

THE GEOPOLITICS OF ENERGY PROJECT

THE SHALE OIL BOOM: A U.S. PHENOMENON

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Maugeri has published four books on energy, among them the *The Age of Oil: the Mythology, History, and Future of the World's Most Controversial Resource* (Praeger, 2006), and *Beyond the Age of Oil: The Myths and Realities of Fossil Fuels and Their Alternatives* (Praeger, 2010). Both books were named "Outstanding Academic Titles" by Choice Review. In June 2012, the Belfer Center published Maugeri paper, "Oil: The Next Revolution," which received worldwide attention. The study forecasted a dramatic increase in the world's oil production capacity to 2020 driven by an unnoticed growth of field-by-field production capacity worldwide.

Maugeri has also written articles and op-eds for *Foreign Affairs*, *Science*, *Newsweek International*, *The Wall Street Journal*, *Forbes*, the *Oil & Gas Journal*, and *Scientific American*.

Maugeri has been a Visiting Scholar at the Massachusetts Institute of Technology (2009-2010), and a member of MIT's External Energy Advisory Board.

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1. INTRODUCTION

There are several issues in the current debate on the so-called U.S. tight and shale oil (hereafter referred to as shale oil—see Box 1) revolution that contribute to reinforce extreme and seemingly irreconcilable attitudes. One of the central questions revolves around the real potential of this revolution and can be formulated simply as follows: Is oil production from shale formations just a temporary bubble or is it an event capable of significantly altering the U.S.—and possibly global—energy outlook?

This study addresses such questions on the basis of a general analysis of more than 4,000 shale wells and a much more focused analysis of 2,000 of these wells¹ along with the activities of about one hundred oil companies involved in shale oil exploitation. The main results of such analysis are multifaceted.

On one hand, the large resource size – and the ability of the industry to develop it through steady improvements in technology and cost – dwarf earlier forecasts, suggesting the possibility that the United States may become the largest global oil producer in just a few years. On the other hand, the unique characteristics of shale oil – the drilling intensity in particular – make it extremely vulnerable to both price drops and environmental opposition in new and populated areas.

Drilling intensity is a key point in order to understand the real evolution of shale oil (as well as shale gas) activity in the United States and its flexibility – e.g. the possibility to rapidly adapt to shifting circumstances.

Given the early state of knowledge and technology, the U.S. shale oil boom is mostly a function of bringing as many wells as possible on line, due to the dramatic decline in production that follows the early months of activity with each new well. For example, by December 2012 it took about 90 new producing wells per month just to maintain North Dakota’s Bakken-Three Forks (the largest shale oil play so far in the United States) oil production of 770,000 barrels per day.

Drilling intensity in U.S. shale oil plays skyrocketed from a few hundred wells brought online (e.g., becoming productive) before 2011 to more than 4,000 in 2012 – a figure that outpaces the total number of oil and gas wells (both conventional and unconventional) brought online in the same year in the rest of the world (except Canada).

In the short- to medium-term (3 to 5 years), the correlation between drilling intensity and shale oil production will shape the evolution of U.S. oil production more than any other factor. And because drilling intensity is largely a function of the oil price, a significant dip in oil price may trigger a rapid twist in the shale oil boom.

The central role played by drilling intensity in this early stage of shale oil and gas development has a crucial but almost unnoticed implication for the possibility of replicating the success of the American experience in other parts of the world. The United States concentrates in its territory 60 percent of the global availability of drilling rigs; moreover, 95 percent of U.S. drilling rigs can perform horizontal drilling that together with hydraulic fracturing or “fracking” is required to liberate shale resources.

Combined with a relatively low population density in several shale areas, this vast supply is a key factor that allows the United States to achieve a drilling intensity level that is impossible for other countries to

¹ See: Appendix B, Disclaimer on Methodology

achieve. No other country in the world has ever experienced even a fraction of the overall U.S. drilling intensity, a common feature of the U.S. oil and gas industry since its inception. In 2012, for example, the United States completed 45,468 oil and gas wells (and brought online 28,354 of them) as against 3,921 wells completed in the rest of the world, except Canada.¹

The drilling-intense nature of the shale business is a factor that will make the expansion of the shale phenomenon in other parts of the world improbable – at least in this decade. But there are other factors that will make the global replication of a U.S. style shale boom difficult, including an absence of private mineral rights in most countries, as well as the absence of the U.S. independent companies whose guerilla-style operational mindset has proven essential to the exploitation of shale formations that (unlike conventional oil and gas fields) require companies to move on a micro-scale, on multiple micro-objectives, and flexibly leverage short-term opportunities.

Although highly difficult to replicate, the U.S. shale experience may have a dramatic impact on the hydrocarbon sector by gradually introducing hydraulic fracturing as a means to recover more oil from conventional, mature, and declining oilfields worldwide.

Box 1

Shale oil, tight oil, and oil shale: A problem of words and substance

Shale and tight oil are conventional oils (light oils with low sulfur content) trapped in unconventional formations whose extremely low porosity and permeability makes it extremely difficult for producers to extract hydrocarbons. Shale oil reservoirs are rich with clay and fissile, meaning they split in layers where the presence of clay stone is massive. These layers may stretch horizontally for hundreds and thousands of miles.

Unlike shale formations, tight oil formations are made of siltstone (a mixture of quartz and other minerals, predominately dolomite and calcite, but many others may be present) or mudstone without a lot of clay in the reservoir.

Despite their differences, most tight oil formations resemble shale on data logs, hence the continued reference to both as “shale” in the media as well as in more technical literature. Although most U.S. so-called shale plays are in effect tight oil formations, I will use the expression “shale” for all unconventional formations so as not to confuse the reader.

Shale oil must not be confused with oil shale, which for several decades enjoyed much higher popularity in the United States.

Oil shale is a precursor of oil called kerogen, a sort of teenage oil that constitutes the building blocks of conventional oil. Also, oil shale is trapped in rocks with low porosity and permeability, making the extraction of kerogen difficult. However, the oil shale rocks are closer to the surface than those containing shale and tight oil. Thus, both the oil shale formations that contain kerogen and kerogen itself are unconventional.

2. A BOOM FROM A HUGE BUT HOSTILE RESOURCE: THE ROLE OF DRILLING INTENSITY

The nascent state of U.S. shale oil production contrasts sharply with its rapid pace of growth. When significant shale oil drilling activity first began in 2007 across the U.S. portion of the Bakken formation (North Dakota and Montana), the resource potential of tight and shale oil was virtually absent from the United States and the international oil map. It remained so until 2011, when Bakken shale oil production started to surprise most experts and the Eagle Ford and Permian Basin shale formations began to emerge as additional contributors to the unexpected shale oil boom. By the end of 2012, that boom released an overall production of more than 1.5 mbd of crude oil, starting from virtually zero in 2006.

Not until recently have industry experts widely recognized the enormous original oil in place (OOP) in the Bakken, Eagle Ford, and Permian Basin – the “Big Three” U.S. shale oil formations – but its precise size is still a matter of speculation and continuous update. For example, the largest operator in Bakken-Three Forks, Continental Resources now estimates that Bakken may hold 900 billion barrels OOP, a two-fold increase in the 2012 assessment. That would make Bakken’s endowment alone larger than Saudi Arabia. However, the extremely low porosity of these formations, the dramatic decline rates after the early months of production of each shale well and its relatively high overall costs, have contributed to a widespread belief that recoverable shale oil reserves only represent a tiny fraction (≤ 2 percent) of the original OOP.² But this belief is also evolving.

For example, the U.S. Geological Survey (USGS) in its 2008 assessment of Bakken reserves, assumed a recovery rate lower than 2 percent, implying an estimated 3.0 to 4.3 billion barrels of undiscovered, technically recoverable oil reserves – an assessment that, at the time, represented a 25-fold increase in the amount of recoverable Bakken oil compared to 151 million barrels of oil estimated in the 1995 USGS assessment. In April 2013, the USGS revised the number again to an estimated mean of 7.4 billion barrels oil, a two-fold increase in 5 years.³

The science of assessing oil and gas resources and reserves is not exact, and these figures are bound to change again in the future, as knowledge and technology evolve.

For many observers and experts, therefore, the shale oil phenomenon will prove merely temporary, a sort of bubble inflated by the very rapid ramp-up of production in the early months of a well activity but doomed to bust as soon the best shale areas have gone.

Yet things are more complex than that, as the U.S. shale gas experience proved. For almost a decade since its inception in 2000, the shale gas boom also was considered a temporary bubble because of the rapid decline of shale gas wells. Yet the huge endowment of shale gas resources and their intensive drilling at a time of high natural gas prices in the United States (before 2002) provoked a glut of natural gas in the United States.

True, like for shale gas, shale oil wells exhibit their peak production rates during the first weeks of operation, generally referred to as initial production during the first 30 days, or IP30. Eventually, they register 40–50 percent lower rates by the end of the first year of production and a further 30–40 percent decline rate by the end of the second year. To date, wells with longer observed production histories of 5–6 years reveal average production rates flattening by about more than 10 percent of IP30 after the fifth year.

