Note de l'Ifri

# The US Shale Oil Revolution:
## The Test of the Business Model is Underway

Sylvie Cornot-Gandolphe

*January 2015*

ifri Centre Énergie

The Institut français des relations internationales (Ifri) is a research center and a forum for debate on major international political and economic issues.

Headed by Thierry de Montbrial since its founding in 1979, Ifri is a non-governmental and a non-profit organization.

As an independent think tank, Ifri sets its own research agenda, publishing its findings regularly for a global audience.

Using an interdisciplinary approach, Ifri brings together political and economic decision-makers, researchers and internationally renowned experts to animate its debate and research activities.

With offices in Paris and Brussels, Ifri stands out as one of the rare French think tanks to have positioned itself at the very heart of European debate.

*The opinions expressed in this text*
*are the responsibility of the author alone*.

ISBN: 978-2-36567-369-3


IFRI
27, RUE DE LA PROCESSION
75740 PARIS CEDEX 15 – FRANCE
Tel: +33 (0)1 40 61 60 00
Fax: +33 (0)1 40 61 60 60
Email : accueil@ifri.org

IFRI-BRUXELLES
RUE MARIE-THERESE, 21
1000 – BRUSSELS – BELGIUM
Tel: +32 (0)2 238 51 10
Fax: +32 (0)2 238 51 15
Email: bruxelles@ifri.org

Site Internet : Ifri.org

# Summary

Since 2010, the United States has been undergoing a second shale revolution with the very rapid development of Light Tight Oil (LTO) or shale oil, following the revolution in shale gas. This development has allowed the production of oil and liquids to increase, so that the US is the world's largest producer today, ahead of Saudi Arabia and Russia. The production of LTO accounts for 55% of US crude oil output now, and has enabled the country to reduce its oil imports and expand its exports of oil products. This has important ramifications for the world oil market, traded oil flows and more recently the oil price.

As with shale gas, this oil production has a key impact on the US economy, especially on its trade balance, but also its security of supplies. It has allowed the country to cut its dependence on oil imports, which fell from 60% of consumption in 2005 to 27% in 2014. The significant industrial consequences for the US refining sector of this development also need to be noted, as it now has important margins, thanks to the price differential between Brent and WTI.

The fall in the price of oil, by 50% for the WTI between June 2014 and the beginning of January 2015, raises significant uncertainties concerning the ability of American producers to pursue further investments needed to sustain the shale oil revolution. As operating costs (OPEX) to produce LTO are limited, production at existing wells is not really called into question. But, LTO output is characterized by very rapid declines in initial production per well (between 60% and 90% in the first year). Therefore, sustained investment in new wells is necessary to maintain and/or increase output. Such rapid output decline means that projects are very strongly dependent on the price of oil in their first year of operation. This contrasts with conventional oil production whose economics spans much longer time periods. Accordingly, there are fears that lower oil prices will lead to cuts in investment in shale oil and hence a fall in production.

Breakeven prices provide information about the minimum prices needed for drilling projects to be profitable. Yet their analysis needs to be qualified. The cost of producing LTO is a determining factor, but it is practically specific to each individual well, given the greatly diverging geological properties of each formation, and even within a same play between "sweet spots" and wells at the periphery. It seems that the three main formations currently being exploited (Eagle Ford, Bakken and the Permian basin), which account for the majority of current output, have sweet spots for which the breakeven

price is relatively low. This is reinforced if land acquisition costs and infrastructural costs are taken as stranded (so-called “mid-cycle” costs”). It therefore seems likely that drilling activities will move towards the sweet spots in these basins, and this has been confirmed by announcements made by operators, as well as the distribution of the fall in drilling activity by shale plays/states, observed since December 2014.

In addition, technological advances and the expected reduction in the cost of drilling and completion services increase the resilience of operators to low oil prices. Technological advances are at the heart of the shale industry. They have allowed significant efficiency and productivity gains. The real breakthrough came in the last two years with the advent of extended reach of horizontal laterals (up to 3 km) combined with hydraulic fracturing in multi stages. In 2014, companies have successfully tested the reduction of the spacing between wells. This new strategy is important in the present oil environment since it allows drilling of new wells in already developed formations, at no additional cost for exploration and infrastructure.

Breakeven prices alone, however, do not explain the level of future investment. There are other important criteria, such as available cash flow, the scale of debt, and hedging strategies for production. These are specific to each operator and will determine their capacity to reinvest in new wells. Most independent US producers have largely drawn on debt to finance their drilling programs. For this strategy to be continued, they will have to be able to carry on accessing capital markets at advantageous rates, as has been the case since 2010. This is a particularly important issue for some independent producers which use a large share of earnings to service debts. As hydrocarbon reserves are used to guarantee such borrowing, the fall in oil prices cuts the value of assets and the capacity of operators to take on debt or, in some cases to repay existing debts, a situation further aggravated by falling revenues. The most heavily indebted companies, and especially those using junk bonds to acquire capital, are the most exposed, following falls in junk bond prices and the increase in returns required by market investors. If low prices continue to prevail, some independent producers will not be able to finance their drilling programs, even if such drilling is profitable. A consolidation of the sector therefore seems likely. At the same time, many operators hedge a significant part of their production in 2015 in the futures markets, thus protecting themselves against falling prices. The impact of falling oil prices will therefore be varied, not only across plays, but also across operators.

A basic trend for 2015 is emerging. Operators who announced their budgets for 2015 in November/December 2014 do indeed anticipate cutting their capital expenditures (CAPEX) by between 20% and 50%, accompanied by similar cutbacks in drilling. Nevertheless, despite such reductions, most independent American producers hope to raise output by focusing on the most productive basins, by differing exploratory drilling of new plays and by cutting costs, especially drilling and completion costs. Growth in output should however still fall, compared to 2014: expansions in output of between 10% and 20% have indeed been announced, but these are lower compared to the 28% growth achieved in 2014 for overall LTO output.

It is both, the fall in prices and its duration that will determine the scale of the American shale oil producers' reactions. They also depend on the responses of other producers of conventional and non-conventional oil. If low prices continue, they should lead to a fall in the growth of LTO output, though not cancelling it entirely. On the basis of an average price of $55 for WTI in 2015 (and $71 in 2016), the Energy International Administration (EIA) is forecasting an increase in US oil production of 0.6 Mbd in 2015, equivalent to half the increase observed in 2014 (STEO, 13 January 2015).

The capacity of US shale oil producers to resist low oil prices and to adapt to oil cycles is a test not just for the US, but also for all countries seeking to develop their shale resources.

# Structure of the Report

This report provides an overview of LTO production in the United States, and examines the likely consequences of the fall in oil prices on its future evolution. The first chapter assesses the five years of this new revolution, which follows that of shale gas. It looks at the most significant trends: the spectacular development of oil production, the fall in US oil imports, and the contrasting rise in exports of petroleum products as well as the march to oil independence.

The second chapter highlights the specificities of shale oil and its ensuing business model, which is very different from the Exploration & Production (E&P) model of conventional oil. It analyses the economics of LTO and the breakeven price required for further investment.

Chapter 3 looks at the progress in technology at the heart of the shale revolution. It describes recent trends and expected improvements in the short term.

The financial situation of LTO producers is also a factor determining levels of future investment. The main financial indicators of the sector are presented accordingly in the following chapter.

Lastly, Chapter 5 studies the impact of the fall in prices on the CAPEX of American producers and on drilling activity. Drawing on forecasts by the Energy Information Administration, the chapter concludes on the resilience of LTO production in the face of falling prices.

# Table of Contents

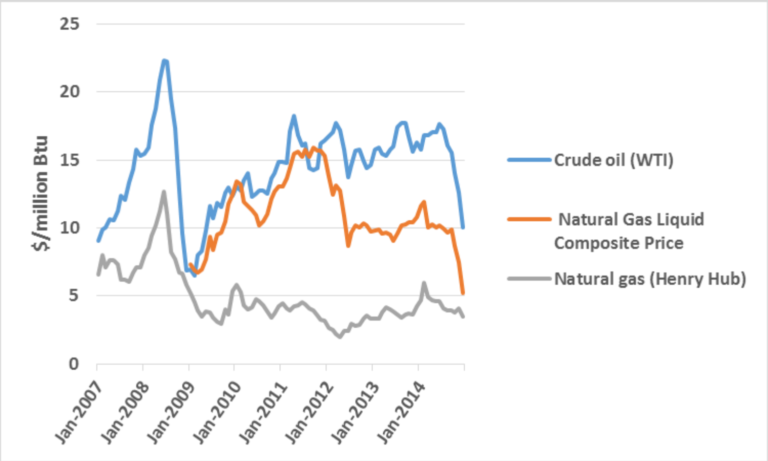
# The USA as a New Oil Power

## *From Shale Gas to Shale Oil*

The shale oil and gas revolution (also referred to as **light tight oil** (LTO) for shale oil) initially concerned shale gas.[1] The latter's gross production rose from 51 billion cubic meters (Gm$^3$) in 2007, to 374 billion Gm$^3$ in 2014, thus representing 52% of total gross production in the United States. The rapid development of production led to overcapacity and gas price falls on the US market. The Henry Hub spot price collapsed from \$8.90 per million British thermal units (MBtu) on average in 2008, to about ±\$4 per MBtu since, with a fall in 2012 to \$2.75 per MBtu and an increase to \$6 per MBtu in early 2014, following the freezing cold episode that hit the northeast of the country. In 2014, Henry Hub price was \$4.4 per MBtu on average, an increase of 18% over the average in 2013 (\$3.73 per MBtu). The value of oil, about 4 to 5 times higher than that of natural gas over the last three years, has led to a radical change in the strategy of the US operators. As of 2010, they have sought basins producing wet gas (including natural gas liquids, NGLs), oil and condensates.[2] As shown in Figure 1 below, the price of WTI, the crude oil benchmark in the United States, stood at around \$17 per MBtu, up until its recent fall. This compares to about \$4 per MBtu for natural gas and \$10 per MBtu for natural gas liquids

[1] There is a difference between so-called 'tight oil' which has flowed from source rocks into to oil reservoirs; and shale oil/LTO which is contained within the source rock and which requires fracking to be released from the shale.
[2] Wet gas contains methane (the main component of natural gas), but also natural gas liquids (ethane, propane, butane and C5+).

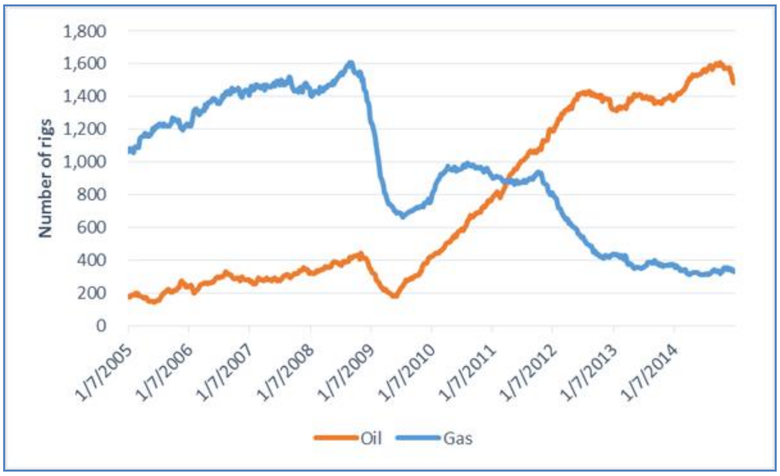
**Figure 1: The Comparative Prices of Natural Gas, NGLs and WTI in the United States (January 2007 to December 2014)**




Source: EIA (except for the price of NGLs from October to December 2014, estimated from the spot price of propane at Mont Belvieu).

Before 2009, 80% of drilling was concentrated on natural gas, but it switched rapidly towards wet gas and oil basins, to ensure greater profitability. This shift occurred very quickly: between the start of 2009 and late 2010, the number of rigs drilling for oil rose from 200 to about 800, in other words about half of all land drilling rigs in the United States, at that time. This trend has continued through to the present, and at the end of 2014 82% of rigs focused on oil basins.

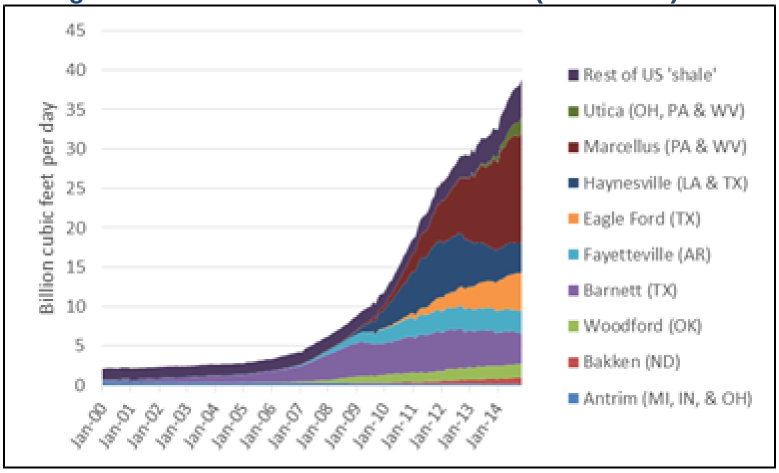
**Figure 2: The Distribution of Drilling between Oil and Gas in the United States (January 2005 to December 2014)**




Source: Baker Hughes, Rig count

It is interesting to note that despite the fall in the number of rigs drilling for gas, output has continued to rise. However, it has changed significantly: activity has shifted to the most productive plays (Marcellus, Barnett), to the detriment of less productive plays, as well as to the production of associated gas in oil plays (Eagle Ford in particular). Vertical drilling has practically disappeared in favor of horizontal drilling. This trend may foreshadow the reaction of American oil companies faced with the current drop in crude oil prices (see Chapter 5).

**Figure 3: Gross Shale Gas Production (2000-2014)**




Source: EIA

## *The Rise in US Oil Production*

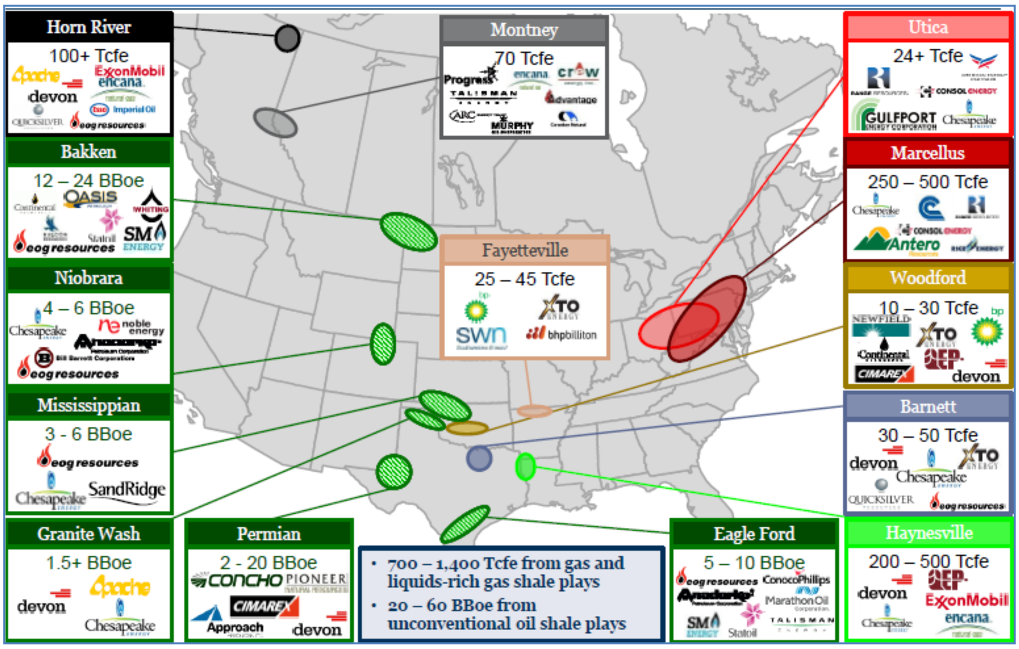
### The rapid expansion of shale oil

The shift in drilling to exploiting shale oil has led to an immediate rise in production. **LTO production has increased spectacularly, rising from 1.5 million barrels per day (Mbd) in 2010 to 4.7 Mbd 2014** (initial estimates by the EIA), of which 4 Mbd are oil and 0.7 Mbd are condensates. This output now accounts for 55% of US oil and condensate production (8.6 Mbd in 2014). In December 2014, the production of LTO reached a record 5.2 Mbd, an increase of 1.2 Mbd compared to December 2013, despite the fall in prices since July 2014.

The growth between 2010 and 2014 – 3.2 Mbd – largely exceeds the expansion of output in the rest of the world. **US LTO is therefore the primary source in the rise of global oil production**. The growth in production is pulled by investment, the improved efficiency of drilling and the greater productivity of wells.

In 2014, the main shale oil plays included Eagle Ford, and Wolfcamp in Texas; the Bakken-Three Forks in North Dakota; the Spraberry and Bone Spring plays in New Mexico; Woodford in Oklahoma; Niobrara in Colorado; Green River in Utah; Utica and Point Pleasant in Ohio; Marcellus in West Virginia and Pennsylvania.

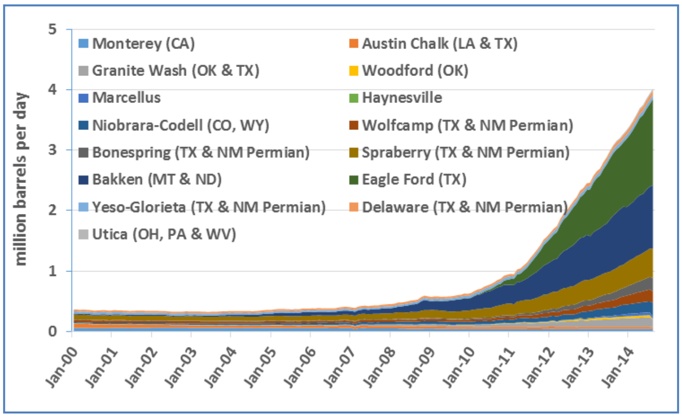
### Map 1: The Main Shale Oil and Gas Plays in the United States




Source: <www.ndoil.org/?id=279&page=2014+WBPC+Presentations>

Three plays/basins yield 90 % of production: the Bakken formation which was the first to be developed; Eagle Ford and the Permian basin, which covers six principal formations: Spraberry, Bone Spring, Wolfcamp, Delaware, Yeso and Glorietta (see Annex 1). The rise in output is mainly due to the plays of Bakken, Eagle Ford, and Wolfcamp, Bone Spring and Spraberry in the Permian basin.

### Figure 4: Production of LTO by Formation



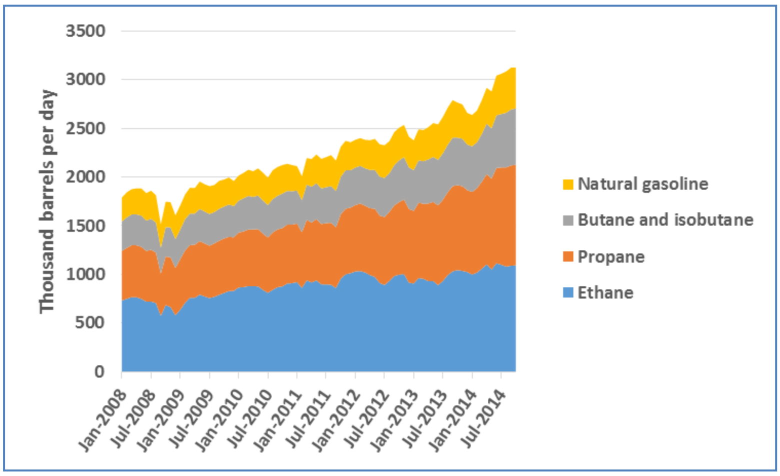

Source: EIA

Drilling of oil basins has now gone on for five years. **During this time, 90,000 oil wells have been drilled**. This rate of drilling has greatly increased the knowledge of the formations and has also led to significant efficiency and productivity gains (see Chapter 3).

## The considerable rise of natural gas liquids

Natural gas liquids (NGLs) stem from the processing of wet gas, and also marginally from refining of oil (about 12%), and their output has risen strongly. Between 2008 and 2014, the output of liquids from wet gas rose by 8.8% per year on average, reaching 2.96 Mbd in 2014, up by 13.4% in 2013. The price of NGLs normally follows the price of oil (see Figure 1), therefore offering a price premium compared to natural gas. Since 2012 however, the abundance of NGLs has caused their prices to fall, especially the price of ethane and propane, which on average are halfway between the price of WTI and Henry Hub gas. Recently, the fall in NGL prices has accelerated in line with the decrease of oil prices. The price of ethane has fallen below the price of natural gas, discouraging producers to separate NGLs and instead selling them with natural gas. In the United States, this phenomenon is called ethane rejection. The new petrochemical plants, which should come on stream in 2016-2017, along with ethane export projects should help raise its price and production. Estimates of ethane not separated from natural gas run from 200 Mbd to 400 Mbd.

**Figure 5: Production of NGLs in Gas Processing Plants (January 2008-October 2014)**



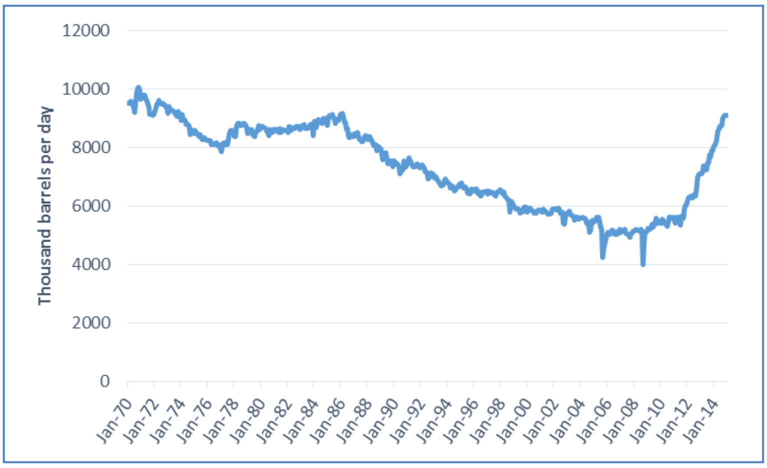

Source: EIA

## The United States as the world's leading oil and liquids producer

Thanks to the rise in LTO production, the United States has witnessed a spectacular rise in its oil production since 2010. Crude oil production has gone up by 56% since that year, reaching 8.6 Mbd in 2014 (9.1 Mbd in December 2014). This is the highest level for nearly 30 years.

