جدوى للإستثمار
Jadwa Investment

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Outlook for Unconventional Oil & Gas Production

Focus on Tight Oil and Shale Gas Production
Impact on Saudi Arabia

Summary

- Oil and gas are produced from underground reservoirs, at rates which greatly depend upon the porosity and permeability of the host rock. Over the years, as energy prices have gone up, oil and gas "reserves" have also gone up since higher prices justified the development and use of more expensive technologies to recover harder-to-get molecules.

- Recent technological advances, in particular 3D seismic, horizontal drilling and hydraulic fracturing ("fracking"), have spurred the exploitation of large tight oil and shale gas formations in the US.

- Forecast of global energy demand growth, coupled with declines in the production from conventional oil fields, have led observers to predict that tight oil and shale gas will play an increasing large role in the world's energy markets and will affect large established players such as Saudi Arabia.

- Our review of specialized public domain industry information suggests instead that, for both technical and economic reasons, tight oil and shale gas production may increase substantially less that most observers assert.

- We view the growth of tight oil and shale gas mainly occurring in the US, not only because of technical reasons (attractive and well understood "tight" geological formations), but also because of uniquely favorable above ground factors such as efficient and low cost industrial services, infrastructure, legal and financial systems, and an accepting society.

- We further doubt that, even in the US, production of tight oil and shale gas will increase as fast and as much in the medium and long term as most observers suggest.

- For tight oil, this is because, since the tight formations have by definition low permeability, each well has a restricted reach and its production is limited and declines rapidly. Many wells are thus needed to sustain production, let alone expand it. Of the two major tight oil plays, which account for 85% of US tight oil production, we view only one as promising long term growth. We suspect that US overall tight oil production may decline after 2018.

- For shale gas, this is because, in addition to the rapid decline in production from each well and a constant need to drill more

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wells, gas prices are now at a level which render shale gas production unprofitable, except when it is accompanied by a significant production of Natural Gas Liquids, and when it can economically access an adequate pipeline infrastructure.

- We see two major shale gas basins as so large and attractive as propelling US shale gas production forward. But we doubt that other fields' production will rise substantially as gas prices may stay near their current levels. We see US shale gas production plateauing after 2020.

- In all thus, we doubt that tight oil production will significantly impact the world's oil industry over the long term. In particular, we do not see it affecting Saudi Arabia's situation.

- With large volumes of cheap Natural Gas Liquids, we believe that US shale gas production will mainly impact the world's petrochemical industry and may induce Saudi producers to expand production there.

The Basics of Oil & Gas Production

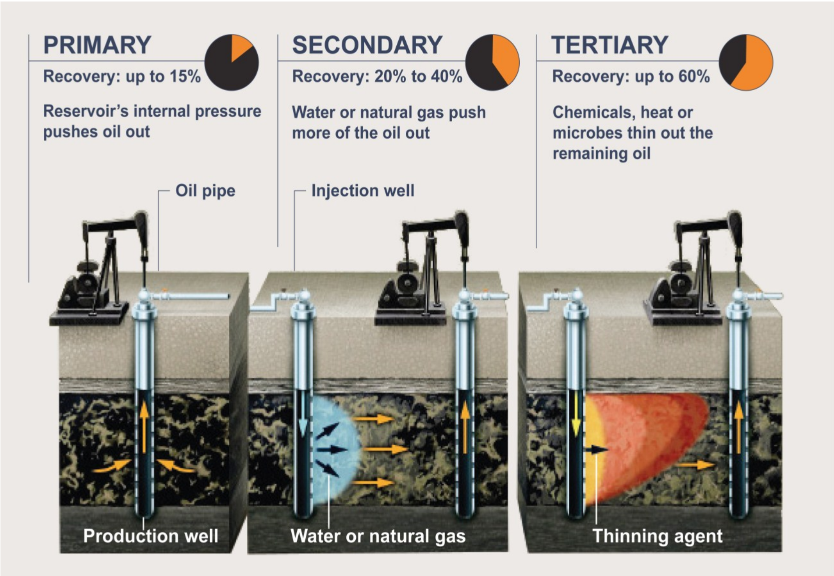
Oil soaked porous rock

Oil and gas are extracted from underground rocky structures called "reservoirs", in which small pores and micro-fractures entrap minuscule droplets of oil, together with water and natural gas. When such a reservoir is drilled, and depending upon the rock's porosity and permeability, the reservoir's internal pressure pushes the oil to the surface.

This goes on, depending upon the reservoir's geometry, pressure, porosity, permeability and oil composition, until the outflow peters out, usually after several years.

Since the late XIXth century when oil extraction began, repeated technical advances have allowed us to recover much more than the 10%-15% of the in-situ oil & gas which natural pressure would normally allow.

Figure 1: Three Classical Stages of Oil Recovery



Source: "Squeezing more oil from the ground" – Scientific American, October 2009

Over the years, through technical advances, the oil & gas industry has exploited previously unreachable resources, and exploited them profitably.

Production from a reservoir depends greatly upon the porosity and the permeability of the host rock.

Looking forward, it is this interplay between (i) physical resources in the deposits, (ii) new technologies which allow their profitable recovery at a given price, and thus (iii) new increases in economically recoverable reserves, which will drive how the global oil & gas industry evolves, including the developments of unconventional, more expensive, sources of oil & gas.

As energy demand grows and oil & gas prices rise, technologies are developed to extract more oil & gas from previously unreachable resources, and extract them at a profit.

In summary, The outlook for tight oil and shale gas developments does not solely depend upon the physical presence of oil and gas molecules in specific geological formations.

It critically rests on the comparative economics of extracting these molecules (given likely technological advances) versus the economics of producing oil and gas from other sources, be they conventional or unconventional.

The Global Reserves of Oil & Gas

When discussing oil & gas reserves, it is critical to differentiate between (i) the physical presence of hydrocarbon molecules in a geologic formation, and (ii) that portion of those molecules which can be economically recovered.

As technology moves forward

The industry uses the following terminology:

oil & gas reserves will keep increasing, depending upon…

1. **Proven Reserves:** the discovered volumes having a 90% probability to be extracted profitably.

2. **Remaining Recoverable Resources:** these are the proven reserves, reserves growth (the projected increase in reserves in known fields) and as-yet-undiscovered resources that are judged likely to be ultimately producible using current technology.

...1) energy demand and price expectations which will justify the capital investments and the fields exploitation and…

Four critical factors impact our understanding and confidence of how much oil & gas we will be able to extract to power our economies' future growth:

...2) satisfy the increasingly strict environmental and societal constraints

1. **Geology:** the actual physical presence of oil & gas molecules in rock formations.

2. **Technology:** the equipment, materials, systems and procedures which allow us to find and extract oil & gas from those rock formations, and how much.

3. **Price:** the key benchmark against which field development and oil & gas production costs must be justified.

4. **Above Ground Constraints:** the permitting, environmental regulations, water and infrastructure availability which will allow for the profitable development of the field and disposal of its production.

Over the years, as energy prices have gone up, "reserves" have also gone up because higher prices justified the development and use of more expensive technologies to recover harder-to-get molecules, either from existing reservoirs or from hitherto unreachable or unexploitable formations.

How technical advances dramatically increase oil reserves Estimates

The Kern River Field in California. When the Kern River Oil Field was discovered in 1899, analysts thought that only 10 percent of its unusually viscous crude could be recovered.

In 1942, after more than four decades of modest production, it was estimated that the field still held 54 million barrels of recoverable oil, a fraction of the 278 million barrels already recovered. In fact industry observers famously remarked that "in the next 44 years, it produced not 54 million barrels but 736 million barrels, and it had another 970 million barrels remaining." But even that estimate proved incorrect.

In November 2007, Chevron, by then the field's operator, announced cumulative production had reached two billion barrels. Today Kern River still yields nearly 80,000 barrels per day, and the state of California estimates its remaining reserves to be about 627 million barrels.

Chevron began to increase production markedly in the 1960s by injecting steam into the ground, a novel technology at the time. Later, new exploration and drilling tools, along with steady steam injection, turned the field into a kind of oil cornucopia, with reports of Chevron on its way to pumping as much as 80% of the crude.

Recent Technological Developments

Over time, four major technological developments have enabled the finding and extracting of more and more oil & gas.

Injection pushes the oil towards the well

Injection. Originally, the key innovation to extract more oil from the reservoirs was to inject gas under pressure to restore the pressure lost during the primary recovery, or to inject water to raise the oil up towards the well. As time passed, this evolved into more and more powerful and sophisticated processes to inject steam to push the oil to the well and to inject chemicals to facilitate the migration of the oil droplets through the host rock by lowering their viscosity.

For impermeable formations such as shale rock, oil producers today inject water, sand and special chemicals to crack the rock and to facilitate the migration of hydrocarbons towards the wells.

3D Seismic tells operators precisely where the hydrocarbon-rich zones are

3D Seismic. By sending acoustic waves from near the surface and listening for echoes from deeper boundaries between layers of different rocks, engineers are able to get a good picture of where hydrocarbon-rich formations are located. With increased knowledge on how best to interpret the sub-surface images, and with massively more powerful computing power, engineers define increasingly precisely the geometry and the geologic characteristics of the "payable zones".

Horizontal Drilling. The industry has known for many years how to change the direction of a well from vertical to another angle, *Horizontal drilling allows operators to reach more hydrocarbon rich zones*

including horizontal. Starting in the 1980s, operators have learned how to control, in three dimensions, at exactly which new angle the drill would turn, in rocks of different geophysical properties, to direct the well with great precision over long distances to the target zones. This has reduced the number of wells needed to extract oil from a reservoir and allowed the reaching of sections which would otherwise not be reachable or economic, when hydrocarbons are in thin horizontal layers for instance. Further, multilateral wells - wells with multiple branches radiating from one main borehole - now allow operators to access various zones of deep under sea reservoirs from one single surface facility.

Mining and Refining of Oil Sands. Oil sands are deposits of sand or loose sandstone and clay saturated with bitumen, a heavy, dense and viscous form of petroleum. The mining and purification of oil sands is expensive, and the bitumen produced is a particularly heavy type of crude. Bitumen from Canada (the only producer of oil sands to date) is either diluted with gas condensates or light oil for export to US Gulf Coast refineries, or it is processed near the mine into light crude.

Improvements in the mining and refining of oil sands allow for economic production of crude from heavy bitumen deposits.

Three technological developments have enabled the economic mining and refining of oil sands. First, mining itself has experienced massive productivity improvements and cost decreases (digging a tonne of ore cost about 40% less now than 40 years ago). Second, bitumen can now be extracted from some zones by melting it with steam and having it flow into horizontal wells at the bottom of the formation. And third, progress in refining technology has significantly cheapened the recovery of oil from the sand and the upgrading of the bitumen into lighter crude.

The mining and refining of oil sands is considered by most as expensive, in particular since it produces heavy lower-value crude. As the marginal source of oil to the US refineries, it has flourished to date in Canada thanks to continued improvement in mining and bitumen processing technologies.

Global Demand Outlook for Energy

Numerous institutions analyze and comment on the status and outlook of the global energy industry. For the outlook for global energy demand, we have elected to use ExxonMobil's data, analyses and projections, as they present in their 2013 publication "The Outlook for Energy: A View to 2040".

Consensus on key trends and conclusions for global energy demand

These are broadly in line with the energy demand projections published by the International Energy Agency, the US Energy Information Administration and other industry participants such as British Petroleum. All key trends and conclusions are similar.

History has shown a strong correlation between economic growth and energy consumption growth. The two key assumptions in forecasting global energy demand are (i) the rate of growth of the world's various regions, and (ii) the levels and changes in the energy intensity of these regions' economies.

Energy demand will grow less rapidly than GDP…

On the basis of (i) a world GDP growing at 2.8% p.a. in average between 2010 and 2040, and of (ii) 35% energy savings through efficiency gains, global energy demand is to grow 35% from 13.2

…because of large efficiency gains in energy use

billion tonnes of oil equivalent (toe) in 2010 to 17.8 billion toe in 2040, an average of 1.0% p.a. Energy demand will grow most in Asia where 45% of all energy will be used in 2040.