These decline rates relate to a gross average that I have inferred from the actual behavior of all the wells I have considered for this study.² Specific decline rates are as follows in Table 1:

Table 1. Estimated decline rates of the Big Three U.S. shale oil plays

Play	Year 1	Year 2	Year 3	Year 4	Year 5
Bakken-Three Forks	43%	35%	30%	20%	20%
Eagle Ford	55%	40%	30%	20%	20%
Permian Basin	50%	40%	30%	20%	20%

NOTE: Year 1 decline is calculated as the average production during the 12th month of production vs. IP30 daily production. Subsequent yearly decline rates are calculated against the last month of the previous year daily average production. After Year 5, I assumed a flat 7 percent annual decline.

Longer-term decline rates and ultimate recovery of a well or entire field are not known within a reasonable approximation until a sufficient history of observable production data is generated and knowledge and technology have achieved a significant level of consolidation. This is not the case with shale oil.

Sure, there are several ways to forecast the estimated ultimate recovery (EUR) of a well or a field through models (the most common of which is the Arps model analysis of decline curves)⁴ that simulate the possible behavior of a well in the future. However, these models may lead to opposite results in the early stages of a new phenomenon, either indicating a too pessimistic outcome or overestimating the actual potential of a well or field.

This is mostly due to the huge variance of productivity among different shale areas as well as the early stage of knowledge and technology concerning shale oil formations, whose evolution may lead to significant change in today's rate of recovery. As of today, it is also not clear what could be well spacing optimization (e.g., the optimum number of wells per acre) in each single formation. Therefore it is not clear what could be the actual extent of drilling intensity and well density in those formations, which in turn has a significant impact on ultimate recovery.

Also, the EUR calculated on the basis of a very brief period of production could be skewed by the different approaches to well development followed by different operators.

In shale, each oil producer has its own drilling and development strategy that influences initial productive results, decline, etc. For example, the use of larger chokes (chokes control the flow of oil and gas into a pipe) may boost initial productivity while reducing the ultimate recovery, and vice versa. In turn, those initial results are used as variables to simulate the future behavior of a well in most models. Consequently, two companies operating in the same area may calculate very different EURs. Also, expert outsiders may calculate EURs on the basis on a set of well data that is not representative at all, thus getting overly pessimistic or overly optimistic indications.⁵

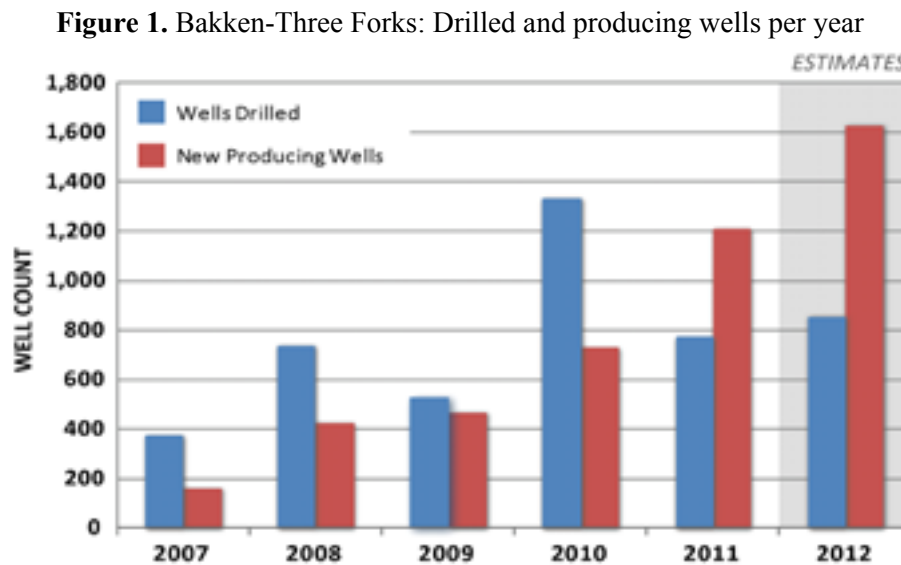
Because of the dramatic decline of shale wells, oil companies resort to intensively drilling for new wells that offset the loss of production from older wells. This is a common feature for all low-permeability and unconventional formations, where drilling more wells per number of acres is always necessary to boost

² See: Appendix B: Disclaimer on Methodology

production rates and increase the overall recovery factor of the entire field/formation.

So far “drilling intensity” has been the key factor that has made possible to recover more oil than previously expected from the huge but hostile shale/tight oil formations existing in the U.S, thereby supporting the boom of the country’s shale oil production.

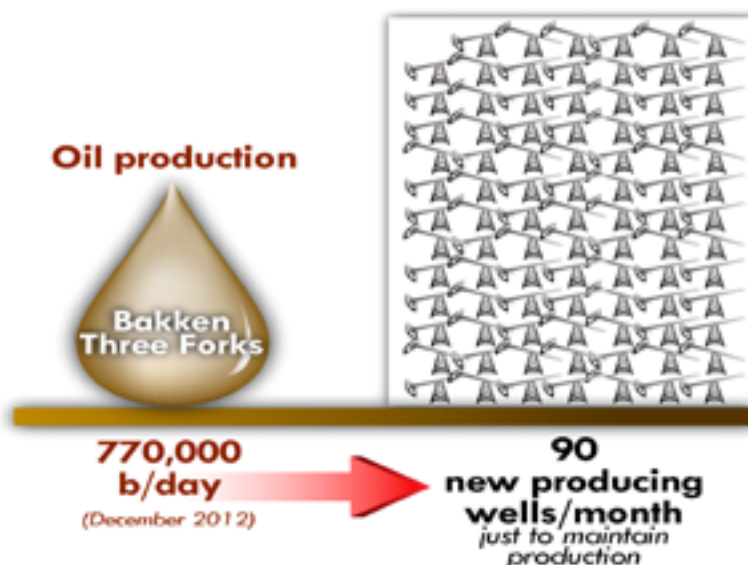
As shown in Figure 1, the number of new producing wells brought online in Bakken-Three Forks in 2012 surpassed 1,600 (with 190 active drilling rigs on average).⁶



NOTE: Data elaborated on the basis of the North Dakota Department of Mineral Resources Database.

A good part of these new wells simply served to offset declining production from older wells. According to the North Dakota Department of Mineral Resources (NDDMR), by December 2012 it took about ninety new producing wells per month just to maintain North Dakota’s Bakken-Three Forks oil production level that, by that month, was about 770,000 barrels per day (b/d),⁷ as shown in Figure 2.

Figure 2. Drilling intensity: The case of Bakken-Three Forks



Drilling intensity is getting even more frantic in Eagle Ford and the Permian Basin, where the number of active drilling rigs targeting horizontal oil plays is becoming higher than in Bakken. As shown in Table 2, drilling permits skyrocketed in Eagle Ford from 2010 onwards. While Texas state agencies do not offer a precise partition of drilling permits targeting shale formations, as well as the number of new producing wells per year, we know that most active drilling rigs in Eagle Ford—or 150 of 232 in January 2013—were targeting shale oil formations. (See Appendix A, Section 3: Eagle Ford.)

Table 2. Eagle Ford shale drilling permits (cumulative)

Year	Drilling Permits Issued
2008	26
2009	94
2010	1,010
2011	2,826
2012	5,230

Source: Texas Railroad Commission (RRC)⁸

I have tracked (but not analyzed in full) more than 4,000 new producing shale oil wells brought online in 2012 across the United States, and this figure probably represents an underestimation. By contrast, the number was lower than 400 in 2008.

To put these figures into a framework, suffice to say that the number of new producing oil and gas wells (both conventional and unconventional) completed in 2012 globally outside the United States and Canada is less than 4,000.⁹

This drilling intensity poses a major challenge to the possibility of replicating the U.S. shale phenomenon in other countries of the world, an issue that is analyzed in Section 7. But it poses also a fundamental question for the future of shale production in the United States: how far drilling can go?

In general terms, drilling intensity depend on a specific area underlying resource dimensions and well spacing, which determines the well density per acre. The latter is a crucial variable.

As well density in an area increases beyond certain levels, any additional well may interfere with the drainage area of the other wells, thus reducing their productivity and ultimate recovery. Also, well interference increases finding and development costs of each well, because the latter will produce fewer hydrocarbons over its entire life. The balance between additional volumes recovered and their costs is thus essential to define what the optimal well spacing per acre is. In the shale oil sector, optimal well spacing evaluation is still evolving, and thus is not clear yet how many wells can be brought online for each of them.

For those expansive shale plays in sparsely populated sections of North Dakota and Texas, the drilling potential appears to be impressive.

For example, the largest operator in Bakken (in terms of combined acreage and production), Continental Resources, initially approached the development of the play with a 1,280-acre/well strategy then turned to a 640-acre/well approach. Now it is performing pilot tests considering both a 320-acre/well and a 160-acre/well spacing.¹⁰ Considering the lower estimate for Bakken's most productive area of 12,000 square miles, or about 7.7 million acres, a 320-acre/well implies the possibility of a total of 29,000 producing wells, or about 6 times the number of producing shale oil wells as of December 2012 (less than 5,000). By increasing well spacing to 160-acre/well, the figure will jump to slightly less than 60,000 wells.

As for Eagle Ford, the spacing is much more dense. The largest operator by far in the play in terms of both acreage and production, EOG Resources, is now applying a 65-acre/well spacing that implies the possibility of getting more than 58,000 producing wells across a productive area for the entire Eagle Ford oil window of slightly less than 6,000 square miles, or 3.8 million acres. The company, however, is also testing a 40-acre/well, which would imply a much higher number of wells.¹¹

Figures about the Permian basin are still in the making, yet it is possible to figure out that the Big Three U.S. shale plays have a combined potential of many more than 100,000 shale producing wells, or about ten times the number of those already on line.