In 2014, the rise reached 1.2 Mbd, or 16% more than in 2013. This is a clear and important break with the previous trend of steady decline since the middle of the 1980s, with output falling from nearly 9 Mbd in 1985, to about 5 Mbd in 2005.

**Figure 6: The Evolution of US Crude Oil Production (January 1970-December 2014)**




Source: EIA

While the output of LTO is growing and today accounts for more than half of total crude oil production, the output of conventional onshore crude oil (in Alaska or California) continues to follow the decline which began in the 1980s.

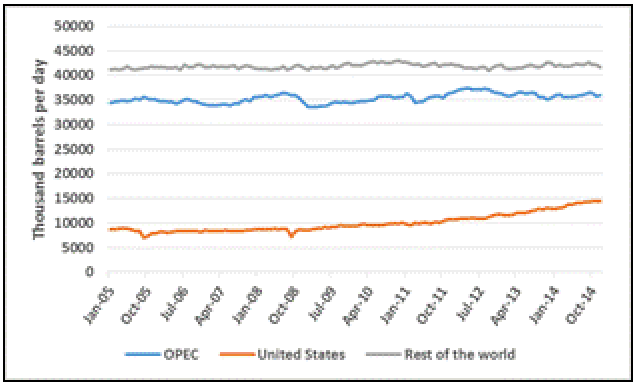
In 2014, **the total output of crude oil and liquids** (including crude oil and condensates, natural gas liquids, bio-fuels and refinery gains) stood at 13.7 Mbd (up from 12.4 Mbd in 2013). This new record confirms the leadership position of the United States as **the world's top producer ahead of Saudi Arabia** (11.6 Mbd) and Russia (10.7 Mbd). Saudi Arabia has therefore lost its status as the lead producer of crude oil and NGLs, overtaken by the US.[3]

Between January 2010 to December 2014, global oil and liquids output rose by 7.3%, increasing from 85.9 Mbd to 92.2 Mbd. Between these two dates, American output grew by nearly 55%, rising from 9.4 Mbd to 14.5 Mbd, in other words, a rise of 5.1 Mbd. Over the same time, OPEC output expanded by 4.1% to reach 36 Mbd, whereas production in the rest of the world fell by 0.5% to 41.7 Mbd. Thus, **in December 2014, the United States accounted for 15.7% of global output, compared to only 10.9% in January**

[3] According to data by the EIA (provisional estimates, December 2014).

**2010. It is both the scale and speed of this increase which have modified the American and global oil scene**.

**Figure 7: Production of Crude Oil and Liquids, by the United States, OPEC and the Rest-of-the-World (January 2005-December 2014)**



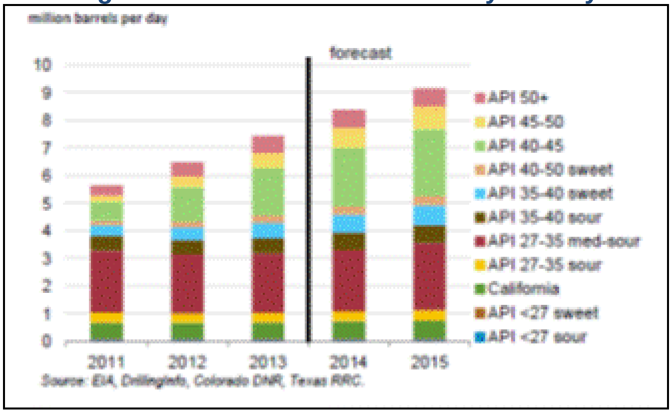

Source: EIA

## The expansion of output is mainly in light oil

The recent expansion of US production is mainly in light oil with little sulfur. About 96% of the 2.9 Mbd increase in production between 2011 and 2014 is made up of light crude oil with an API gravity of 40 or more, and a sulfur content of less than 0.3.[4]

[4] The “API density” (formulated by the American Petroleum Institute) is used in the Anglo-Saxon system to express crude oil density. A liquid with an API value of 10°API at a temperature of 15°C is said to have a density of 1.00 (as water, or 1kg/liter), at the same temperature. Generally speaking, heavy crude has a density of less than 20°API, an average density of 20 and more than 30°API is considered as light. These limits do vary across countries. During refining, lighter oils directly produce many lighter cuts (diesel, petrol/gasoline and naphtha). In contrast, heavy crudes produce more bitumen and residual oil. These must be sold either at low prices or converted into lighter cuts, notably through hydrocracking (by adding hydrogen).

**Figure 8: Crude Oil Production by Gravity**




Source: EIA, <www.eia.gov/analysis/petroleum/crudetypes/pdf/crudetypes.pdf>, May 2014

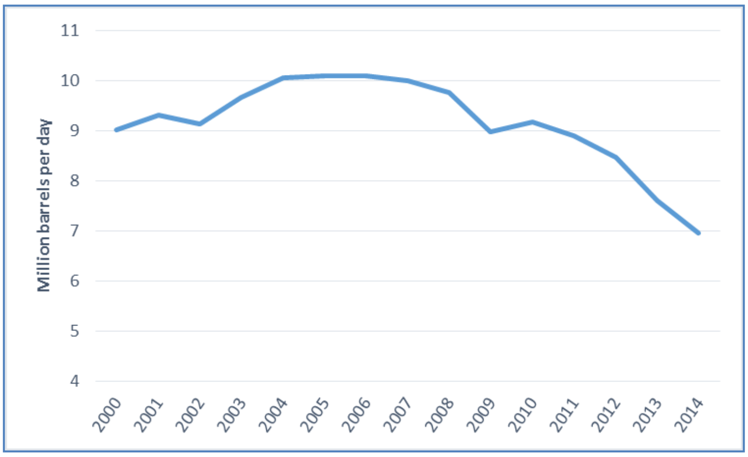
As US refineries were not designed to process such quantities of light crude oil, the extra volumes sold into the market have mainly displaced American imports of light crude oil (see below). This surge in light oil has strongly modified the US and global oil scene. It contributed to a surplus on the market in 2014, and transformed the Atlantic market from being short in light oil to being in surplus. The quality of LTO is important in understanding the dynamics of oil markets and the reaction of producers (especially Saudi Arabia) faced with problems of overcapacity in the light oil market.

## *A Radical Change in the World Trade of Crude Oil and Petroleum Products*

### A drastic reduction in crude oil imports

The strong rise in LTO output has reduced the demand for imports to cover US refining needs. Net crude oil imports have fallen by 2.2 Mbd since 2010, to an average of 6.95 Mbd in 2014 (the fall relative to 2013 was 8.6%).

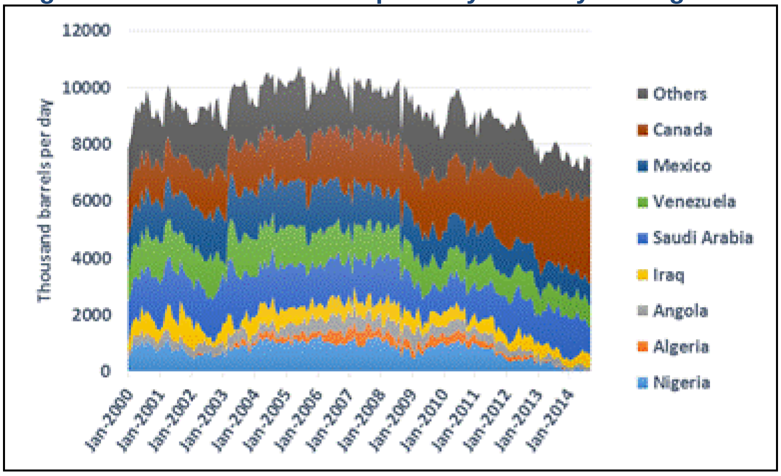
**Figure 9 : Net Crude Oil Imports by the United States (2000-2014)**




Source: EIA

Suppliers to the United States have seen their outlets dwindle rapidly. As US shale oil is light, American production has substituted imports of similar quality, such as crude oil from west Africa, which has virtually disappeared from the American market: Nigeria (American exports fell by 94% between 2010 and 2014), Angola (down 67%) or Algeria (-98%). Following west Africa, it is now the turn of Latin American imports to be replaced by domestic production: Columbia (-17% between 2010 and 2014), Venezuela (-18%), and Mexico (-32%). Imports from Saudi Arabia continued to expand (+22.5% between 2010 and 2013) until they dipped in 2014 (-5.5%). Only imports from Canada have continued to grow. They now account for 36% of net US crude oil imports. Canada, Mexico and Saudi Arabia, which produce heavier crude oil now account for 64% of American imports. Imports from Canada should continue to grow in 2015, as well as in the coming years, thanks to the implementation of new transport infrastructures. The opening of the Flanagan South Pipeline System (FSP) of Enbridge in December 2014 will make it possible to deliver additional heavy oil from Canada to refineries in the Gulf of Mexico, therefore reducing the need for imports from more distant sources. In time, the Keystone XL pipeline could reinforce the role of Canada in American oil imports.

**Figure 10 : U.S. Crude Oil Imports by Country of Origin**



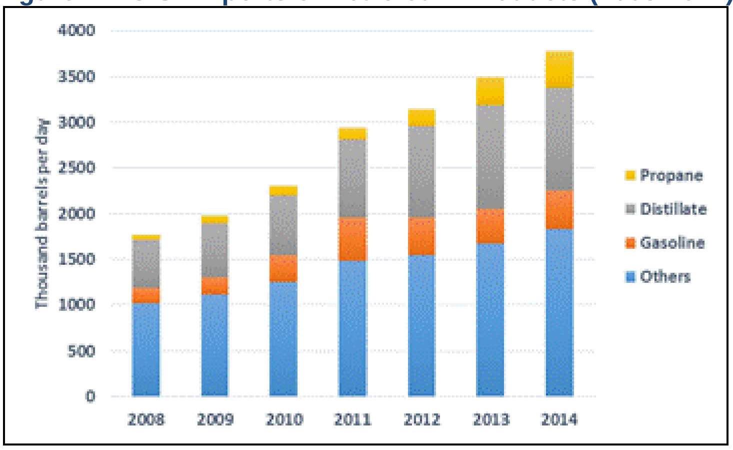

Source: EIA

## The United States has become a net exporter of petroleum products

Turning to the exports of petroleum products, these have risen strongly since 2008. They stood at 3.77 Mbd in 2014 (a provisional estimate based on the first nine months of the year). This represents an 8% increase over 2013, and a doubling compared to 2008.

.

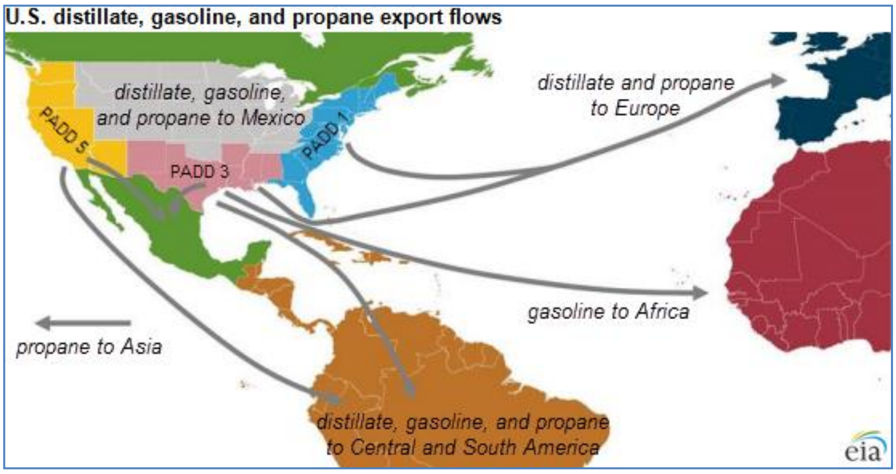
**Figure 11: U.S. Exports of Petroleum Products (2008-2014)**




Source: EIA

As shown in map below, all global flows in petroleum products have been affected by these new exports. This is especially so for European refineries which saw a fall in gasoline demand and a strong rise in diesel and propane imports, as well as heightened competition in the Asian market.

**Map 2: Export Flows of Petroleum Products from the United States**



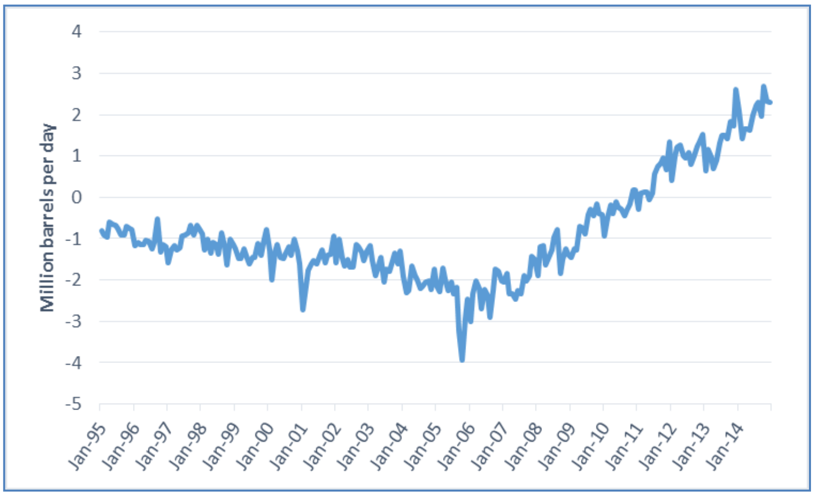

Source: EIA

Despite these record exports, the United States is still importing petroleum products, but such exports are in decline. In 2014, they stood at 1.74 Mbd, a fall of 17% compared to 2013. Even though the Gulf of Mexico remains an important net exporter of gasoline, the East Coast continues to import significant quantities of gasoline from Europe and Canada, given present infrastructural constraints. Similarly, imports continue to play a crucial role in the supplies of fuel oil and propane during winters, especially on the East Coast. In this region, production and shipments from other regions continue to lag behind rising demand, especially in very cold periods, such as the one experienced in the winter of 2013/2014.

These significant exports of petroleum products mean that the United States has become a net exporter of such products since 2011. The net growth of exports between 2011 and 2014 (1.6 Mbd) is equivalent to more than half of the growth in global demand for crude oil and petroleum products during this period.

.

**Figure 12: Net Exports of Petroleum Products (January 1995-December 2014)**

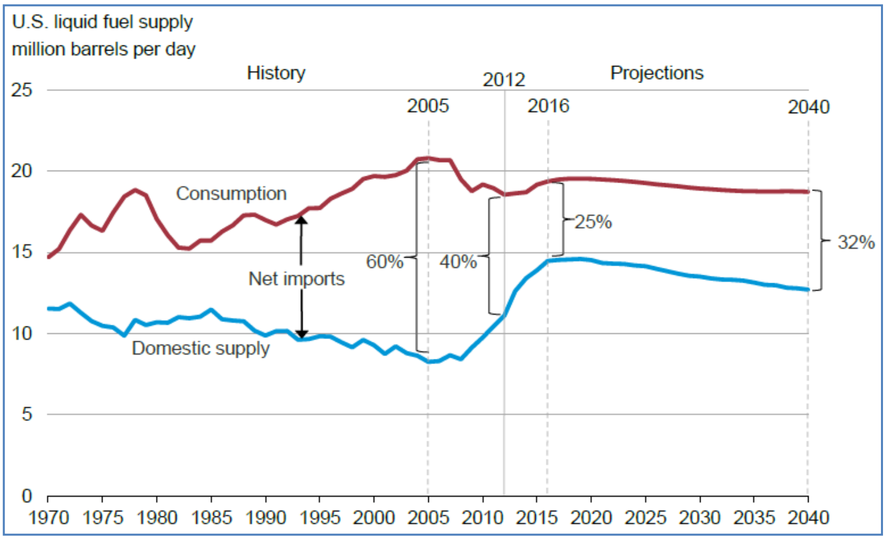



Source: EIA

## Towards oil independence

American oil dependence has been cut spectacularly. The share of consumption of crude oil and petroleum products covered by imports fell from 60% in 2005 to 33% in 2013, and to 27% in 2014. According to the EIA, this trend should continue into the medium-term.

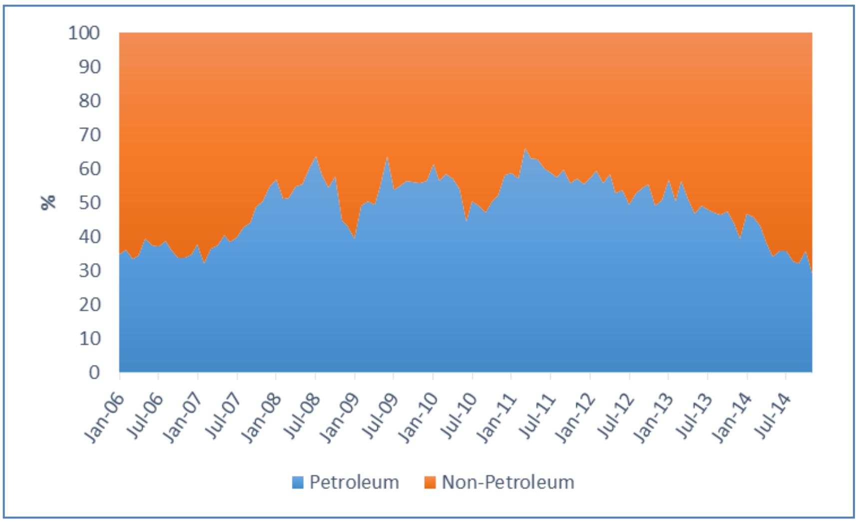
**Figure 13: The Share of Net Crude Oil and Petroleum Product Imports in US Consumption**




Source: EIA, Annual Energy Outlook 2014, May 2014.

The drop in oil imports has not only had an impact on the **supply security of the United States**, but it has also improved the **trade balance**. The latter stood at $39 billion in November 2014, a 7.7% fall on the previous month. Crude oil and petroleum products, play an important role in balancing America's current account. **In March 2011, oil and petroleum products accounted for 66% of the trade deficit. Thanks to shale oil and falls in the price of crude oil, this share fell to 29% in November 2014**. Until now, the United States has always imported more crude oil and petroleum products than it exported the trade balance on oil reached a maximum of $452 billion in Q3 2008, given the strong rise in prices. Since then, and despite high prices until recently, the increase in petroleum product exports and the reduction of crude oil imports have allowed the oil trade deficit to be reduced to $183 billion in the months of September to November 2014. The total value of crude oil and petroleum product imports fell to its lowest level since August 2009, bringing the US oil deficit down to its lowest level for nearly 11 years. The contribution of oil to foreign trade is equal to 0.8 percentage points of GDP growth.

**Figure 14: The Share of Crude Oil and Petroleum Products in the US Trade Deficit**




Source: <www.census.gov/foreign-trade/statistics/graphs/PetroleumImports.html>

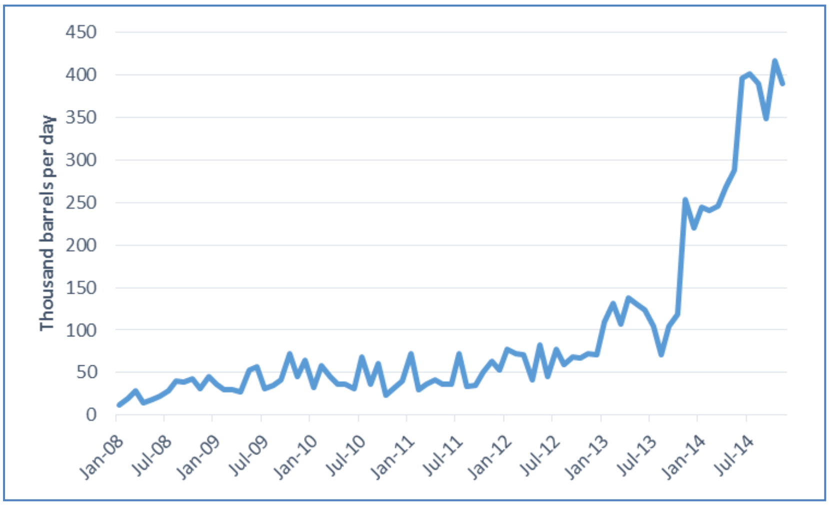
## The lifting of the ban on crude oil export

Oil exports are also rising, despite the ban on crude oil export. This ban was implemented in 1975, in the wake of the first oil shock. That year the Energy Policy and Conservation Act (EPCA) instructed the Bureau of Industrial Security, which is supervised by the Department of Commerce, to provide export licenses for crude oil only in the following cases: Alaskan Cook Inlet crude for consumption by Canada, crude oil stored in the SPR, certain types of Californian crude oil up to 25,000 bd per year, crude oil covered by international agreements or selected by the President of the United States, and the re-exportation of foreign crudes.[5]

[5] Source: *Pétrostratégies*, 3 November 2014.

In the face of the rapid growth in American output of oil and liquids, pressure is rising increasingly to lift the ban on exports (at least partially). Already in July 2014, the United States exported on average 401,000 bd of crude oil, the highest level in 57 years.[6]

**Figure 15: US Exports of Crude Oil (January 2008-November 2014)**




Source: EIA

The crude oil export ban and bottlenecks in transporting crude oil to Cushing and refineries in the US have led to a price discount of WTI *vis-à-vis* Brent. Historically, WTI traded at a slight premium of $2-$3 per barrel. In 2013, WTI sold on average at a $10 discount compared to Brent. Since the fall in oil prices, the discount has fallen, though it persists. The discount, along with the low price of crude oil in the United States, especially in the Bakken (where prices are further discounted compared to WTI due to transport costs) are all pushing for an end to the ban on crude oil export.

This is a sensitive issue in the United States. The general public fears that US crude oil exports would raise the price of crude and hence the price of gasoline. Yet the latter is in fact linked to the price of Brent and not to WTI. Wholesale prices, excluding tax, of refined products are practically aligned with prices in international markets. Indeed, the exports and imports of refined products are free and in competition with refined products from all over the world. This is a major difference between the oil and gas industry. While American consumers and industries benefit from lower gas bills, following the falls in the Henry Hub price, it is the US refining industry that has been able to get supplies at lower costs and hence increased

[6] Part of this performance nevertheless stems from a change in calculation methods. Since April 2014, US statistics have taken re-exports of Canadian crude oil into account, oil which is transported to the Gulf of Mexico by pipeline (passing through the US) for export to Europe and Asia. In July, some 28,000 bd were exported in this way. The goal of the Canadians is to limit the use of rail transport in moving oil from Alberta to the Atlantic coast. Source *Pétrostratégies*, 3 November 2014.

margin. This competitive advantage favors the exports of petroleum products.

