Crude Oil (Thousand Barrels)	Mississippi	48	56	61	64	65	64	64	66	68	70	72	74	76	78	80
New Mexico Field Production of Crude Oil (Thousand Barrels)	New Mexico	164	161	163	168	179	196	220	259	294	329	357	388	412	435	456
Texas Field Production of Crude Oil (Thousand Barrels)	Texas	1088	1087	1090	1106	1176	1474	1898	2262	2589	2863	3033	3142	3259	3383	3507
Federal Offshore--Gulf of Mexico Field Production of Crude Oil (Thousand Barre	GoM - Offshore	1299	1277	1155	1559	1551	1316	1305	1347	1310	1609	1857	2009	2076	2014	1953
Rocky Mountain (PADD 4) Field Production of Crude Oil (Thousand Barr	**PADD 4**	**357**	**361**	**358**	**357**	**372**	**395**	**438**	**512**	**605**	**687**	**763**	**815**	**856**	**890**	**918**
Colorado Field Production of Crude Oil (Thousand Barrels)	Colorado	64	64	66	78	89	107	130	196	284	364	442	498	543	579	608
Montana Field Production of Crude Oil (Thousand Barrels)	Montana	99	95	86	76	69	66	69	71	73	73	74	73	73	74	74
Utah Field Production of Crude Oil (Thousand Barrels)	Utah	49	53	60	63	68	72	80	91	101	108	111	114	117	120	124
Wyoming Field Production of Crude Oil (Thousand Barrels)	Wyoming	145	148	145	141	146	150	160	153	147	143	136	130	123	117	112
West Coast (PADD 5) Field Production of Crude Oil (Thousand Barrels)	**PADD 5**	**1426**	**1385**	**1340**	**1274**	**1214**	**1165**	**1073**	**1046**	**1014**	**982**	**951**	**922**	**895**	**870**	**848**
Alaska Field Production of Crude Oil (Thousand Barrels)	**Alaska**	**741**	**722**	**685**	**645**	**601**	**572**	**501**	**485**	**456**	**428**	**403**	**379**	**357**	**336**	**317**
Alaska South Field Production of Crude Oil (Thousand Barrels)	Alaska South	17	15	13	8	10	10	10	10	10	10	10	10	10	10	10
Alaska North Slope Crude Oil Production (Thousand Barrels)	Alaska North Slope	724	707	672	638	591	562	491	475	446	418	393	369	347	326	307
Arizona Field Production of Crude Oil (Thousand Barrels)	Arizona	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
California Field Production of Crude Oil (Thousand Barrels)	California	612	594	588	567	552	537	527	526	529	530	529	528	526	524	522
Nevada Field Production of Crude Oil (Thousand Barrels)	Nevada	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Federal Offshore California Field Production of Crude Oil (Thousand Barrels)	California - Offshore	72	67	66	60	54	54	43	35	28	22	18	14	11	9	7
Total US Field Production		**5,102**	**5,064**	**4,964**	**5,361**	**5,482**	**5,676**	**6,358**	**7,134**	**7,767**	**8,587**	**9,184**	**9,676**	**10,040**	**10,253**	**10,452**
Yoy Growth, KBD		(76)	(38)	(100)	397	121	194	682	777	632	820	597	493	364	213	199
Mom Growth, KBD																
Total US (ex offshore)		**3,732**	**3,720**	**3,742**	**3,742**	**3,877**	**4,306**	**5,009**	**5,753**	**6,429**	**6,956**	**7,309**	**7,653**	**7,953**	**8,230**	**8,491**
Yoy Growth, KBD		(92)	(12)	23	(1)	136	428	704	743	676	527	353	344	300	277	261

Source: Credit SuisseUS Equity Research Oil & Gas team

Impact on Broader Energy Use?

Historical perspective on energy trends

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"Miners are more likely to exhaust the supply of ores than foresters the supply of the wood needed to smelt them. Very great forests are found everywhere, which makes one think that the ages of man would never consume them…especially since nature, so very liberal, produces new ones every day" – Vannoccio Biringuccio, Pirotechnia (1540)

In the 16th century Britain ran out of wood. The clearing of native forest for agriculture and the rapid expansion of towns resulted in depletion of the primary source of energy. Wood became far too costly to burn at scale and scarce enough to preserve for other uses (especially shipbuilding). The consequences were far reaching. Although other factors were also important, the world's first major energy crisis led to the widespread use of coal in Britain, a pattern which set in train decades of technological innovation and fuelled the industrial revolution.