Taking into account this potential, the limits to drilling intensity probably would start affecting Bakken-Three Forks and Eagle Ford only in the second half the 2020s. By that time, their survival will rely on technological advancements that allow for less and less drilling to recover the same or greater amount of resource.

3. TECHNOLOGICAL AND MANAGERIAL FACTORS SUPPORTING THE BOOM

Along with drilling intensity, additional technological and management improvements have increased the productivity of shale oil plays and expanded their economically recoverable resource base.

First, shale activity is becoming more effective, as indicated in Figure 1 by the number of new producing wells outpacing that of drilled wells. This element needs some explanation.

In the early stages of the Bakken development, it took 40–60 days to successfully drill a well, after which the operator would join a waiting list for specialized crews to perform a fracking job; the latter stage could often prolong the completion stage by months. (See Box 2 about terminology.)

Things have changed now.

Shifting companies' investment from shale gas to shale liquids has increased the availability and affordability of oil services and associated labor. Moreover, the use of various drilling technologies has further enriched well operational efficiencies by reducing drilling and completion cycles and their cost.

In particular, the increasing use of steerable rotary bits in shale activity has nearly cut drilling time in half while enhancing drilling accuracy.¹² In Eagle Ford, several wells recently have been drilled to depth (~17,000 feet, or 5,185 meters) in as little as nine days, compared to an average of eighteen days in 2010–11.¹³ By the same token, because of steerable rotary bits, it took 14–18 days to drill the typical Marcellus shale well in the second half of 2011, compared to 6–10 days in the second half of 2012.¹⁴

Other efficiency-enhancing technologies include, first and foremost, pad drilling and multipad drilling (whereby multiple descending wells from a single surface location eliminate the need for rig transfers between locations, reducing costs per well and the well's impact on the surface) and zipper fracking (in which two or more parallel wells are drilled by perforating each at alternating intervals, thus increasing productive capacity).¹⁵

These technological innovations represent only a handful of potential future efficiency gains as the industry continues to enrich its understanding of specific features and geological formations of shale plays.

As a consequence, a lower rig count (e.g., the number of active drilling rigs) in a certain shale area does not imply a diminishing activity but may instead underscore increasing efficiency per rig. In other words, a drilling rig is now capable of releasing many more wells per year than in the past.

A second factor that has supported the continuous growth of U.S. shale oil production has been constant well productivity increases over the years.

As the training ship of all subsequent shale oil plays, the Bakken shale, exemplifies, per-well average productivity has more than doubled between 2007 and 2012, as shown in Figure 3.

Box 2

The phases of a well life: An essential terminology

There are three main phases that allow a well to produce oil and gas.

The first phase is drilling, e.g., perforating a hole in the earth with a drilling rig that rotates a drill string with a bit attached. Drilling follows a vertical path, after which it also may be curved by ninety degrees to get a horizontal wellbore, that allows better recovery of oil and gas from a horizontal strata of a reservoir. This is called horizontal drilling. Part of the drilling phase is the casing of the hole, which consists of placing a steel pipe into the hole and putting cement between the outside of the casing and the borehole. The casing provides isolation and structural integrity to the wellbore, preventing it from collapsing and coming in contact with water aquifers and other strata of the earth.

The second phase is completion, the process that enables a well to produce oil and gas.

It usually consists of making small perforations in the portion of the casing that passes through the production zone to provide a path for the oil to flow from the surrounding rock into the production pipe.

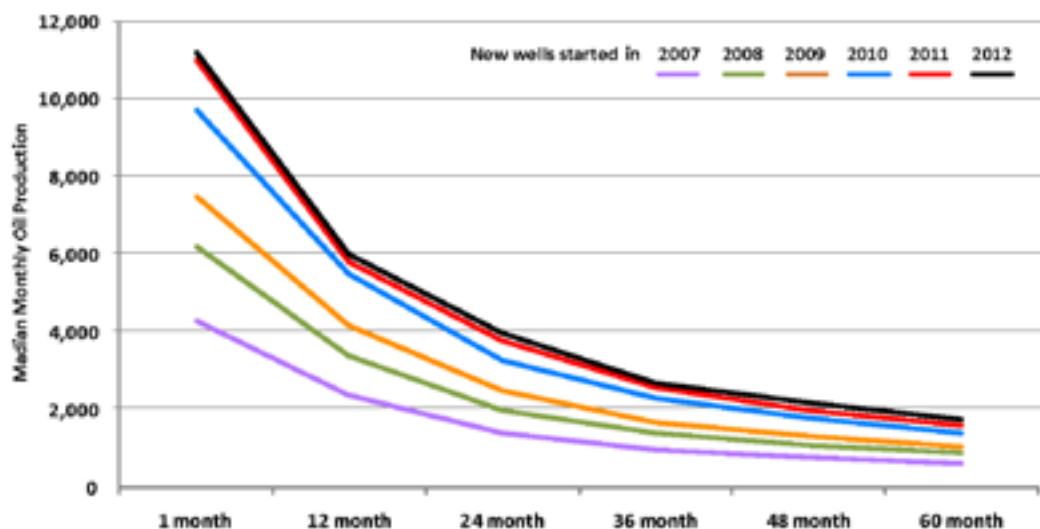
Fracking occurs during the completion phase. It consists of the propagation of subsequent fractures, or fracking stages, in a rock layer by injecting at very high pressure a mix of fluid (water), sand (proppant), and chemicals down the perforated still pipe of a well. Sand prevents the fractures from closing when the injection is stopped (other kinds of proppants may be used, such as ceramic, that many experts consider more effective) while chemicals serve to tailor the injected material to the specific geological situation, protect the well, and improve its operation. The first use of hydraulic fracturing was in 1947.

The production phase occurs once completion is done and the oil rigs and workover rigs (used to complete the well) have moved off the wellbore. The top of the well on the surface is then outfitted with a collection of valves called a Christmas tree of production trees. These valves regulate pressures, control flows, and allow access to the wellbore in case further completion work is needed. In particular, this may occur as the internal pressure of the field decreases, making it necessary to install surface pumps (a typical landmark of any oil and gas setting), as well as to inject water, natural gas, and other gases and steam (the improved oil recovery (IOR) or enhanced oil recovery (EOR) technologies) for recovering more oil and gas.

From the outlet valve of the Christmas tree, the oil and gas flow is connected to a distribution network of pipelines and tanks. A well is finally abandoned when it reaches an economic limit—e.g., when its most efficient production rate does not cover operating expenses, including taxes. At this point, all pipes are removed from the well, which is filled with cement.

It is worth noting that when a well is shut down, the reservoir it targeted still holds a significant amount of oil and gas that cannot be recovered economically with current technology.

Figure 3. Bakken-Three Forks: Per-well production and decline curves, 2007–2012



There are several factors behind this productivity upsurge, but the most important are the increase and optimization of the lateral well length (up to two miles), sand volume and type (natural or synthetic) used in fracking, and the number of fracking stages per single well completion (e.g., the number of fracking operations performed along the length of a horizontal well).¹⁶

A final contributing dynamic behind shale oil's rising well productivity lies in the tendency of private companies to concentrate their drilling efforts within a basin's most productive core areas once the latter have been identified. Most observers consider this approach as proof that the shale oil boom will bust as soon as the best shale areas have been exploited.

Yet the core area approach is consistent with the oil industry's behavior during its history. It can be summed up as "grab the easiest fruits soon and while doing so learn how to grab the ones on the top of the tree—e.g., the most difficult ones." This approach has led over time to learn how to "grasp the more difficult fruits," leading to recovering much more oil than initially estimated. Moreover, as we have seen in Section 2, the room to exploit the best shale area is still huge. Given the high price of oil of the last few years, however, companies have not shied away from aggressively drilling other areas and new prospects, a strategy that could probably be the first victim of a significant oil price downturn.

It is worth noting, however, that there are less productive areas whose costs are much lower so that they also could represent a profitable business, as explained in the next section.

4. THE DIFFERENT UNIVERSE OF SHALE ECONOMICS

The shale and tight oil universe bears several highly distinctive characteristics that makes it very different from the conventional oil and gas patch, and have a profound impact on its actors, activity, and economics.

In military language, whereas conventional oil and gas companies are the equivalent of traditional armies that need a comprehensive plan, a long time to be deployed and plenty of men who move accordingly, shale/tight oil companies are more like guerrilla groups, that need to move on a micro-scale, on multiple micro-objectives by flexibly leveraging on time and opportunities, and know almost perfectly the environment they are operating in.

The conventional oil and gas sector is a long-term business that requires the ability to manage huge projects over several years, sometimes decades. Once the exploration phase has shown the commercial feasibility of a given discovery – a process that requires, on the average, about two years – it may take on average an additional 8-10 years (or more) to bring the newly discovered field on line, e.g., to start producing oil and gas.

Over this period, an oil company may invest several billion dollars before the field reaches its early production phase and begins to recover costs. Also, during this period the company decides the development strategy of the field by selecting the number and location of production wells that – combined – may optimize production over a given period of time. It then takes additional years before the new field production ramps-up and reaches its peak production and stabilizes for many years around that (so called “plateau production”). With additional investments over the years, so, an oilfield is usually a long-term cash-cow for an oil company, sometimes generating profits for decades. As a result of such timeframe, companies calculate their expenditures and returns against a long-term oil price scenario and are less sensible to short-term fluctuations of the market.