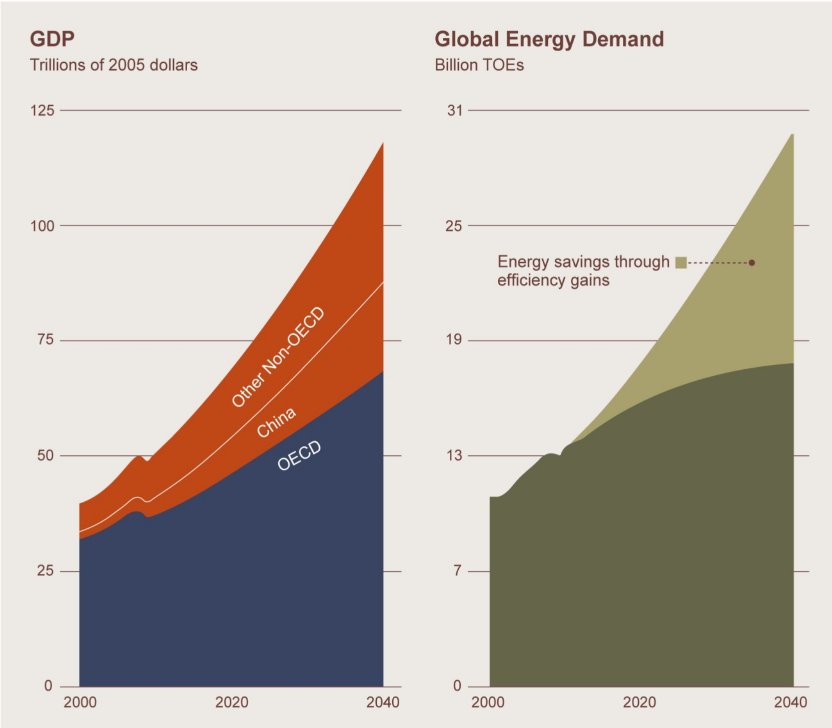
Electricity will grow the most and will represent 41% of global energy used in 2040

Of all the uses of energy, electricity will grow the most. Demand for electricity will grow by 54% and will represent 41% of global energy use in 2040 (from 36% in 2010). Transportation, another major use of energy, will grow by 37%, in line with global energy demand, and will keep representing 18% of global energy use.

Demand for gas will grow 65%
Demand for oil will grow 25%
Demand for coal will fall 2%

Oil & gas will represent, by far, the major sources of energy for the world. They will represent 59% of all energy used in 2040, up from 56% in 2010. The major growth will be for gas. It will grow by 65%, whilst demand for oil will grow more modestly by 25%. Demand for coal will decrease by 2%.

Figure 2: GDP and Global Energy Demand



Source: ExxonMobil – Outlook for Energy, 2013

Global Demand Outlook for Oil & Gas

Oil & Liquids

Oil demand is driven by transportation needs and industrial activities

Oil will continue to be used mainly for the transportation and industrial sectors. Oil demand will grow from 4.5 billion toe in 2010 to 5.6 billion toe in 2040, a growth of 0.8% p.a. on average. This will be propelled by a significant increase in global transportation needs and industrial activities.

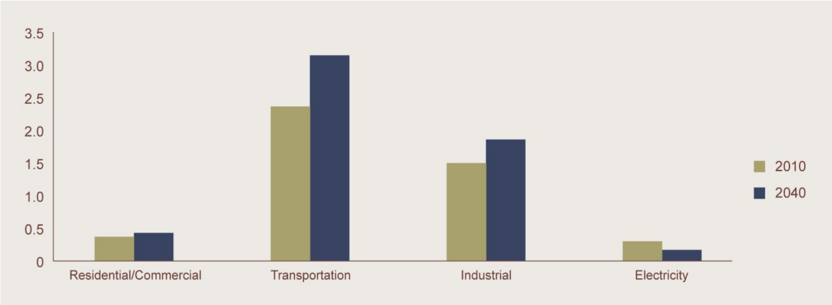
Gas

Gas will continue to be used mainly for the electricity and industrial sectors. Gas demand will grow fast, from 2.9 billion toe in 2010 to 4.7 billion toe in 2040, a growth of 1.7% p.a. on average. This 1.8

Gas demand is driven by increased electricity generation and industrial activities

billion toe increase will result from a significant increase in gas use for electricity generation (1 billion toe) and for industrial activities (0.6 billion toe).

Figure 3: Global Oil & Liquids Demand (in billion toe)



Source: ExxonMobil – Outlook for Energy, 2013; Jadwa Investment

Global Supply Outlook for Oil & Gas

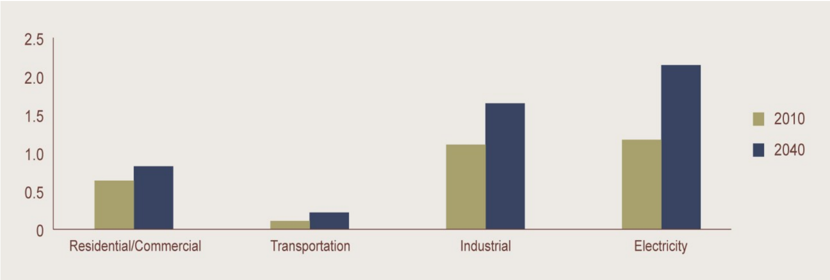
Natural Gas Liquids (NGLs) are produced from oil and gas wells. NGLs are grouped with crude oil when looking at the production of oil & gas

Many hydrocarbon reservoirs contain a mix of crude oil and natural gas. A significant production of hydrocarbons is in the form of natural gas liquids (NGLs) that come with the extracted crude or sometimes also come from wells primarily drilled for gas. The industry looks at the supply of oil & gas by (i) grouping all the liquids (NGLs) with straight crude oil production and by (ii) isolating natural gas production, since they have much different downstream processing and value chains.

Consensus on key trends for global oil & gas production

As for global oil & gas demand, several institutions publish forecast of global oil & gas supply. We have elected to use data, analyses and projections from ExxonMobil's 2013 "Outlook for Energy: A View to 2040" and from the International Energy Agency's "World Energy Outlook 2012". These are broadly in line with the forecast of other industry observers, and all key trends and conclusions are similar.

Figure 4: Global Gas Demand (in billion toe)



Source: ExxonMobil – Outlook for Energy, 2013; Jadwa Investment

Global Reserves of Gas

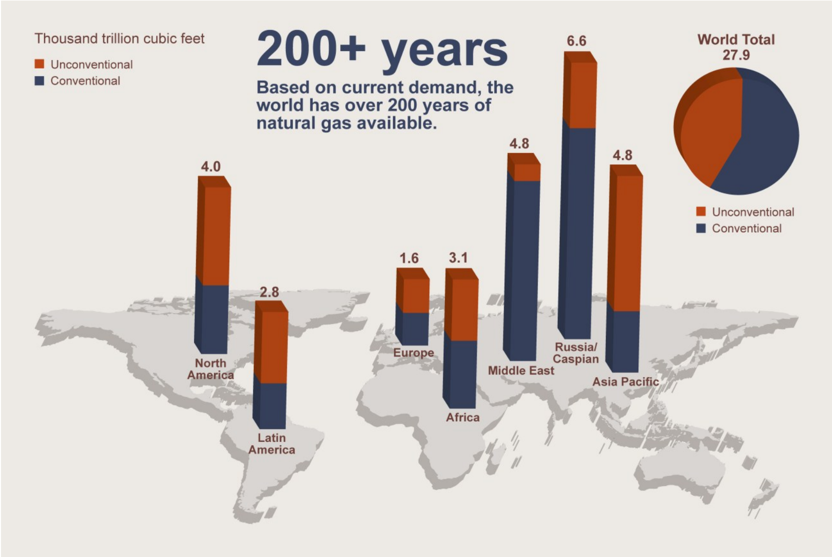
Global reserves of gas are more than we need for 200 years

Global reserves of natural gas are known to be large. In their 2012 reports, ExxonMobil and the IEA estimated that there was about 28,000 tcf remaining of natural gas resources, enough to meet current demand for more than 200 years. Globally, 60% of these reserves are from conventional fields, and 40% come from unconventional (35% shale and 5% coalbed methane formations).

Also, observers note the potential to find more substantial gas resources, in particular in areas richly endowed with oil and conventional gas such as Africa, Eurasia and the Middle East.

Gas production is expected to increase by 65% between 2010 and 2040.

Figure 5: Remaining Global Resources of Gas as of 2011

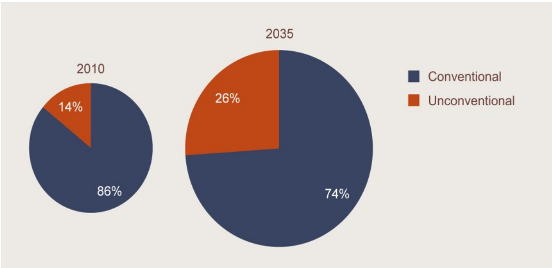


Source: IEA, as quoted in ExxonMobil's "Outlook for Energy, 2013"

Global Supplies of Gas

The IEA forecasts gas production to increase by 51% between 2010 and 2035, with half of the increase is expected to come from unconventional sources. Unconventional gas production will in particular increase rapidly in the North America. The IEA forecasts that unconventional sources of gas will represent 26% of global supplies by 2035, up from 14% in 2010 (ExxonMobil forecasts a 65% increase to 2040.)

Figure 6: Global Gas Supply 2010-2035, by sources



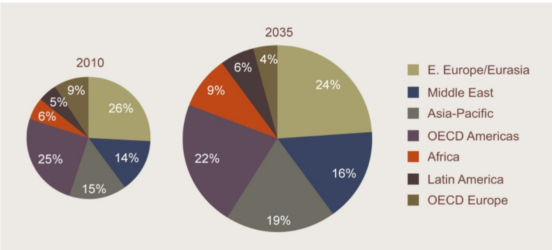
Production 2010: 317.6 bcf/d

Production 2035: 479.2 bcf/d

Source: IEA - World Energy Outlook, 2012

The largest increases in gas supply are expected to come from Asia/ Pacific (China & Australia), East Europe (Russia), the Middle East (Qatar, Iraq and Iran), and North America (US).

Figure 7: Global Gas Supply 2010-2035, by regions



Production 2010: 317.6 bcf/d

Production 2035: 479.2 bcf/d

Source: IEA - World Energy Outlook, 2012

Inter-regional trade will increase 77% between 2010 and 2035

International gas markets will expand and deepen.

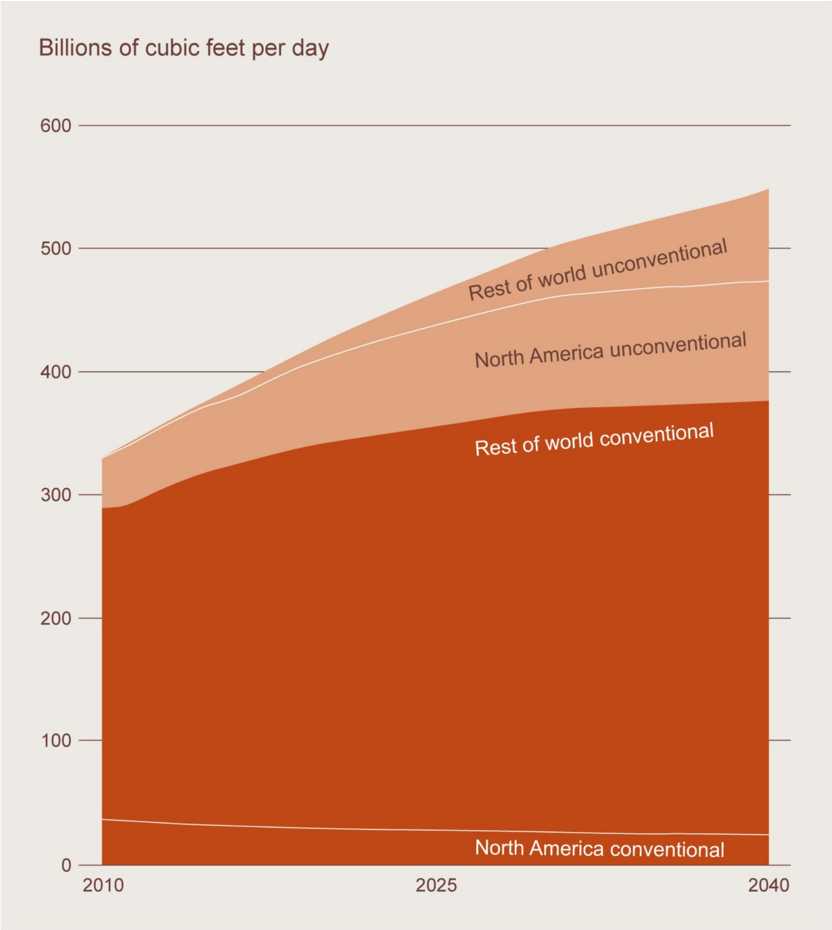
Global Trade of Gas

Gas will also experience a rapid increase in inter-regional trade, from 65 billion cubic feet per day in 2010 to 116 billion cubic feet per day in 2035, a 77% growth (whilst pipelines transport gas over land, an increasing proportion of gas is shipped as LNG over long distance across the oceans).