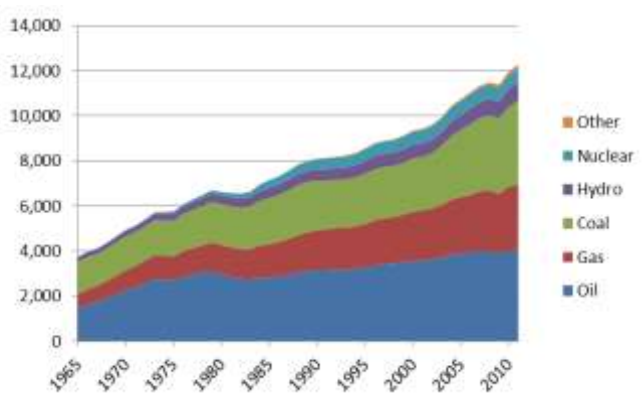
Energy crises tend to be followed by technological innovation

Five centuries later, society's dependence on fossil fuels is presenting economic and political challenges once again. This time, the high cost of oil and concerns over greenhouse gas emissions from coal are stimulating the search for alternative fuels and mitigating technologies. The cost of energy is too high to enable unfettered use of fuels in emerging markets in the same manner as experienced in the United States and Europe during their industrialization. In particular, the heavy reliance on imports of expensive oil is a major source of concern for nations like China and India. These two nations are having a dramatic impact on world energy use, and will dominate growth in use over the next 2-3 decades. Further, China and India are likely to retain an energy mix dominated by coal – the one fuel of which they have strong natural endowment – but the quest to reduce this footprint is central to both countries' long-term energy planning.

In this section we explore the implications of larger than previously expected supplies of gas on global energy balances – assuming resources of unconventional gas are opened up for exploitation in time – and in particular the ramifications for other fuel commodities by potential changes in energy mix in China and other emerging markets dominating growth in primary energy demand.

Exhibit 227: World primary energy consumption by fuel type – dominated by fossil fuels

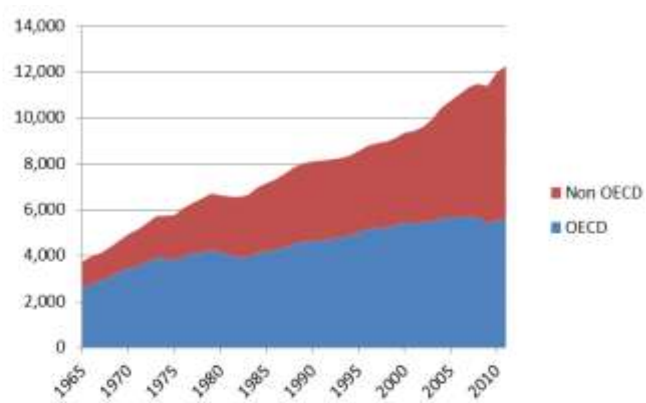
Mtoe



Source: BP Statistical Review of World Energy 2012, Credit Suisse.

Exhibit 228: Demand in the non-OECD nations accounts for virtually all the growth

Mtoe



Source: BP Statistical Review of World Energy 2012, Credit Suisse.

Other factors are playing a hand here too, namely the accident at Japan's Fukushima nuclear power facility which is leading to a more rapid substitution of nuclear energy by gas (and coal) in Japan and a deep rethink on the approach to adopting nuclear power elsewhere, including China. However, China has re-iterated its commitment to nuclear power and renewable energy.

Policy decisions will also shape future energy considerations, although the imperatives here differ very greatly between China, for example, primarily seeking to protect economic growth and security of supply, and developed nations, which are more heavily influenced by populations now more fearful of nuclear energy and urging a stronger contribution from renewable energy sources.

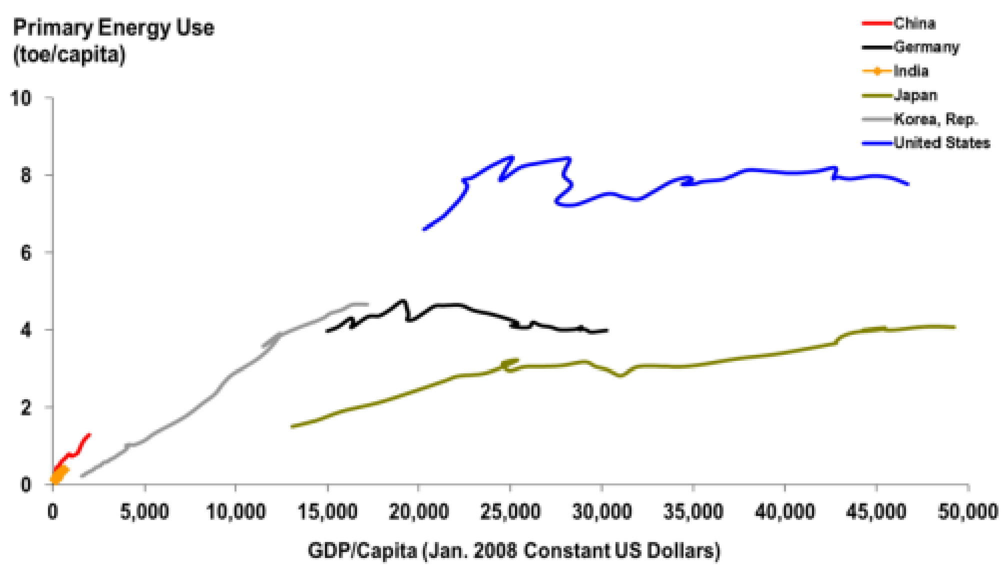
Non-OECD nations driving growth; reliance on fossil fuels