All of this changes dramatically in the shale and tight oil business. First of all, the shale oil well is considered as nearly a universe within itself, in that it is not part of the network of wells that is necessary to develop a conventional oilfield: It is something like a micro-oilfield with its own economics and much faster development and decline times.

In fact, it takes only a few months from obtaining a drilling license to bringing a well online. As we have seen, a shale well initial production rate over the first weeks of operation represents peak output that is bound to wane substantially during the following months of a well’s life. This implies that the foreseeable short to medium time price of oil is essential to any drilling strategy: In other words, starting production when the market is down means selling the bulk of a well total production for cheap without possibility of recovery because after one year of activity that well would produce 50 percent less.

This critical dependence on short-term oil prices explains why companies engaged in shale development usually hedge a much higher part – or more than 50 percent – of their expected production against a drop of oil price than they do when engaged in conventional oil projects.¹⁷

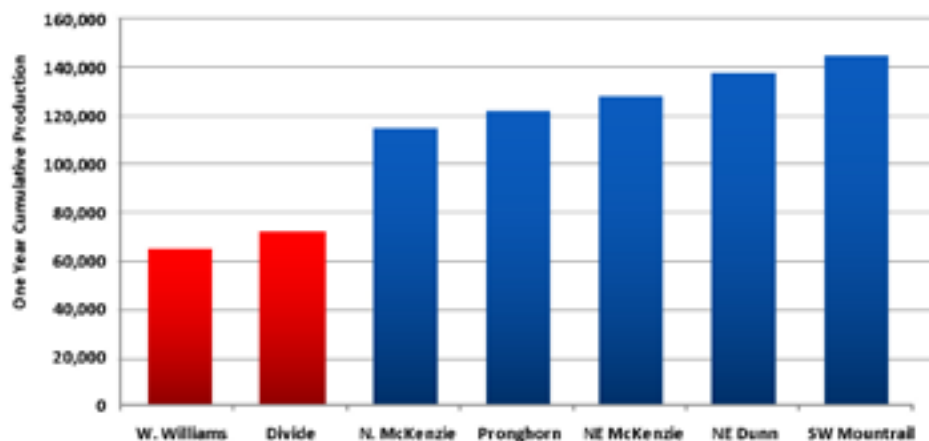
Secondly, unit economics across shale wells differ more widely than for conventional wells given the shale’s greater degree of variance in geology and resource characteristics across a given formation. As a consequence, there are areas of a shale field that may be highly profitable and others that are not. Selecting the best areas is essential to the future success of a company. In addition, shale economics are significantly influenced also by the cost per acreage paid by companies over time, which bears huge differences. For example, early movers in Eagle Ford Shale, such as SM Energy, ConocoPhillips, and EOG Resource, scooped up their acreage lease agreements at \$250-\$450 per acre in 2007-2009. By converse, Marathon Oil had got a significant position in Eagle Ford by taking over Hilcorp Resources in June 2011, paying an

implicit \$ 21,000 to \$ 22,000 per acre (when adjusted for production).¹⁸

Because of either the variances among different areas of a single play, or the different approaches followed by different operators in developing oil wells, it is particularly difficult to evaluate data concerning shale economics.

Figure 4 provides a snapshot of such variances concerning the first year crude oil production of different areas in Bakken-Three Forks (NGLs and natural gas production not included). Per-well costs also vary significantly across the areas shown in Figure 4, spanning from an average \$7.3 million in W. Williams, an average \$9.5 million in the MCKenzie area, to an average \$10.2 million in SW Mountrail.¹⁹ Notwithstanding these variations, it is possible to infer conservatively that shale oil wells in the Bakken now produce in excess of 100,000 barrels on average in the first year of activity, or about 275 b/d, and most of them have a capital cost between \$8.5 million and \$10.5 million.

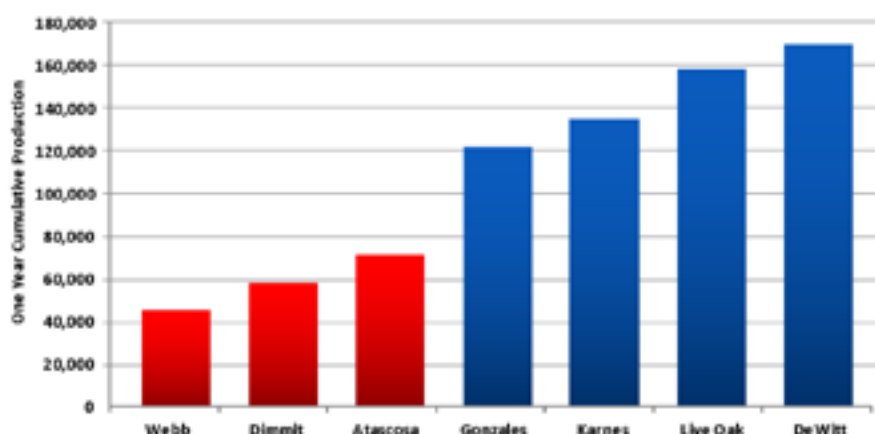
Figure 4. Bakken-Three Forks: Average per well crude oil first year production in different areas



Source: Author elaboration on NDDMR and companies' data²⁰

In Eagle Ford, my conservative estimate puts the average crude oil production at about 80,000 per well during the first year (or 219 b/d), but the well cost is lower than in the Bakken, typically between \$5.5 million to \$7.5 million per well. Production variances are huge in Eagle Ford, too. There are areas, such as DeWitt, Live Oak, Karnes, and Gonzales, whose production levels seem even higher than Bakken's and others that are well below Bakken's less productive areas, as shown in Figure 5.²¹

Figure 5. Eagle Ford: Average per well crude oil first year production in different areas



Source: Author elaboration on RRC and companies' data²²

Although Figure 5 seems to suggest that an average of 80,000 b/d per well production in production during year 1 is too low, it's worth recalling that there are other areas of this play that produce at levels lower than Dimmit. Further, given the higher uncertainty about data from the RRC about Eagle Ford, I preferred to assume a much more conservative approach to this play.

On top of the above-mentioned productions of the two bigger U.S. shale plays, Bakken wells also produce an average of 13 percent of NGLs and natural gas while Eagle Ford's oil window produces an additional 25–30 percent of NGLs and natural gas.

Assuming an \$85 per barrel oil price and additional expenses of an average \$1.5 million to \$2 million a year (royalties, operating costs, etc.) per well, many shale oil wells seem capable of repaying their capital costs in a year or less while the vast majority take no more than two years to do so, if the additional volumes of NGLs and natural gas produced by those wells are considered.

Of course, there are many wells that do much better than the average, others that are less productive (but also cost much less than the average), and wells that entail a net financial loss. But, in a way, oil producers have so far considered the latter to be in the same category as dry or noncommercial wells found in conventional oil exploration—the near-inevitable cost of doing business typically incurred during initial stages of exploration.

Clearly, all this has a limit.

There have been companies that have been extremely successful in getting the best areas, achieving the best performances, balancing costs and revenues, and hedging their production against significant downward fluctuations of oil and gas prices while others have not. Even in less productive areas of the same shale formation, performances by companies have shown a huge variance, with companies capable of making a profit and companies that simply have overspent and accumulated an increasing debt.

So far, however, the high price of oil has supported the extraordinary drilling effort brought about both by successful and less successful companies, but a sudden decline in oil price could put the weakest operators in danger.

Given the industry's current cost structure, per-well productivity profile, transportation bottlenecks, and refining constraints, the higher-cost, marginal shale oil barrel has had a break-even point of \$85 per barrel, without taking into account the additional production of natural gas and NGLs.

Yet the dramatic variance in shale productivity within individual shale formations means that any given shale play possesses core areas with much lower break-even points, starting from as low as \$40 per barrel, or even less.

Shale resource break-even points per barrel are likely to decline further as the ongoing adoption of more cost-efficient methods of extraction proceeds.

The advancement of understanding and improvement of technology and production methods has so far allowed for decreasing per-well costs by a rough 30 percent from 2010 to 2012 in nominal terms. The cost reduction trend probably will continue in the near future, helped also by the progressive easing of transportation problems that have imposed so far significant discounts upon shale oil crudes, particularly on Bakken's. (See Appendix A, Section 2, Bakken.) All of this will make shale projects more resilient to fluctuating oil prices and sustain their economic viability.

But so long as technology and better understanding of shale formations do not further revolutionize the shale sector, the overall increase of U.S. shale oil production critically will depend on the continuation of a highly intensive drilling activity and on a relatively high oil price: something that no one can take for granted.

5. BLOWING AGAINST A SUSTAINED SHALE BOOM

Despite its huge potential, not everything is bright and rosy for U.S. shale oil.

First and foremost, a sudden oil price fall in the short term will likely determine a significant contraction of oil drilling, starting with the most expensive areas of U.S. shale formations. In turn, this would lead to a drop in production.

Fluctuations of this kind cannot be ruled out in the shale sector, given another peculiar feature of shale activity that differentiates it from conventional oil (and gas) activity.

In fact, the drilling of new shale wells can be interrupted very rapidly, within a few months or even weeks, in a scenario in which a drop in oil prices renders continued investment unprofitable or much less profitable. This is because shale development occurs on a per-well basis and not on a field basis, as in conventional oil activity, and critically depends on short-term oil prices given that peak production is achieved during the first weeks of a well activity and the bulk of production is obtained during the first and second year of production.