To date, LNG has been priced on the basis of long-term contracts; with the development of a large and deep LNG trade, international gas pricing may evolve towards a more fluid market, which could end up reducing gas price, another factor in increasing gas use.

The key question is whether gas production can and will increase so much.

Figure 8: Global Natural Gas Supply – 2010-2040



Source: ExxonMobil – Outlook for Energy, 2013

Global Supply of Liquids

Crude oil production from conventional sources will decline…

...but production from unconventional sources will increase very rapidly

Unconventional oil will account for 75% of the supply increase

Unconventional supplies of liquids will increase to 14% of total liquid supplies, up from 5% in 2011.

OPEC will increase its production of conventional oil and its share of total liquids supply to 48% from 42% in 2011

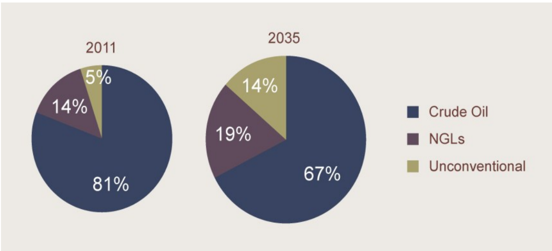
Global liquids supply is expected to grow from 87 million bpd in 2010 to 113 million bpd in 2040. See the graph next page.

Crude oil production from conventional sources is expected to decline slightly over time, as the natural decline from currently producing fields will not be matched by increased production from the existing or new conventional oil fields.

Conversely, crude and liquids production from NGLs and unconventional sources will increase rapidly and will constitute the key new source of liquid hydrocarbons to meet long-term liquids demand.

The IEA foresees unconventional fuel supplies – deep-water, oil sands and tight oil – to grow from 3.9 million bpd in 2011 to 13.2 million bpd in 2035, accounting for as much as 75% of the increase in crude oil supply needed to meet global oil demand. Unconventional sources of crude oil will represent 14% of Global Oil Production in 2035, up from 5% in 2011.

Figure 9: Global Liquids Supply 2011-2035, by sources



2011 Supply: 84.5 million bpd

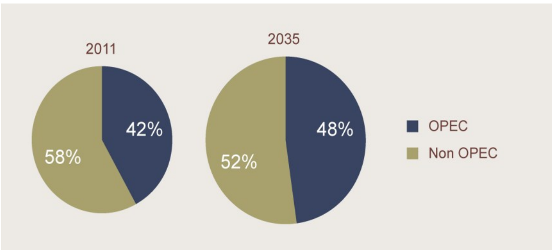
2035 Supply: 96.7 million bpd

Source: IEA - World Energy Outlook, 2012

In terms of geographical distribution and groups of oil producers, the IEA forecasts a rapid decrease of conventional oil production by Non -OPEC countries. In absolute terms, Non-OPEC countries will compensate this loss by increasing their production of NGLs and of unconventional sources of oil (from 3.2 million bpd in 2011 to 10.4 million bpd in 2035).

OPEC, on the other hand, is expected to increase significantly its production of conventional oil (from 29.3 million bpd in 2011 to 33.9 million bpd in 2035), and of NGLs. OPEC's increase in unconventional oil will be much more limited.

Figure 10: Global Liquids Supply 2011-2035, by groups



2011 Supply: 84.5 million bpd

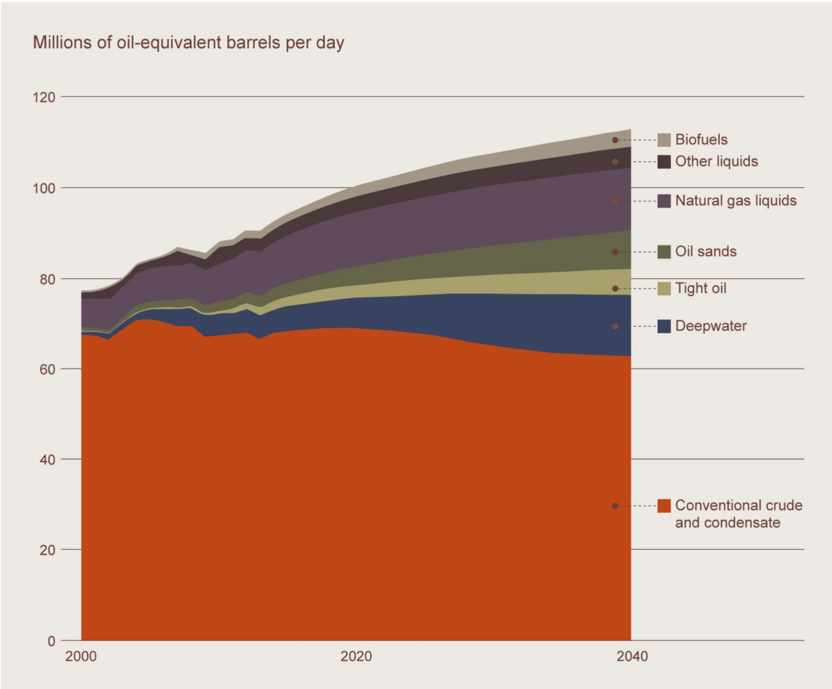
2035 Supply: 96.7 million bpd

Source: IEA - World Energy Outlook, 2012

Clearly, the key questions facing the oil & gas industry today are whether

- the resource base for these unconventional sources of oil and liquids are large enough;
- the technology to extract the oil from these unconventional reservoirs is economic enough at forward oil prices; and,
- the regulations - including environmental permits - and the above ground factors (legal, infrastructure, logistics and societal considerations) are favorable enough to justify the exploration, development and exploitation of these fields.

Figure 11: Global Supply of Liquids – 2010-2040



Source: ExxonMobil – Outlook for Energy, 2013

The Basics of Tight Oil and Shale Gas Production

Tight oil and shale gas are extracted from deep, low permeability formations

The presence of hydrocarbons in deep low permeability formations has been known for a long time. It is however only in the last 15-20 years that, first for gas and then for oil, US entrepreneurs combined horizontal drilling and hydraulic fracturing to extract hydrocarbons profitably from these hitherto uneconomic reservoirs, first for gas from shales (shale gas), and then for oil from various types of tight formations (tight oil).

To extract oil and gas, these formations need to be fractured

Hydraulic fracturing – "fracking" – consists in digging a (classical) vertical oil well, to reach the impermeable layer of tight rock deep below the surface. The well is then sent horizontally to reach the target zones, and large amounts of very hot water, sand and chemicals are injected under high pressure to fracture the rock and to allow gas and oil to migrate to the well bores.

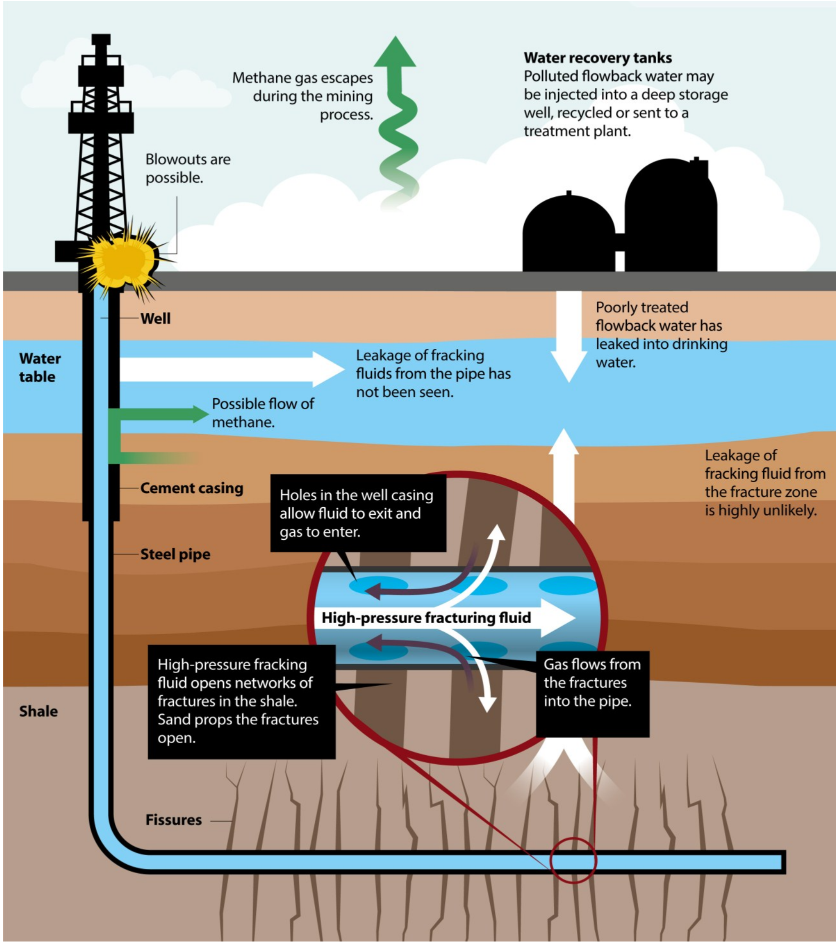
Because of the low permeability, each well has a limited reach...

...thus tight oil and shale gas wells production declines rapidly

Many wells are needed to sustain production

Obviously, since the tight rock is highly impermeable, only a limited amount of gas and oil adjacent to the induced and natural fractures can be drained. Tight oil and shale gas wells will thus experience rapid declines in production. There is considerable variability within tight oil and shale gas plays, with smaller "sweet spots" and larger less productive areas. Early production is concentrated on the sweet spots. Due to their high decline rates, these plays require high levels of capital input for drilling and infrastructure development to maintain production levels.

Figure 12: Schematic of a tight oil or shale gas well



Source: Nature – "Should Fracking Stop?" September 2011

US Tight Oil and International Shale Oil

US Tight Oil

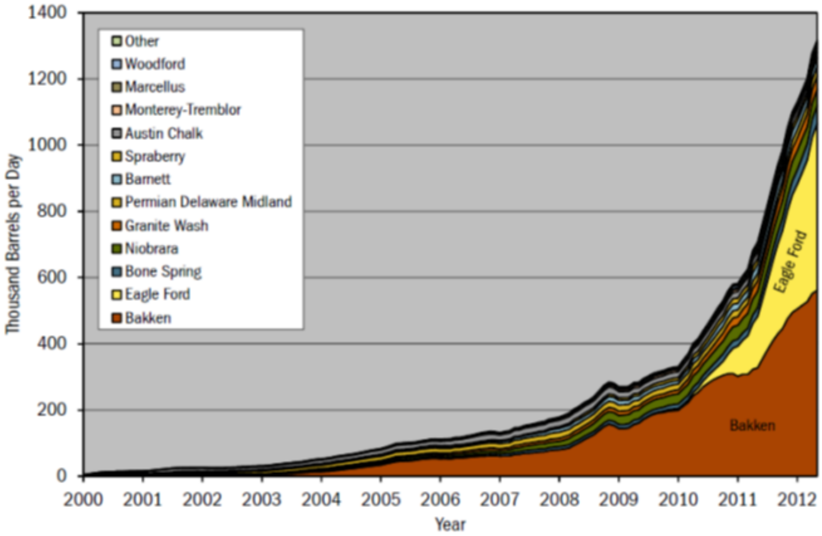
Tight oil now accounts for 32% of all US oil production

Tight oil production in the US has jumped from virtually nothing in 2004 to an estimated 2 million bpd in 2012 (32% of all US oil production). Substantial amounts of natural gas are commonly produced in association with the oil.

Two plays account for 81% of US tight oil production

81% of that production comes from only two plays: the Bakken play in North Dakota and Montana and the Eagle Ford play in southern Texas. As shown on the graph below, production from the US' nineteen other plays has not increased significantly in the last 4 years.