The first observation about historical primary energy consumption is that fossil fuels (oil, coal and gas) continue to dominate the energy mix – this includes use of these fuels to generate energy directly, but also consumption as a raw material in broader uses (e.g., in chemicals manufacture). Hydro-electric power, nuclear power and renewable energy sources make up barely 10% of global primary energy use. Gas has grown its share of the energy mix, at the expense of oil, while coal use has grown too, led by China (Exhibit 227).

Second, energy use in the OECD nations appears to have essentially peaked, partly as a result of the Great Recession, and non-OECD countries have dominated growth in energy use, especially since the early 2000s (Exhibit 228). The large populations of China and India, combined with rising incomes and rapid industrial development, are at the heart of this trend.

Exhibit 229: Energy use rises with incomes – the US is a heavy user of energy in comparison to other nations, mainly reflecting high use in transport

Tonnes of oil equivalent (toe)/capita – left scale; realGDP/capita – lower scale



Source: BP Statistical Review of World Energy 2012, World Bank, IMF, Credit Suisse

On a per capita basis however, the United States is an outlier in terms of its high energy use relative to Japan, South Korea and Germany, for example. To some extent this reflects the US's stronger natural resource position for energy commodities, but is predominantly a function of high gasoline use in vehicles. Countries such as Brazil, Canada and Australia, with large energy resources, also tend to have high per capita energy use.

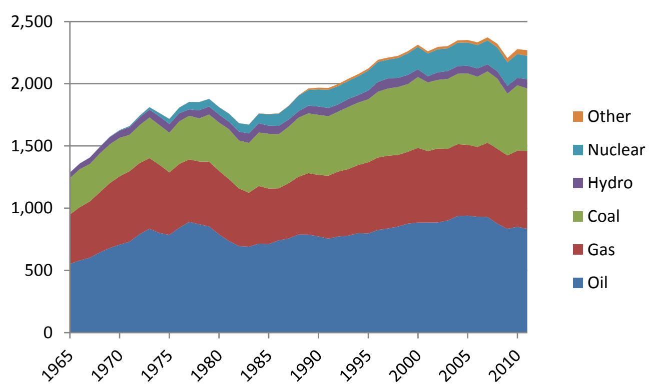
Exhibit 229 in comparison shows that China and India's per capita use of energy is far lower than in the developed nations – it is inconceivable that the energy path of these populous countries will mirror that of the United States on this measure.

The pattern experienced by Japan is informative in making predictions for China and other industrializing economies. Exhibit 232 illustrates Japan's strong reliance on fossil fuels, despite constructing one of the world's largest nuclear power fleets. Until the Fukushima disaster in 2011, nuclear power generation accounted for about one third of Japan's electricity production – electricity in turn caters for around 25% of primary energy use, a level typical of developed nations.

In contrast, electricity represents just 17% of China's energy use and even less in India, although these proportions are likely to rise as they progressively electrify, displacing less efficient direct use of coal and, especially in India, diesel as an important back-up for power generation.

Exhibit 230: US energy consumption – oil use being reined back, gas growing

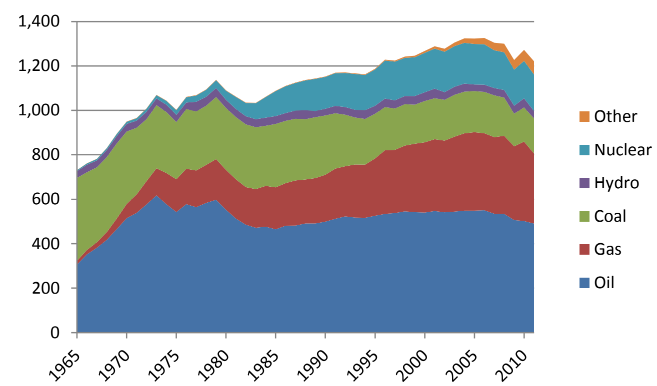
Primary energy use, Mtoe



Source: BP Statistical Review of World Energy 2012, Credit Suisse

Exhibit 231: … as is the case in Europe's leading economies

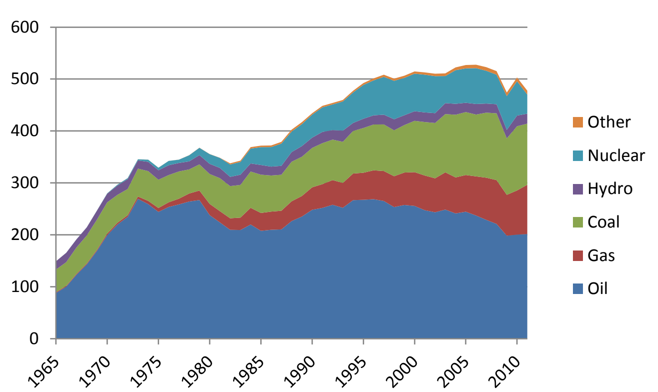
Primary energy use, Mtoe



Source: BP Statistical Review of World Energy 2012, Credit Suisse (countries include Benelux, France, Germany, Italy, Spain and UK)