The opposite is true as well: shale activity can be resumed outright if oil prices later would resume their upward climb.

Hedging strategies aimed at protecting the value of future production may ease or delay a drastic cut of drilling, and thereby of production. As we have seen, shale oil companies typically hedge significant vol-

umes of their next year expected production, so as to lock in a pre-determined price. Also, a certain level of drilling is required for a company not to lose its acreage lease that usually expires in three years if no activity is performed. But the longer oil prices stay low, the more difficult it becomes for an oil company to hedge its future production and the cost of preserving its acreage leases. That's why a long-term, significant fall of the price of oil would likely knock down U.S. oil production.

Beyond oil economics, there are other factors that may adversely affect drilling intensity, and thus the growth of shale oil production.

Drilling intensity is highly weather-sensitive in that it is affected significantly by bad and extreme weather conditions. In Bakken, extreme temperatures and intense snowfalls tend to reduce drilling and thus production during the most severe months of winter, typically January to March, while occasional flooding may endanger drilling as snow and ice melt as spring arrives. For example, by January 2013, Bakken's oil production was 4.2 percent lower than its December 2012 temporary peak because of bad weather conditions.²³

As reported by the director of the NDDMR, "(...) Even though the drilling rig count held in the middle 180s, rig efficiency fell and the number of well completions plummeted 26 percent to eighty-five. That number of completions is half the previous 12-month average and below the threshold needed to maintain production."²⁴

The issues of drilling intensity and well density, however, have a major implication in terms of impact on population and environment.

The U.S. shale revolution has taken place in traditionally oil drilling-prone states, such as North Dakota and Texas, which are characterized by sparsely populated areas and have been intensively drilled in the past. Because of these features, it is highly improbable that these two states that are pillars of the U.S. shale revolution will face any significant obstacles on their way to produce more and more shale oil.

But the situation could change dramatically in several areas of shale formations that are much closer to densely populated areas. In the United States this could be the case in those states that share mainly shale gas resources (New York, Pennsylvania, Ohio, etc), but also California, home to one of the most promising shale oil formations – the Monterey Shale, that may be the only formation that can match the resource potential of Bakken, Eagle Ford, and the Permian Basin.

Drilling intensity will become an insurmountable environmental hurdle in Europe and other parts of the world that have a high population density and have no tradition of intensive drilling. More sophisticated technology, such as multipad drilling, drastically may ease the surface impact of drilling intensity but will not change the number of wells that are necessary to sustain growing shale production.

Drilling intensity might become the premier environmental problem for many areas and countries of the world that so far have not realized this peculiar aspect of shale activity.

Whatever the foundation of most environmental concerns about fracking—which I dealt with in my paper "Oil: The Next Revolution"²⁵—drilling intensity likely will have a more direct and visible impact on public opinion in many parts of the world than highly debated fracking-related issues, such as water consumption and contamination, whose impact continues to appear less significant than generally perceived.

To this aim, it is worth considering the latest results delivered by the Texas Water Development Board, the state entity that presides over water planning and development in Texas.

According to those results, in 2010 water consumption in all mining activities in Texas, including oil and gas, represented just 1.6 percent of all water consumption of the state as against 55.9 percent used for irrigation, as shown in Table 3.²⁶

Table 3. Texas water demand, 2010

Use	Per- cent
Irrigation	55.9
Municipal	26.9
Manufacturing	9.6
Steam Electric	4.1
Livestock	1.8
Mining (includes oil and gas)	1.6

Source: Texas Water Development Board

Those results consider a period when shale gas activity was at its peak while shale oil was barely starting.

Further, the Texas Railroad Commission, the state entity that presides over and regulates oil and gas activities in Texas, recently stated that its “records do not include a single documented groundwater contamination case associated with hydraulic fracturing—a process that has been employed in Texas for more than 60 years.”²⁷

Texas statistics are all the more important because Texas is by far the most intensively drilled state of United States (and area in the world)²⁸ and it has been the home of the shale gas revolution. Consequently, water consumption by the oil and gas industry and potential water contamination by fracking activities should be more intense in Texas than in other parts of the United States, as proved by the case of Colorado, a medium oil- and gas-producing state where fracking activity is significantly growing. Colorado authorities estimated that the oil and gas industry would use 0.1 percent of overall water consumed in the state in 2012 as compared with 85.5 percent requested by irrigation and agriculture.²⁹

This may also explain the reason why the severe drought that afflicted Texas in 2012 did not significantly affect the oil and gas activity in the state.

A much more severe threat to intensive drilling might come in the future from the suggested correlation between fracking and earthquakes, an issue that has received growing attention after earthquakes hit Oklahoma (Prague, November 2011), and Ohio (Youngstown, December 2011) across areas interested in fracking.

The science on this issue is still in its infancy but it is well known in geology that pumping huge amounts of water into the subsurface may lead to fault slides and, thus, earthquakes.

Several studies so far, including a major one by the U.S. National Academy of Sciences, have suggested

that earthquakes may be correlated not with oil and gas fracking but with fracking aimed at wastewater disposal (e.g., pumping wastewater in a fracked subsurface reservoir where it can be stored).³⁰ This could represent a problem for the oil industry, too, because wastewater derived from oil and gas extraction is usually pumped into disposal wells. But it affects whatever kind of wastewater if stored through the same procedure.

According to a recent study published in *Geology*, the Oklahoma earthquake of 2011 was likely related to wastewater injected into the disposal wells that came from conventional oil drilling operations, not from hydraulically fractured wells.³¹

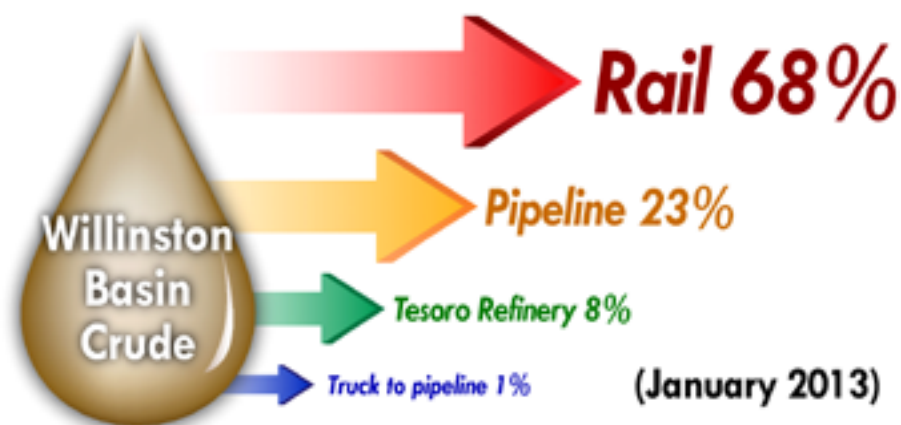
Similarly, the Ohio Department of Natural Resources (ODNR) stated in early 2012 that the Ohio earthquakes were likely the results of the injection of salty wastewater from hydraulic fracturing operations that impacted a previously unknown fault line. The ODNR also noted that there are 144,000 injection wells nationwide and only six have been directly linked to seismic activity. But this suggestion was made before the study on Oklahoma earthquakes.³²

More than affecting oil and gas drilling, therefore, the issue of fracking-induced seismicity likely will spur a much stricter and severe regulation of wastewater disposals, as already occurred in Ohio. In turn, this will require the oil industry to deal carefully with the problems provoked by the disposal of wastewater coming from its oil and gas activity.

Finally, the U.S. shale oil boom will remain hostage to the transportation, storage, and refining bottlenecks in the United States that I described in my paper “Oil: The Next Revolution.”³³

There are now plenty of projects to build up new infrastructure in the most critical areas and hubs of the country. Some of those projects entered the construction phase while old natural gas pipelines have been converted into oil pipelines, particularly in Texas. Moreover, the lack of pipeline capacity has been partly offset by massively resorting to oil transportation by rail. As shown in Figure 6, at the beginning of 2013, for example, the majority of Bakken’s oil production was transported by rail, a phenomenon that was impossible to imagine just a few years ago.³⁴

Figure 6. Willinston Basin crude exports by channel (January 2013)



Despite the industry's construction spree, several regulatory problems and environmental concerns still linger with respect to the possible filling of existing gaps in the U.S. oil infrastructure system vis-à-vis the expected upsurge in oil production in the next few years.

The problems of the U.S. infrastructure system are magnified by the prohibitions on crude oil exports and the Jones Act (1920) that makes it very expensive for U.S. flagged vessels to ship goods between domestic ports.³⁵

According to the EIA, exports of U.S. crude oil totaled 124,000 b/d in February 2013, the highest level since 2000,³⁶ and yet it is a drop compared to the glut of existing oil in the United States – particularly in Cushing. Further, all exports went to Canada, the only destination where approval for exports is easy under existing U.S. laws. Canada is also the cheapest alternative to move oil via vessel from the Gulf of Mexico coast to, for example, the U.S. east coast refineries, due to the effects of the Jones Act. According to the largest U.S. refining company, Valero, “it costs \$5-\$6 a barrel to ship crude from the Gulf of Mexico to the U.S. east coast but only \$2 to ship to Canada's east coast on a foreign-flagged vessel”.³⁷

Whereas exporting crude oil has always been a highly sensitive and heated issue in the United States, a growing surplus of domestic oil will likely catalyze a reassessment of U.S. policies on several fronts including the prohibitions on exports, the Jones Act, and a number of other initiatives put into place to address a world in which domestic production was in decline and energy security was a major concern.