Despite the sensitivity of the subject, it seems very likely that the crude oil export policy will be re-examined. This is spurred on by the current fall in prices, and the **increasing export of US condensates, which the United States has recently authorized under certain conditions**. Four factors favor the exportation of crude oil:

- **The economic upturn brought on by investments in the sector.** Investments in shale oil and gas reached $129 billion in 2014, with more than 70% of investment in the upstream part of the industry. This investment is contributing to growth in the United States, creating many new jobs directly and indirectly, generating revenue for States and value-added for the American economy. An easing or a lifting of the export ban would allow American producers to obtain higher margins on foreign markets and so compensate partially the current fall in prices.

- Even without lifting the ban, the government has already relaxed its policy. At the end of December 2014, **the US government adopted a less restrictive policy allowing for the export of condensates under certain conditions**.[7] The Bureau of Industrial Security (BIS) specifically authorized the export of lease condensates by publishing a guide in the form of FAQs (frequently asked questions). In 2014, the Department of Commerce had already authorized two companies (Pioneer Natural Resources, and Enterprise Products Partners) to export lease condensates after only slight processing (which did not mean proper refining). The production of lease condensates from LTO output has risen, and reached 0.7 Mbd in 2014, mainly from the Eagle Ford play. US refining capacity to process such condensates is limited. Moreover, the refining of condensates translates into petroleum products of lower value on the US market, such as naphtha and gasoline. Export markets offer higher returns. According to Jacob Dweck, an associate with Sutherland Asbill & Brennan, exports of condensates could reach 500,000 bd in 2015.[8]

- Furthermore, **the victory of the Republicans in the mid-term elections in November 2014 is also likely to have important consequences for the energy sector, as it was at the top of their electoral agenda**. The Republicans favor lifting the ban on exports of crude oil, because they believe it no longer corresponds to the current realities of the market. In December 2014, **a new bill, sponsored by a Republican representative**

[7] Reuters, "US opens door to oil exports after year of pressure", 31 December 2014.
[8] Argus, "US lawmaker files bill to lift crude export limits", 9 December 2014, <www.argusmedia.com/News/Article?id=960865&page=7>.

**from Texas, Joe Barton, was filed to end the ban** on American crude oil export.[9] The bill would repeal the EPCA of 1975. The fall in oil prices could favor the lifting of the ban, because such a reform would likely lead to a rise in the price of WTI. This in turn would allow American producers to be (partially) compensated for the lower attractiveness of investments in non-conventional oil production, linked to current low oil prices.

- Several studies carried out in 2014 indicate that **the price of gasoline in the United States would not rise. On the contrary, it would slightly fall** if crude oil exports were authorized. A study by the Government Accountability Office (GAO) shows that if the United States authorized the export of crude oil produced domestically, then the price of crude in the US market could rise between 2% and 8%, i.e. $2 to $8 per barrel (the study concerned prices before their recent fall).[10] In contrast, the prices of refined products sold into the American retail market (mainly fuel for road transport) could fall on average by 0.4% to 3.4%. If the United States were to export crude oil, then this would indeed contribute to a fall in crude prices on the international market, and hence the prices of refined products too. This would affect the American market as well. A second study by the Congressional Budget Office (CBO) reaches the same conclusions concerning the fall in gasoline prices linked to the rise of US crude oil exports.[11] For its part, the EIA has recently published a study which concludes not only that the price of gasoline would not rise, but that lifting the export ban would help raise economic growth, employment and trade.[12] The transfer of a share of the economic benefits which currently go to US refineries would go to producers and would lead to a net advantage for the country.

Even without lifting the ban, exports of crude oil and condensates should exceed 1 Mbd in 2015, according to a study by CITI.[13] This total includes about 200,000 bd in trade of light crude against heavy crude with Mexico, 500,000 bd with Canada, and 100,000 bd from Alaska. Exports of condensates could reach 200,000 bd (more than currently authorized exports) and exports to Mexico could expand and reach 200,000 bd.

The debate over the United States' export policy should intensify as of January 2015, when the new Congress meets. The effects of lifting restrictions on crude oil exports should be felt well

[9] *Ibid*.
[10] Petrostrategies, 3 November 2014
[11] Argus, "US crude exports would lower global prices: CBO", 10 December 2014, <www.argusmedia.com/News/Article?id=961726&page=6>.
[12] <www.eia.gov/analysis/studies/gasoline/pdf/gasolinepricestudy.pdf>.
[13] CITI Global Perspectives & Solutions, *Energy 2020: Out of America, The Rapid Rise of the United States as a Global Energy Superpower*, Citi GPS, Novembef 2014.

beyond the US oil industry. Thus, the end of the oil export ban should transfer a share of the volume of exports in petroleum products to exports in crude oil itself. The potential reduction of exports of petroleum products could benefit Asian refiners, as the market share of the US falls. Moreover, a fall in gasoline production (and exports) by the United States could be beneficial to European refiners, whose market has contracted strongly.

The geopolitical influence of the United States would also be increased, as would competition in the Asian markets with producers from the Middle East, Russia and West Africa.

# The Business Model and Economics of Shale Oil

## *The Characteristics of E&P in Shale Oil*

The exploration and production (E&P) model in shale oil and gas in the United States significantly differs from the model in conventional hydrocarbons, based on "explore, discover, produce".[14] The model is similar to the model of traditional industrial operations, which strive for the standardization of operations and significant economies of scale.

### The low risks in exploration

In conventional oil extraction, exploration risks are very high, given the risk of drilling dry wells. This is not so for the American shale oil. After more than 100 years of experience in E&P for conventional oil and gas, America's subsoil is well-known. It has been mapped and source rocks are well identified (which is not the case in other regions in the world). "Exploration" costs are therefore not linked to drilling wells which risk being dry. Instead, **costs are incurred in the acquisition of large surface areas which make it possible to drain important volumes of shale**. Costs are also generated in finding sweet spots – the places where drilling and hydraulic fracturing of the rock will be the most productive – through seismic and geo-science technologies which draw on increasingly sophisticated models.

Risks in the exploration stage are not zero: buying up the necessary land area for drilling and fracturing shale rocks, as well as the exploration costs linked to identifying sweet spots may be costly and the volumes of output can turn out to be insufficient for operations to be profitable, or they may be too far from existing transport infrastructures, making them stranded (this was the case of associated gas in North Dakota, which until now was just burnt off, given the lack of significant volumes and gas pipeline infrastructure to take away the gas). The land area acquisition boom required in the industrial exploitation of shale oil and gas took place between 2006

[14] This description is appropriate only for the United States, as American property laws give ownership to underground resources, which is not the case elsewhere. Access to mining areas is granted in exchange of licence fee payment and commitments to drill.

and 2009. Independent producers, who were at the origin of the revolution in shale gas, were thus able to benefit from very low land costs (less than $1,000 per acre).[15] Later entrants had to pay significantly higher sums to acquire land. This was the case of the oil majors, which paid high prices for their acquisitions in 2010 to 2011, the peak of the shale gas revolution, and prior to the falling gas prices in 2012. The price per acre varies strongly between plays, according to the properties of the rock and the stage of exploitation of the play. The acquisition of Althon by Encana in September 2014 (140,000 acres spread across the most productive oil window in the Permian cost $5.93 billion) had a price of $42,000 per acre. This was a high price compared to recent land transactions (about $25,000 per acre, and even very low costs of $1,000 per acre in exploratory shale basins such as the Tuscaloosa Marine Shale). But it was justified by the coexistence of several productive horizons of source rock within the same play.[16] The acquisition cost of land affects the total production costs of a well and varies strongly from play to play and operator to operator.

## "Industrial" exploitation

Due to the low risks in exploration, the business model of operators has evolved from being a model based on exploration to being a model based on industrial exploitation.

The exploitation of shale oil is different to conventional oil exploitation in a number of ways.

**Horizontal drilling and hydraulic fracturing:** the low permeability of source rocks requires the use of hydraulic fracturing, without which hydrocarbons will not run into wells, and the horizontal drilling of rocks to allow wells to drain as much source rock as possible.

**Geological diversity of source rocks:** Nature abhors analogy, and production characteristics diverge even at the level of the same play. This means that exploitation conditions and costs differ from one basin to another, from one play to another, and even within the same play. The production of shale oil is characterized by two parameters: **initial production** (IP) by wells and **the decline curve of production**.

These two parameters make it possible to calculate the Estimated Ultimate Recovery (EUR). The parameters vary according to plays, but also within a play, between the sweet spots and the periphery (marginal wells). For example, in the Eagle Ford oil window, the initial production of "average" wells was about 700 to 800 boepd

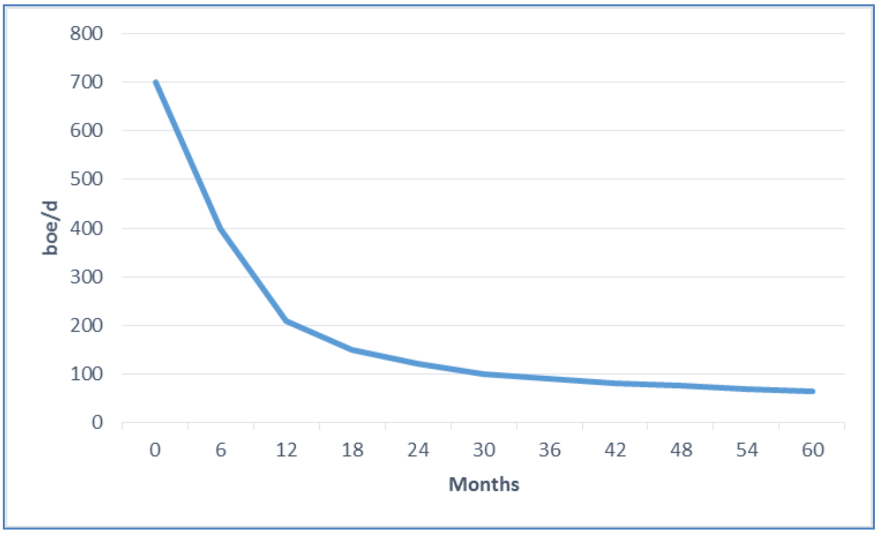
[15] 1 acre = 4 046,86 m$^2$

[16] Midland Reporter Telegram, "Analysts: Permian still hot spot despite lower prices", 20 November 2014, <www.mrt.com/business/oil/article_10097948-7141-11e4-8d72-5719745dab6d.html>.

(barrels of oil equivalent per day), and the distribution of production of 90% of wells can vary between 250 and 1,500 boepd. **Generally speaking, shale wells follow a "80/20 rule", whereby 20% of wells produce 80% of the total output of a play.[17] This rule is particularly important in the present context of reduced drilling activity**. Both parameters vary each year, in line with technological progress, leading to significantly higher initial production by wells each year (see Chapter 3).

**A rapid rate of decline**: output per well is characterized by very rapid decline. During the first year, the rate of decline is between 60% and 90%. In the Eagle Ford formation, the rate of decline is 60% to 70% in the first year, between 30% and 50% in the second year, and 20% to 30% in the third year. The rate of decline is then falling gradually by 10% per year. Again, significant differences can be observed between plays. For example, a well drilled in the oil window of Eagle Ford may have a high IP of 8,000 boepd (the rate observed during the first 24 hours of production), but this may rapidly decline to 100 to 200 boepd. The sweet spots drilled in the Bakken have an IP of 2,000 boepd, but in this case they are still producing 1,900 boepd six months later and 1,500 boepd one year later.[18]

**Figure 16: A Typical Production Curve for Shale Oil Wells**




[17] Livingston D., *Tight oil in the United States: recent development and future financial sustainability*, Carnegie Endowment for International Peace, 2014/3 ISG&OJ, 1 November 2014, <http://carnegieendowment.org/2014/11/01/tight-oil-in-united-states-recent-developments-and-future-financial-sustainability>

[18] Ryan Carlyle, "What is the average life of a shale oil well in the Bakken formation?", <www.quora.com/What-is-the-average-life-of-a-shale-oil-well-in-the-Bakken-formation>, 27 July 2013.

**Table 1: Annual Decline in Production in the Eagle Ford Region**

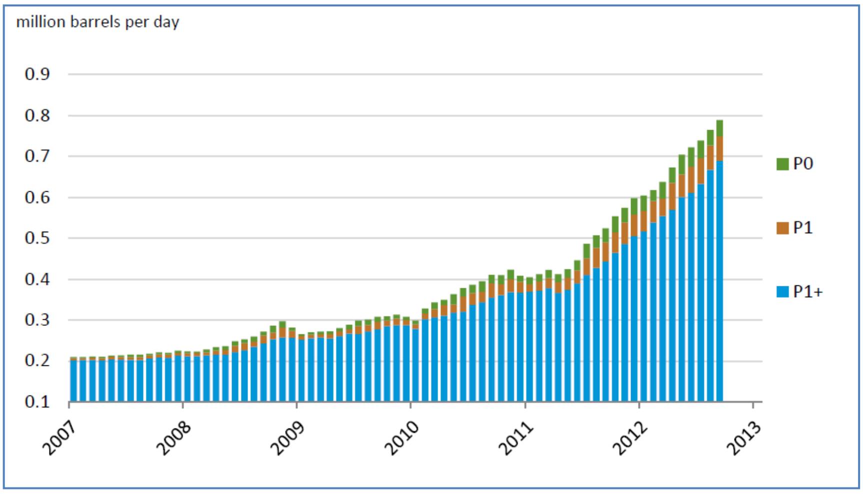
Year-over-year decline in production in wells drilled in the Eagle Ford region from 2009-13

| | year 1 | year 2 | year 3 | year 4 |
|---|---|---|---|---|
| 2009 | -70% | -30% | -20% | -20% |
| 2010 | -68% | -39% | -28% | -42% |
| 2011 | -65% | -47% | -27% | |
| 2012 | -64% | -48% | | |
| 2013 | -69% | | | |

Source: EIA, Today in Energy, New Eagle Ford wells continue to show higher production, 29 September 2014, <www.eia.gov/todayinenergy/detail.cfm?id=18171>

As Figure 16 above shows, output falls to very low levels after 3 to 5 years if the source rock is not stimulated anew. Even though production is low after the first years, the very high number of drilled wells means that cumulative output of existing wells (legacy production) is significant. Figure 17 below shows the output of new and legacy wells in the Bakken.

**Figure 17: Production of New and Legacy Wells in the Bakken Basin**




P0 refers to wells brought into production during the last month. They are not taken into account in the month's production.
P1 refers to production for a complete calendar month for new wells (initial production).
P1+: all other wells in production.

Source: EIA, DPR Methodology

**Low output per well and recovery rates**: even though technological progress has allowed production per well to be increased significantly, output remains modest by industry standards. Shale basins are also characterized by **very low recovery rates using present technology**. In the main oil plays, this rate is about 5% (the recovery rate is higher for shale gas at about 10% to 20%). This is a significant difference compared to conventional oil deposits (where recovery runs at between 35% and 50%). The EURs are estimated at around 0.1 to 0.5 Mbd over a period of 30 years. In the Eagle Ford oil window, the EURs may vary on average between 0.3 and 0.4 Mbd, with a distribution of 0.1 to 0.6 Mbd. The application of advanced recovery technology is still in its experimental stages for shale oil.

**Continuous drilling:** these characteristics (low production per well and a very rapid rate of decline in output) mean that **drilling programs have to be continuous and intensive**, covering vast surface areas in order to maintain/increase output. They strongly encourage operators to seek means for raising output per well and for cutting costs. The number of working rigs is therefore a good indicator of future output, apart from productivity improvements and strategies of companies (a concentration of rigs in sweet spots and the breaking off of drilling in exploratory areas, for example).

**Modularity/standardization of operations**: the standardization of operations is pursued in order to achieve economies of scale. This is a trend which makes it possible to speak of the industrial exploitation of shale oil and "manufactured" oil, as found in industry.[19] The production of shale oil is also characterized by its modularity. In comparison with the development of major conventional oil projects, the development of shale oil projects is relatively flexible. Each well constitutes an independent project and operators decide whether to drill or not, according to economic conditions. There are some factors leading to inertia, however, such as long-term contracts with service providers, especially for drilling rigs as well as the obligation to drill wells in order to retain mining licenses. In the relatively short to medium term, the E&P of shale oil should theoretically adjust more easily to changes in demand than conventional oil exploitation for which investments often have to be maintained even in the face of price falls. Announcements of cuts in CAPEX by US operators show that this adaptation is underway, even if it is important to qualify its impact on output (see Chapter 5).

**The speed of the project cycle**: once the permit to drill has been obtained, it only takes a few months for a trained operator to set up the first foundations for drilling (spud), to start drilling and to complete the well so that it can produce. Project implementation deadlines are very short (18 to 24 months), compared to conventional oil production, for which exploration takes several years and output

[19] Despite such standardization of operations, each play and even each well is unique and requires hydraulic fracturing to be specifically adapted to rock conditions in each location.

may stretch out over 30 years, rising to a plateau before falling naturally at a rate of about 5% per year. Given the very rapid decline in output during the first year, the exploitation of shale oil is very sensitive to **the price of oil, during the year of drilling and its completion**. This contrasts with conventional oil projects for which the economics of a project depends on the price of oil throughout the life of the reservoir.

**Mixed production**: an important characteristic of project economics (and the calculation of the breakeven price) is the fact that **most wells produce a mixture of hydrocarbon: oil, NGLs and natural gas**, rather than only one of these three products. This explains why operators calculate output and reserves in barrels of oil equivalent (boe) so that they can sum the different energy and heat values of the products. For example, a well drilled in the oil window of Eagle Ford will produce 75% oil, 10% NGLs and 15% dry gas, whereas a well drilled in the wet gas window will produce 35% oil, 20% NGLs and 45% of dry gas. As the prices of these three products vary significantly (see Figure 1), the economics of wells will differ according to the distribution of output across oil, gas and NGLs.

**Low project cost**: lastly, a major difference between shale oil and conventional oil lies in the low costs of projects (of individual wells) compared to the hundreds of millions or even tens of billions of dollars required in conventional oil projects. The drilling and completion costs (D&C costs) vary according to the play (in particular, depending on the depth of the source rock), the extent of horizontal drains (1km to 3 km), and the degree of sophistication of the completion (the number of fracturing stages). These costs run from $7 million-$13 million, and have tended to fall since they peaked in 2012 to 2013. In mid-2014, the cost of wells was estimated at $10 million in the Bakken, $9 million in Permian and between $9 million to $9.5 million in the Eagle Ford.[20] This low cost is crucial to the development of productivity gains as it allows new drilling and completion technologies to be experimented.

## The Crucial Role of Independent Producers

The revolution in shale gas (and oil) has been made possible by low entry costs into the sector and the inventiveness of independent producers. They have played and continue to play a major role in the sector. It was the independent producers who triggered the shale revolution by perfecting technologies that allow hydrocarbons to be extracted from source rocks. American independent producers have the qualities needed to develop non-conventional formations: flexibility, rapid decision-making, and the search for growth. The later

[20] <http://powersource.post-gazette.com/powersource/companies-powersource/2014/10/21/Hedging-the-bets-on-oil-prices/stories/201410210013>.

entry of the oil majors into the industry brought unparalleled technology and important financial resources into play. However, the operating model of the majors is not really adapted to the exploitation of shale oil, as shown by BP's decision to sell-off its non-conventional operations in the United States.

**There are hundreds of independent producers**, of varying size, that are exploiting hydrocarbons in the US. Mirroring the geological formations, **their situation is very heterogeneous**, ranging from small operators (drilling 1 to 3 wells per quarter), to independents with significant capital (for example, Occidental Petroleum, EOG, Pioneer Natural Resources) which are drilling hundreds of wells per year. Apart from their size, which allows them to achieve economies of scale or not, these operators face very different financial situations, especially in terms of their levels and types of debt (see Chapter 4).

Even though the production of shale oil accounts for 55% of US oil output, **many US operators are price-takers**. Individually, they only generate a very small share of output. They have no control over prices, and they only thing which counts for them is the cost of production and delivery to markets. Moreover, they have obligations to their lenders to raise production continuously. This factor led to overcapacity in the gas market and a fall in prices in 2012. At the annual general meeting of ExxonMobil in May 2013, the company's CEO noted about the acquisition of XTO in 2010 that ExxonMobil had underestimated the capacity of American operators to continue raising production in a context of low prices.[21]

## *The Business Model and the Economics of Shale Oil*

The characteristics of shale oil explain the business model of the operators: *prove it, optimize it by trial and error, standardize it, rethink it.*[22] First, the existence of sweet spots is proved, by investing in well-selected large surface areas likely to contain them. These spots are then identified using pilot wells and geo-science. Next, output is optimized by drilling and fracking, and testing different completion techniques. Production is subsequently standardized, with the implementation of intensive drilling programs aimed at reducing costs and achieving economies of scale. The play is then reassessed:

[21] ExxonMobil underestimated the US natural gas industry's capacity to keep growing output through the low price period. "We missed, slightly, the industry's pent-up capacity." "Maybe we were off a year or two," Breaking Energy, Timing was Off for XTO Deal, says Exxon CEO, 30 May 2013, <http://breakingenergy.com/2013/05/30/timing-was-off-for-xto-deal-says-exxon-ceo/>.
[22] National Petroleum Council (NPC), Working Document of the NPC North American Resource Development Study, U.S. oil & gas industry business models, Macroeconomic Subgroup, NPC, 15 September 2011.

either drilling moves on to the next sweet spot (given the very rapid fall-off in output) or, mature assets are sold, or alternatively, the source rock is re-stimulated. Some companies are specialized in the initial production of shale hydrocarbons and sell their assets as soon as output falls below a certain level.

The economics of shale projects also differs substantially from that of conventional oil production. It is characterized by:

- **The importance of CAPEX** (the initial investment for drilling and completion and the purchase of land), **compared to OPEX**, in contrast to conventional oil production. The OPEX of shale oil are low (apart from the re-stimulation of source rock), accounting for 20% of the costs of a project, or less. According to a presentation by EOG, the OPEX (lease operating expenses) are between $4 and $8/boe for the production of liquids.[23] Given the importance of CAPEX compared to OPEX, existing production will not be stopped whatever the market price of oil. As OPEX are low, existing wells remain in operation as long as workover costs are less than earnings.[24]

- **The CAPEX are concentrated in the first year of production**: the price of oil during the first year of output is therefore crucial to the economics of a project. It is an important element in the present context. The WTI prices being in contango (i.e. the future price being higher than the spot price), operators who can delay drilling (or the completion) of wells have an economic interest to do so (except for obligations to drill to preserve licensing rights or long term contracts with service companies). This phenomenon has been observed for certain gas wells waiting for evacuation infrastructure or a rally in gas prices.