Exhibit 232: Japan's reliance on coal, and now gas, is growing

Primary energy use, Mtoe



Source: BP Statistical Review of World Energy 2012, Credit Suisse

Exhibit 233: Japan's energy consumption by sector – dominated today by commercial, residential and transport activities

Billion liters oil equivalent (lhs); trillion yen (rhs)

Source: Agency for Natural Resources and Energy, Japan

Economic mix dictates energy patterns, but efficiency gains are important too

Exhibit 233 points to how energy use evolves with economic development. In the 1960s and early 1970s, Japan's energy use was driven mainly by growth in industry and especially energy-intensive industrial activity. Following the first oil price shock in 1973, Japan's economic mix rapidly changed. Energy-intensive industry lost competitiveness, as illustrated by the wholesale closure of primary aluminium smelting. As a nation dependent on imported fuel, Japan's economic activity shifted towards less energy-intensive light manufacturing and services. Incomes continued to grow, and non-industrial uses of energy took over as the predominant forces.

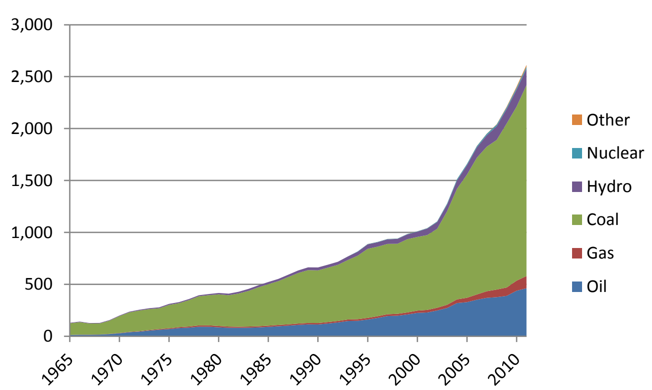
Another way of looking at this pattern is that in the industrial stages of development an economy largely consumes energy to produce goods. In the more mature stages of its development, energy use becomes more important in supporting urban living and transport. As incomes grow, citizens become more intensive consumers of energy as a life-style "reward" for having generated economic wealth. At this point, gains in energy efficiency become more important than broader changes in economic mix in reining back growth in energy use.

The same pattern of broad energy use is likely to emerge in other nations, principally China. However, there are important differences between Japan and China and the timeframes involved are uncertain. China's large coal resources have helped promote a large heavy industrial sector, with rises in energy intensity of GDP taking place until recent years.

In the absence of substantial coal resources, it could be argued that China's economic growth would be hampered severely. Beijing is fully aware of this skewed energy mix and has a major pre-occupation with energy security and rebalancing the energy portfolio in its planning. Under most mainstream growth expectations, China will rely on a growing contribution from virtually all energy sources.

Exhibit 234: China's energy consumption – surging in the past decade

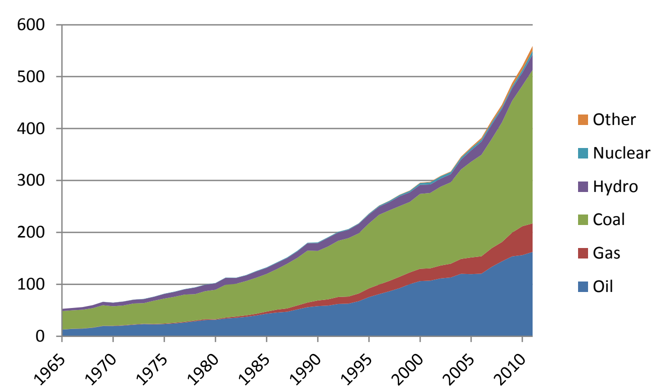
Primary energy use, Mtoe



Source: BP Statistical Review of World Energy 2012, Credit Suisse

Exhibit 235: India's energy use also growing rapidly and heavily dependent on oil and coal

Primary energy use, Mtoe



Source: BP Statistical Review of World Energy 2012, Credit Suisse

China's path is critical to global outcomes

The focus on addressing this "unbalanced" economic and energy mix will hinge on:

- **Less energy-intensive manufacturing and services in the economic mix**: Changes in economic mix will result in the biggest reductions in energy intensity (of GDP). However, rapid transformation of the economy toward higher-value-adding light manufacturing and services is not an easy, or rapid, transition, and the current economic climate has forced Beijing to back pedal, at least for the time being, on imposing greater impediments to excessive heavy industrial activity.
- **Power pricing reforms and demand management**: China cannot afford to charge high prices for energy to many low-income earners. For example, residential users pay lower electricity charges than for most industrial and commercial users, the opposite of the norm in Europe and the United States. However, the balancing act between tariff-based pricing for electricity on the one hand and market-based pricing for coal on the other has created anomalies in the power and industrial sectors.