6. WHAT COULD THE POTENTIAL OF U.S. SHALE OIL PRODUCTION BE IN THE NEAR TERM?

To sum up, the resource size of U.S. shale and tight oil formations, and the ability of the industry to develop them through steady improvements of technology, support the continuation of the U.S. shale oil boom and dwarf earlier forecasts about its scope and potential. On the other hand, the unique characteristics of shale oil – and in particular the drilling intensity it involves – make it extremely vulnerable to both a drop in price and environmental opposition in most areas while persisting bottlenecks of the U.S. midstream and downstream system may further endanger the boom's scope.

What is the result of all this? To answer this question, I used a possible best-case scenario encompassing a West Texas Intermediate (WTI) price of \$85 per barrel in 2013, \$80 per barrel in 2014, \$75 in 2016, and \$65 long term, along with an 8 percent per-well cost reduction per year through 2017 (that is consistent with what is already happening across the shale industry), and the progressive easing of the transportation problems that now imply significant price discounts for most of U.S. shale crude oils. My projection of the total U.S. oil potential also assumes that, from 2013 to 2017, more than 6,000 new oil producing wells are brought online annually in the shale/tight oil arena alone. Appendix A, which focuses on the analysis of the big U.S. shale formations and their specific potential, offers the detailed figures I used. I only summarize the results of that analysis here.

If this scenario materializes, by 2017 shale crude oil production in the United States could approach 5 mbd per year compared to more than 1.5 mbd in December 2012.

Over this same period, growth in U.S. crude oil produced by conventional sources will likely stabilize or grow modestly as a result of contrasting forces.

True, U.S. conventional oilfields are mature and declining, but the extensive application of advanced technologies to recover more oil can temper and, in some cases, can revive their output. Among these technologies are EOR methods, such as the use of steam, chemicals, and heavy gases such as carbon dioxide as well as the same technologies used to get the oil out of shale formations—e.g., horizontal drilling and fracking. Several oil basins in the United States are already experiencing this new stage of redevelopment that, combined with emerging production from shale and tight oil formations, has reversed the decline of most American oil producing states since 2007, as shown in Table 4.

At the same time, after the plunge in production as a result of the Deepwater Horizon blowout in April 2010 and the temporary moratorium on drilling, production in the Gulf of Mexico will recover in the next few years, spurred by a renewed rush for drilling and development that has already brought about potential new massive discoveries, such as those of Shenandoah and Coronado.

Table 4. The revival of U.S. crude oil production, 2007–2012
(Average, thousands of barrels per day)

State	2007	2008	2009	2010	2011	2012
Texas	1,072	1,109				
Gulf of Mexico	1,282	1,156				
North Dakota	124	172	218	310	419	662
California	599	586	567	552	531	532
Alaska	722	683	645	601	561	526
Oklahoma	175	184	183	186	213	243
New Mexico	162	164	168	179	196	230
Louisiana	211	198	189	185	189	193
Wyoming	148	145	141	146	150	158
Colorado	71	80	83	89	107	130
Kansas	100	108	108	111	114	119
Utah	54	60	63	68	72	82
Montana	96	86	76	69	66	71
Mississippi	57	63	65	66	66	66
<i>Others</i>	204	206	192	195	198	206
Total	5,077	5,000				

Source: US Energy Information Administration³⁸

So far, of all U.S. oil producing states, only Alaska, California, Montana, and Louisiana have faced an apparently irreversible decline of their crude production. In California, however, shale activity could be boosted in the future by the massive shale resource of the huge Monterey shale, whose potential still needs to be properly assessed. The same is true for Montana, which holds the less productive part of the Bakken formation.

Even assuming that U.S. conventional oil production remains relatively steady from 2012 to 2017, one can still plausibly envision the United States producing 10.5 mbd of crude oil by 2017, the highest production level in the country's history after the peak of 1970 (10.9 mbd). Adding contributions from rapidly growing NGLs, a consequence of both the shale gas and oil boom, and biofuels suggests that total U.S. liquid production could reach slightly less than 16 mbd by 2017, as shown in Table 5.

Table 5. U.S. projected oil production, 2012–2017

Liquid production	2012 Average Production	2012 December Production	2017 End year Production
Conventional crude oil	5.3	5.4	5.4
Tight and shale crude oil	1.14	1.5	5.
NGLs	2.3	2.5	3.5
Bioefuls and other	1	0.9	1
Processing gains	1	1	1
Total crude oil	6.44	6.9	10.4
Total liquids	10.74	11.3	15.9

This trajectory could make U.S. oil production and production capacity the world's largest.

This revival of U.S. production likely will make Texas re-emerge as a top world oil producer, with about 4 mbd of crude expected by 2017. This can be traced to Texas housing the Eagle Ford and Permian formations, two of the country's largest, fastest-growing shale areas, along with other conventional oil formations that are experiencing a revival of their production, sometimes in the very basins of shale activity.

Based on my analysis, the Big Three U.S. shale plays, Bakken-Three Forks (North Dakota), Eagle Ford, and Permian Basin (Texas), have a combined potential production of 4.7 mbd by 2017. (See Appendix A.)

The production potential of most other U.S. shale plays remains uncertain. (See Appendix A.)

Plays such as the Utica-Point Pleasant, Monterey, and Tuscaloosa-Marine shales, with substantial resource potential, continue to linger in the initial stages of appraisal while others such as the Niobrara-Codell shale require further analysis after yielding mixed results. Based on a purely probable method, the combined output of all U.S. shale and tight oil plays other than the Big Three may reach 400,000 b/d of crude oil by 2017. This projection may turn very conservative. True, although other U.S. states may lack monster plays such as Bakken-Three Forks, Eagle Ford and the Permian Shale, arguably with the sole exception of California's Monterey Shale, most of the other shale formations may do better than anticipated due to the intense exploration and development activity they are now witnessing.

However, while the overall trajectory of the U.S. shale production seems destined to materialize a long-term revolution, the nature of shale and tight oil sector makes it vulnerable to periods of sluggish growth and even significant falls of production.

First, a dip of oil prices could entail a fall of drilling activity and thus of U.S. oil production, whose en-

tity should be commensurate with the size of the oil price decrease. Also, in the conventional oil sector, a substantial decrease in oil prices would entail a slowing of exploration and development, particularly in the Gulf of Mexico ultra-deep offshore, but also of mature fields whose re-development requires require substantial investments in costly technologies.

This would make the development of solution of the midstream and downstream bottlenecks that loom large on the full deployment of the U.S. shale potential even more daunting.

Consequently, the potential of U.S. crude oil production growth is huge, but this does not necessarily imply a linear upward trend of growth so long as both the knowledge and technology concerning shale formations do not improve substantially and key infrastructure problems are finally solved.

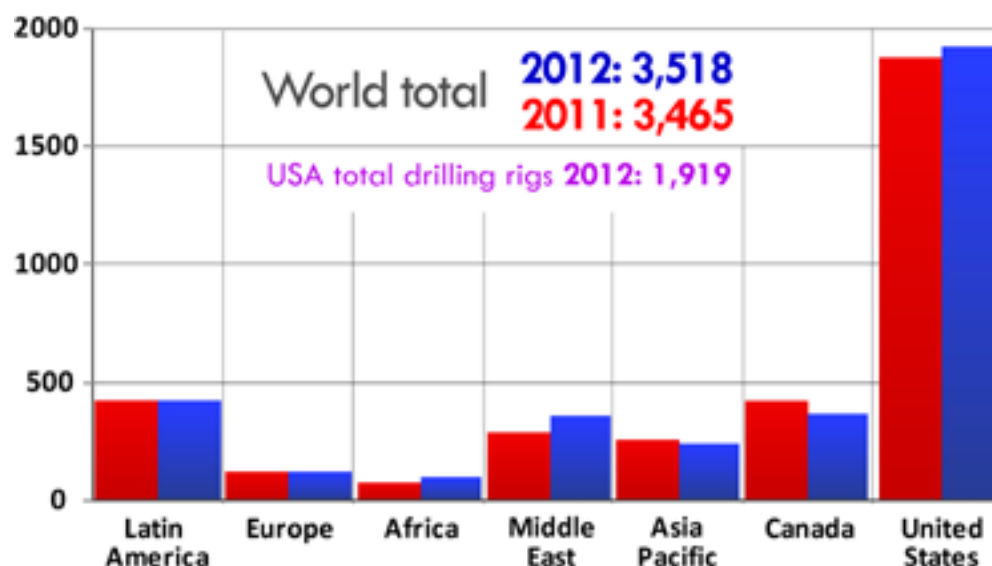
7. THE DIFFICULTY OF REPLICATING THE U.S. SHALE BOOM GLOBALLY

As we have seen, drilling intensity has been a key factor in supporting the boom of oil production in the United States (and, earlier, of natural gas), and it will continue to play a key role in sustaining additional growth of such production. Consequently, regardless of where it occurs, future development in shale will continue to rely heavily on the availability of surrounding rig and fracking tools.

Elsewhere internationally, however, this equipment is far less accessible than in the United States The extent of this divergence becomes clearer upon recollection of a few key figures regarding the global rig market.