- **The obligation to invest continuously to maintain or raise output**: though low for drilling per well, the capital needs of E&P of shale oil are very high. Investments in E&P have also risen strongly since the start of the shale revolution (see Chapter 5). Price falls mean that the ability to reinvest is brought into question.

- **Important economies of scale** are made possible by the standardization of intensive drilling programs. This favors large independent producers compared to smaller ones.

---

[23] EOG Resources, presentation to investors, 18 November 2014, <www.eogresources.com/investors/slides/InvPres_1114_2.pdf>

[24] A well reaches the end of its working life according to two criteria: 1) the daily cost of collecting oil from the well (the electricity for the pumps, the maintenance of equipment, the management of flowback water, etc.) exceeds the value of output; and 2) the cost of rising well production (through re-stimulation, for example) exceeds the value of the forecast rise in production.

- **Cost heterogeneity** arises from the geological diversity of the plays, and even within plays, and the differing prices of land acquired.

Given these economic characteristics, **the economics of each well is very sensitive to the costs of drilling and completion, to the price of oil**, to initial production and to the decline in output. It follows that **each well is unique**, with its own production characteristics, initial rate of production, decline curve and recovery rate. Each well therefore faces different business conditions which makes it extremely difficult to generalize economic calculations. This explains the heterogeneity of the breakeven price put forward by different operators.

## *The Breakeven Price*

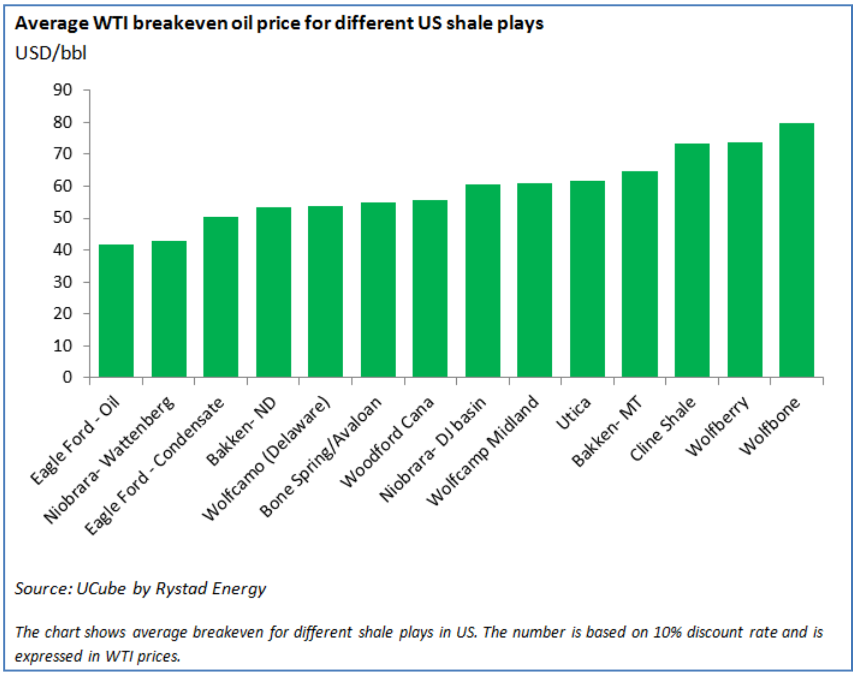
Since the oil price has begun to fall in July 2014 and especially since the end of October when it dropped below the psychological level of $80 per barrel, analysts across the globe have been estimating the breakeven price of American shale oil production, in order to predict how output is going to react to lower oil prices. **While it is useful to know the breakeven prices of the main plays**, it is nevertheless important to qualify their importance. As the previous section has shown, **the cost of production is a determining factor, but it is virtually specific to every well and operator.** The notion that there is a nearly-homogenous profitability threshold for shale production is false. Indeed, the figures of a $60 to $80 barrel price, which are often put forward, need to be qualified according to the location of production and the operator in question.

The breakeven price corresponds to the price needed for drilling projects to be profitable. In theory, if the price of oil falls below the profitability threshold of a project, then drilling should be cancelled or postponed. In practice, it is hard to predict the exact impact of the fall in oil prices. There are other important criteria which determine the capacity for reinvesting in new wells, including: available cash flows, debt levels, and hedging policies. These are specific to each operator and will determine their capacity to reinvest. In addition, technological progress is significant in the sector and it is diffusing rapidly.

Furthermore, estimating the breakeven price may be especially difficult and disputed among experts. Estimates by the IEA and Berstein Research offer extreme variations. When the price of oil fell to $80 per barrel, the IEA estimated that only 4% of US shale oil projects were no longer profitable compared to one third of projects, according to Bernstein Research.[25] OPEC experts also consider that the US boom would run out of steam at this price.

Figures 18 and 19 below provide illustrations of various breakeven price estimations by Rystad Energy and Wood Mackenzie (repeated by Business Insider). These are two consulting companies working on a database with thousands of wells.

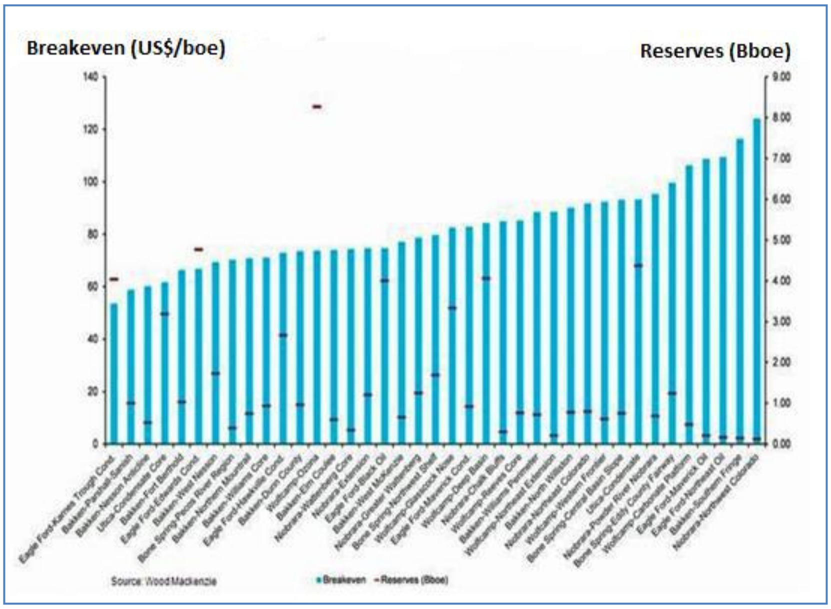
**Figure 18: The Breakeven Prices of Shale Oil by Major Play (estimations by Rystad)**




Source: Rystad Energy, Shale remains economical with lower prices, 7 November 2014, <www.rystadenergy.com/AboutUs/NewsCenter/PressReleases/shale-remains-economical-with-lower-prices>

[25] See for example: Reuters, "FACTBOX-Breakeven oil prices for U.S. shale: analyst estimates", 23 October 2014, <www.reuters.com/article/2014/10/23/idUSL3N0SH5N220141023>.

**Figure 19: The Breakeven Price of Shale Oil by Major Play (estimations by Wood Mackenzie/Business Insider)**




Source: Business Insider Australia, 23 October 2014, <www.businessinsider.com.au/shale-basin-*breakeven*-prices-2014-10>

Rystad Energy indicates that most of the main plays will remain profitable as long as the WTI price is higher than $65 per barrel, while sweet spots in the Eagle Ford, Niobrara and the Bakken plays remain profitable at less than $50. This estimate is shared by IHS, which estimates that half of all developments in North America will still be profitable with a WTI price of $57 per barrel.

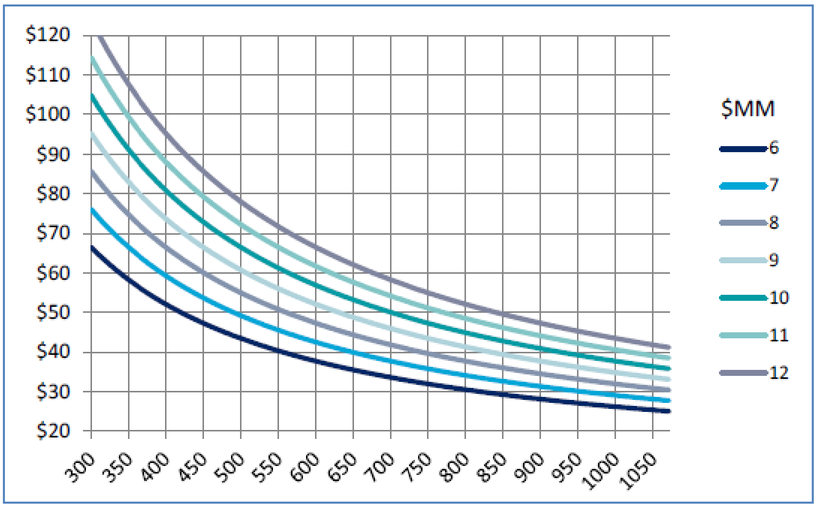
Business Insider takes the data provided by Morgan Stanley and Wood Mackenzie which indicate a weighted breakeven price of $76-77 per barrel. The estimations by Wood Mackenzie indicate significant regional differences between plays, and within each play: for example, ranging from $50 to $100 per barrel in Eagle Ford.

The differences between analysts can be explained by the assumptions used in the models for calculating breakeven prices, concerning **the rate of initial production, costs per well, EUR, the share of oil, gas and NGLs per well, as well as assumptions about the price of gas and NGLs**. It should be stressed that the breakeven price in a play, and within a play (between the sweet spot and the periphery) varies considerably, making it difficult if not impossible to generalize particular results for a whole region. These do actually depend on each well and operator. For example, there are more than 100 operators in Bakken. Each has its own costs, because they use different methods for drilling and completing the well, while exploiting different zones/sections of the rock.

It should also be noted that there is a fundamental difference in calculating the breakeven price depending on the costs which are taken into account: i.e. **full costs or mid-cycle costs**. The former takes all costs into account, including the acquisition of land, the costs of drilling and completion, the costs of connecting to infrastructure and OPEX. The latter, in contrast, only takes drilling and completion as well as OPEX into account. This can be justified by the fact that operators have already invested in acquiring land and infrastructure, which are therefore sunk costs. According to calculations by CITI Research, based on "mid-cycle" costs, the breakeven price for sweet spots could be as low as $40 per barrel, or even less in Bakken and Eagle Ford, and about $45 per barrel in the Permian.[26]

The analysis of profitability thresholds is very sensitive to **wells' initial production (IP) and costs**, as shown by Figure 20 below. Given a cost per well of $10 million, a well producing an IP of 400 boepd will have a breakeven price of $80, whereas a well producing 600 boepd will have a breakeven price of $60. Similarly, with an IP of 500 boepd, the oil price needs to be $80 if the cost of drilling the well is $12 million, whereas the price only has to be between $65 and $70 per barrel if the well costs $10 million.

**Figure 20: Variations in the Breakeven Price as a Function of Initial Production and the Costs of Wells**




Notes: X-axis: initial production in boepd; y-axis: price of WTI in $ per barrel. Cost of wells in $ millions.

Source: CITI Research, The abyss stares back, 16 October 2014.

Technological progress is bringing about significant increases in initial production, which rose fourfold, on average, in the Eagle Ford formation from 2010 to 2014, for example (see Chapter 3). With lower oil prices, the pressure on service companies to decrease their costs of service will continue, as several operators have already announced. They hope to obtain cost reductions in drilling and

[26] CITI Research, *The abyss stares back*, 16 October 2014.

completion services of 15% to 20%. Such increases in IP and reductions in costs both change the breakeven price.

It is therefore not easy to reach a simple conclusion concerning the profitability threshold for US shale oil, given the heterogeneity of situations. **Nevertheless, three plays/basins (Eagle Ford, Bakken and the Permian) are already well-developed, especially Eagle Ford and Bakken. They produce a majority of current US output, and their breakeven price is relatively low** (about $50 to $60 per barrel, with all the qualifications indicated above). This is especially the case when land acquisition and infrastructure costs are taken as stranded. The analysis of breakeven prices thus provides information on the future relocation of drilling activity, which has been confirmed by announcements made by operators, and the fall in drilling per play/State.

New basins which are presently being explored have higher profitability thresholds. **For the Tuscaloosa Marine Shale (TMS) play, in Mississippi and Louisiana, the breakeven prices are estimated at $92 per barrel**, given the deepness of the formation, which raises drilling costs, and the lack of infrastructures.[27] Two operators in the TMS (Comstock Resources and Halcon Resources) have already announced that they are postponing their E&P efforts, and concentrating instead on other plays with higher profitability. That said, formations that are already well-developed are not immune from budget and drilling cuts. Two companies operating in the Permian (Rosetta and Approach Resources) have indicated that they are cutting their budget in 2015.[28]

Lastly, **the price of oil varies across regions in the United States, due to infrastructure constraints**. These are mainly linked to the transport of crude by pipeline or rail to Cushing and refineries in the Gulf of Mexico or the East and West coasts. The output of Permian and Bakken has developed more rapidly than shipment infrastructures to bring oil to the refineries. The bottlenecks that have built up around Cushing have brought down the WTI price, especially that of Midland (Texas). Thus, the price obtained by operators in the Permian (WTI Midland) is about $5 to $10 lower per barrel than WTI, with this spread rising to $17.5 per barrel at the end of August 2014. Similarly, prices obtained by producers in Bakken are lower than WTI, due to transport costs of reaching refineries. In contrast, the price paid by refineries in the Gulf (Light Louisiana Sweet, LLS) is higher than WTI. In 2013, it carried a premium of $9.37 per barrel compared to WTI. In 2014, this premium fell, to settle at about $1.5 to $2 per barrel, in January 2015.

---

[27] Argus, "Drillers shun costly Tuscaloosa shale", 22 December 2014, <www.argusmedia.com/News/Article?id=967383&page=2>.
[28] Argus, "Focused shale producers trim budget", 17 December 2014, <www.argusmedia.com/News/Article?id=965266&page=3>.

# An Industry Characterized by Innovation and Productivity Gains

**Innovation and technological progress are at the heart of the shale oil and gas revolution.** The combination of horizontal drilling and hydraulic fracturing allowed such extraction to start in the mid-2000s. Since then, technological progress have been an integral part of the industry, and has enabled significant productivity gains to occur. Such technological progress and improvements in project management include:

- multi-well drilling pads, wherein several wells are drilled from a single surface location (or pad) ;
- the extended reach of horizontal drilling, running to 3 km;
- multi-stage fracturing;
- the optimization of hydraulic fracturing thanks to the improved assessment of rocks during fracturing (measurement-while-drilling, MWD) and micro-seismic imagery to monitor fractures during the fracking process;
- the simultaneous hydraulic fracturing of wells from one pad;
- drill bits designed specifically for low permeability of shale rocks;
- mobile drilling rigs;
- the optimization of mining leases;
- the reduction of spacing between wells (downspacing).

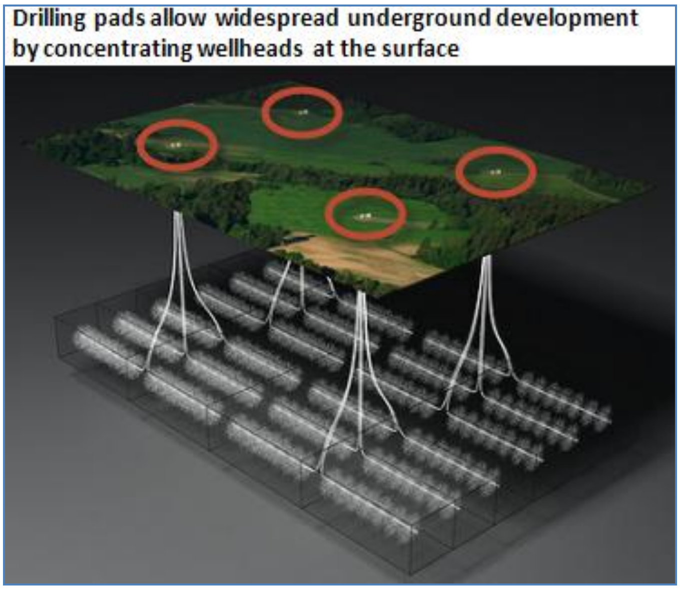
Real breakthroughs have come in the last two years with the advent of extended reach of horizontal laterals (up to 3 km) combined with hydraulic fracturing in multi stages. These new techniques have significantly increased the initial production rates of wells, increasing the production of LTO and broadening the base of economically recoverable resources, as well as accelerating their production phase. Between January 2010 and December 2014, the average production of new oil wells in the Eagle Ford basin increased by almost 700% (EIA, DPR December 2014). More recently, reduced spacing between wells has been tested with promising results. The application and dissemination of new technologies are very fast in the industry and are expected to further reduce costs.

## *Increased Drilling Efficiency through Multi-Well Drilling at Extended Reach and Multi-Stage Fracturing*

**Multi-well drilling pads** are a major breakthrough since the beginning of the decade. These pads help to lower drilling costs while reducing the land footprint of drilling. **The proliferation of lateral branches (drains)** enables operators to drain a larger surface of the rock. This increases production and recovery rates. Each branch can span long distances (4,500 feet or 1.3 km in the early 2010s, and up to 3km today, see below). Currently 16 branches of 1.5km to 2km per well are used, while ongoing developments are striving to achieve 32 branches with more than 3 km reach each.

Recently, the application of this innovation has gone even further: it is used to drain **different levels/horizons of the rock**. Thus, in some basins, such as the Permian Basin in Denver or in the Bakken, producers are drilling several formations stacked up one on another.

**Figure 21: Multi-Well Drilling**



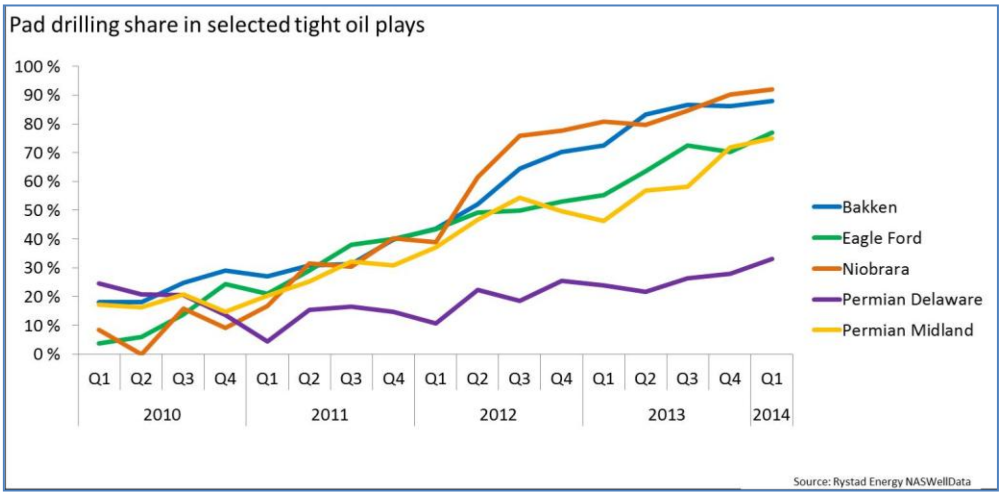

Note: Three-dimensional diagram of the production of shale hydrocarbons based on four drilling pads (the orange circles), each with six horizontal branches.

Source: EIA (based on Statoil)

As shown in Figure 22 below, drillers in the Bakken, Eagle Ford, Niobrara and Permian plays have generalized the use of pad drilling, which today accounts for 75% to 95% of all wells drilled. Progress can still be made on the Delaware formation in the Permian. **The widespread use of multi-well pad drilling has reduced drilling costs per well. But this cost reduction is limited since the**

**cost of drilling is only 30% of the total cost of a well (Rystad, 2014).**

**Figure 22: Multi-Well Drilling (Pad Drilling) per Basin**




Source: Rystad Energy, July 2014, <www.rystadenergy.com/ResearchProducts/NASAnalysis/usshalenewsletter>

**Drilling efficiency**, defined as the number of days required to drill a well, has steadily improved since 2010, thanks to the generalized use of multi-well drilling. In 2011, it took 23 days to drill a well in the Eagle Ford basin (EIA, Today in Energy, 11 September 2012); today, it only takes a week. This reduces the number of drilling rigs required to produce the same amount of oil or gas.

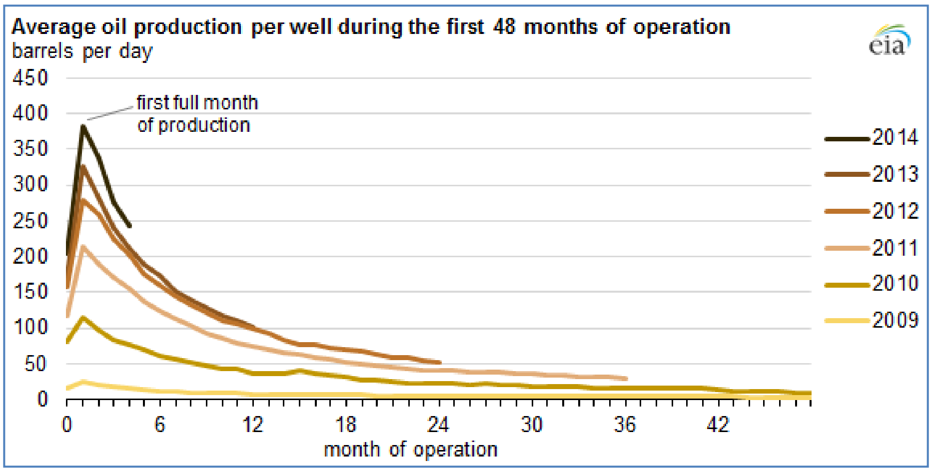
Another recent innovation used by operators is the **mobile drilling rig**, which can move between the well drilling pads without having to be disassembled and reassembled. This saves the costs of assembly and disassembly.

Producers have gradually **extended horizontal drilling** in oil formations where source rock is continuous. In the Bakken, for example, horizontal lateral branches are now typically of 10,000 feet (3 km) in length with 30 stages of fracturing.[29] The wells with long branches not only help to reduce production costs and increase production, but they also reduce the risks to the producer as a larger section of the rock is drained. According to Rystad, the reach of lateral branches increased from 25% to 55% between 2010 and 2014 in the Bakken, Niobrara and Permian Delaware. However, wells with long laterals are more expensive (about $13 million compared to $9 million for wells with branches of 5,000 feet) and are subject to diminishing returns. So an economic optimum needs to be found.