Figure 13: US Tight Oil Production by Plays
(2000 through May 2012)

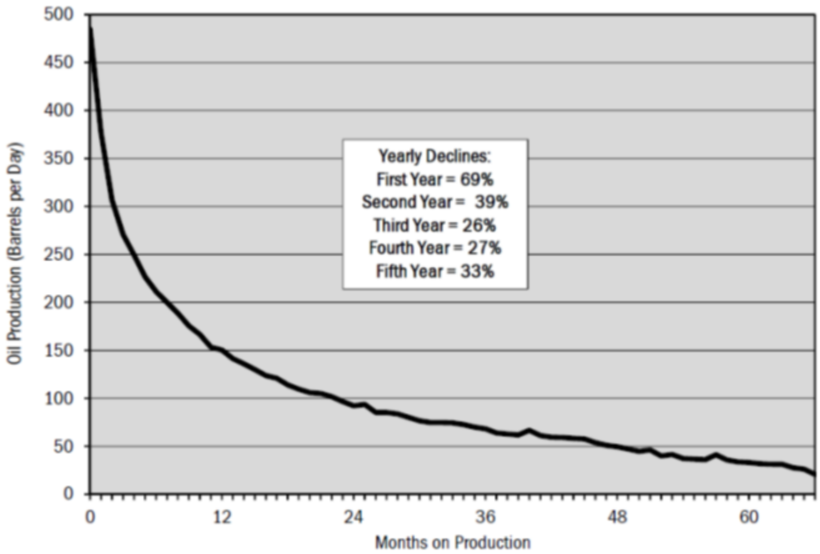


Source: J. David Hughes, Post Carbon Institute, February 2013

Because of the very low rock permeability, tight oil wells can only drain a limited amount of oil from the rock adjacent to the wells. These plays thus have steep decline curves.

Tight oil wells have steep decline curves - production falls quickly

Figure 14: Typical decline curve for Bakken tight oil wells



Source: J. David Hughes, Post Carbon Institute, February 2013

The consequence of such decline curves is immediate: one needs to dig more and more wells to sustain, let alone increase, production.

Also, the plays' "sweet spots", zones with high productivity and slow declines wells, are the first drilled.

The Bakken Tight Oil Play

Bakken had 4,598 wells operating as of 2012...

Bakken, the most productive US tight oil play, had 4,598 operating wells as of 2012. That year, it produced 568 thousand bpd of oil and 0.6 bcf of gas (much of the gas was flared for lack of downstream infrastructure).

...with1,500 wells were drilled that year

There were 1,500 wells drilled in the Bakken in 2012. At US$10 million per well, this represent a capital investment of US$15 billion, for a rather short term (but profitable) oil production.

The keys thus for continued production growth in the Bakken (and other tight oil plays) are:

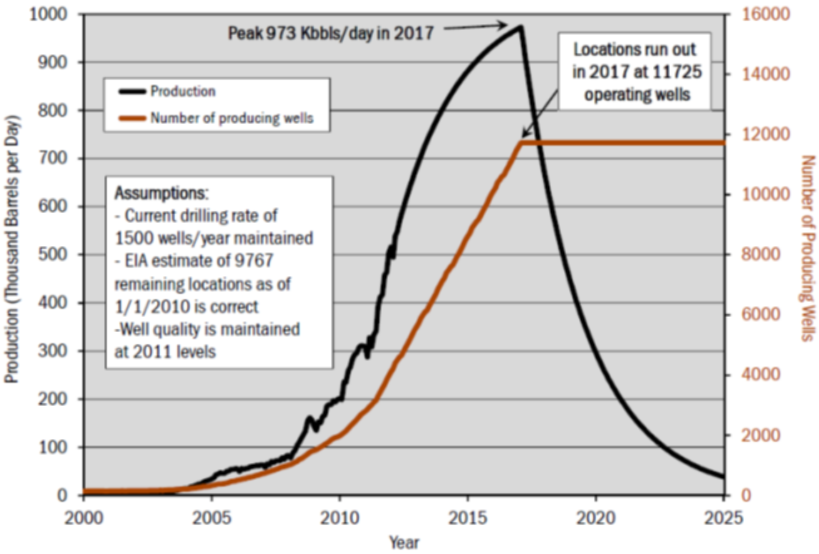
- What will the productivity of future wells be, and
- How many wells are left to drill?

The US EIA estimated that 9,727 available well locations were left to drill in the Bakken as of January 2010, for an estimated ultimate recovery of 4.3 billion bbl.

Once all available locations have been drilled, production soon falls off

The graph below shows the Bakken oil production to 2025 with (i) current rate of drilling until all well locations are exhausted and (ii) well productivity and decline pattern as experienced to date. It shows that the Bakken play's tight oil production may decline at an overall field rate of 40% after peaking in 2017.

Figure 15: Bakken Future Production Profile at Current Rate of Well Additions



Source: J. David Hughes, Post Carbon Institute, February 2013

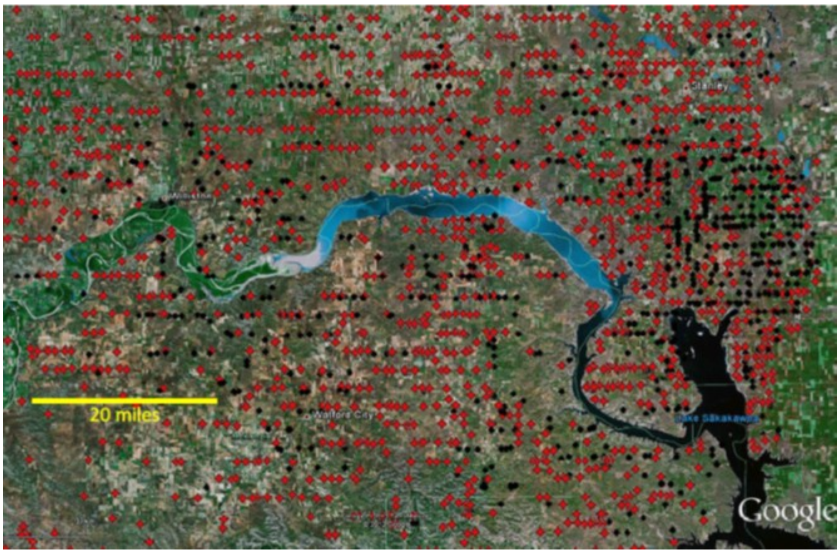
Tight oil is estimated to cost between US$60 and US$85/bbl

In all, the industry estimates that the breakeven price of oil in the Bakken at between US$60 and US$85 / bbl. With a very short payback, this is attractive to small and medium size, nimble, low-cost US E&P (Exploration & Production) operators. We doubt that it will remain strategically attractive to large oil companies which favor large, long-life reserve with low overall development and production costs.

The maps below the distribution of wells in the Bakken's area of highest activity and the details of the wells and horizontal lateral extensions.

The Bakken has now been drilled extensively

Figure 16: Distribution of wells in the Bakken's area of highest concentration

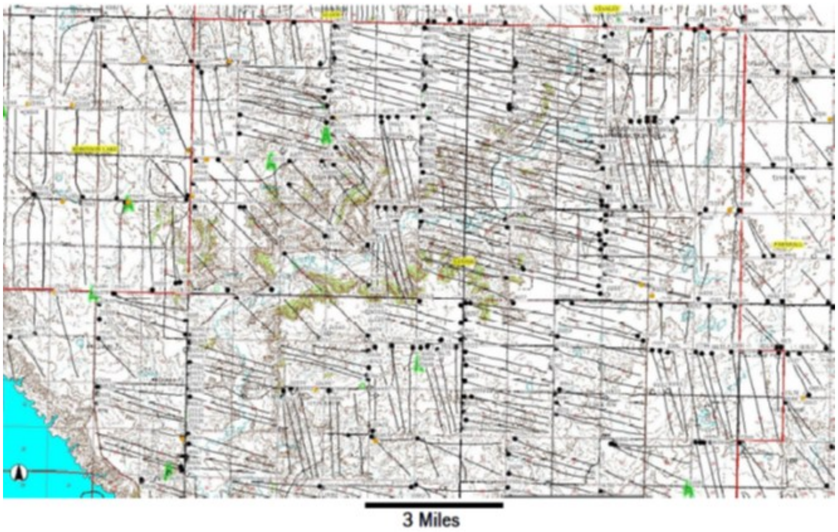


Source: J. David Hughes, Post Carbon Institute, February 2013

The wells in black have the top 20% productivity. Many of these sites have pads with two or more wells. The highest productivity wells (in black) tend to be concentrated in "sweet spots".

The horizontal laterals to reach the oil-bearing zones are one to three miles long

Figure 17: Horizontal wells in the Parshall "sweet spot" of the Bakken



Source: J. David Hughes, Post Carbon Institute, February 2013

This area (right hand side of the map top of this page) is almost completely saturated with wells although there are still a few locations left. Green symbols indicate rigs drilling as of December 17, 2012.

The Eagle Ford and the Other US Tight Oil Plays

Eagle Ford is still young…

Eagle Ford is the second largest tight oil play in the US. Still in its youth, it exhibits overall productivity and production declines broadly similar to Bakken. As of June 2012, oil production from the Eagle Ford play totaled 524,000 bpd, from 3,129 wells. It also produced a large amount of associated gas, 2.14 bcf/d. The US Energy Information Administration estimates the ultimate recovery of the Eagle Ford at 2.46 billion barrels.

...with attractive upside and good logistics

There is much activity at Eagle Ford, with 1,983 wells added in 2012. Eagle Ford benefits from a pipeline infrastructure to Texas' refining and gas processing centers which can be relatively easily improved.

The US other plays are not reported to be developed as rapidly as Bakken and Eagle Ford, and their attractiveness is not confirmed as high as those two plays. The press relates that some plays are no longer being pursued. It is not clear whether this is temporary and results from (a) technical difficulties to exploit the specific shale formations there (low production rates from initial wells) or from (b) other legal, environmental or infrastructure reasons. It is also not clear whether the massive number of rigs being used in Bakken and Eagle Ford simply leaves enough physical rigs capacity to develop other fields in North America (the press reports indeed an acute shortage of rigs for Canada's oil fields' developments).

The graph below forecasts long-term tight oil production in the US assuming that other plays are developed at current rates of wells productivity and production profiles, as Bakken and Eagle Ford taper off. It shows US tight oil production reaching, and possibly stabilizing at, about 750 thousand bpd in 2025, well below the 2.3 million bpd achieved in 2017.

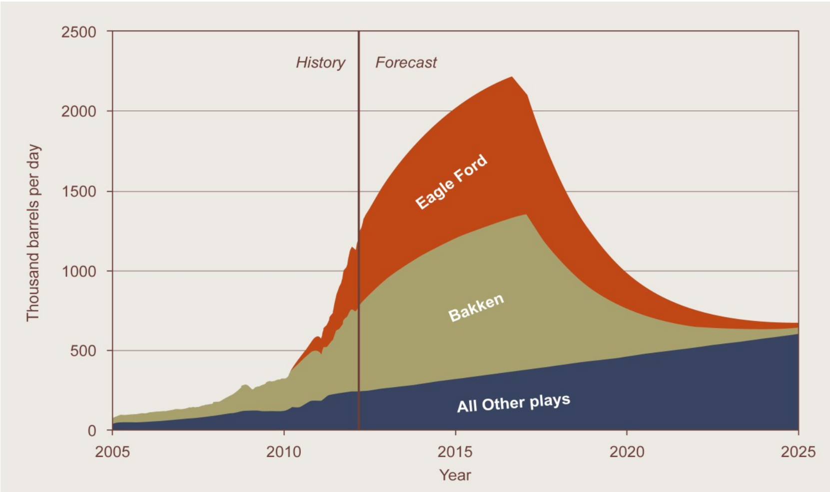
Obviously, the production forecast above critically depends on (i) the richness of the tight oil formations yet to be drilled, and (ii) the productivity of the wells in those formations.

The productivity of the wells in turn will depends on (i) how "sweet" are the zones left to drill and frack, (ii) what technology advances may allow for better recoveries than currently achieved, and (iii) how many available locations are to be drilled.

US tight oil production may decline rapidly after 2017-2018

New plays will have to compensate for Bakken and Eagle Ford declines

Figure 18: Projection of tight oil production by plays in the US to 2025



Source: J. David Hughes, Post Carbon Institute, February 2013

Technological advances may slow down this decline

Some industry participants affirm that, as they understand the zones' micro-geology better, technical progress is and will remain rapid, so that new wells will produce more oil and exhibit flatter decline curves. They also affirm that the plays are so large as still to contain numerous "sweet spots" so that the weighted average productivity of all producing wells will remain high.