As shown in Figure 7, in 2012 the United States averaged 1,919 active drilling rigs, just below 60 percent of worldwide activity, and held a potential of more than 2,100 drilling rigs. Canada came in second with 356 active drilling rigs.³⁹

Figure 7. Worldwide active drilling rigs count (2012 average)



Of the U.S. drilling rigs, roughly 90 percent were equipped for horizontal drilling, an essential component in shale development. In 2011, nearly 95 percent of U.S. horizontal and vertical wells were fractured⁴⁰ compared with less than 10 percent outside the United States.

Across the U.S.'s three principal shale plays, the Bakken-Three Forks, Eagle Ford, and Permian basins, slightly less than 500 oil rigs are actively targeting shale formations; in a year, each rig may drill from a handful to more than fifteen wells.

By contrast, there were only 119 drilling rigs across all of Europe (excluding Russia) in 2012,⁴¹ of which only one-third was equipped to perform horizontal drilling. With the exception of Canada, the scale and scope of Europe's rig deployment is roughly similar to other areas of the world today. Further, no other country in the world outside of the United States has the specialized crews, tools and capabilities to perform intensive fracking activity.

These figures aid in explaining why, as of today, no country in the world can likely match even a fraction of the U.S. drilling and fracking power.

Moreover, any change in this reality remains years away, given both the lengthy period required to manufacture rigs and oil servicers' traditionally conservative approach toward new construction (oil companies do not own drilling rigs; oil service companies do).

Consequently, near-term discoveries of shale resources outside of North America likely will prove to be short-lived because shale's increasing cumulative production requires drilling hundreds, even thousands, of new wells a year. This particular aspect may be perhaps the most significant restraint on shale development outside the United States in this decade.

A still uncertain candidate to break this rule could be the Russian Federation, whose drilling rig number is not clear. The emergence of the supergiant Bazhenov shale formation in western Siberia,⁴² which may cover an area as big as Texas and the Gulf of Mexico combined (or about 570 million acres) and has already triggered a joint development venture among Russia's Rosneft, ExxonMobil, and Norway's Statoil, might open up a new shale frenzy outside the United States. Yet the problem remains: A major shale formation could remain a paper project without hundreds of rigs capable of drilling horizontally and without other essential tools to frack and bring online thousand of wells a year.

Another candidate to witness some kind of shale boom could be China, particularly as far as shale gas is concerned. This is because China has shown so far an incredible capacity to develop in few years whatever it needs to ensure the development of strategic sectors. Consequently, if China really discovers major shale gas formations on its territory, it once again could surprise the world through the production of an adequate fleet of drilling rigs.

A second, potentially less appreciated factor supporting the U.S. shale boom is the hundreds of independent companies operating in North America that have historically pioneered exploration and development of new resources and technology.

Independent sector involvement is particularly important in shale because the characteristics of unconventional resource development are more suited to smaller companies operating mainly in the United States than to large, internationally integrated oil giants – as already discussed in Section 4. As shown in Table 6,

the first 10 top producers in both Bakken-Three Forks and Eagle Ford at the end of 2012 were all big and smaller independents whose operations are concentrated in the United States, with few exceptions.

Table 6. Top ten producers, Bakken and Eagle Ford, (2012)

Bakken-Three Forks⁴³	Eagle Ford⁴⁴
Continental Resources	EOG Resources
Whiting Petroleum	Burlington Resources*
Hess Corporation	Chesapeake Energy
Brigham Exploration**	GeoSouthern Energy
EOG Resources	Anadarko
XTO***	Plains Exploration & Production
Marathon Oil	EP Energy
Petro-Hunt	Marathon Oil
Slawson Exploration	Murphy Oil
Kodiak Oil & Gas	Pioneer Natural Resources

* *Acquired by ConocoPhillips*

** *Acquired by Statoil*

*** *Acquired by ExxonMobil*

In three cases, big oil names such as ExxonMobil, ConocoPhillips, and Norway's Statoil decided to enter the shale arena by taking over existing independent companies (Burlington, Brigham, and XTO). Other producers in both areas are mostly much smaller than the ones listed in Table 5, with only a handful exceptions, and their names are almost unknown even to the international oil community. Other big independents, such as EOG, Chesapeake, or Continental Resources, exclusively owe their current status as relatively big companies to the success they achieved when they entered the shale arena.

Independent operators typically search for high-risk, high-reward opportunities with uncertain potential, whereas big oil developers pursue opportunities based on an established, more risk-averse financial framework. Also, independent operators tend to focus more heavily on generating cash flow and growth vs. stable profits over the long run. Often run by single executive or small management teams, independents understand that achieving success in their undertakings while generating cash flow enables them to raise further financing to grow their business. Eventually, many small cap companies merge with larger independents, are acquired by integrated oil companies, or decide to go public.

The time frame for success for independents, therefore, is much shorter than that of big multinational oil companies. They cannot afford to be cash negative for long periods, otherwise their investors would stop supplying money. They cannot afford to be unsuccessful in growing their business, otherwise selling part (or all) of their equity ownership stake becomes much less attractive.

Finally, the U.S. independents' business model is already familiar with managing low-producing and/or stripper wells, wells that, according to different definitions, produce less than 10 b/d or 15 b/d,³ a figure that so far represents the future trajectory of a shale well following a few years of production.

³ The EIA available statistics on stripper wells are based on the 15 b/d figure, and this is the maximum production level that the agency considers in its glossary of energy definition. However, the most common U.S. definition of a stripper oil well is "a marginal oil well producing no more than 10 barrel per day."

Traditionally, stripper wells have comprised a significant portion of U.S. oil production. Before shale oil catapulted into industry awareness in 2009, the United States housed over 300,000 active oil stripper wells producing less than 15 b/d and representing more than 50 percent of all its producing wells and 16 percent of the country's oil production.⁴⁵ Historically, these stripper wells have been the domain of small independent companies,⁴⁶ although no recent precise statistics exist on this sector, while the big oils have tended to sell low-producing mature assets.

Of course, there are exceptions to this pattern, particularly in the case of large, mature oil and gas formations with combined production sufficient to be significant to the big oils. However, for a country to replicate the U.S. shale boom will be challenging without the vibrant ecosystem of independent companies that always have shaped oil and gas activity across North America.

Other dynamics currently constraining a U.S.-style shale boom outside the country are by now well known and can be summarized as follows:

- In the United States, individuals and companies may possess property rights to mineral resources while elsewhere internationally these rights belong to state actors alone. As a result, U.S. land-owners are freely capable of and often incentivized to transfer their property rights to the oil industry via sale or lease. Such a secondary market often facilitates rapid energy exploration and development.
- Unlike Europe, U.S. shale formations' concentration in sparsely populated areas enables drilling intensity to reach normally unattainable heights.
- The U.S.'s oil and gas sector also benefits from the presence of domestic financial institutions, venture capital and private equity firms eager to fund independent companies and more open to forms of private financing.
- Finally, a shale revolution requires the existence of an ample articulation of midstream and downstream infrastructure (pipelines, storage, refineries), as well as adequate water supplies, that in many countries – including China – appears to be inadequate.

For all these reasons, it is difficult to believe that a U.S.-style shale revolution may occur in any other part of the world in the foreseeable future. However, the U.S. shale experience may have a dramatic impact on the hydrocarbon sector by gradually diffusing hydraulic fracturing as a means to recover more oil from conventional, mature, and declining oilfields worldwide – whose average recovery rate is currently no higher than 35 percent. In fact, right now hydraulic fracturing of vertical or horizontal wells has been responsible for the revival of production of mature oilfields in the United States where more than 90 percent of all wells are now hydraulically fractured.

8. WINNERS AND LOSERS: GEOPOLITICAL AND ENERGY MARKET IMPLICATIONS

The shale revolution likely will strengthen the U.S.'s national energy security by lowering its heavy reliance on oil imports.

The United States consumed just over 19 mbd of oil in January 2013. They were comprised of crude oil imports (8.3 mbd) and domestic production of crude oil (7 mbd), refinery inputs of domestically produced NGLs, liquid biofuels, and other liquids (3.6 mbd).⁴⁷

While the nation is largely self-sufficient in terms of coal, natural gas, NGLs, and biofuels production, the potential fault line in terms of energy security is the import of crude oil. Yet, since peaking around 10 mbd in 2007,⁴⁸ U.S. crude oil imports have declined steadily in tandem with falling consumer demand and rising domestic supply. The United States received its 8.3 mbd crude oil imports in January 2013 primarily from Canada (2.2 mbd), the Persian Gulf nations (2.2 mbd, 1.25 mbd of which from Saudi Arabia)⁴, Mexico (1.05 mbd), Venezuela (0.95), and Nigeria (0.5 mbd).

The rate of future decline of U.S. crude oil imports will depend upon evolving domestic production as well as consumption. The latter is now roughly 2.5 mbd lower than its peak in 2007 and may well recover in the coming years with rebounding economic growth. However, further decline in domestic demand could occur from the effects of energy efficiency legislation and high oil prices. Regardless, if U.S. oil consumption remains steady at 2013 levels or increases 2–3 percent annually, we can expect domestic crude production to continue weighing on import volumes.

Clearly, if the United States wants to target the highest degree of oil security, it should rely not only on an increase of its domestic crude production, but also on pushing further for energy efficiency measures that could curtail crude oil consumption. This scenario offers the opportunity to develop a new industry capable of producing vehicles, tolls, engines, etc., that do the same work, or even a better one, while consuming much less.