[29] 1 foot = 0.30480 meters.

As to hydraulic fracturing, the main technology advances concern **multi-stage fracturing**. This increases the number of contact points of the rock and reduces the gaps between fractures to ensure that the entire reservoir is drained. The interval between fracturing has decreased from 300 feet to 150-200 feet. The average number of fracturing stage per well in the Bakken Basin increased from 22 to 30 between 2010 and 2013. EOG Resources have experimented with 50-70 stages on several wells since 2013. The growing number of hydraulic fracturing stages and the lengthening horizontal branches has dramatically improved initial production rates since 2009. This can be clearly observed in the six years of production of the Eagle Ford basin (Figure 23). The production of a new well drilled in the play reached 550 bpd on average in December 2014, compared to 110 bpd in January 2010. Since 2013, many producers have used a lot more proppants (sand or other materials designed to keep a hydraulic fracture open) in order to increase initial production rates. But higher initial production rates are often accompanied by a faster rate of decline, which gradually stabilizes at a constant level of decrease for the remaining years of the productive life of a well.

**Figure 23: Average Production of Oil per Well during the First 48 Months of Exploitation, in the Eagle Ford Play**

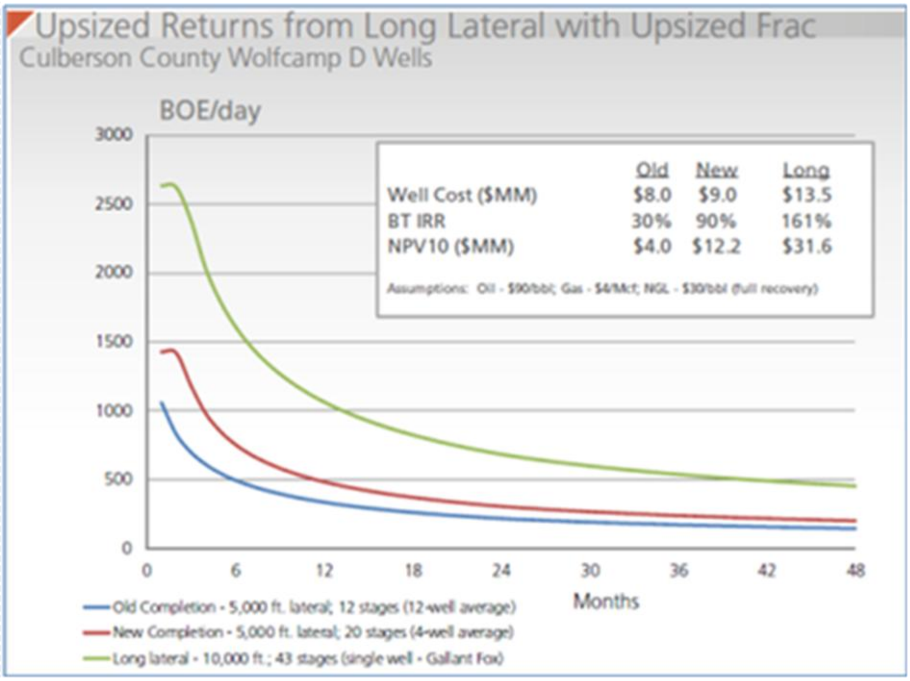



Source: EIA, Today in Energy, New Eagle Ford wells continue to show higher production, 29 September 2014, <www.eia.gov/todayinenergy/detail.cfm?id=18171>

Operators also use new engineering techniques to strategically place the different stages of fracturing along the lateral branches of a well, and seek optimization of fracturing permitted by increasingly sophisticated simulation models. Most studies indicate that the average recovery rate for shale oil wells is about 5%, so there is great potential for improvement.[30]

Figure 24 below shows an example of increased production due to longer horizontal drilling and multi-stage fracturing.

**Figure 24: Improved Returns on Investment Thanks to Longer Laterals and Mutli-Stage Fracturing**

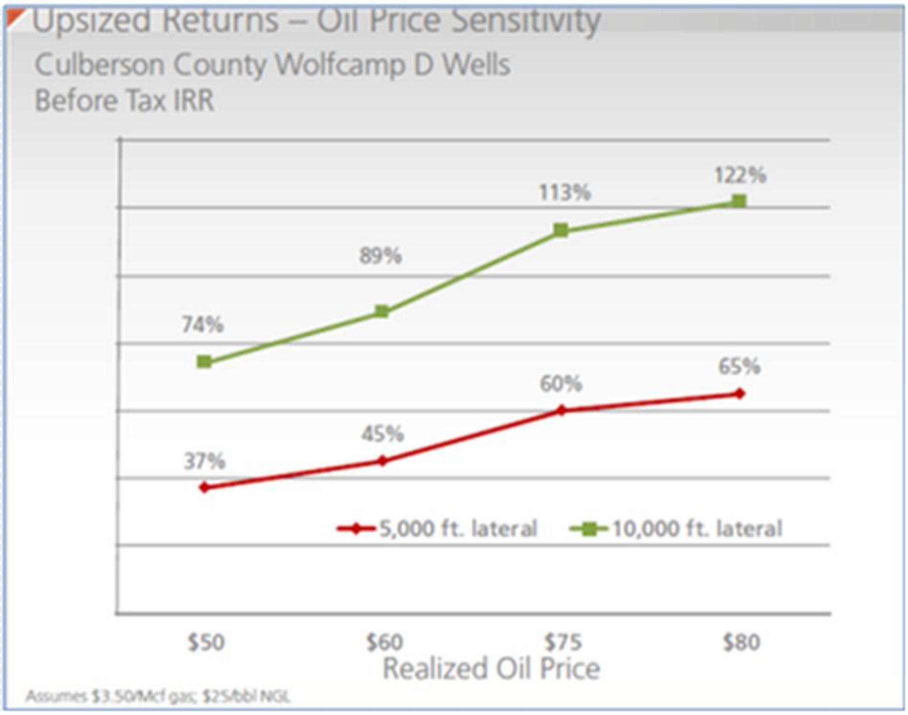



Source: Cimarex, November 2014

Using multi-stage fracking and long lateral drilling, Cimarex was able to increase initial production, measured over 90 days, to 2,450 boepd, up from 1,095-1,365 boepd for wells drilled in the same play, but using branches of shorter length (5,000 feet) and fewer stages of fracturing (12 to 20). As shown in Figure 25 below, these productivity gains are crucial in a low oil price environment. According to calculations by Cimarex, **long reach drilling remains very profitable at $50 to $60 per barrel, with an internal rate of return of 74%-89%.**

[30] Drilling Contractor, *Multistage stimulation: one size does not fit all*, 22 April 2014, <www.drillingcontractor.org/multistage-stimulation-one-size-doesnt-fit-all-28476>.

**Figure 25: The Sensitivity of Drilling to the Price of Oil**




Source: Cimarex, presentation to investors, November 2014.

## *Improved Project Management*

Improving project management by operators also allows significant productivity gains to be achieved. In some plays, such as the Bakken and Eagle Ford, the most productive areas have already been allocated. Producers are now generating new economies of scale in purchasing, selling and negotiating leases in order to increase the size of their contiguous mining leases. This allows drilling rigs and production teams to work on large continuous surface areas rather than fragmented areas, enabling significant savings (including in infrastructure).

**Companies have also reduced the spacing between wells**. For example, Pioneer Natural Resources has reduced the distance between its wells from 720 feet to 480 feet, for the wells drilled in Southern Wolfcamp and is testing distances of 300 feet in Eagle Ford (instead of 1,000, and then 500 feet previously). The results of these experiments showed that the same levels of productivity could be achieved. The tests are now focused on a spacing of 175 to 200 feet. Reducing spacing between wells allows companies to increase their inventories of wells to be drilled (Pioneer has added 300 potential wells in Eagle Ford following its downspacing strategy). This new strategy is important in the present context because it allows new wells to be drilled in plays that are already developed, without extra exploration and infrastructure costs.

All these technological advances and improvements in the management of projects/mining leases have enabled significant productivity gains to be achieved. They also make it possible to consider that production will keep increasing, despite the unfavorable market environment. Although operators forecast significant reductions in capital expenditures and rigs (and hence the number of wells drilled), most have announced expected increases in production. If the technologies as described above continue to improve well productivity, costs could be further reduced, and operators could show more resistance to low prices.

## *Future Productivity Gains*

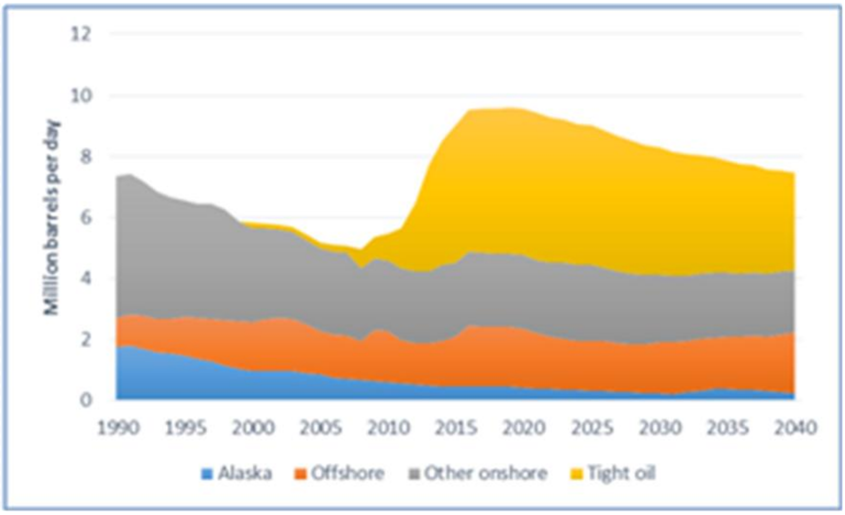
The service companies have however indicated that the most important productivity gains have already been achieved, and that future gains should be more progressive, converging to the overall rate of technological change in the oil industry. For example, Schlumberger notes that drilling in the Bakken now includes 30 stages of fracturing with lateral branches running to 3km, and that these parameters correspond to the optimum in the Bakken.[31]

Furthermore, as the most productive areas have already been drilled, operators will have to drill in less productive areas in the future (not in the short term because of the collapse of oil prices). More wells will therefore need to be drilled just to maintain output levels. The slowdown of technological improvements combined with drilling activity in less productive areas, mean that a greater number of wells will need to be drilled in order to rise, or merely maintain output.

This explains why the EIA is forecasting a leveling off of LTO production by 2021 and its decline thereafter, if there are no new technological breakthroughs.

[31] Drilling Contractor, *op. cit.*

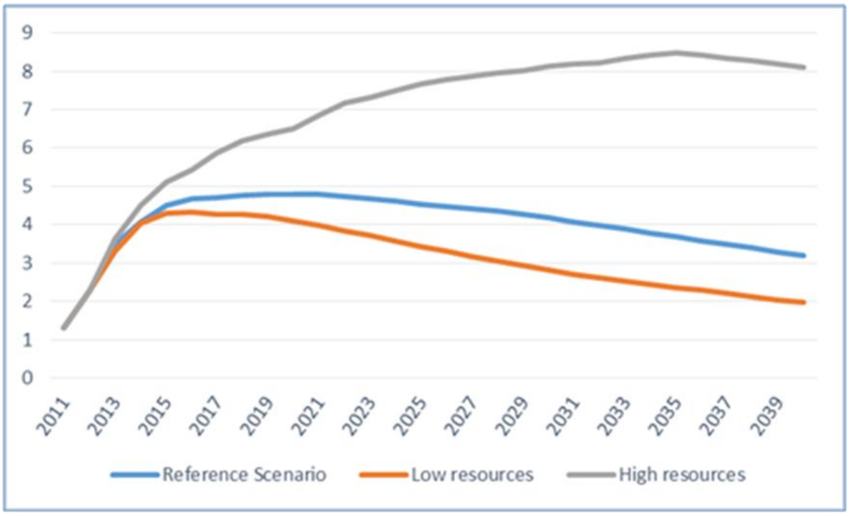
**Figure 26: Outlook for Oil Production to 2040 – EIA Reference Scenario**




Source: EIA Annual Energy Outlook, 2014
(1990-2012: historical, 2013-2040: forecasts)

However, the EIA also notes that there are uncertainties concerning trends in future production, as the exploitation of shale oil is recent and these uncertainties may vary both upwards and downwards, according to EURs.

**Figure 27: LTO Output Forecasts, According to EURs Scenarios**




Source: EIA Annual Energy Outlook, 2014
(1990-2012: historical, 2013-2040: forecasts)

Enhanced recovery technologies (such as $CO_2$ injection) are currently being tested by operators in Eagle Ford, the Bakken and the Permian. According to Wood Mackenzie, these tests do suggest that there is potential for raising the recovery rate by 100%. This would allow LTO output to rise from 1.5 Mbd to 3 Mbd, by 2030.[32]

[32] Wood Mackenzie, *US tight oil: Is technology key to a new era?*, 23 September 2014, <www.woodmac.com/public/industry-views/content/12524993>.

# Financial Challenges

The need to drill continuously requires high levels of capital investment. Breakeven prices provide information about the price levels of oil needed to pursue investment in new wells. But they are insufficient in explaining future investment levels alone. Other criteria are important too, such as available cash flow, debt levels, or the hedging strategies of expected production. These are specific to each operator, and will also determine capacity in reinvesting in new wells. Financing is therefore likely to be the key factor in development. Most American independents have used debt to finance their drilling programs. For such a strategy to be continued, they need to continue having access to capital markets on very favorable terms, as it has been the case since 2010. The issue is all the more important for some heavily indebted independents, which channel a significant share of their earnings into servicing debt. On the other hand, many operators have hedged a large share of their expected production in 2015 on the futures markets, protecting them from price falls.

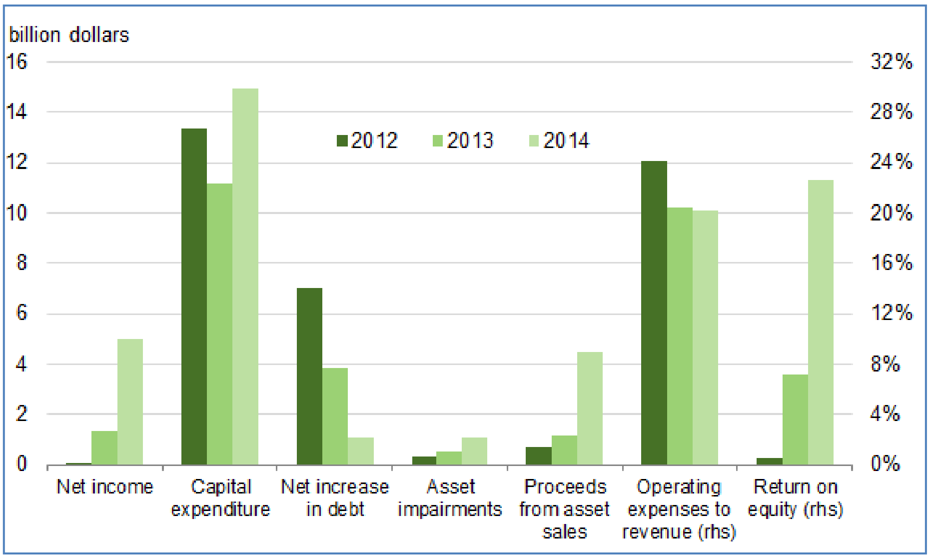
## *The Very Different Profiles of US Operators*

**The profile of companies operating in shale oil is very diversified.** On the one hand, there are the major, diversified oil companies, whose operating results benefit from their diversification downstream (refining and petrochemicals), along with integrated firms. On the other hand, the sector includes a multitude of independent producers of varying size with diversified financial structures. This explains why the financial results of US operators are so disparate. Moreover, it is practically impossible to isolate financial flows attributable to oil production from those generated by gas output, even though the economics of the two commodities is very different. Thus, aggregate statistics on cash flow and capital spending are not very pertinent in providing information about the performance of the business model associated with shale oil production, or even about the economics of a specific play. Similarly, the heterogeneity of actors (and their levels of production), even among independents, makes it very hard to generalize on their finances. To analyze the impact of falling oil prices on operators and their capacity to invest further actually requires looking at each company in detail: its income statement and balance sheet, financial structure and debt, the share of oil in its production and revenues, and its hedging policy. It is also necessary to study each company’s assets and what could be sold off to weather the storm. In this report, aggregate results are examined, with the limitations they entail.

## Improved Financial Results in Q3 2014

Figure 28 below compares the main financial results of 30 North American shale gas and oil producers, for the 3rd quarters (Q3) in 2012, 2013 and 2014.[33]

**Figure 28: Financial Results of North American Shale Gas and Oil Producers in 3rd Quarters in 2012, 2013 and 2014**




Source: EIA, based on data from Evaluate Energy, This Week in Petroleum, Third-quarter results for North America-focused crude oil producers, 26 November 2014, <www.eia.gov/petroleum/weekly/>

According to analysis by the EIA, **North American operators improved their financial results in Q3 2014**, compared to the same quarters in 2012 and 2013. This improvement is due to productivity gains, the sale of assets and the rise in the value of hedging contracts. It came despite the fall in oil prices, with WTI losing $8.56 between the 3rd quarters of 2013 and 2014. Q4 2014 results were not available at the time of writing (January 2015), though the fall in earnings during the quarter suggests that a strong fall is likely.

During Q3 2014, the net income of the 30 companies tripled, rising from $1.6 billion in Q3 2013, to $5 billion in Q3 2014. During the same period, their output of oil and liquids expanded by 23% (338,000 bd), to reach 1.8 Mbd. These companies have increased

[33] EIA data relating to 30 North American operators producing shale oil and petroleum from oil/tar sands. Source: EIA, based on data from Evaluate Energy, *This Week in Petroleum, Third-quarter results for North America-focused crude oil producers*, 26 November 2014, <www.eia.gov/petroleum/weekly/>.

their profitability thanks to better cost controls and rising output, as borne out by the fall in the ratio of spending to operating revenue. All of these factors taken together contributed to generating the highest returns on equity in three years (23%).

## *Reliance on Debt*

The sector is generating profits. But until now the 30 operators have been continuing to spend more on capital than they generate. The EIA does not specify the size of their deficit in cash terms. However, an analysis by *The Financial Times* of 25 North American independents (with a total capital spending of $120 billion) indicates an improvement in free cash flow[34] from -$32.2 billion in 2012, to -$8.8 billion in 2013. The analysis expected a surplus of $2.4 billion in 2015.[35] Yet, the fall in prices will not allow this forecast to be achieved. The deficit in free cash flow has two main explanations: i) the stage of development of shale oil (the optimization of the production and the testing of new technologies), and ii) results which are still burdened by write downs and falling gas revenues in 2012 and 2013, given that nearly all operators produce both oil and gas. In 2014, free cash flows should have shown further improvement, as the sector was entering a new phase of development, characterized by large-scale standardized production, and an increasingly marked displacement from gas operations to petroleum.

To finance their investments, independent producers are issuing shares and bonds in capital markets, as well as selling assets and creating joint-ventures. Operators have also invested all or part of their operating cash flow. The large- and medium-sized independents have completed their cash needs by issuing shares, resorting to borrowing and creating joint-ventures. The smaller independents have increasingly resorted to private investment funds, and junk bond markets. Over the last years, US operators have also turned to other forms of financing to raise capital, such as Master Limited Partnerships (MLPs).

**The use of debt has been a motor in the expansion of output of shale hydrocarbons.** Thanks to low interest rates following on from the Fed's policy of quantitative easing, operators have had the benefit of significant leverage.[36] Such leverage has permitted many small, independent producers to finance their investments.

---

[34] *Free cash flow* is the difference between operating *cash flows* and investment expenditure.
[35] Financial Times, "Shale oil and gas producers' finances lift growth hopes", 27 August 2014, <www.ft.com/intl/cms/s/0/5cefeb8a-2d34-11e4-aca0-00144feabdc0.html#axzz3NwuHoFZI>.
[36] Leverage allows assets to be bought through borrowing, based on limited equity.

However, as shale hydrocarbons are used as collateral on these loans, **falling oil prices reduce the value of assets and the capacity of operators to take on debt**, and in some cases to pay back their loans. This situation is worsened by falling earnings. Companies that are most indebted, especially those which resorted to junk bonds to get finance, are the most exposed. According to Barclays, the energy sector accounted for 17% of the junk bond market in December 2014, making it the largest sector in this market. With the fall in oil prices, bonds in the energy sector have fallen too, and yields demanded by investors in this market have risen spectacularly. Yield rates rose to 10% at the end of December 2014, their highest level in two years (up from 5.75% in June 2014). Such high rates will make operators' debt refinancing more difficult. The most heavily-indebted investors run the risk of not being able to meet their obligations and having difficulties in restructuring their debts. Such rates indeed lead to worries about bankruptcy and hence a consolidation in the sector. It should be stressed, however, that the large number of independent operators face very different debt situations, and that the strongest companies could therefore buy up assets at attractive prices. Nevertheless, in the present context, such purchases are likely to be limited to assets with high-yield drilling possibilities. Assets geared more to exploration are not sure of finding buyers, and their development will likely be postponed, as well as being conditional to a renewed rise in prices.

## The Sale of Assets

Since the fall in oil prices, all operators have been looking to reduce their debts and costs, and to finance spending through cash flow and the sale of assets. In Q3 2014, operators resorted to the sale of non-core assets to finance their E&P activities, such as the sale of midstream gas assets, in order to focus on E&P. According to the EIA, asset sales ran to $4.5 billion during the quarter (equivalent to about a third of CAPEX). This was the highest level in five years. Such sales made it possible to reduce significantly the net rise of debt, compared to the preceding quarters. This trend continued in the Q4 2014 (Table 2). During the quarter, most companies did indeed resort to asset sales for a number of reasons: to optimize their portfolios and focus on specific regions/plays; to meet loan repayment schedules or pay out dividends to shareholders/ investment funds; and finally to invest in new areas.