They thus predict a continued large tight oil production after 2017, as yet-to-come technology advances continue to deliver higher oil recoveries from better known shale formations.

In its "2013 Annual Energy Outlook", the US Energy Information Administration predicts US tight oil's production about 2.5 million bpd in 2025 (3.5 times more than the projection above), declining slowly to 2 million bpd in 2040.

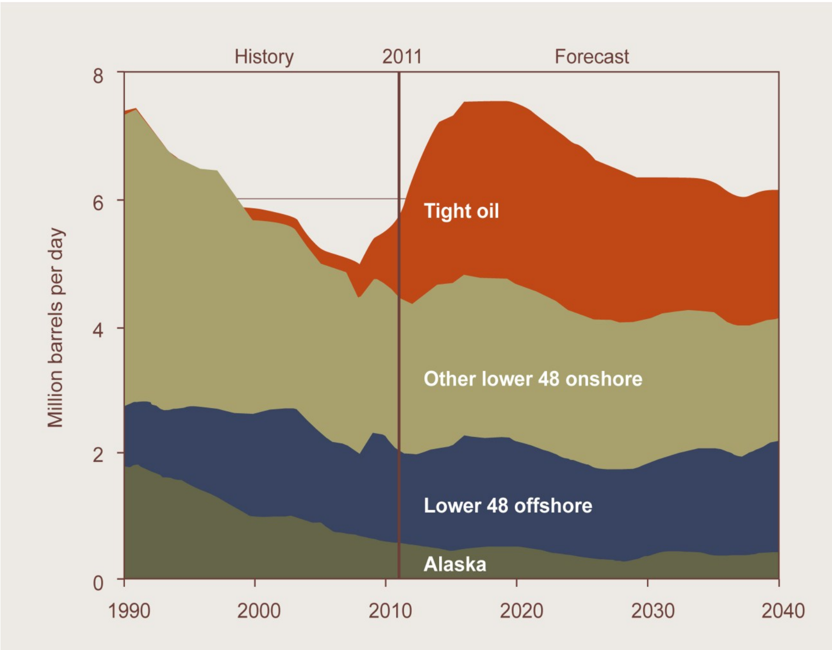
Not clear from which plays post 2018 production will come

Publicly available information does not present (i) assessments of play by play resources and (ii) evidence of specific technical advances, which would support this large and sustained future tight oil production.

Whilst we see production continuing to grow rapidly until 2017-2018, we are thus not convinced that US tight oil production will reach, and remain at, the high levels predicted above over the long term.

We thus doubt that the production of oil from the US tight formations will significantly change the long-term structure of the world's oil industry.

Figure 19: US Oil Production 1990-2040



Source: US EIA – Annual Energy Outlook 2013

Above Ground Factors

As it developed its tight oil and shale gas production, the US has benefited from a unique set of favorable circumstances. Not only in geology and hydrology (good source rock not far from abundant water resources), but in what the industry calls "above ground" factors.

In addition to strong and effective R&D support which US Federal Agencies provided to industry players in the 1980s and 1990s, these factors concerned:

Above ground factors critical in the profitable development of the US tight oil industry

- a deep and vibrant set of private entrepreneurs, familiar with the costs, technologies and risks of drilling for oil or gas;
- a unique long-established engineering expertise in the exploration and definition of complex hydrocarbon reservoirs;
- a well-developed and low cost service industry to drill the wells and to provide and manage the necessary equipment;
- a legal system which rewards landowners for the profitable extraction of the hydrocarbon resources under their ground;
- deep and liquid financial markets which provide efficient equity through partnerships and tailor-made debt to fund such specialized a-priori risky investments;
- the definition by the local governments and acquiescence by the local population of acceptable-to-the-industry environmental regulations; and,
- a transport infrastructure (network of pipelines, rail tracks or roads) which permitted connecting the new fields to refineries or gas processing / export centers.

Further, there has been significantly less societal opposition to fracking in the US than experienced to date in other democratic countries, such as in Europe in particular.

No fundamental reasons for fracking to damage the environment

Indeed, the environmental impact of fracking, whilst naturally contested by some, have been seriously studied and deemed acceptable and manageable by most parties. Regulations to prevent accidental discharges have been or are being put in place, and the industry does not foresee serious impediments to the responsible development of tight oil and shale gas production.

Outlook for International Shale Oil

With the rapid growth in tight oil production in the US, the industry has naturally looked at identifying and exploiting low permeability formations elsewhere, specifically shale formations. As exploration programs around the world start to yield results, industry and international institutions frequently report significant increases in estimates of global shale oil resources.

Reports of large resources of shale oil in Russia, China, Argentina and Libya…

In May this year for instance, the US Energy Information Administration estimated the “technically recoverable” tight oil resources at 345 billion barrels in the 42 countries it surveyed (this is about 10% of global crude supplies). It specifically estimated Russia to have the largest technically recoverable tight oil resources with 76 billion barrels in its Bazhenov field in Siberia, followed by the US with 58 billion barrels (up from 32 billion estimated previously), then China with 32 billion barrels in seven basins, Argentina 27 billion barrels in its Vaca Muerta basin in Neuqen (an existing oil producing region), and Libya 26 billion barrels in its Silurian shales.

… but geology not understood yet and above ground factors much less accommodating

All point out however that the geological data on and understanding of the technical characteristics of these fields are much less precise than for US reservoirs and that the estimates of recoverable oil are much less precise. Further, most of these countries lack the US’ deep and efficient industrial and financial infrastructure to support tight oil and shale gas developments. The technology, equipment and infrastructure to extract the crude may thus simply not readily be available in the short- /medium-term to develop these fields profitably.

Thus, in addition to believing it too early confidently to assess the recoverability of oil in these international shale plays, we believe that "above ground" factors may not allow for profitable exploitation in the short and medium term.

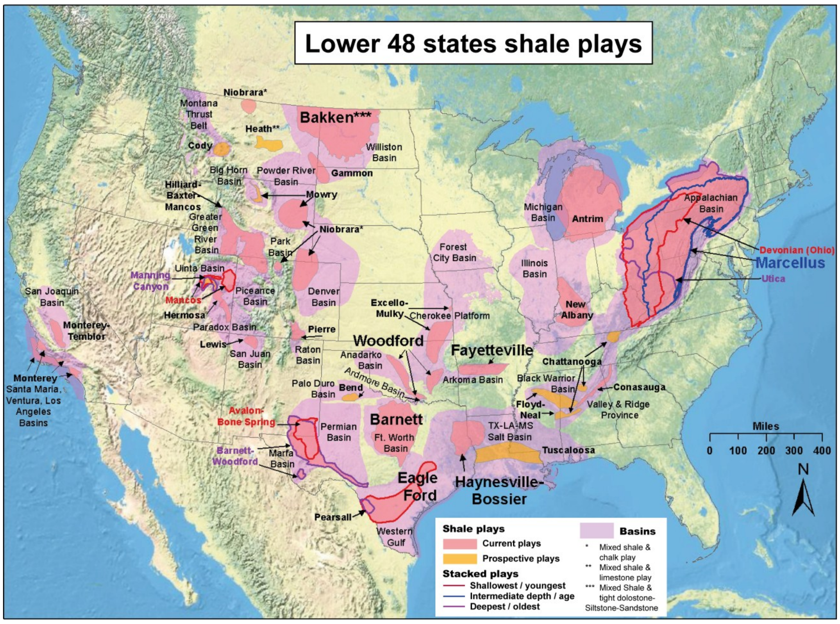
US and International Shale Gas

US Shale Gas Plays

The US benefits from numerous large tight oil & shale gas basins

The map below shows the shale plays identified by the US Energy Information Administration.

Figure 20: US Tight Oil and Shale Gas Basins



Source: EIA

Shale gas now accounts for 40% of US gas production

Production of gas from shale formations in the US started earlier and grew much faster than oil production from tight oil formations. As of mid-2012, there were about 30 shale gas plays active in the US, with shale gas now accounting for about 40% of the US gas production, up from 2% in 2000.

Three plays account for 66% of production

The next three account for another 22%

As for tight oil production, but to a lesser degree, shale gas production is concentrated in a few plays. The graph next page shows that the top three plays - Haynesville, Barnett (both in Texas) and Marcellus (in West Virginia, Pennsylvania, New York and Ohio) - accounted for 66% of total shale gas production as of mid-2012. Adding the next three plays - Fayetteville (Arkansas), Eagle Ford and Woodford (Oklahoma) - shows that six plays account for 88% of the US shale gas production.

Each play has specific characteristics, and there are even wide variations in productivity within each play. These are critical to appreciating the long-term future of shale gas production in the US as decline curves for shale gas wells are often steeper than those for tight oil wells.

Shale gas wells have steep declines …

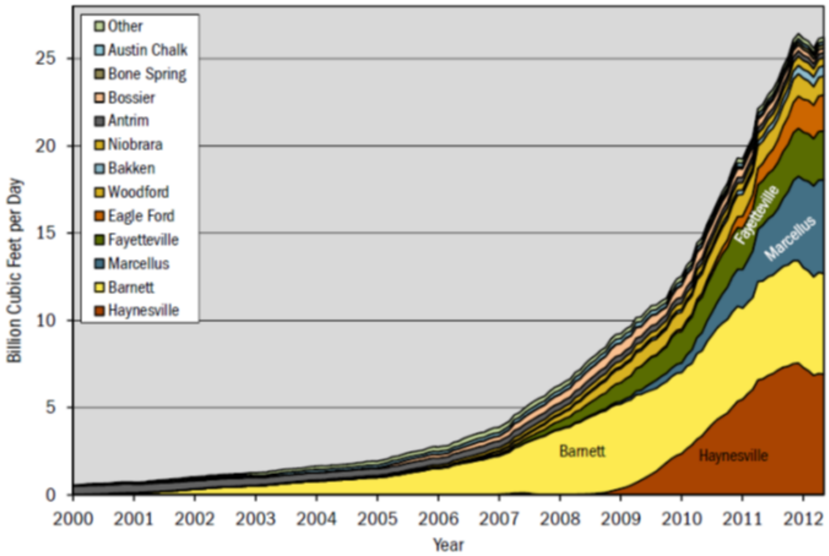
… but they produce NGLs …

… which justify their economics

As for tight oil, the economics of shale gas wells depend upon the productivity of each well and how rapidly its production declines, when compared to prevailing gas prices. As explained below, another key factor in justifying drilling shale gas wells is the production of NGLs (Natural Gas Liquids), which have a much higher value than natural gas (methane) alone. The continued growth of the US shale gas production will thus depend upon the production of NGLs from the various shale basins and the availability of the infrastructure necessary to deliver them to downstream processing centers.

Shale gas production declined in late 2011 as low 2010 gas prices discourage drilling

Figure 21: US Shale Gas Production by Plays (2000 to May 2012)



Source: J. David Hughes, Post Carbon Institute, February 2013

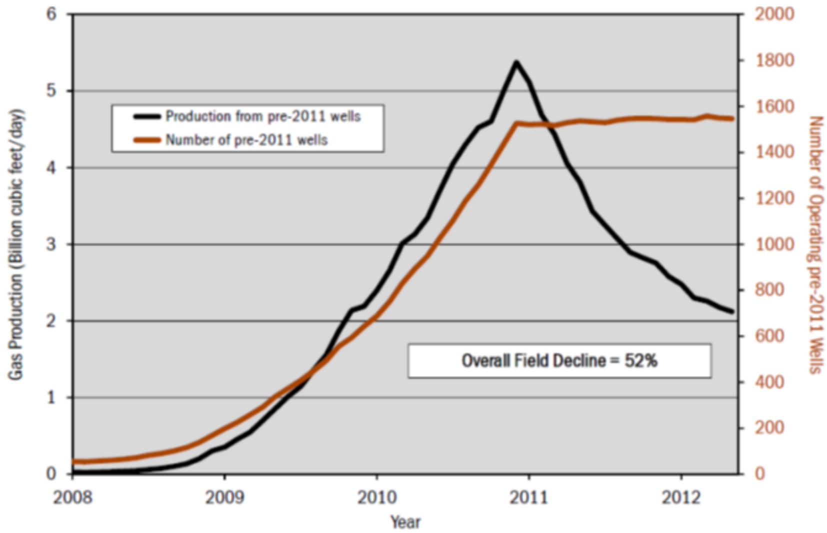
Decline Curves and the Outlook for US Shale Gas Production

Shale gas wells usually exhibit steeper decline curves than tight oil wells. Haynesville's wells for instance decline on average about 68% in the first year, about 50% in the second, third and fourth years.