  However, it is unlikely that China's electricity pricing mechanisms will move fully toward market-based pricing (indeed, few countries have truly deregulated power prices). Nevertheless, we see room for a steady, and more sophisticated, evolution of power and energy pricing; high users in the residential sector are paying higher marginal prices for instance. Better power demand management has already helped reverse China's rising intensity of energy use per unit of GDP and peaking power pricing mechanisms will likely facilitate more rapid emergence of gas power generation.
- **Electrification and improved power transmission and distribution systems**: Strengthening national and regional grids and power distribution effectiveness is a primary goal of the current five-year plan, including installing ultra-high voltage (UHV) systems for long-distance power transfer. A more efficient electricity distribution system is necessary to increase the contribution of electricity in the energy mix from 18% to around 25%, in line with more advanced economies. The focus on UHV technology is also aimed at overcoming deep bottlenecks in the transportation of coal from the north and north-west of the country to areas of demand in the center and south.
- **Renewable energy thrust and technology solutions**: The government has emphasized growth of renewable energy and creating "technology options" (such as on hybrid and electric vehicle manufacture and urban mass transit solutions). Beijing is effectively placing a range of bets to reduce the risks associated with high dependency on imports of oil and, to a lesser extent, gas. The value of these imports is running at about US$200B annually, compared to coal imports at around US$30 billion in 2012. The push also comes with the added bonus of seeding more innovative manufacturing activity. The National Energy Administration has laid out ambitious targets for renewable energy capacity, although utilization rates for this planned installation of wind and solar are likely to be low; gas is seen to play an important part in contributing to back-up and peak power management.
- **Growth in the contribution from nuclear power**: China's ambitions to install a large nuclear power base are well documented (RMB80B of spending in the current five-year plan). However, the Fukushima incident prompted a temporary halt to approvals of new reactors in China pending deeper safety reviews. This review has been completed and we believe China will continue to see nuclear power as a long-term goal of reducing a large reliance on coal, perhaps accounting for more than 35-40% of power generation within 20-30 years. Current targets entail 40 GW by 2015 and 80 GW by 2020, reflecting the long lead times for building up a substantial nuclear fleet.

Almost certainly, the emphasis will now rest with adopting and modifying more advanced GIII reactor technology and, ultimately, GIV technology, which remains at pilot/experimental stage. GIII technology will require co-operation with external service providers, such as Westinghouse, but brings with it considerably greater safety. In time (beyond 2030), GIV technology promises to harness spent fuel, leading to greater fuel efficiency and reduced volumes of hazardous waste.

Exhibit 236: China's power generation capacity targets

GW and % of total by fuel

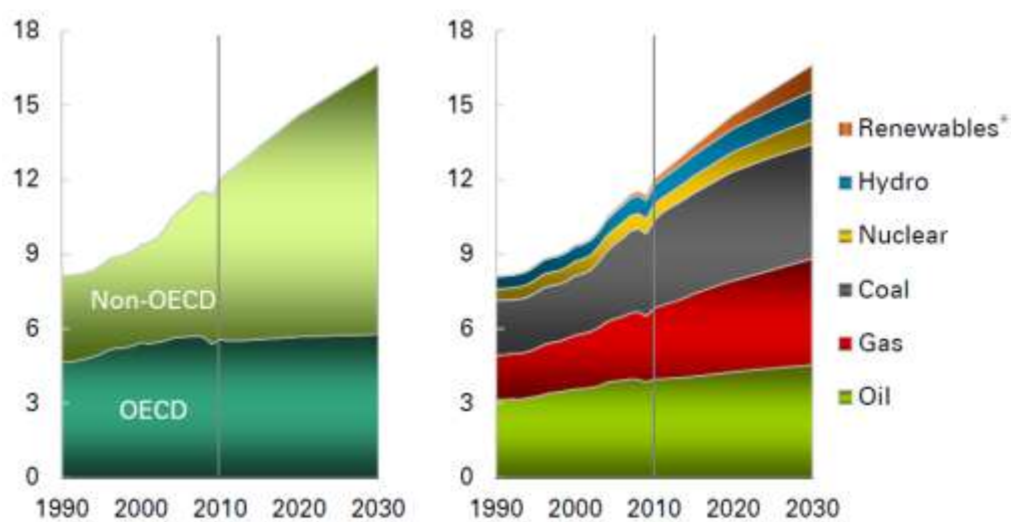
	GW			%		
	2011	2015	2020	2011	2015	2020
Coal	697	928	1170	65	63	60
Hydro	236	342	420	22	23	22
Gas	32	40	50	3	3	3
Nuclear	11	43	80	1	3	4
Wind	64	100	180	6	7	9
Solar	2	5	25	0	0	1
Other	30	5	10	3	0	1
	1073	1463	1935	100	100	100

Source: National Energy Administration (NDRC), Credit Suisse.