**Table 2: The Sale of Oil Assets in Q4 2014**

| Company | Sold assets | Value ($) |
|---|---|---|
| Apache | Oil and gas assets in southern Louisiana and the Anadarko Basin, spanning western Oklahoma and the Texas Panhandle,. | 1.4 billion |
| Chesapeake | Chesapeake Energy Corp. has agreed to sell a portfolio of 435 wells on the Marcellus and Utica shale formations to Southwestern Energy Co (413,000 net acres in West Virginia and southern Pennsylvania) | 4.975 billion |
| Althon Energy | Encana acquired Althon Eergy in September 2014 (140,000 net acre spread in the oil-rich Permian basin). | 5.93 billion |
| Statoil | Reduction of its working interest in the US southern Marcellus onshore shale gas asset to 23% from 29% after reaching a $394mn deal with US independent Southwestern Energy. | 394 million |
| Linn Energy | In December 2014, the company closed the sale of its holdings in the Granite Wash and Cleveland plays in Texas and Oklahoma to EnerVest Ltd. and FourPoint Energy LLC for $1.95 billion. | 1.95 billion |
| EOG | In December 2014, EOG Resources announced the divestiture of all its assets in Canada's Manitoba and certain assets in Alberta in two separate transactions that closed on November 28 and December 1, 2014. The sold assets had forecast production of ~7,050 barrels of oil per day, 580 barrels of NGLs per day and 43.5 MMcf of natural gas per day. In the transaction, EOG divested 1.1 million net acres (97% of which were in Alberta). | 410 million |
| Goodrich | In December 2014, Goodrich divested some of its non-core East Texas assets | 61 million |

Source: Companies' press releases

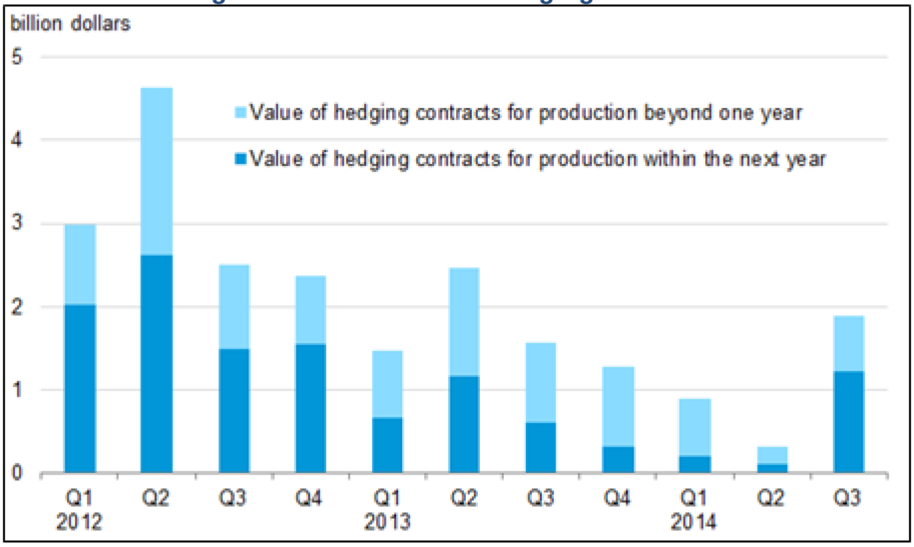
## Hedging of production

Hedging strategies must also be taken into consideration. Most US operators have adopted hedging strategies of their oil (and gas) production, in case of price falls. Thus between 50% and 75% of expected production in 2015 has been sold forward. Such hedging should in part compensate falls in revenue from their oil sales. Hedging strategies vary a lot across operators. At one extreme, Continental Resources liquidated all its positions in September 2014, as its CEO (who holds most of the company's share) considered that the fall in oil prices would be temporary.

Producers use different financial instruments to cover their production, including futures, options and swaps. Most have strategies for reducing risks in the face of price falls (futures contracts or swaps). But some have also tried to preserve partly the benefits of a rise in prices by using collar type contracts, backed by options which do not protect them entirely in case prices fall.

According to the EIA, the value of hedging contracts of the group of 30 North American operators increased in Q3 2014. This led to an annual, non-realized gain of nearly $4.1 billion on hedging contracts bought before, and the value of hedges bought during the quarter. The value of hedges had fallen at the end of 2013, due to the high prices of oil and their low volatility.

**Figure 29: The Value of Hedging Contracts**




Source: EIA, drawing on the Evaluate Energy database, (Week in Petroleum, September 2014).

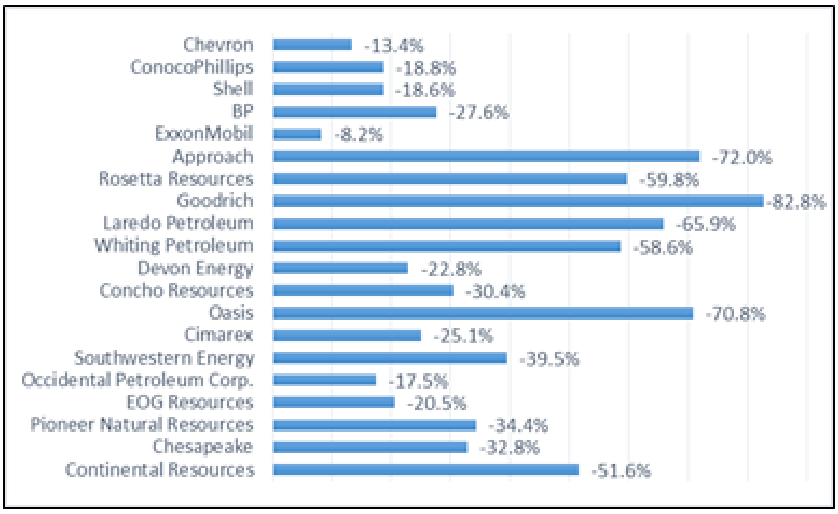
Some big independent operators (EOG Resources Inc, Anadarko Petroleum Corp, Devon Energy Corp) have hedged part of their output for 2015 at $90 per barrel. These hedges therefore provide them with comfortable earnings, despite the fall in oil prices, and this should strengthen the resistance of such operators – and hence their production – at low price levels. It should delay changes in output in the face of price falls. Operators such as Pioneer Natural Resources have sold the collar contracts used to hedge part of their production, and have bought fixed-price contracts instead.[37]

[37] *Pioneer Natural Resources Announces Updated Commodity Derivatives Schedule*, 6 January 2015, press release Pioneer, <http://investors.pxd.com/ phoenix.zhtml?c=90959&p=irol-newsArticle&ID=2004412>.

## A Difficult Operating Environment in 2015

The sector is going to face a tough operating environment in 2015, depending on the extent to which prices remain at their current levels. The stock market capitalization of independent US producers has fallen since July 2014, in line with the fall in oil prices, and those of firms operating in the sector (Figure 30). The stock market value of independent producers has fallen more than that of the majors, who have managed to benefit from good results downstream. Market valuations of the large independent operators dropped between 20% and 40%, from 1 July to end December 2014. The fall in share prices of small operators have been even greater, ranging from 60% to 70% or more, since July 2014.

**Figure 30: Falls in Stock Market Valuations of Companies Operating in American Shale Oil and Gas, during the Second Half of 2014 (beginning of July to end December)**




Source: Yahoofinance.com

Moreover, it the price fall persists, then firms will need to depreciate their assets, as occurred in 2012 when gas prices dropped 31% compared to 2011. Rules by the Securities and Exchange Commission (SEC) oblige companies to carry out ceiling test write downs, taking the operating environment into account. SEC rules are used to determine proven reserves. They are also used in accounting to determine the book value of oil and gas assets according to the full costs method, which employs the average price of crude oil on the first day of every month, over a period of twelve months (the rule was changed in 2010, as previously the reference was the price as of the 31 December each year). Depreciation tests are carried out each quarter. As the price fall at end of September 2014 was still limited, it did not lead to important changes in asset valuations. Nevertheless, the EIA estimates asset depreciation at $1.1 billion in Q3 2014. The price fall during Q4 2014 was spectacular ($37 per barrel), and if maintained will lead to much more important asset write downs at the end of 2014 and in 2015 (given calculation over twelve months). It will also lead to the reclassification of proven undeveloped reserves (PUD) into probable reserves, reducing the book value of oil assets held by operators.

Gas asset write downs in 2012 were massive when prices fell, with companies depreciating assets by $29 billion. Several such write downs concerned foreign operators and the majors that had bought land/companies at the top of the shale gas revolution. Thus, in 2012, BHP Petroleum cut the value of its gas assets in Lafayetteville by $2.84 billion, which it had bought from Chesapeake for $4.75 billion 18 months earlier.

More recently, write downs in oil assets can be observed, as shown in Table 3 below. In August 2013, Shell wrote down its American shale oil assets by $2.1 billion, having invested $24 billion in unconventional North American hydrocarbons.[38] Shell also sold its assets in the Eagle Ford play. In September 2014, Sumitomo announced a depreciation of its assets in the Permian by ¥170 billion ($1.54 billion).[39] The company had invested ¥110 billion in the basin in 2012, subsequently stated that drilling results had shown that oil was more difficult and costly to produce than expected.

[38] Financial Times, “Peter Voser says he regrets Shell’s huge bet on US shale”, 6 October 2013, <www.ft.com/intl/cms/s/0/e964a8a6-2c38-11e3-8b20-00144feab7de.html#axzz3NlMzJtea>.

[39] Nikkei Asia, Sumitomo *tarred with big loss on failed US shale oil project*, <http://asia.nikkei.com/Markets/Tokyo-Market/Sumitomo-tarred-with-big-loss-on-failed-US-shale-oil-project>, 30 September 2014.

**Table 3: Recent Depreciations of Assets in US Shale Oil**

| Company | Value ($) | Date | Shale play |
|---|---|---|---|
| Sumitomo | 1.7 billion | Sep-2014 | Permian |
| Forest Oil | 127 million | Sep-2014 | Downward revision of proved undeveloped reserve estimates in the Eagle Ford |
| BP | 521 million | Apr-2014 | Utica |
| Itochu Corp. | 279 million | Mar-2014 | US Shale (oil and gas producer Samson Investment Co.) |
| Shell | 2.1 billion | Aug-2013 | US tight oil |
| Marathon | 340 million | May-2013 | Eagle Ford |

Source: Company press releases.

These depreciations are changing asset values on companies' balance sheets, and will reduce firms' capacities to borrow, capacities already reduced by the decrease in earnings. The drop in oil prices will also erode improvements in available cash flows. CAPEX necessary to support output growth could then exceed available cash flows substantially. If there are no new capital injections, the industry may not be able to expand organically and assure production growth. While it is impossible to apply this observation to the whole of the sector, given the highly varied self-financing capacities of the sector, some independent producers will not be able to continue to finance their drilling programs, even where drilling is profitable. A profound restructuring and consolidation of the sector is therefore to be expected.

Yet the reactivity of independent operators should not be underestimated. Some small producers, which have been singled out by the rating agencies, have renegotiated their debts, sold assets or merged with more solid partners. For example, Forest Oil, whose operations were too small to benefit from economies of scale, has recently merged with Sabine Oil & Gas. Magnum Hunter Resources has sold its assets in the Bakken and concentrated its E&P activities on gas in the Appalachian basin (Utica). Until now, only one company – American Eagle Energy (2,700 bd), has announced that it is stopping drilling, until oil prices have risen again.[40]

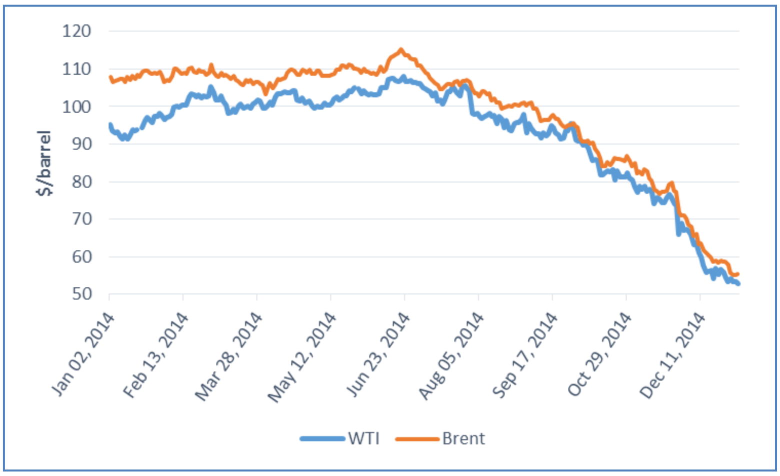
[40] Midland Reporter-Telegram, "Small oil company to quit drilling amid falling crude", 5 January 2015, <www.mrt.com/business/oil/article_fa45ab80-9513-11e4-8fec-4bc509ccafb4.html#ixzz3OEqp1CeX>.

# The Short Term Consequences of the Fall in Oil Prices

## *The Spectacular Fall in the Price of Oil*

Since July 2014 and especially since November and December, oil prices have halved. The rise in US output and the resumption of Libyan exports in the summer of 2014, coupled with weak global demand, mean that excess production is weighing strongly on prices. OPEC's decision on 27 November 2014 to maintain its output levels at 30 Mbd accelerated the price fall. Between then and 31 December 2014, the price of a barrel of Brent fell by $20, to $55.27. WTI stood at $53.45 on 31 December 2014. On average, WTI had a price of $93.20 in 2014, a reduction of $5 compared to 2013. The Brent price fell by $10 to $99. The differential in the price of Brent and WTI also diminished ($6 on average in 2014), compared to $15 in the years 2011 to 2013.

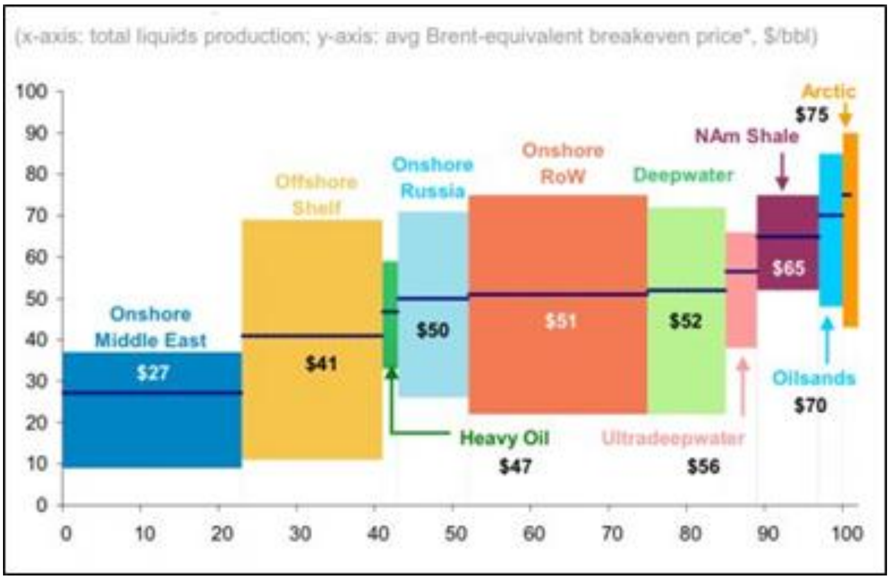
**Figure 31: Brent and WTI Prices (January 2008 to December 2014)**




Source: EIA

At these levels, it may legitimately be asked whether US producers have the capacity of carry on investing in order to ensure further output growth. The question may also be raised for a number of conventional oil producers, as shown in Figure 32 below. It gives the breakeven price of production by regions in the world.

**Figure 32: Breakeven Prices of Global Oil Production**




Source: Business Insider (from Rystad data), Saudi Arabia Won't Win This Oil-Price Standoff, 6 November 2014, <www.businessinsider.com/citi-saudi-arabia-wont-win-this-oil-standoff-2014-11#ixzz3L2y3e9Gz>

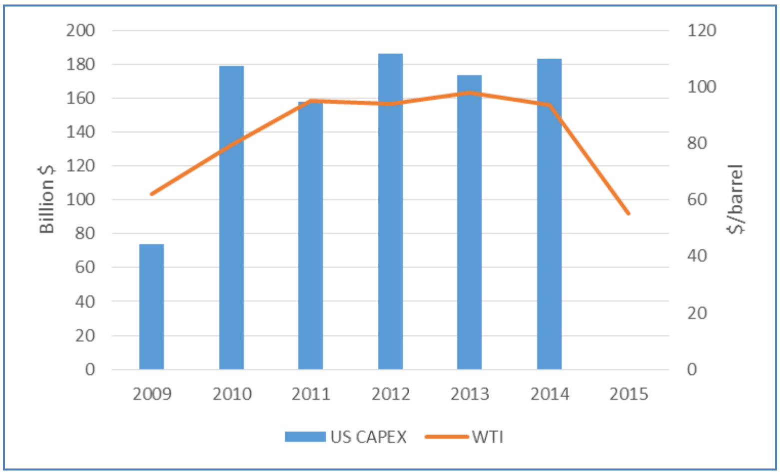
The price issue is most acute for US shale oil producers, whose business model is very different from conventional oil extraction. **On the one hand, American producers need to keep drilling continuously in order to ensure growth in production. On the other hand, new drilling is very sensitive to the price of oil in the first year of the project.** This is not the case for mega conventional oil projects, which have long lead time, even if future developments may be postponed. Lastly, the number of wells drilling for shale oil can be easily and rapidly changed. The fall in prices is therefore likely to test the sustainability of shale oil production and its capacity of resisting oil-price cycles, which characterize the oil market.

## *Reductions in CAPEX*

The collapse of prices has made itself felt in investment spending by US operators, both by the majors and small independent firms. Having resisted after July 2014, drilling activity began to fall in December.

The spectacular rise in LTO output was allowed by high levels of E&P, helped by the level of oil prices in the years 2010 to June 2014, as well as by the Fed's monetary policy which allowed independent producers to borrow at very low rates. From 2010 to 2014, E&P investment in the United States ran to $880 billion. Investment grew strongly in 2011, and pursued its rise thereafter (except in 2013), though at slower rates which did not prevent output from soaring. In 2014, E&P investments in shale gas and oil were estimated at $129 billion, accounting for about 70% of US upstream investment in the oil and gas industry. Such investments are strongly dependent on the price of crude oil.

**Figure 33: Upstream Investments in US Oil and Gas and the Price of WTI**




Source: CAPEX (2009-2013): EY US oil and gas reserves study, 2014, CAPEX for 2014 is estimated. Price of oil in 2015: EIA STEO, 13 January 2015.

Since the fall in WTI prices, several operators in the United States (as elsewhere in the world) have announced reductions in their CAPEX for 2015. These reductions are affecting all producers, whatever their size. But it is more marked for small and medium independent operators, some of which are heavily indebted, and do not have financial revenues from diversified activities compared to the major, integrated companies.

The majors have announced further cutbacks in their capital spending in 2015, a trend which already began in 2014. Companies are focusing on financial discipline, cost control, project yield and the distribution of dividends. For example, ExxonMobil has announced cuts in its global budget of more than 10% through to 2017, with priority being given to downstream activities. The company will nevertheless pursue its acquisitions in shale oil and gas in North America, when opportunities arise. ExxonMobil is active in shale hydrocarbons through its XTO subsidiary, acquired in 2010 for $41 billion. BP is also going to cut investment to between $24 billion and $26 billion. The firm has spinned off its E&P activities in shale hydrocarbons in the US into a new entity, which should invest $1 billion to $1.4 billion in 2015. BP is going to add four to six drilling rigs in the Mid-Continent region in 2015 and could add ten more to raise output. ConocoPhillips has announced a 20% reduction in its investment budget in 2015, down to $13.5 billion. The company is aiming to defer investment in certain shale oil and gas basins, including in its Canadian shale production (Montney and Duvernay), as well as in Permian and Niobrara. Chevron has also announced a

$35 billion investment program for 2015, 13% lower than the previous year. Shell and Total had already implemented cost cutting measures and asset sales at the start of 2014, before the falls in oil prices.

Yet it is the independent producers, especially the small and medium-sized ones, which are going to be affected by price falls most. In contrast to the majors, they have no downstream activities, allowing them to diversify revenue sources. Table 4 shows the evolution of E&P budgets of the US independents, which announced forecasts in November and December 2014. Some large independents, such as EOG and Anadarko have indicated that they will announce their budgets during the first quarter of 2015, in order to observe oil market price trends, which remain uncertain, for a few months. Although not exhaustive, the table provides an overall picture of trends: **falls in CAPEX by 20% to 50%, with drops in cash flows, and equivalent cuts in drilling activity**. Only some companies, exceptionally, forecast increases in spending (information as of November/December 2014). The total fall in CAPEX announced at the end of December 2014 ran to $6 billion. On average, the fall is 16% compared to 2014 (this average takes into account indications given by Devon Energy and Whiting Petroleum to maintain the same level of spending in 2015, an assumption that will surely be reviewed during Q1 2015). However, some small producers are forecasting more drastic cuts. Oasis has announced that it is halving its 2015 budget to $750 million to $850 million, compared to $1.4 billion in 2014. Linn Energy has announced a 53% cut. Goodrich Petroleum, which is operating in the most costly regions such as Louisiana and Mississippi, has reduced investment plans for 2015 by half, and is in the process of selling assets in its Eagle Ford formation, in order to raise cash flow. Continental Resources has cut its forecasts for 2015 twice, slashing them to $2.7 billion, down from the announced $5.2 billion in September 2014.

Despite the reductions in announced budgets, **most independent producers hope to raise output** by focusing on the most productive plays; postponing exploration in new areas; and by cutting costs, especially those linked to drilling and completion. Growth in output should still fall, however, compared to 2014: output increases of 10% to 20% have been announced compared to the 28% growth of total LTO production in 2014. According to various estimates, budgets would need to be cut by between 50% and 60% to stop the output of US shale oil from rising.[41]

The operators are nevertheless being careful in the face of falling oil prices. Depending on the duration of the price fall, they could re-adjust their budgets for 2015, by the end of the first quarter.

[41] Midland Reporter Telegram, “Shale producers unruffled by prices”, 8 December 2014, <www.mrt.com/business/oil/article_5f7ffe76-7f2d-11e4-b8d2-f76663133fc3.html>.

Most of the budgets for 2015 were set out in November/December 2014, and are based on an oil price of $70 to $80 per barrel in 2015.

Service companies are likely to feel the oil price cuts strongly. Not only are their activities expected to fall, but so too are service costs, which are forecast to drop by 20% for clients to be retained. Given this situation, Haliburton – the second lead service provider – acquired Baker Hughes for $34.6 billion in November 2014.