This results in a steep loss on production if wells are not continuously drilled, as shown in the graph below.

Production will decline rapidly if no more wells are drilled

Figure 22: Haynesville – Production Decline for pre-2011 Wells



Source: J. David Hughes, Post Carbon Institute, February 2013

NGLs are critical to the profitability of shale gas production

Pipeline and NGLs processing infrastructure is critical.

Marcellus and Eagle Ford are the key to the continued growth of US shale gas production

Shale gas production in the US will thus rest upon the continuous drilling of attractive wells in existing or prospective shale plays.

This will in turn depend upon:

- Finding and exploiting areas intrinsically rich in gas and NGLs;
- Benefiting from adequate pipeline infrastructure to bring the gas and NGLs to downstream processing centers; and,
- Enjoying a high enough gas price to justify drilling short life wells.

The Economics of Shale Gas Production

With the extremely rapid growth in domestic shale gas supplies, wellhead gas prices plunged from US$10.8/million BTUs in July 2008, to a low of US$1.9/million BTUs in April 2012, and to US$3.8/ million BTUs in August 2013.

With typical shale gas wells costing between US$5 million and US$8 million to drill and complete, and a significant loss of production after 2-3 years, producers need gas prices above US$5.5 per million BTU to justify drilling a shale “dry-gas” well. Hence operators stopping to drill in dry shale formations, such as Barnett for instance.

This changes dramatically when the wells produce valuable NGLs. The industry reports indeed that wet gas plays with liquids in excess of 25% are attractive even for gas at US$3 per million BTU.

The Marcellus and Eagle Ford Plays

Of all the US shale gas plays, two plays, the Marcellus and Eagle Ford, are still profitable at today’s gas prices. They are large plays with a significant production of NGLs and much upside potential for zones not yet drilled.

These two plays benefit in addition of existing or of reasonably cheap to build infrastructure to deliver the gas and the NGLs to downstream markets. Marcellus is linked to Pennsylvania’s oil & gas processing complexes and to the North East gas market. Eagle Ford is already an important part of Texas’ overall oil & gas industry.

The Outlook for US Shale Gas Production

With production backlog from the shale wells recently put in production, a large backlog of already drilled wells not yet put in

Table 1: Prognosis for Future Production in the Top Nine Shale Gas Plays in the US - May 2012

Field	Rank	Number of Wells needed annually to offset decline	Wells Added for most recent Year	October 2012 Rig Count	Prognosis
Haynesville	1	774	810	80	Decline
Barnett	2	1507	1112	42	Decline
Marcellus	3	561	1244	110	Growth
Fayetteville	4	707	679	15	Decline
Eagle Ford	5	945	1983	274	Growth
Woodford	6	222	170	61	Decline
Granite Wash	7	239	205	N/A	Decline
Bakken	8	699	1500	186	Growth
Niobrara	9	1111	1178	~60	Flat

Source: J. David Hughes, Post Carbon Institute, February 2013

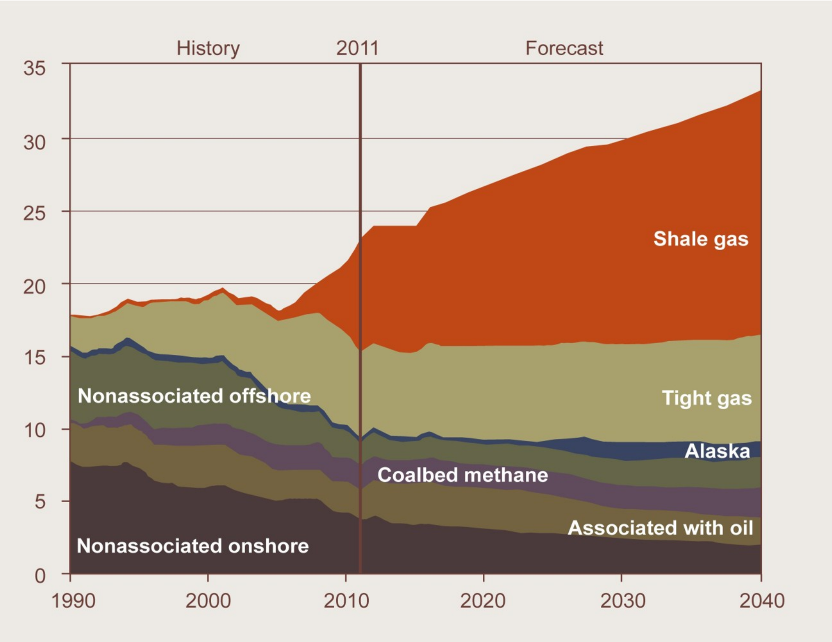
production, and continued production increases from Marcellus and Eagle Ford, we see continued growth in the US shale gas production, at least until 2020.

As for tight oil, most observers affirm that advances in the understanding of the fields' geology and in drilling and fracking technology will significantly improve the economics of shale gas production. They thus foresee a continued long-term growth of shale gas production in all fields, even if gas prices stay in the US$3-4 per million BTU range.

Most observers forecast that advances in technology will underpin increased shale gas production

The US Energy Information Administration projects US shale gas production to grow from 21.5 bcf/d in 2011 (34% of all US gas production), to 35.2 billion in 2025, and 45.8 billion in 2040 (50% of all US gas production). It estimates gas production from tight oil plays to grow from 16.0 bcf/d in 2011 (25% of US gas production) to 20.1 bcf/d in 2040 (22% of all US gas production).

Figure 23: US Gas Production – 1990-2040 (trillion cubic feet)



Source: US EIA - Annual Energy Outlook 2013

Not clear which technology improvements will underpin the assumed long term high growth of shale gas

As for tight oil, publicly available information does not present (i) assessments of play by play resources and (ii) evidence of specific technical advances which would support this large and sustained future shale gas production, in particular since gas prices may remain under pressure from Marcellus and Eagle Ford production. Whilst we see US shale gas production continuing to grow rapidly until 2020, we are thus not convinced that it will reach, and remain at, the high levels predicted above over the long term.

Outlook for International Shale Gas Production

As for tight oil, and in addition to the significant resources deployed to find and develop on-shore and off-shore conventional gas fields, there is much activity around the world to find, assess and prepare the development of shale gas resources.

The largest opportunities for future shale gas production are reported to reside in China, Argentina, Mexico, Algeria and Australia. Geology is also reportedly promising in Poland, France and Britain. Most

Large resources of shale gas in China, Argentina, Australia and Mexico

observers assume that shale gas deposits also exist in the Middle East – in particular in Saudi Arabia – but they question whether these could be developed at a profit given the low gas prices prevailing there.

China. China is believed to have the largest shale gas resources in the world, surpassing those of the United States. The US Energy Information Administration estimates these at 1,115 trillion cubic feet (tcf) of technically recoverable shale gas in seven basins. The largest and most promising basins are in Sichuan a highly populated area in the middle of the country (about 56% of the total estimated resource), and in Tarim, a more isolated (water-poor) basin in China's western-most region.

Initial results not as promising as expected

Expectations for actual production have however been tampered recently, since initial wells have been more complex technically, and "above ground" challenges more difficult, than expected.

Recent public comments by Chevron's executives point to a possible considerable reduction in the estimates of China's shale gas potential.

We believe that significant additional field results will be needed before China's economically recoverable shale gas reserves can be estimated at the levels surmised to date.

Neuquén appears an attractive shale gas and oil basin

Argentina. Argentina is reported to have large and high quality hydrocarbon shale formations, possibly the most prospective outside of North America, primarily within the Neuquén Basin. Some commentators see the Vaca Muerta field there as the world's second -largest deposit of recoverable shale gas.

The US Energy Information Administration estimates Argentina's economically recoverable gas resources at 802 trillion cubic feet (in addition to 27 billion barrels of tight oil). Argentina's formations appear much simpler to exploit than those found in China, and they are in an area of the country in which oil has already been quite successfully produced.

In spite of political risk concerns stemming from Argentina's 2012 expropriation of Repsol and from its dispute with the foreign holders of its sovereign bonds, major oil companies appear eager to try and develop significant oil & gas exploration and production facilities in the Vaca Muerta shale formation.

Argentina may thus to develop a sizeable shale gas industry in the years to come, perhaps faster than currently envisaged. Forthcoming results of pre-development wells will indicate whether Argentina will also produce large amounts of shale oil.

Not enough data to confirm the attractiveness of other international shale plays

Australia. Australia is also advertised to have large (437 tcf) potential shale gas resources. These resources are in remote basins, but basins with both existing infrastructure - such as the Central Cooper Basin - and long histories of oil & gas production. Existing or easy-to-build pipelines would in fact allow this gas to flow to Queensland and be fed in existing or expanded LNG export plants (Australia is one of the world's largest LNG exporters, and has been for decades). Major oil companies are familiar with the Australian legal and fiscal systems and several of them (Chevron, ConocoPhillips, Total) have recently initiated exploration ventures. We believe it too early to comment on the extent and timing of Australia's shale gas production.

Mexico. Mexico should offer excellent prospects for tight oil and shale gas production. The US Energy Information Administration estimates technically recoverable shale resources at 545 tcf for natural gas and 13.1 billion barrels for oil and condensates. The best documented play is Eagle Ford, where oil- and gas-prone windows extending south from Texas into northern Mexico have an estimated 343 tcf and 6.3 billion barrels of recoverable shale gas and shale oil resource potential.

We believe that Mexico's potential development of its shale gas and shale oil resources may be constrained by several factors such as PEMEX's focus on large conventional oil plays, limitations on JVs with foreign partners, limited capabilities of the local oil-services sector and public security concerns in many shale areas.

Above ground factors may impede the development of shale gas production outside the US

Algeria. In addition to its reserves of conventional oil, Algeria is reported to have large (707 tcf) and a-priori attractive shale formations. The most attractive of these formations are in the South of the country, presumably far from water resources. Yet, several international oil companies such as ExxonMobil, ENI and Shell are reported to have expressed interest in conducting exploration campaigns in these formations. With its share of the LNG export markets slumping a bit and production from its conventional reserves plateauing, the government is also reported to relax the tax regime to attract foreign investors. The extent and speed at which Algeria will develop its shale gas production should be clearer once the initial exploration wells confirm the attractiveness of the formations and once the government finalizes its policies to attract foreign investors.

Poland. With a-priori attractive geological formations and a favorable infrastructure and public support for shale development, Poland has attracted numerous shale gas exploration investments for several years now. Early results did not however meet the industry's expectations, and ExxonMobil, Marathon and Talisman had abandoned their exploration programs by early 2013. Results from new test wells last month have been more positive, but it remains to be seen whether these developments and the hope-for decreases in drilling costs will usher a sizeable commercial production of shale gas in Poland.

England. The United Kingdom has substantial volumes of prospective shale gas and shale oil resources, but these are in geologically complex formations. Shale testing is at a very early stage. Further, the initial reaction of the local population has been quite negative, so that the development of substantial shale gas production in England it does not appear likely in the medium-term.

France. France is reported to possess attractive shale gas formations in large basins around Paris and Marseille. There is however strong political opposition in France even to drill exploration and confirmation wells to ascertain the existence of such hydrocarbon-bearing shales. Commercial exploitation of these shales is unlikely for the foreseeable future.

Impact on the Global Refining Industry

With about 2.3 million barrels per day, tight oil now accounts for about 35% of the US oil production (up from less than 5% in 2008).

Tight oil is light and sweet

By nature, tight oil is light and sweet (it contains little sulphur). It is quite different from the heavy and sour crudes which, over the years, the US refineries have been designed to process. A significant portion of the US oil imports have to date been heavy and sour crudes from Venezuela, Mexico, Canada (in particular from super heavy bitumen from oil sands) and from the Middle East.

US refineries have been designed to process heavy sour crude

With the rapid increase in light tight oil production, industry observers noted the a-priori mismatch between the composition of the crude which the US refineries increasingly have to process, and their basic technical configuration (by law, US crude cannot be exported, so tight oil is to be processed domestically).