- **Increased attention on protecting and harvesting energy resources**: China's extraction of coal comes at high cost, both economically and socially (accident rates are appalling by world standards). In recent years, Beijing has pushed for industry consolidation in an effort to improve safety and prevent resource degradation. Some progress has been made in this regard, but there is a long way to go. Meanwhile, import volumes for thermal coal and coking coal have grown. China does not appear to be uncomfortable with this increased flow of imports, but is much more determined to diversify its reliance on imported volumes of oil and gas through an increased exploration focus, onshore and offshore.

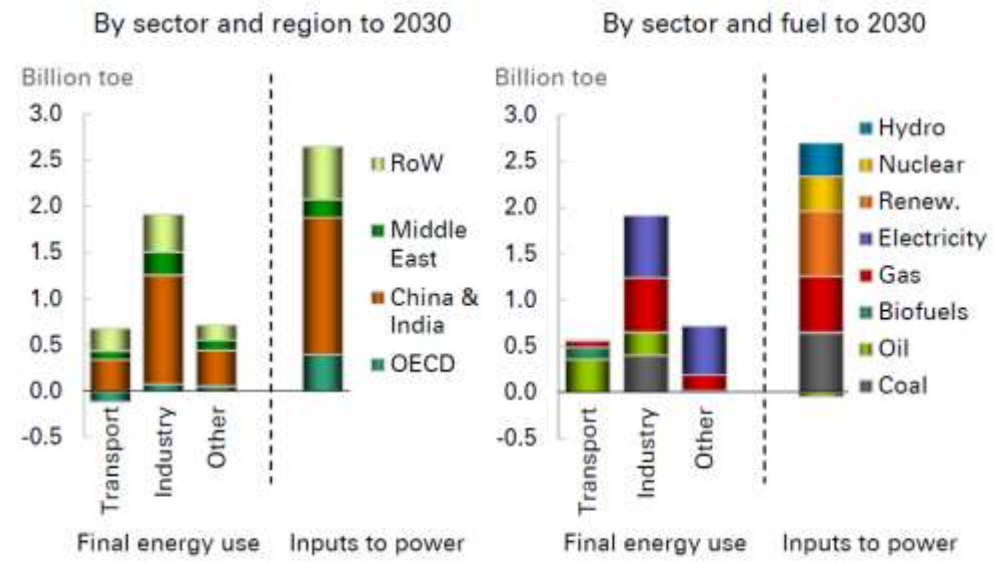
Exhibit 237: Rising energy use will be driven by non-OECD nations – fossil fuels will dominate but gas will increase its share in the fuel mix

Btoe



Source: BP Energy Outlook 2030.

Exhibit 238: China and India driving growth in energy use – gas, renewables and electrification increasing their contributions



Source: BP Energy Outlook 2030

Impact on Future Energy Use?

Weaning the world off fossil fuels

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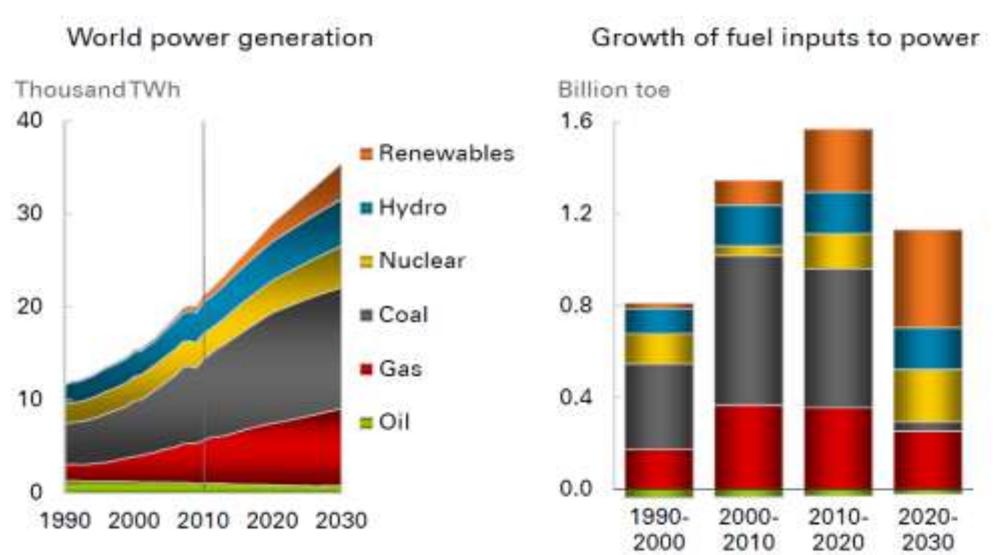
Renewables, nuclear and hydro will make inroads…in the longer run

Despite improvements in energy efficiency, rising population and incomes are expected to drive a 1.6% p.a. increase in primary energy use through to 2030 (compared to 2.0% in the previous 20 years), according to BP's forecasts as outlined in its latest *Energy Outlook 2030*. Energy use per capita is predicted to increase at about 0.7% p.a., a similar rate to that of 1970-2011. Almost all of this growth is in non-OECD countries. Energy use overall is anticipated to rise by almost 40% from current levels, but the pace of this growth is likely to moderate over time, reflecting efficiency gains and technological advancement.