**Table 4: CAPEX Trends of the Main Independent US Producers for 2015/2014**

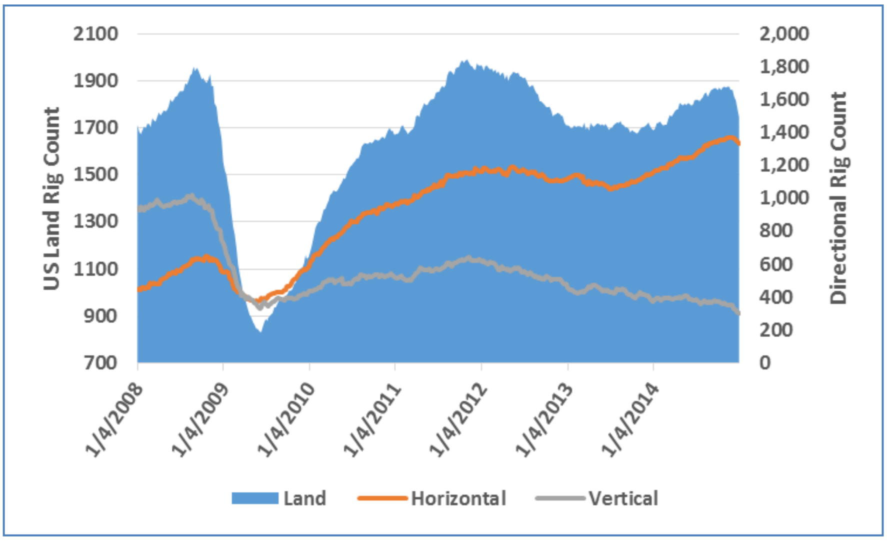
| | 2014 US CAPEX (billion $) | 2015 US CAPEX (billion $) | %change | Comments |
|---|---|---|---|---|
| **Marathon Oil** | 5.5 | 4.3-4.5 | -18% to -22% | Will tailor its budget to favor high-return investments in the U.S. and pare back exploration spending. Expects annual production growth to be in the high single digits in 2015. |
| **Continental Resources** | 4.6 | 2.7 | -41% | The leading Bakken operator. Second spending cut after a first cut to $4.6 billion announced in November. -48% compared with the plan of $5.2 billion anounced in September. The company expects to post output growth of 16%-20% with the new capex versus 23%-29% targeted earlier. Completed well costs in 2015 are expected to average at least 15% below 2014 as service costs fall. |
| **Apache** | 5.4 | 4 | -26% | North America spending. Apache expects oil and natural gas liquids output from onshore North American fields to rise 12 to 16% in 2015, after adjusting for asset sales |
| **Concho Resources** | 2.6 | 3 | +15% | Concho is targeting year-over-year production growth of 28% to 32% in 2015 (anounced at the beginning of November) |
| **Devon Energy** | 5-5.4 | 5-5.4 | - | Devon currently plans to keep spending flat y/y in 2015, although they will be shifting allocations around to maximize returns (as announced in October 2014) |
| **Whiting Petroleum** | 3.8 | 3.8 | - | Assuming $80 oil, the Bakken player believes they can keep spending flat next year ($3.8bn w/ the Kodiak acquisition) and still achieve 20% growth. |
| **Encana** | 2.6 | 2.7-2.9 | +4 to 12% | About 80% of Encana's capital budget will be invested in four of the company's highest margin assets, the Montney, Duvernay, Eagle Ford and Permian areas. These areas have relatively low supply costs averaging about $35-$55/barrel of oil equivalent (boe), according to the company. In the Permian Encana plans to invest $850mn-$950mn and run 9 to 13 rigs, drilling around 180 and 200 net wells. 2015 budget based on $70/bl WTI |
| **Linn Energy** | 1.55 | 0.73 | -53% | Linn also said it had reduced its distribution per unit and the dividend per share for subsidiary LinnCo to $1.25 each from $2.90 on an annualized basis. |
| **Laredo Petroleum** | 1.3 | 0.525 | -60% | Production for 2015 is expected to grow more than 12% |
| **Range Resources** | 1.6 | 1.3 | -18% | The company expects production growth in the 20% to 25% range despite the reduction in its capital budget. |
| **Oasis Petroleum** | 1.4 | 0.75-0.85 | -39 to -46% | Oasis expects its production to increase 5 percent-10 percent next year. |
| **Denbury** | 1.1 | 0.55 | -50% | Denbury is a unique operator, focused on secondary and tertiary oil recovery. Denbury is targeting flat production for 2015. |
| **Rosetta Resources** | 1.2 | 0.7-0.8 | -20% to -30% | Rosetta Resources, an important Eagle Ford operator. Will pare back the number of drilling rigs it will use (drilling of 70 to 100 wells in 2015 compared with 150 wells in 2014). Plans to refocus more of its budget on the Permian Basin. |
| **Goodrich** | 0.325 | 0.15-0.2 | -38 to -54% | Goodrich expects 2015 oil production to increase about 30%-42% over last year. |
| TOTAL | 36.625 | 30.73 | -16% | |

Source: Companies' press releases, websites and presentations to investors, November/December 2014

## *Falls in Drilling and Permits*

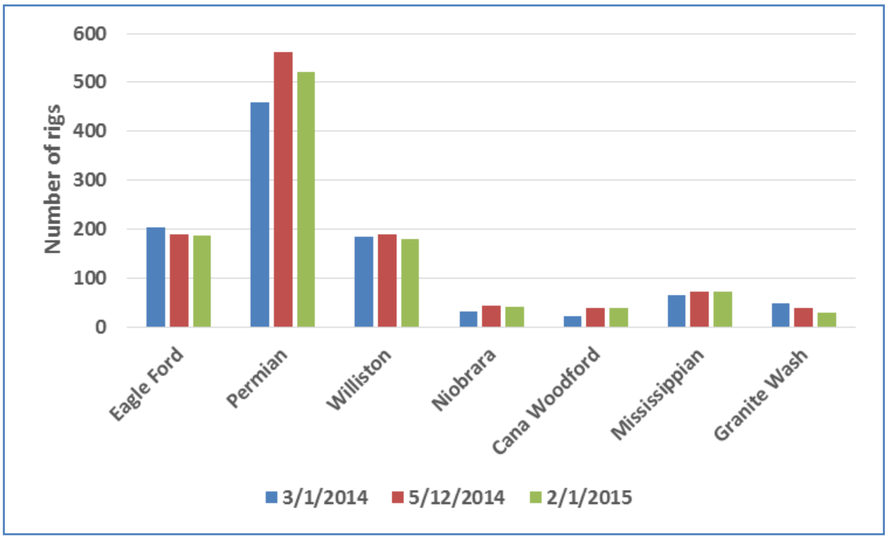
After having resisted the fall in prices which began in July 2014, drilling activity has dropped since December 2014. There were 1,811 rigs overall at the start of January 2015, down by 109 (-6%) from 5 December 2014, but higher than at the start of 2014. Rigs for oil drilling have experienced the greatest falls (-93), linked to the announcement of cuts in drilling programs. Cutbacks have been more important for vertical and directional drilling (-77), than for horizontal drilling (-32), indicating a trend towards concentrating on the most productive operations. The basins most affected by falls in oil drilling are Permian (-38) and Granite Wash, Oklahoma (-11). Eagle Ford and the Williston basin (Bakken) have so far resisted. But drilling activity has started to fall in North Dakota, where the price of oil is lower than WTI (close to $40 at the beginning of January 2015).

**Figure 34: Number of Active Rigs in the United States (January 2008-December 2014)**




Source: Baker Hughes

**Figure 35: Number of Drilling Rigs for Oil Production by Formation**




Source: Baker Hughes

The falls should extend into Q1 2015, as a number of operators have announced that they are withdrawing rigs from their drilling programs. According to analysts, the fall could reach 25%, i.e.

550 rigs compared to the situation at the beginning of December and the number of active rigs could fall to 1,400 during Q1 2015.[42] There should be a clear reduction in the Permian basin: operators are set to stop vertical drilling in favor of horizontal drilling, and this is a basin in which vertical drilling activity is still important. However, experts are not expecting the decrease in activity to be as important as it was in 2009, when the oil price slumped from $147 per barrel to $40, and the number of rigs fell by 180 per month between December 2008 and April 2009.

Similarly, the number of new permits, which provides an indicator of the utilization rate of rigs two to three months in advance, fell by 40% in November 2014 compared to October. Especially strong reductions occurred in Permian (-38%), Williston basin (-29%) and the Eagle Ford play (-28%).

The indicator on the number of active rigs is important in forecasting future production. It has however become less significant in recent years, in the wake of efficiency gains achieved. Thus, gas output has reached record levels, despite the fall in the number of rigs for gas production. This is partly due to the production of associated gas in oil basins, but also thanks to the effectiveness of drilling. Similarly, the number of new permits is a good indicator, but the operators already have an important portfolio of wells to drill.

The fall in drilling activity should not make itself felt on oil output before the second half of 2015, given the backlog of new wells being developed currently. Service companies are the first to be hit. Thus, Halliburton announced a staff cut of 1,000 in December.

## *The Resistance of US Production*

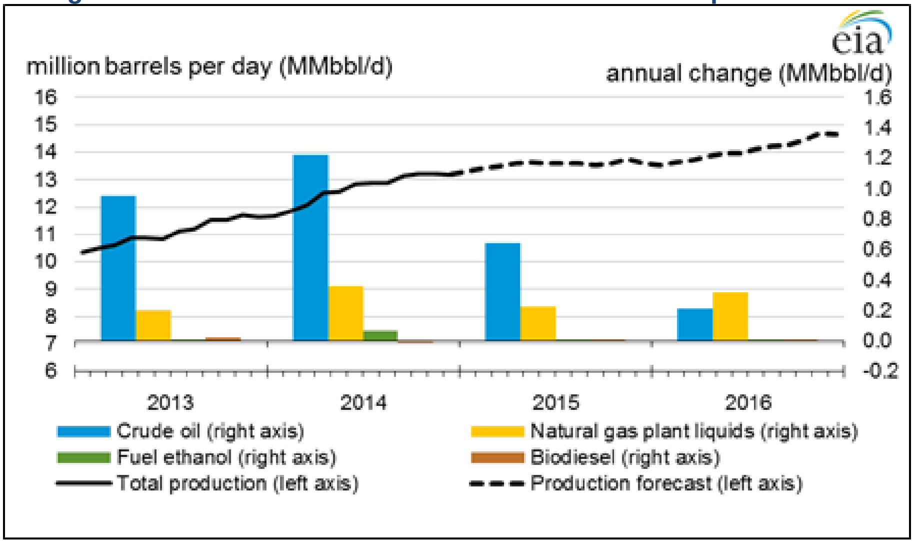
As we saw in Chapter 1, LTO output has continued to expand, reaching 5.2 Mbd in December 2014. The EIA is forecasting a fall in the price of WTI to an average $55 per barrel in 2015, followed by a rise to $71 in 2016.[43] **As a result, the EIA expects a continuation of the growth in US output from 8.67 Mbd in 2014 to 9.31 Mbd in 2015, in other words a growth of 0.64 Mbd**. This is half the expansion which occurred in 2014. US output in the 48 Lower states (excluding Alaska but also the Gulf of Mexico) is mainly made up of LTO, and output should rise by 0.58 Mbd from 6.74 Mbd in 2014, to 7.32 Mbd in 2014. This is a slowdown in the rise observed between 2013 and 2014 (1.06 Mbd). The slowdown should be felt in the second half of 2015, with a slight fall off in production. The EIA also forecasts lower drilling activity in the first half of 2015, linked to lower

[42] Argus, "Drop in US rigs may be start of longer trend", 12 December 2014, <www.argusmedia.com/News/Article?id=963135&page=5>.

[43] The fall in the price of WTI is expected to continue during Q1 2015, and a slight recovery is expected from April 2015.

oil prices ($49 per barrel on average during the first half), and the loss of drilling profitability in some basins, be they emerging or mature. The EIA is therefore forecasting that operators will redirect their investments towards sweet spots in the main oil plays. The EIA is also estimating that prices will be sufficiently high to allow drilling in the Bakken, Eagle Ford, Niobrara and Permian formations. In the second half of 2015, the EIA predicts a pick-up in drilling thanks to falling lease and services costs combined with a slight rise in the price of oil ($60.5 on average for the semester). Although output will peak at 9.53 Mbd, production will continue to slow in 2016 (a growth of 0.2 Mbd only).

**Figure 36: Forecasts for US Production of Oil and Liquids in 2015**




Source: EIA, STEO, 13 January 2015

The 2015 output forecast published in January 2015 marks down production by 0.32 Mbd compared to the October 2014 forecast, when the EIA was predicting an oil price of $94.6 for 2015, and a rise in oil production of nearly 1 Mbd.

Moreover, in its Annual Energy Outlook 2014 (AEO 2014), published in May 2014, the EIA tested production scenarios for LTO for the long term, according to various price assumptions for oil, including a reference price, as well as low and high prices (Table 5).

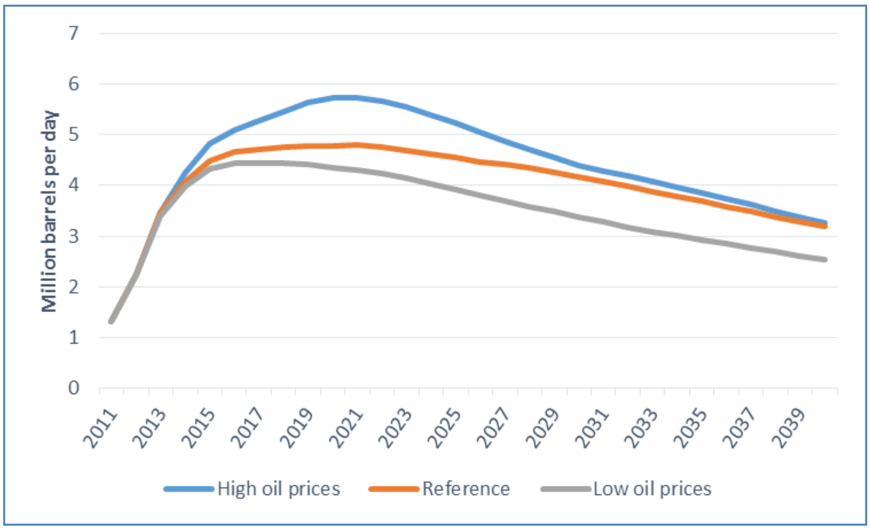
**Table 5: Price Assumptions according to Three EIA/AEO 2014 scenarios**

| ($2012/b) | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2030 | 2040 |
|---|---|---|---|---|---|---|---|---|---|---|
| **Reference** | 97.5 | 98.5 | 93.2 | 89.8 | 88.2 | 88.9 | 90.8 | 92.9 | 114.7 | 137.6 |
| **Low prices** | 97.5 | 83.1 | 70.2 | 66.8 | 65.9 | 65.6 | 65.6 | 65.6 | 69.1 | 72.2 |
| **High prices** | 97.5 | 118.0 | 127.4 | 135.1 | 140.2 | 142.6 | 144.3 | 146.1 | 167.7 | 198.8 |

Source: EIA Annual Energy Outlook, 2014 (1990-2013: historical data; 2014-2040: projections)

Figure 37 below shows the evolution of LTO output (excluding condensates), according to the three price forecast assumptions. It is quite remarkable that in the short term output is fairly insensitive to a fall in the price of oil, and continues to expand albeit at a more modest rate. Over the long term, the impact is stronger. In the low price scenario, LTO production levels off between 2016 and 2018, starting to decline in 2019. This is two years earlier than in the reference scenario.

**Figure 37: LTO Production Forecasts to 2040, according to AEO 2014 Price Scenarios**




Source: EIA Annual Energy Outlook, 2014.
(2011-2012, historical data; 2013-2040, projections)

# Conclusion

**LTO production is recent, and it raises economic, geopolitical and technological issues simultaneously.** The present period of very low prices, as we experienced since November/December 2014, is a clear test for this new and atypical oil production.

In a low-price environment, a rapid fall in drilling and hence in LTO production is to be expected, given the steep decline in output per well during the first year of exploitation, the estimated production costs which until recently were estimated between $60 and $80 per barrel, amongst the highest marginal production costs for oil throughout the world. Also to be taken into account is the flexibility of the operating mode: project cycles are very short and very sensitive to the price of oil in the year of drilling. It is therefore to be expected that operators are very reactive to price falls.

Until now (January 2015) however, little has changed: production has continued to grow spectacularly. Between July and December 2014, output rose by 0.5 Mbd, even though the price of WTI fell by $50. Drilling activity has resisted, though falls were recorded in December 2014, suggesting the industry is at a turning point. In its latest *Short Term Energy Outlook*, released 13 January 2015, the EIA forecasts a reduction in the growth of US oil output of 0.6 Mbd in 2015, compared to 1.2 Mbd in 2014 (assuming a WTI price of $55 in 2015).

It will be both the price level and its duration that will determine the scale of the reaction by US shale oil producers, and also the response of other producers of conventional and non-conventional oil. The current level of prices (WTI fell below $50 in trading on 6 January 2015) is largely below the forecasts set out for 2015 by most financial institutions and global energy analysts, who do not believe that prices will remain at this level durably. Yet it is not to be excluded that in the short term (first half 2015) WTI and Brent oil prices will continue to fall, given the sustained production overcapacity and forecasts for weak demand.

## *A Differentiated Impact across Formations and Operators*

The breakeven prices indicate the minimum prices required by operators to continue drilling according to basins/plays. Even though estimations vary among experts (and justifiably so given the heterogeneity of situations, including within the same play), breakeven prices (mid-cycle costs) of sweet spots in the most developed plays (Eagle Ford mainly, and to a certain extent in the Bakken and Permian) should allow the strongest operators to continue their drilling programs focusing on the sweet spots in these areas. If only mid-cycle costs are considered, along with the condition that prices rise during the second half of 2015, **downspacing between wells** (a new technology tested with success in 2014) and **the expected cost decline in drilling and completion** should enable their profitability. **A shift in production within basins towards sweet spots and the breaking off of exploration in new basins are therefore to be expected.** If the “80/20 rule”, which is generally, accepted in the sector, does indeed function, then the output of new wells should be enough to compensate the usual decline in output, despite falling CAPEX and drilling. This situation was already well illustrated by the resistance of shale gas output when gas prices fell in 2012, and its displacement to more productive basins (Marcellus) and to associated gas (Eagle Ford). Inertia also explains why production will likely continue rising in the short term, even though periods of decline should not be excluded in 2015. Such inertia follows from long term contracts with service companies, the obligation to drill linked to acreage leases, and the production of new wells drilled in recent months or still in progress.

The financial situation of the independent US producers also shapes their capacity to reinvest in times of low prices. Financial indicators show that their situation varies across the board, though they have one thing in common: most operators continue to spend more cash than they earn, and so resort to debt to finance their investments. Yet independent producers are far from being a homogenous group, varying in structures of debt, level of exposure to oil production, hedging policies and operating results according to the plays exploited. The second half of 2014 is characteristic of the reaction of US operators to the fall in prices and to the options they have in reducing their debts and raising their available cash flows, to finance future drilling and ensure future growth of their business, and so collectively the output of US shale oil. The sale of non-core assets was the initial reaction of operators to increase cash, raising nearly $5 billion during Q3 2014. The sale of oil assets was more marked during Q4 2014, with operators refocusing on specific plays, according to their drilling history. For the most indebted operators, and especially those who have massively resorted to junk bonds, the risks of default have grown as junk bond prices have fallen in the energy sector, while the demand of returns by investors in this market has risen. If low oil prices persist, and some operators are unable to meet their obligations, then a wave of consolidation without precedent is likely to hit the shale oil sector.

Hedging policies are crucial to analyzing the impact of the fall in prices on operators’ output, as forward sales of output will ensure operators' earnings and hence their ability to pursue their drilling programs, independently of low oil prices. Although hedging strategies are strongly differentiated, most operators have sold a large share of their expected output in 2015 to hedge funds, and this will reinforce their resistance to low prices.

Thus, despite the fall in oil prices, it is expected that US LTO output will resist. Production growth will indeed diminish, but will not cease entirely, even though times of output falls are not to be excluded in 2015 and 2016, depending on price trends.

## *Consequences beyond LTO and the United States*

At today's prices of less than $50 per barrel, the shale oil business model is being tested, not so much in terms of its capacity to continue expanding output at such price levels, but more in terms of **its ability to adapt to oil-price cycles**. The repercussions will be important both for the United States and for the rest of the world, especially for countries seeking to develop their own shale resources. It is perhaps here that the risk is greatest. It will be difficult to continue investment in exploration for shale resources outside North America, if the US industry, which has all the most favorable conditions for resource exploitation, encounters difficulties.

The reaction of US producers is also conditional on that of **other producers**, both of conventional oil and oil sands. Even though the estimated production costs of US shale oil are amongst the highest in the world, other producers could be more affected by price falls: drilling activity is in the process of falling in Canada, where the cost of producing oil sands resources in Alberta is higher than LTO costs. Producers in the North Sea are facing difficulties and have started to downsize. Companies in the Arctic have delayed investments. Lastly, though they have not yet announced any changes in output levels for 2015, it may be asked how long Russia and the OPEC countries, especially Nigeria and Venezuela, can hold out with such low prices, be it for economic or social reasons. A long spell of low prices could lead to a collective response by OPEC countries. Assuming that OPEC resists as long as is needed and at prices required for the desired quantity of LTO to be removed from the market, a future rise in prices will still lead to a new wave in investment by the strongest US operators, who managed to ride out the downturn and will therefore be better prepared to deal with oil cycles. Lastly, while prices do not reflect the geopolitical risks associated with production, tensions in the Middle East show that such risk has not disappeared, making the continued growth of US LTO production all the more important.

On this last point, it is expected that the US government will adopt all policies necessary for the continuation of the shale hydrocarbons revolution, as shown, by the decision taken on 30

December, to allow slightly processed condensates to be exported. Lastly, it must be stressed that **low oil prices affect not only the production of LTO, but also that of shale gas**. Low oil prices make US exports of LNG to the Asian market less attractive, this being their main potential outlet. In these markets, the price of LNG contracts is still largely indexed on oil and could fall to $10 per MBtu, if low oil prices persist. At this level, US LNG would be considerably less attractive. If the production of LTO in the United States has led to an upheaval in the global oil industry, then the price fall is reshuffling the cards in the short term. In the medium- to long term, the fall in upstream investment could have serious consequences for future production.