We believe that the US refining industry will adapt to this increasingly different crude supply situation without too much difficulty, by:

- modifying relatively cheaply or adjusting the operating configurations of the existing refineries;

But they will easily adapt to the new supply of light oil

- importing less “light crudes”;
- adapting the pipeline and blending infrastructure to the new flows of oil and liquids to relieve bottlenecks and to increase the value which producers may capture from their fields; and,
- setting up blending operations to mix heavy Canadian crude with condensates and NGLs by-products of the nearby Bakken, for easier transportation of the derived crude to US refineries.

With a surplus of light oil, the light to heavy oil price differential has narrowed

With US tight oil production resulting in a surplus of light crudes, the price differential between light and heavy crudes should narrow. It appears that the global oil markets are experiencing this and that the producers of light crudes (African in particular) and the importers of such crudes (European in particular) are suffering from this new reality.

Impact on the Global Petrochemical Industry

US tight oil and shale gas wells can produce valuable NGLs. Depending upon storage and pipeline constraints, and depending upon the value which producers may realize for these liquids, the NGLs are either separated or left in the natural gas streams. When separated, NGLs are piped to consumption and export centers.

Large production of cheap ethane and NGLs will provide cheap feedstock to US petrochemical complexes

This abundant new supply of cheap ethane, propane and butane, as well as of heavier condensates, is seen as propelling again the US petrochemical industry towards a uniquely-advantaged position when compared to producers from Europe, Asia and even the Middle East.

Over the years, and to produce ethylene (the key petrochemical building block), US olefins/thermoplastics producers have built and operated with great efficiency (i) ethane crackers with significant flexibility to process various NGLs feedstocks, and (ii) naphtha crackers with a diversified output slate (propylene, butadiene, etc.).

Ethylene production in the US - and by inference the whole petrochemical industry - thus benefits from a unique flexibility to capture the highest margins, depending on the relative values of ethane, NGLs and naphtha (the price of which is linked to oil prices).

Most crackers in the Middle East do not have that flexibility since they are designed to process only ethane; neither do the European and Asian crackers since they are designed to process only naphtha.

Due to expected rapidly growing supply, US ethane and NGLs prices expected to remain low for the foreseeable future. With high expectations for enduringly attractive margins to produce ethylene, several large players, American firms and international firms as well, have announced plans to expand their plants or build new ethane-based ethylene crackers in the US.

Plans are afoot to add 7% to global ethylene capacity in the US on basis of ethane and NGLs from tight oil & shale gas

As of mid-2013, these plans amount to adding about 10 million tonnes per year capacity, which would increase the US ethylene capacity by 40%, and the world's by 7%. The exact timing of these projects remains uncertain since they and their pipeline links to the fields will need to be built in time just as shale ethane becomes available - and is judged so available on a long term sustainable basis.

Massive ethylene capacity additions are also planned in Asia and the Mid-dle East

This substantial increase in US ethylene capacity is to take place as considerable capacity additions are also planned in Asia and the Middle East. These additions will be driven by (i) the availability of cheap gas in some specific situations (Abu Dhabi), (ii) the integration with very large new refining complexes (Saudi Arabia, India and China), and (iii) the proximity to fast growing markets (Asia).

US capacity additions will be the most attractive…

...but will primarily affect American and European players

Most industry observers thus surmise that, whilst massive, the increase in US ethylene capacity from shale gas will in fact primarily be a regional phenomenon, with additional exports to Latin America and renewed pressure on European crackers, and that it will merely contribute to - not cause - the expected tightening of global ethylene margins and, indirectly, the increased pressure on European and Asian naphtha crackers.

Deep-water, Oil Sands & Extra Heavy Oil

In addition to tight oil, there are three major other unconventional sources of oil which will impact the world's energy industry in the next 30 years: deep-water reservoirs, oil sands and extra heavy oil deposits. A fourth one - kerogen oil (kerogen is organic material which has not yet been decomposed into oil but can yield oil upon heating) – is not discussed here since, whilst abundant, it will not likely be an economic source of oil in the next 40 years.

Deep-water

Offshore fields contain 45% of the worlds' oil recoverable from conventional sources

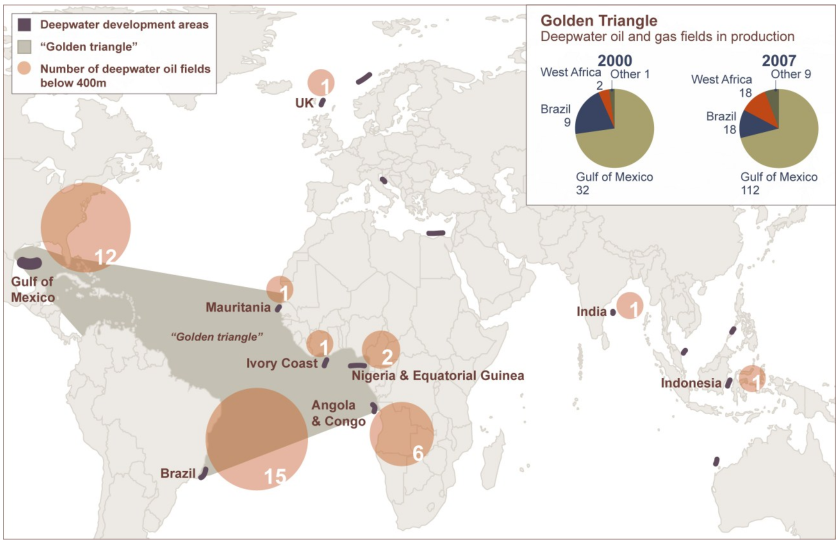
The industry has known for many years that large oil resources are found under the sea. The International Energy Agency estimates that offshore fields contain about 1,215 billion barrels of recoverable oil, 45% of the world's remaining recoverable conventional oil. It expects that, of this, about 300 billion barrels (a quarter) are in deep-water fields, defined as water with a depth in excess of 400 meters.

Deep-water is 45% of offshore resources

Deep-water oil production has almost doubled to about 5 million bpd between 2005 and 2010, and represented 6% of the world's 2010 total crude output. Obviously, the exploration for and the development of deep-water oil fields slowed after the April 2010 deep-water Horizon Macondo disaster and oil spill in the Gulf of Mexico.

Since then, regulators, oil companies and service companies have significantly tightened up the regulations and operational safety standards which the industry must follow. Deep-water investments and operations have by now regained momentum, and industry observers expect deep-water oil production to double again by 2020.

Figure 24: Deep-water Offshore Basins



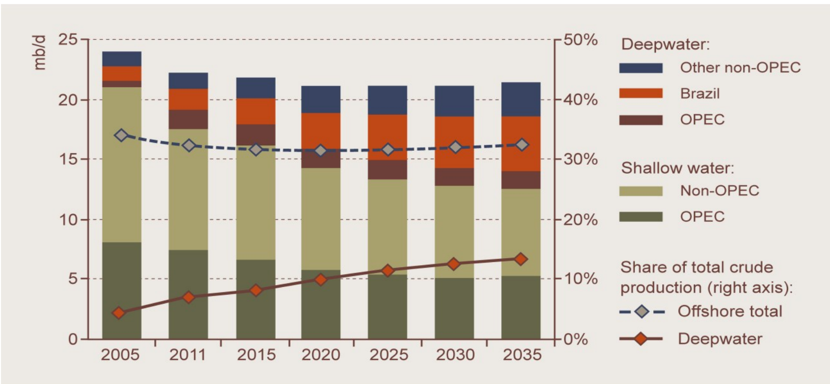
Source: Petroleum economist - 2010

Brazil is most advanced in developing deep-water fields

Deep-water offshore Brazil is in particular considered to offer bright prospects for deep-water oil production. Petrobras has started to develop large fields in the Campos and Santos Basins, more than 250 kilometers off the country's southeast coast. The press recently reported significant new discoveries in these fields (Libra in the Santos Basin is said to contain possibly 8 billion barrels of recoverable oil) and in new fields offshore the northern state of Sergipe.

The recent auction to develop one of Brazil's deep-water field has attracted wide press coverage, and shown again how "above ground" factors (in this case the auction's rules) may influence potential investors.

Figure 25: World Offshore Crude Oil Production – 2005-2035



Source: Petroleum economist - 2010

But numerous other areas are being explored

Longer term, the International Energy Agency projects the contribution of offshore fields to global crude oil production to remain relatively stable to 2035. Deep-water production expands from 4.8 million bpd in 2011 to about 8.7 million bpd by 2035, offsetting a decline in shallow-water production (mainly in the North Sea and the Gulf of Mexico). The expansion of output from deep-water fields will be driven mainly by new developments in Brazil, West Africa and the US part of the Gulf of Mexico.

Large oil companies are committed to developing deep-water fields

Most large international oil companies have active exploration programs in deep-water fields and expect deep-water oil to provide a significant proportion of their production for years to come.

Oil Sands

The mining of oil sands or bitumen from Alberta (Canada) has developed into a large industry over the last 30 years. In 2011, 600 million barrels of oil from these mines was exported to the US.

Oil sands is expensive to mine, transport and refine

The mining of these oil sands is expensive (between US$60 and US$90 per barrel). The output, bitumen, is a very heavy oil which is either (i) diluted with NGLs and exported as heavy crude feedstock to US Gulf Coast refineries, or (ii) upgraded into light crude near the mines, also for (higher value) export to downstream refineries.

Canada's National Energy Board estimates oil sands resources at 174 billion barrels, and, until the development of tight oil production in the US, production of oil sands was expected to grow and increasingly to contribute to the supply of crude to US refineries. Major investments in upgrading complexes – each costing in the US$10-15 billion range – were planned to increase the export attractiveness of the mines' output and capture some of the large (up to US$40 per barrel) price differential between Canadian bitumen and light crudes.

The rapid expansion in US tight oil production has had a major negative impact on Canadian oil sands production.

Canadian oil sands production is seriously impacted by the development of the Bakken

First, the increase in US light oil supply from tight oil formations has significantly reduced the light-over-heavy premium upon which the Canadian oil sands upgrading complexes were justified. With such premium at only US$10 per barrel now, observers assume that these complexes will not be built.

And, second, the dramatic expansion of light tight oil production from the Bakken field in North Dakota and Montana has taken up all the pipeline capacity which used to transport Canadian diluted bitumen to the US Gulf Coast refineries. The transport logistics and cost of heavy Canadian material have become so complex and expensive as potentially to cripple the economics of the oil sands industry - hence the Canadian government's push for the US to build the Keystone pipeline.

Oil sands are the unconventional source of oil most at risk of slowed down development

Since, in addition, the mining of oil sands has significant environmental impacts (CO2 and water contaminants), we believe that oil sands will be the "unconventional source of oil" most at risk of slowed down development.

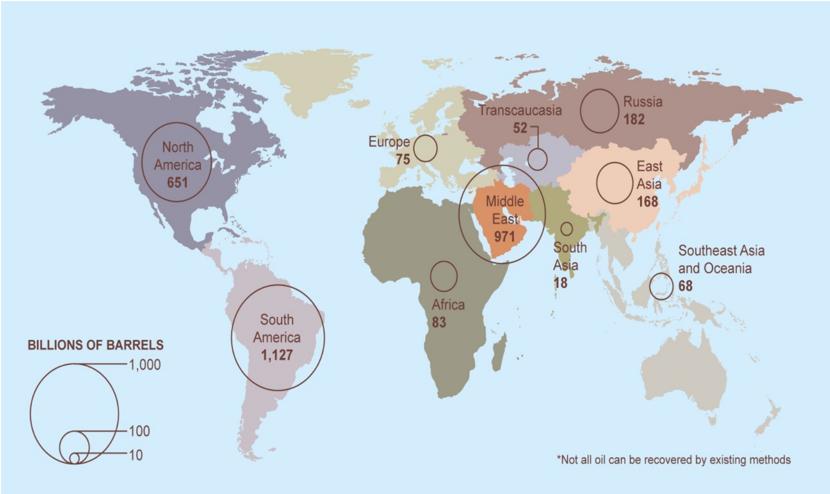
Extra Heavy Oil

A major portion of the world's known remaining technically recoverable oil resources is in extra heavy oil deposits. Oil from

The vast majority of the world's resources of recoverable oil is in extra heavy oil

these deposits is too viscous to extract by simple conventional technology. The industry has already succeeded in markedly improving the recoveries, in particular with steam injection, so that production is economic at current prices in a few of these fields. Significant efforts are under way to develop more efficient and economic ways to extract the oil from such deposits.