Although forecasting patterns over such a long period is a challenge, BP's projections provide a very useful and credible reference point. Features include:

- Slow changes in fuel mix due to long gestation periods for new technology and long asset life times. Barriers to entry in oil and gas owe a lot to this high capital intensity – both oil and gas sectors have oligopoly supply characteristics.
- Globally, gas and non-fossil fuels expand their share at the expense of coal and oil – gas gains at 2.1% p.a., with renewables even faster (8.2% p.a.) but off a much lower base. Renewables in aggregate are forecast to account for 34% of growth in energy use, but gas is the largest single source of contributing to growth (31%).
- In the OECD countries, renewables displace oil in transport and coal in power generation; gas takes market share from coal in power with influences arising from a combination of relative fuel prices, technological developments and policy intervention. For most developing countries, the imperative is the securing of affordable energy to support economic growth.

Exhibit 239: Electrification is expected to advance strongly, while gas and renewables eventually eclipse coal's contribution in the power sector fuel mix

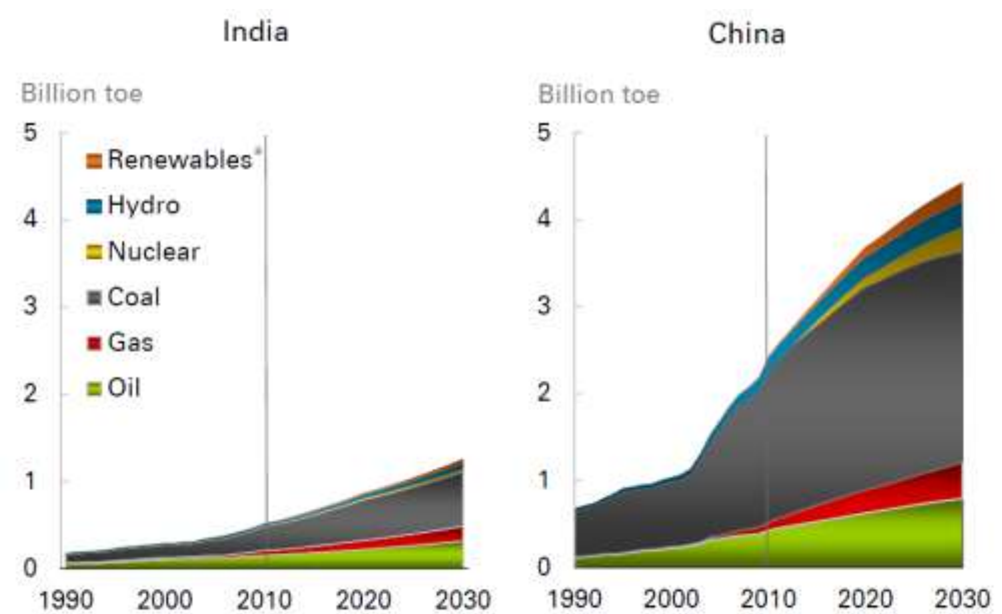


Source: BP Energy Outlook 2030.

- Electricity increases its contribution to energy use, accounting for 57% of the projected growth (vs. 54% in 1990-2010). Non fossil fuels are seen as the main driver of diversification in power sector fuel mix, responsible for more than half the growth. Efficiency gains in power output mean that fuel inputs grow more slowly than power output. Nevertheless, coal accounts for almost 40% of power sector fuel input growth in the next decade (from larger scale super critical and ultra-super critical plants).
- Major changes are being faced in the transport sector where biofuels are forecast to lead greater diversification of fuel sources by 203. Gas contributes 13% to growth in sector energy use according to BP's projections, which assume relatively modest contributions from electricity (2%), implying slow and limited success in expanding the fleet of purely electric vehicle. Changes in the energy efficiency and fuel mix within transport account for one of the greatest overall reductions in global energy intensity in the next 20 years, stimulated by rising energy trade, technology diffusion and standardization. By 2030, world energy intensity of GDP will be less than one half of the level of 1970.

Exhibit 240: Growth in China's energy use begins to slow in the 2020s and gas, renewable energy and nuclear power eventually halt growth in use of coal

Primary energy use, Btoe



Source: Credit Suisse.