# Annex 1: Three Plays Produce the Major Share of LTO

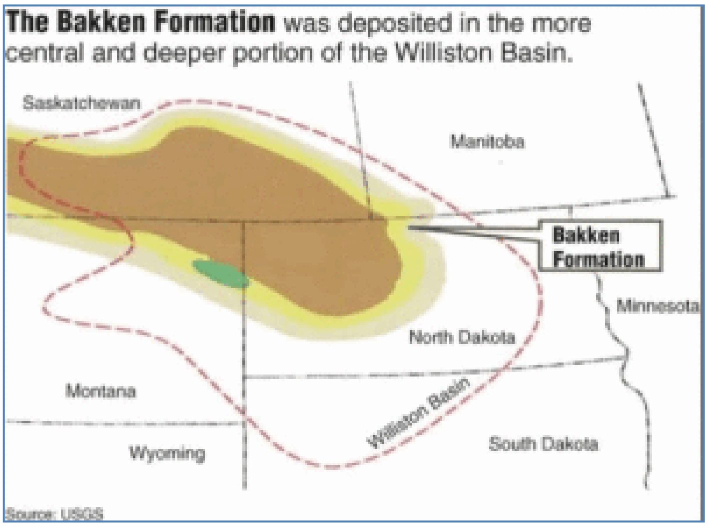
Three plays/basins in the US account for 90% of LTO output: **Bakken** (North Dakota and Montana), which was the first to be developed; then **Eagle Ford** (Texas) and the **Permian** basin (Texas/New Mexico), which includes six main plays: Spraberry, Bone Spring, Wolfcamp, Delaware, Yeso and Glorietta.

## *Bakken*

The Bakken/Three Forks basin was the first to be developed, and covers 200,000 square miles, stretching from Saskatchewan and Manitoba in Canada, to North Dakota and Montana in the United States. Oil was initially discovered in 1951, but has only recently become marketable on a large scale thanks to hydraulic fracturing and horizontal drilling.

The US Geological Survey estimates proven reserves in the Bakken to be 4.3 Gb of oil, which seems conservative (1% of the resources available).

**Map 3: The Bakken Formation**



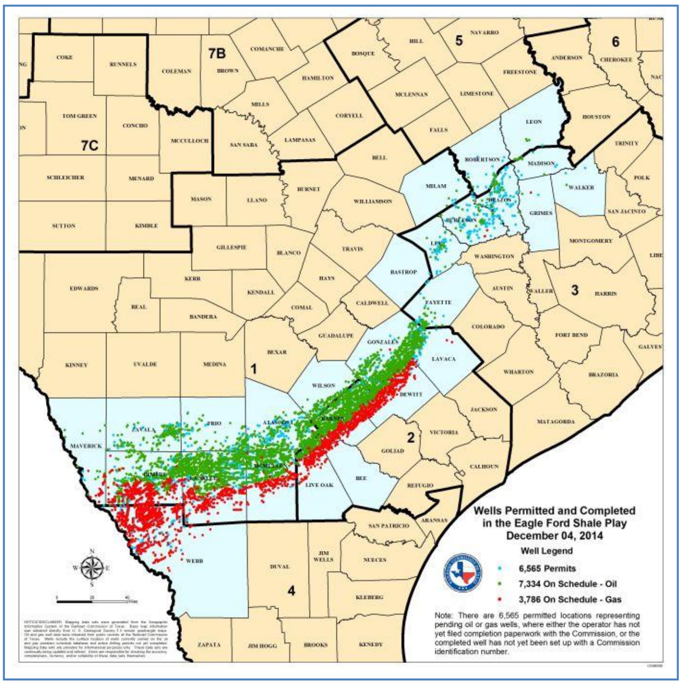

Source: http://bakkenshale.com/

Oil output in the Bakken exceeded a million barrels per day in 2013. In 2014, it reached 1.1 Mbd, accounting for 13% of the US total. Productivity gains have enabled output to rise despite a reduction in drilling. 179 rigs were in operation in January 2015.

## Eagle Ford

The Eagle Ford formation stretches for about 400 miles from the south-west to the south-east of Texas. It contains a high level of organic matters and includes oil, liquids and natural gas windows. The carbonate content of the source rock (60% to 70%) makes it brittle and easy to stimulate by fracking.

**Map 4: The Eagle Ford Formation**




Source: Railroad Commission of Texas (RRC), <www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/>

According to an infographic by Wood Mackenzie, Eagle Ford produced its billionth barrel in November 2014.[44] Moreover, more than 70% of the cumulative output since the start of hydrocarbon production by the source rock has been achieved in the last two years alone. In 2014, production in Eagle Ford ran to 1.46 Mbd, equivalent to 17% of total US output. It is growing rapidly, rising from 1.2 Mbd in January 2014, to 1.7 Mbd in December. Furthermore, more than half

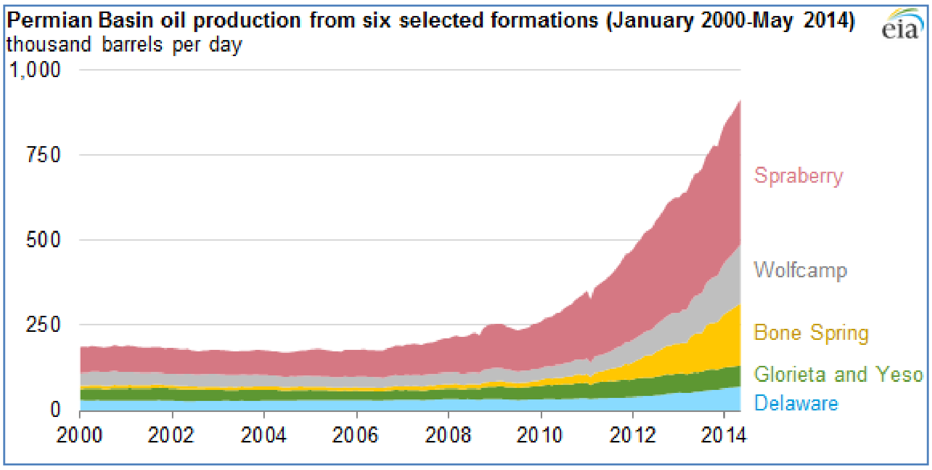
44 <http://public.woodmac.com/content/portal/energy/highlights/wk1_Dec_14/Infographic-Eagle-Ford%202014.pdf>.

of this output comes from an area which represents less than 10% of the formation, a fact that is very significant from the point of view of low prices. In particular the Karns trough condensate formation should provide 26% of all output in 2015, according to Wood Mackenzie. The latter also forecasts that E&P spending in the formation will rise to 30.8 billion in 2015. The main producers are Chesapeake, EOG, Conoco Philips, Marathon, Pioneer, Anadarko, Statoil and BHP.

## The Permian Basin

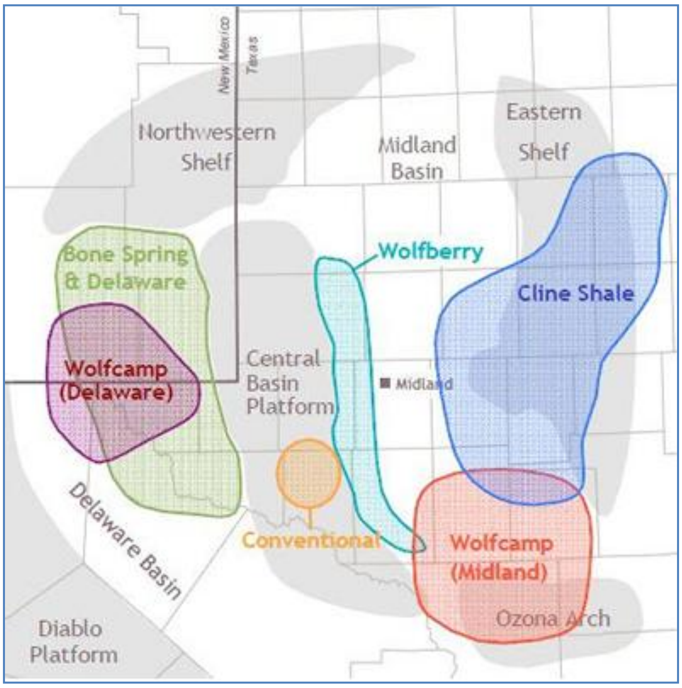
The Permian basin covers a surface area of 250 miles wide and 300 miles long, straddling Texas and New Mexico. This is the most prolific oil area in the United States. Crude oil output in the basin rose from 850,000 barrels per day in 2007 to 1.63 Mbd in 2014, equal to 19% of total US output. Six formations in the basin (Spraberry, Wolfcamp, Bone Spring, Glorietta, Yeso and Delaware) have provided most of the increased output since 2007. Thanks to such soaring production, output in the basin has exceeded that of the Gulf of Mexico, since March 2013. This makes Permian the largest producing region in the United States. Nearly three quarters of the rise in output comes from the Spraberry, Wolfcamp and Bone Spring formations.

**Figure 38: Oil Output in the Six Large Formations of the Permian Basin**




Source: EIA

**Map 5: The Permian Basin**




Source: Devon

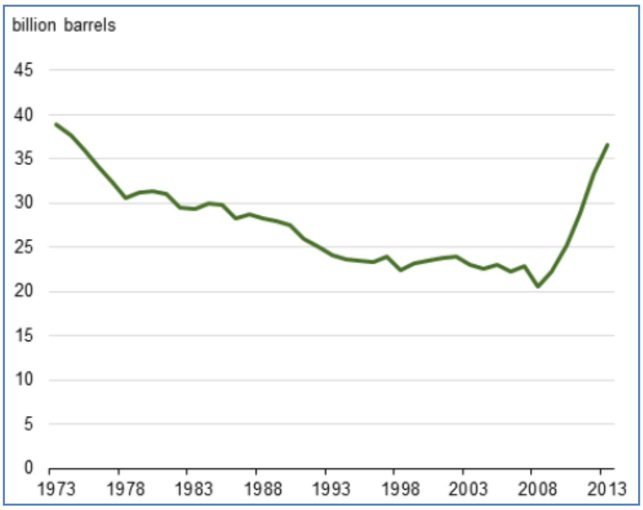
The Permian basin is known for its vast resources of conventional oil – the source rock is the source of oil deposits which have allowed the development of oil in Texas, and has experienced a renaissance in recent years, thanks to E&P for non-conventional hydrocarbons, and the rise in horizontal drilling, at the expense of vertical drilling. The basin is very promising and its production exceeds that of mature shale basins, such as Eagle Ford and the Bakken.[45]

[45] Rystad, *Permian is becoming the largest tight oil play in the us, North American Shale*, vol. 1, no. 2 avril 2014.

# Annex 2: Oil Reserves Rising Strongly

The revolution in shale oil is also borne out by the rise in proven reserves and resources which are technically recoverable, and following from this the lengthening outlook of US oil production. **Proven reserves of crude oil and condensates increased for the fifth year in a row in 2013, reaching 36.5 giga barrels (Gb) at end 2013, up by 9.3% on 2012 (33.4 Gb).**[46] The oil price serving as the basis for this estimation was the average price observed during the 12 months running up to the estimation ($97.28). The fall in crude oil prices during the last six months of 2014, but especially in November and December will affect proven reserves as estimated at the end of 2014 end even more so at the end of 2015, should the price fall continue.

**Figure 39: Evolution of Proven Reserves of Oils and Condensates (1973-2013)**




Source: EIA

[46] Proven reserves are the volumes of hydrocarbon resources for which geological and technical data provide reasonable certainty that they are recoverable given present economic and technological conditions. The estimations of reserves change from year to year, depending on new discoveries, a better knowledge of existing fields, production, as well as price and technology changes.

The rise in proven reserves (3.1 Gb) is mainly explained by the extension of reserves in existing fields/basins (5 Gb). North Dakota is the state where reserves have expanded most (up 1.9 Gb, excluding production), thanks to the development of shale oil formations in Bakken/Three Forks in the Williston basin. Texas is in second position with a rise in reserves of 900 Mb, mainly in the Eagle Ford formation (805 Mb) and in the Permian basin (99 Mb). **As of 31 December 2013, the formations of shale oil accounted for 28% of proven oil and condensate reserves (10 Gb).** Six formations hold 95% of these reserves. The Bakken/Three Forks formation has the most important proven shale oil reserves in the United States (4.8 Gb). It regained first place having overtaken Eagle Ford in 2012 (4.18 Gb at end December 2013).

In 2013, production of shale and tight oil and from compact reservoirs stood at 701 Mb according to the EIA. On the basis of present conditions, proven reserves as of 31 December 2013 could support this level of output for 14 years.

**Table 6: Proven Reserves of Shale Oil Formations in 2012 and 2013**

Table 2. U.S. tight oil plays: production and proved reserves, 2012-13

million barrels

| Basin | Play | State(s) | 2012 Production | 2012 Reserves | 2013 Production | 2013 Reserves | Change 2012-13 Reserves |
|---|---|---|---|---|---|---|---|
| Williston | Bakken/Three Forks | ND, MT, SD | 214 | 3,166 | 270 | 4,844 | 1,678 |
| Western Gulf | Eagle Ford | TX | 209 | 3,372 | 351 | 4,177 | 805 |
| Permian | Bone Spring, Wolfcamp | NM, TX | 12 | 236 | 21 | 335 | 99 |
| Appalachian | Marcellus | PA, WV | 4 | 72 | 11 | 129 | 57 |
| Fort Worth | Barnett | TX | 10 | 64 | 9 | 58 | -6 |
| Denver-Julesberg | Niobrara | CO, KS, NE, WY | 3 | 14 | 2 | 17 | 3 |
| **Sub-total** | | | **452** | **6,924** | **664** | **9,560** | **2,636** |
| Other tight oil | | | 28 | 414 | 37 | 483 | 69 |
| **U.S. tight oil** | | | **480** | **7,338** | **701** | **10,043** | **2,705** |

Note: Includes lease condensate. Bakken/Three Forks tight oil includes fields reported as shale or low permeability on Form EIA-23L; "Other tight oil" includes fields reported as shale on Form EIA-23L not assigned by EIA to the Bakken/Three Forks, Barnett, Bone Spring, Eagle Ford, Marcellus, Niobrara, or Wolfcamp tight oil plays.
Source: U.S. Energy Information Administration, Form EIA-23L, Annual Survey of Domestic Oil and Gas Reserves, 2012 and 2013.

Source: EIA

According to the EIA/ARI (in a study in 2013), technically recoverable resources[47] of shale and tight oil were estimated at 58 Gb in June 2013 (345 Gb globally). This puts the US in second position after Russia. These data evolve with exploration and exploitation techniques. In May 2014, the EIA drastically cut its estimates of technically recoverable resources of shale in the

[47] Technically recoverable resources are those which can be produced with present technological conditions but not taking into account economic conditions. They change with technological development and better knowledge of the source rock.

Monterey zone in California, by 96% to 600 Mb, whereas INTEK Inc. had given estimates of 15 Gb in 2011, and the EIA's own estimates had been 13.7 Gb in 2012. Even though resources *in place* are clearly in the source rock, existing technologies do not allow them to be produced. Despite this revision, US technologically recoverable resources are now estimated at 59 Gb, thanks to better knowledge of source rock of other formations.[48]

[48] EIA, *Oil and gas module*, 2014, <www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf>.

# Annex 3: Number of Active Rigs in the United States

| | 2-Jan 2015 | 5-Dec 2014 | +/- | Year ago | +/- |
|---|---|---|---|---|---|
| Land (inc. Inland waters) | 1756 | 1862 | -106 | 1690 | 66 |
| Offshore | 55 | 58 | -3 | 61 | -6 |
| **United States Total** | **1811** | **1920** | **-109** | **1751** | **60** |
| | | | | | |
| **US Breakout** | | | | | |
| Oil | 1482 | 1575 | -93 | 1378 | 104 |
| Gas | 328 | 344 | -16 | 372 | -44 |
| Miscellaneous | 1 | 1 | 0 | 1 | 0 |
| | | | | | |
| Directional | 175 | 198 | -23 | 226 | -51 |
| Horizontal | 1336 | 1368 | -32 | 1148 | 188 |
| Vertical | 300 | 354 | -54 | 377 | -77 |
| | | | | | |
| **Major State Variances** | | | | | |
| Alaska | 9 | 11 | -2 | 11 | -2 |
| Arkansas | 11 | 12 | -1 | 11 | 0 |
| California | 22 | 43 | -21 | 34 | -12 |
| Colorado | 66 | 70 | -4 | 65 | 1 |
| Kansas | 29 | 26 | 3 | 29 | 0 |
| Louisiana | 109 | 114 | -5 | 112 | -3 |
| New Mexico | 101 | 100 | 1 | 79 | 22 |
| North Dakota | 169 | 180 | -11 | 174 | -5 |
| Ohio | 46 | 45 | 1 | 35 | 11 |
| Oklahoma | 209 | 211 | -2 | 169 | 40 |
| Pennsylvania | 53 | 55 | -2 | 56 | -3 |
| Texas | 840 | 896 | -56 | 832 | 8 |
| Utah | 23 | 23 | 0 | 23 | 0 |
| West Virginia | 28 | 31 | -3 | 32 | -4 |
| Wyoming | 56 | 59 | -3 | 53 | 3 |
| | | | | | |
| **Major Basin Variances** | | | | | |
| Ardmore Woodford | 6 | 7 | -1 | 10 | -4 |
| Arkoma Woodford | 5 | 5 | 0 | 5 | 0 |
| Barnett | 24 | 24 | 0 | 34 | -10 |
| Cana Woodford | 45 | 43 | 2 | 36 | 9 |
| DJ-Niobrara | 58 | 61 | -3 | 50 | 8 |
| Eagle Ford | 200 | 206 | -6 | 228 | -28 |
| Fayetteville | 8 | 9 | -1 | 9 | -1 |
| Granite Wash | 52 | 63 | -11 | 52 | 0 |
| Haynesville | 40 | 40 | 0 | 43 | -3 |
| Marcellus | 77 | 82 | -5 | 85 | -8 |
| Mississippian | 72 | 74 | -2 | 75 | -3 |
| Permian | 530 | 568 | -38 | 468 | 62 |
| Utica | 49 | 48 | 1 | 38 | 11 |
| Williston | 179 | 189 | -10 | 185 | -6 |

Source: Baker Hughes

# List of Tables, Figures and Maps

# References


Baker Hughes, Rig count

<www.bakerhughes.com/rig-count>

Bakken Shale, <http://bakkenshale.com/>

Barclays Equity Research, *Global 2014 E&P Spending Outlook*, 9 December 2013

CITI Research Commodity, *The Abyss Stares Back*, 16 October 2014

CITI Research Commodity, *Peering Over the Oil Cliff*, 14 October 2014

CITI Global Perspectives & Solutions, *Energy 2020: Out of America, The Rapid Rise of the United States as a Global Energy Superpower*, Citi GPS, November 2014

Energy Information Administration (EIA), Washington, DC

EIA, *Annual Energy Outlook 2014*, mai 2014

<www.eia.gov/forecasts/aeo/>

EIA, *U.S. Crude Oil and Natural Gas Proved Reserves*, 2013,

December 2014,

www.eia.gov/naturalgas/crudeoilreserves/pdf/usreserves.pdf

EIA, *Oil and gas Module*, 2014,

http://www.eia.gov/forecasts/aeo/assumptions/pdf/oilgas.pdf

EIA, *Drilling Productivity Report* (DPR),

<www.eia.gov/petroleum/drilling/>

EIA, *Short-Term Energy Outlook* (STEO),

<www.eia.gov/forecasts/steo/>

EIA, *Petroleum and Other Liquids (Database and Analysis)*,

<www.eia.gov/petroleum/>

EIA, *This Week in Petroleum*,

<www.eia.gov/petroleum/weekly/>

EIA, *Weekly Petroleum Status Report*,

<www.eia.gov/petroleum/supply/weekly/>

EIA, *Petroleum Supply Monthly*,

<www.eia.gov/petroleum/supply/monthly/>

EIA, *Today in Energy*, <www.eia.gov/todayinenergy/>

EY, *US Oil and Gas Reserves Study*, 2014,

<www.ey.com/Publication/vwLUAssets/EY-US-Oil-and-Gas-reserves-study-2014/$FILE/EY-US-Oil-and-Gas-reserves-study-2014.pdf>

IEA, *Oil Market Report*,

<www.iea.org/oilmarketreport/omrpublic/>

IEA, *Medium-Term Oil Market Report 2014*,

<www.iea.org/Textbase/npsum/MTOMR2014sum.pdf>

IEA, *World Energy Outlook 2014*, November 2014, OCDE/IEA, Paris

IFP Énergies nouvelles, *Les investissements en exploration-production et raffinage 2014*, G. Hureau, S. Serbutoviez, C. Silva avec la participation de G. Maisonnier, Direction Économie et Veille, November 2014

IFP Énergies Nouvelles, *Hydrocarbures de roche-mère, État des lieux*, R. Vially, G. Maisonnier et T. Rouaud, Rapport IFPEN 62 729, 22 janvier 2013

Livingston D., *Tight oil in the United States : recent development and future financial sustainability*, Carnegie Endowment for International Peace, 2014/3 ISG&OJ, 1 November 2014,

<http://carnegieendowment.org/2014/11/01/tight-oil-in-united-states-recent-developments-and-future-financial-sustainability>

National Petroleum Council (NPC), *Working Document of the NPC North American Resource Development Study*, U.S. oil & gas industry business models, Macroeconomic Subgroup, NPC, 15 September 2011

OEIS, <www.oxfordenergy.org/>

OIES, *The US Tight Oil Revolution in a Global Context*, Bassam Fattouh and Amrita Sen, September 2013

OEIS, *US Shale Gas and Tight Oil Industry Performance*, Ivan Sandrea, 21 mars 2014

OEIS, *The Impact of the US Tight Oil Revolution on GCC Producers*, Bassam Fattouh, 13 Octobre 2014,

Patel Suken, *Manufacturing model vs. Exploration-Development Model*, CFA, mars 2014

<www.diamond-hill.com/exploration-production-an-evolving-business-model/>

Railroad Commission of Texas (RRC),

<www.rrc.state.tx.us/oil-gas/major-oil-gas-formations/eagle-ford-shale/>

Rystad Energy, <www.rystadenergy.com/>

Scotia Bank, *Commodity Prices Decline In October*, 28 November 2014, Global Economics, Commodity Price Index,

<www.gbm.scotiabank.com/English/bns_econ/bnscomod.pdf>

The Economist, « US : Failing in shale », 20 November 2013,

<www.eiu.com/industry/article/921249876/us-failing-in-shale/2013-11-20>

Vially R., *Les hydrocarbures de roche-mère. État des lieux*, 23 avril 2013, <http://alumni.ifp-school.com/alumniweb/index.php/fre/content/download/32011/582176/file/Conf%C3%A9rence_Roland_VIALLY_23_avril_2013.pdf>

Wood Mackenzie, <www.woodmac.com>

Presentations for investors and press releases by independent US companies.

*Reuters, Pétrostratégies, Argus Media, Platts, Midland Reporter Telegram, Financial Times, Drilling Contractor, Business Insider, Les Échos*