Figure 26: Resources of Heavy Oil by Regions



Source: US Geological Survey

Extra heavy oil accounts for 80% of the unconventional oil resources

The International Energy Agency estimates that about 1,700 billion barrels of extra heavy oil can be technically recovered worldwide. This is about 80% of the estimated recoverable resources of unconventional sources (including tight oil and oil sands) and 35% of the estimated recoverable oil resources, conventional and unconventional.

As of today, only 13% of these resources can be recovered economically with existing technology. It will be the interplay between oil prices, technology developments and above ground factors which will determine how much of these resources will be exploited and how fast.

Venezuela has large extra heavy oil resources and already exploits them

At this point, most of the world's extra heavy oil is produced from the Orinoco belt in Venezuela. PDVSA and international companies started to invest 20 years ago in Orinoco production wells, pipeline infrastructure, upgraders, etc. With Venezuela's political situation (the stakes of initial operators were either nationalized or significantly reduced) growth has however been quite below initial hopes. The industry doubts that PDVA's ambitious plans to develop additional projects for 2 million bpd capacity will soon be realized, as political uncertainties and above grounds issues continue to delay actual investments decisions.

Venezuela's heavy oil production may not grow as it expects

Thus, even with the world's second largest estimated proven reserves of oil, Venezuela's contribution to the world's oil supply may remain at, or slightly decline from, today's levels. Most observers assume that, if the investment climate for foreign firms improves and if "above ground" issues are resolved, Venezuela's production and export of upgraded crude from its extra heavy oil fields should materially add to the world's oil supply by 2040.

Unconventional Oil & Global Recoverable Oil Resources

As technology progresses, new more-difficult-and-expensive-to-exploit oil resources may become commercially attractive, significantly increasing the energy resource base from which we will power our economies.

The table below summarizes the International Energy Agency's estimate of total technically recoverable oil resources, for both conventional and unconventional sources (we have amended their original data (i) to omit kerogen oil and (ii) to show deep-water oil under unconventional sources instead of conventional as they classify it).

Table 2: Global Technically Recoverable Liquids Resources
(As of end-2011,)

Half of technically recoverable liquids is from conventional sources

Half of technically recoverable liquids is from unconventional sources

Conventional liquids	Million barrel	% of total
Onshore	1,463	30
Conventional Offshore	915	19
Sub-total	**2,378**	**50**
Unconventional Liquids	**Million barrel**	**% of total**
Deep-water Offshore	300	6
Extra Heavy & bitumen	1,881	39
Tight & shale oil	239	5
Sub-total	**2,420**	**50**
Total	**4,798**	**100**

Source: International Energy Agency; Jadwa Investment

This table shows that extra heavy oil and bitumen deposits constitute the largest physical technically recoverable resources of oil (39% of total resources), followed by conventional onshore deposits (30%) and conventional offshore (19%).

Tight and shale oil deposits contain only 5% of the world's technically recoverable liquids

The table also shows that, to-date, tight and shale oil are estimated to account for only 5% of the world's technically recoverable liquids resources.

The actual exploitation of each resource will depend upon it economic attractiveness. Most extra heavy oil / bitumen deposits are not economically exploitable currently.

Conversely, numerous US tight and shale oil plays are attractive. Thus, even though their absolute in-situ quantity may be much less than that of other sources, tight and shale oil plays are seen by all as important sources of oil and liquids for the short-/medium-term.

Wafra Field Large Scale Steamflood Pilot Project. It has produced heavy oil at six times initial production levels

An Extra Heavy Oil Project: Wafra in the Saudi Arabia-Kuwait Neutral Zone

In the desert sands in the Neutral Zone across the Saudi Arabia/ Kuwait border, a massive experiment has been ongoing since 2009 to determine whether heavy hard-to-extract oil can be economically recovered from the large, well-known and long-exploited Wafra Field.

Until now, in more than 50 years of production, traditional methods have only captured around 5 percent of the oil in place in Wafra

Pipes carry steam to the oil field, where it is injected underground, thinning the heavy oil for pumping

Field's "First Eocene" reservoir. Just an additional 1 percent recovery from this reservoir alone would add more than 100 million barrels to Wafra's reserves. The "First Eocene" reservoir holds an estimated 9 billion barrels of net oil, and additional resources are expected in the "Second Eocene" reservoir.

To get to Wafra's thick oil, workers are injecting steam into the ground to heat the oil and make it less viscous, allowing it to flow to the surface. The technique, "steamflooding", is tricky, expensive and unproven in the type of rock that holds Wafra's oil. Chevron, which is experienced in developing heavy oil recovery technologies, is responsible for the project's development.

To date, findings from the 16 steam-injection wells in the field and from the Large-Scale Steamflood Pilot plant have been encouraging. Full-field development would be the first commercial application of conventional steamflooding in a carbonate reservoir anywhere in world. The project would involve drilling some 10,000 producing, steam-injection and temperature-observation wells and installing large, standalone power and steam-generation facilities.

Final full scale project go-ahead had been expected by end 2013. Recently however, Chevron decided to carry on with its large-scale pilot tests to understand better the difficulties inherent in injecting steam into the field's carbonate reservoir to extract the heavy crude.

A spokesperson recently declared that the front-end engineering design for Stage 1 of the Wafra steamflood project would commence in 2014. Stage 1 is expected to produce a maximum of 80,000 bpd, but it is not yet clear when Chevron plans to reach this target.
In the end, it will not be the presence of oil at Wafra which will determine whether taking the project to full-scale development is worth the massive investment; it is whether forward oil prices and the emerging technology will allow recovering that oil from Wafra economically.

Tight Oil, Shale Gas & the Long-term Global Energy Outlook

Tight oil and shale gas must be looked at as part of the evolution of the global energy markets

This Publication has presented the technical, economic and societal aspects of tight oil and shale gas production. Whilst it has focused on the achievements and prospects of such production in the US, the Presentation has framed its analyses in the likely overall evolution of the global energy industry.

Below is a summary of our view of the long-term outlook for global energy demand and the key impact which tight oil and shale gas production may have on the global supply of hydrocarbons to meet that demand.

Global Demand for Energy

The keys to forward energy demand are GDP growth and efficiency of energy use

The key assumptions underpinning the consensus forecast for the long-term demand for energy are (i) the continued high rate of GDP growth in Asia (specifically China and India), and (ii) the 35% reduction in the energy intensity of the world's economy.

We are not convinced that Asia may continue to generate unabated for the next 25 years the high growth rates it has experienced in the last decade. On the other hand, we are not convinced either that forthcoming technology improvements will result in the large energy efficiency gains now postulated.

Global energy demand is expected to increase 35% between 2010 and 2040

As these broadly balance out, we believe that the consensus forecast of global energy demand growing by 35% between 2010 and 2040 offers a good base for estimating the energy supplies which will have to be developed to meet that demand.

Tight Oil Production

We are not convinced that the production of tight oil in the US and shale oil elsewhere will increase as much as most observers now believe.

Tight oil production may not increase as most observers forecast

This is because, since tight formations are by definition impermeable, the migration of oil towards the wells, even after hydraulic fracturing, is limited and wells are much less productive than in conventional formations with permeable and porous rock. The decline curves of tight oil wells are steep and new expensive wells must continually be drilled to maintain production, let alone expand it.

Since the host rock is impermeable, the wells are short lived and not very productive

We are in particular less optimistic than most commentators for oil production from international shale formations.

Forecasts of international production of shale oil also appear optimistic

This is both because we believe that other countries do not benefit from the US' uniquely favorable "above ground" factors, but also because we are not aware that the target geological formations are as well understood as those in North America. The exception may be the Vaca Muerta basin in Argentina. This however is unlikely to account for the 4-5 million bpd which most observers assume for tight oil production in 2040.

Notwithstanding the above, we believe that the industry will reasonably comfortably produce enough liquids to meet long-term demand, and this for two reasons.

Yet the industry should comfortably produce the liquids to meet demand

Tight oil will represent only 3% of global liquids supplies

First, tight oil production represents only about 3% of total liquids supply, so a smaller production of tight oil will not seriously affect global oil markets.

Deep-water production may offset shortfall in tight oil production

And, second, deep-water production may actually be larger than now assumed. Further, additional supplies will likely be forthcoming from extra-heavy oil and oil sands if oil prices rise significantly above their current levels.

Shale Gas Production

As for tight oil, we are not convinced that the production of shale gas in the US and elsewhere will increase as much as most observers now believe.

Shale gas production may not increase as most observers forecast

This is because shale gas wells exhibit particularly steep declines, which implies that numerous new wells must be drilled annually to maintain production.

US gas prices have declined and shale gas is not profitable without NGLs by-product

With the rapid increase in shale gas production initiated when prices were high, US gas prices have declined to a point where drilling shale wells is uneconomic, except when they produce meaningful volumes of NGLs. Thus, once the inventory of drilled-but-not-yet-in–production wells is worked off, shale gas production will rapidly decline for dry plays.

Marcellus and Eagle Ford are large basins with NGLs by-products, significant production upside and good logistics

The exceptions are the Marcellus and Eagle Ford plays which produce significant quantities of NGLs and have favorable logistics situations. Their continued sustained pace of drilling and increased production will likely keep downwards pressure on gas prices and will constrain the activities in other plays.

Thus, whilst we agree that shale gas production from Marcellus and Eagle Ford will keep increasing, we doubt that US overall shale gas production will keep increasing as rapidly and reach and remain at levels as high as most observers now assume.

Forecasts of international production of shale gas appear optimistic

We also doubt that international shale gas production will grow as rapidly as most observers foresee. This is because the geology of the shale basins is not understood enough and the productivity of shale wells cannot be forecast accurately, as initial exploration wells results have now indicated. Also, most importantly, “above ground” factors will likely be much less favorable for international basins than in the US.

Yet the industry should comfortably produce enough gas to meet demand…

Notwithstanding the above, we believe that the industry will reasonably comfortably produce enough gas to meet long-term demand.

…from conventional fields…

First, there will likely be enough conventional sources of gas which can be developed in Africa, Eurasia and the Middle East to compensate for a shortfall in shale gas production.

...and from shale basins if prices rise

LNG trade will help balance supply and demand

And, second, were a long-term shortage of natural gas to develop, gas prices will increase and more US shale deposits will be exploited. In that respect, the emergence of a deeper international LNG/gas trade will increase the rationale for developing hitherto “stranded” gas resources, in the US and elsewhere.

Impact of Tight Oil and Shale Gas on Saudi Arabia

Oil

Tight oil production is unlikely to grow as observers assume

It will account at most for 3% of long-term liquids supply

Since we doubt that tight oil production will grow as much as most commentators surmise, and since we believe that tight oil production will keep representing only about 3% of total liquids supply, we do not believe that the growth in oil production from tight rock formations in the US, or from shale formations elsewhere, will materially affect Saudi Arabia’s long-term position in the oil industry.

US tight oil and international shale oil will not significantly impact Saudi Arabia’s position

We view the production of tight oil in the US as mainly impacting Saudi Arabia through the narrowing of the price differential between heavy and light crudes. That narrowing may force a restructuring of downstream global refining activities, in particular in Europe, but should not affect Saudi Arabia’s refining complexes.

Pricing of domestic energy will remain the key factor affecting the Kingdom’s long-term position

We thus remain of the opinion that the key factor that will impact Saudi Arabia’s long-term position in the world’s energy industry is the high, and growing, internal demand. As we have previously opined, we believe that high internal demand, spurred by low internal energy prices, will not only distort internal economic decisions, but will also, in the long-term, crowd out and reduce the income from Saudi Arabia’s oil exports.

Shale gas production is unlikely to grow as observers assume

Ethane and NGLs production from shale gas & tight oil fields will dramatically improve the attractiveness of petrochemical manufacture in the US

Saudi Arabia's petrochemical industry may see its profitability reduced and may consider expanding production in the US

Gas

As for tight oil, we doubt that the production of shale gas in the US and elsewhere will increase as much as most observers surmise.

Yet, we believe that the large production of cheap (by-product) NGLs from tight oil and shale gas formations will have a significant impact on the world's petrochemical industry.

Saudi Arabia is not a large producer of natural gas (methane). Also, its production of cheap by-product NGLs, including ethane, for petrochemical production will remain somewhat limited.

We thus see the main impact of the US shale gas and cheap NGL production on Saudi Arabia as (i) reducing the comparative profitability of Saudi's existing petrochemical complexes, and (ii) inducing Saudi petrochemical firms to consider expanding their capacity in the US to profit from abundant, cheap yet valuable, feedstock.