Gas to gain at the expense of oil and coal

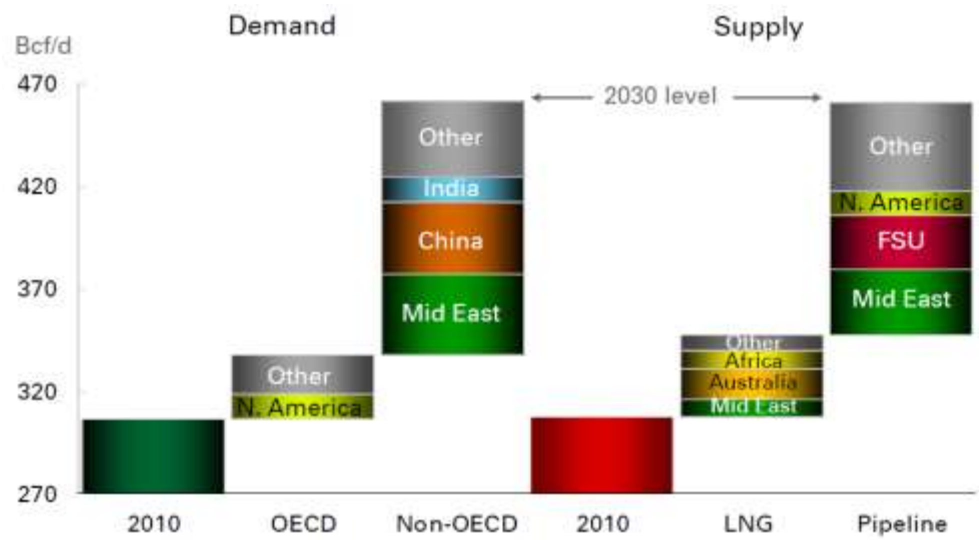
Demand growth for natural gas is expected to be greatest in emerging markets. China is an important component of this demand growth and its demand will essentially remain supply constrained in the absence of much greater-than-expected supply growth. In other words, the more gas that becomes available, the more gas will displace rival fuels and raw materials.

However, the pecking order of this displacement will depend on relative prices and policy intervention. For example, use of gas in certain applications is prohibited in China and tariffs are set at different levels to allow use of gas in order of preference in residential and commercial activity (essentially in buildings), transport and in selective industrial uses.

The use of gas in base-load power generation in China is prohibited, and would not make economic sense on cost grounds against coal. However, gas's role in peaking power management (and as back-up for renewable energy) is likely to grow, at least where pricing allows for competition against rival fuels. China's gas supply will come from a range of sources, from continental pipelines, to LNG to domestic conventional and potentially unconventional discoveries. It is almost certain that the state will continue to manage gas pricing through differentiated tariffs (currently the NDRC sets well-head prices), meaning that more expensive imports of gas are effectively blended into the distribution system and costs cross-subsidized by cheaper forms of gas.

Exhibit 241: Natural gas demand growth is likely to be strongest in non-OECD countries

Bcf/d



Source: BP Energy Outlook 2013.

Exhibit 242: Gas will continue to displace other fossil fuels in the power sector and in certain industrial uses, predominantly in emerging markets

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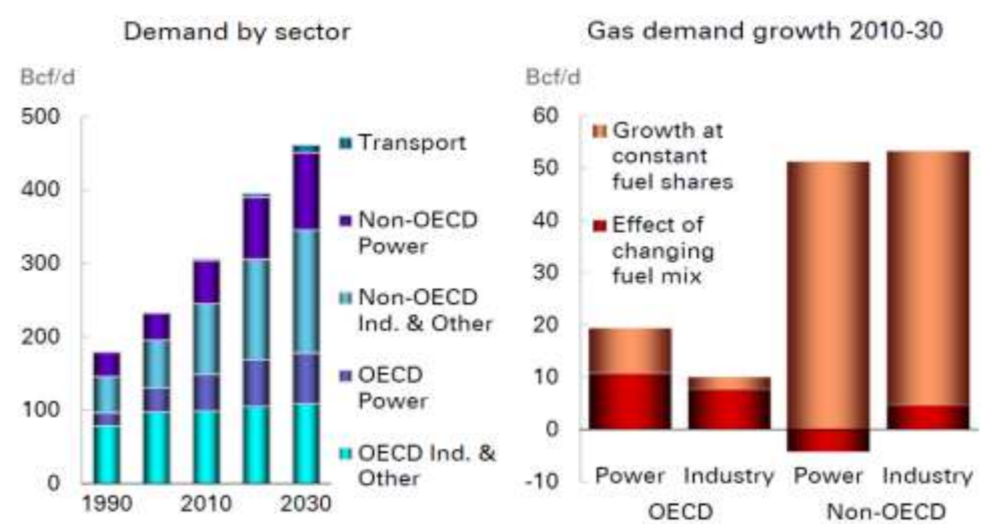

Source: BP Energy Outlook 2013.

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