In a scenario of declining imports, the most probable victims will be the traditional suppliers of light crude to the United States, namely the West African producers (mainly Nigeria and Angola), whose supplies are going to be displaced by U.S. surging production of light oils from shale. However, another probable candidate to become a victim of U.S. growing oil production is the safest source of U.S. oil imports—Canada. On this issue, my view is more pessimistic than that expressed by other excellent analyses on the consequences of the U.S. shale revolution.⁴⁹

As the United States traditionally has absorbed 95 percent of Canada's crude and liquid exports, rising U.S. shale oil production stands to jeopardize a significant portion of Canada's future potential exports, for two main reasons.

First, Canadian oil exports already compete for transportation capacity, particularly via pipeline, with North Dakota's surging production. Further, both producing areas rely on the same trading and storage hub, the already overburdened Cushing, Oklahoma. But while North Dakota is finding alternative take-away options because of rail transportation, a significant part of future Canadian oil production risk being landlocked without the availability on new pipelines, such as the much debated Keystone XL.

Second, marginal production costs for a substantial amount of Canadian crude are the highest in the world, with several oil sands projects presenting a break-even of more than \$90 per barrel. Conversely, the price discount for West Canadian Select (WCS, the benchmark for Canadian heavy crude derived from oil sands) hit a five-year low in December 2012 of just over \$40 per barrel against WTI, or less than

⁴ Persian Gulf nations represent Saudi Arabia, Iraq, Iran, Kuwait, Qatar

half of the price of Brent crude, making it the cheapest crude oil on the planet.⁵⁰ Although WCS spread vs. WTI eventually narrowed, the most expensive projects with respect to Canadian oil sands will remain highly vulnerable in the future, a prospect that already led several oil sands companies to slash their 2013 investment budget and cancel new development projects.

Once again, without new pipeline capacity to the United States and, possibly, to other, more rewarding markets, Canadian oil producers increasingly will suffer from their landlocked location and the simultaneous price squeeze. While there are plenty of transportation projects already waiting for authorization, experience so far has shown that it will be difficult for most of these projects to materialize, at least in a brief period of time, mainly because of environment-based opposition.

For example, in May 2013, the government of British Columbia said it would oppose the construction of the Northern Gateway pipeline unless there was a greater ability to respond to a spill. Northern Gateway is a critical project in that it would open up the Asian markets to Canada's oil sand, carrying 525,000 b/d of diluted bitumen – heavy oil mixed with lighter liquids so it will flow – about 730 miles from the oil sands of Alberta to a terminal at Kitimat on the coast of British Columbia.⁵¹

In any case, the current and foreseeable U.S. oil market situation makes Canada too vulnerable, obliging it to think about structurally changing its energy policy and diversify the exports of crude oil and natural gas, shifting away from the comfortable policy of putting all of its eggs in one basket. This would remain the case if the Keystone XL project is approved. In fact, whereas the pipeline will ease the short to medium-term delivery problems of increasing Canadian oil sands production, it will not match the huge potential for growth of such production.⁵²

Venezuelan exports also may suffer from rising U.S. domestic production, given the country's high costs of processing and upgrading a significant part of its ultra-heavy oils and the uncertain policies of the post-Chavez era. Similar to Canada's more challenging projects with oil sands, the total cost of many Venezuelan ultra-heavy oils is among the most expensive globally. Any additional downward pressure on U.S. crude oil prices could make the U.S. market unprofitable for part of the Venezuelan crudes and oblige the country to search for other outlets.

Much depends also on the evolution of the spread between Brent, the international price benchmark, and WTI. A spread of about \$20 a barrel, such as the one registered in 2012, will make room for Venezuela's exports to markets other than the United States because the additional transportation costs (that may vary between \$5 to \$8 a barrel) easily could be offset by the higher margin obtained by selling oil at international prices.

In geopolitical terms, therefore, the paradox of growing U.S. oil security is that it risks negatively impacting traditionally safe Western Hemisphere exporters while providing expansion opportunities for other countries seeking to step in large producing countries such as China.

The Persian Gulf, the chief target of the "import-destruction" mantra of U.S. energy independence advocates, could lose shares of the U.S. market as well, but that area possesses the flexibility of turning to Asian markets to offset potential losses.

The major problem for Persian Gulf producers and the entire Organization of Petroleum Exporting Coun-

tries (OPEC) will not be the U.S. shale oil revolution per se (although this is and will be a major issue for the African members of OPEC) but the combined effect of a steady growth of the world's oil production capacity face to a sluggish growth of the demand for oil.⁵³ In this framework, the key issue for OPEC over the next few years will be how much spare capacity—e.g., unused oil production capacity—it will be able to manage without encountering growing tension among its members: Above all, this problem impacts the future policies of Saudi Arabia, which is the largest holder of spare capacity globally by far. So far, the problem of spare capacity has been partially eased by the international sanctions against Iran that have dramatically reduced the country's oil exports and made room for other countries' on the market. Without those sanctions, the additional exports of Iran would have likely derailed the oil market.

Broadly speaking, the rise in U.S. shale oil will take other victims too, but the kill list will be determined by cost and price, not politics. This is because U.S. oil refiners are the buyers of crude oil, not politicians, and refiners first consider the price they pay and the margin they can make.

Another paradox of the U.S. shale boom is that the seemingly greatest beneficiaries today—a plethora of oil and financial companies—may be tomorrow's victims. This distress cycle likely could occur because of the various peculiarities of shale economics and development.

In fact, in their quest for shale, many companies have simply overspent on new development without either improving performance or acquiring high-quality assets. Most of these assets, often trophies won in bidding competitions, are overly concentrated in natural gas and NGLs with highly depressed prices or in high-cost, low-productive oil areas. Consequently, those companies are now stripped of cash, overburdened by debt, or simply lack the quality resource assets necessary to generate significant growth and returns. Their increasingly wobbly operational performance, imperceptible to those unfamiliar with the nuances of shale, will at some point entangle the funds of their investors who have poured billions into these enterprises over the last few years.

The growth of NGLs and its low cost will be a boon for the U.S. petrochemical industry. Having an opportunity to rely on such cheap feedstock, the industry may face an unprecedented revival and enjoy an enviable competitive position with respect to the world. (Only Persian Gulf producers may enjoy a better competitive positioning, but in their case the advantage is artificial because of a very low price imposed upon petrochemical feed stocks by the governments of the area for the sake of developing the petrochemical industry. In turn, however, the policy of administered prices is constraining the availability of feedstock, whose production is uneconomic for many producers.) Along with the petrochemical sector, the railways sector has entered a golden age because of its essential role in easing the problem of how to get the oil out of its production areas.

Finally, growth in the U.S. biofuels industry could stand to soften from both the rise of U.S. crude oil production and strained budgets at the U.S. federal and state levels. To make matters worse, a nationwide drought in 2012 and ongoing food shortages across the globe have mounted pressure on Washington to revise its biofuels policy,⁵ with the United Nations Food and Agriculture Organization director recently calling for suspension of domestic biofuels production.⁵⁴

The Obama administration continues to support biofuels development so that any call for suspending their

⁵ The UNITED STATES is the largest corn producer of the world, but U.S. law dictates that 40 percent of the corn harvest must be used to make biofuel.

production appears totally unrealistic. But because of the above-mentioned factors, as well as the growing problems and costs that biofuels blending are creating for U.S. refineries, it seems plausible that U.S. biofuel production (primarily bio-ethanol) might either plateau around the level reached between 2010 and 2012 at slightly less than 1 mbd (oil equivalent) or grow at a much slower pace than during the last decade.⁵⁵

Conversely, other renewable sources of energy will not be affected by the boom of shale oil. Solar and wind energy, in fact, serve mainly to produce electricity while crude oil is 75 percent absorbed by the transportation sector. Rather, they will compete with cheap natural gas—a consequence of the shale gas revolution—even if the chief victim probably will be coal.

APPENDIX A: THE U.S. SHALE OIL PLAYS

1. INTRODUCTION

So far, the U.S. shale boom has been driven by what I referred to as the Big Three shale plays: Bakken-Three Forks, Eagle Ford, and the Permian Basin. Since Eagle Ford and the Permian are still in the making, all three have shown a huge potential and are already producing increasing volumes of crude oil at a very fast pace. There are many other shale oil plays in the United States on which the jury is still out.

In terms of sheer size and other characteristics, only two of them seem to have a theoretical potential to enter the big league of the Big Three: the Utica and Monterey shales. However, the very early stages of exploration and understanding of these plays does not allow for elaborating any precise projections on their future evolution.

This appendix focuses on a detailed view of the Big Three shale plays and a brief introduction to the main characteristics of other interesting shale plays that have emerged thus far.

The basic scenario variables I used for the elaborations made in this appendix are:

- A. Price of oil (WTI nominal terms): \$85 (2013), \$80 (2014), \$75 (2015), \$65 long-term.
- B. Per-well cost reduction: 8 percent per year through 2017

A decreasing price of oil is consistent with my general view, expressed in “Oil, the Next Revolution,” that oil prices may fall in the future because of the accumulation of broad oil production capacity globally.

2. BAKKEN-THREE FORKS

The Bakken-Three Forks shale (in fact, a tight oil formation) is part of the Williston Basin, a huge sedimentary basin that stretches about 300,000 square miles across North Dakota, South Dakota, and Montana in the United States and across Saskatchewan and parts of Manitoba in Canada (Figure 8).

Figure 8. The Williston Basin and the Bakken formation

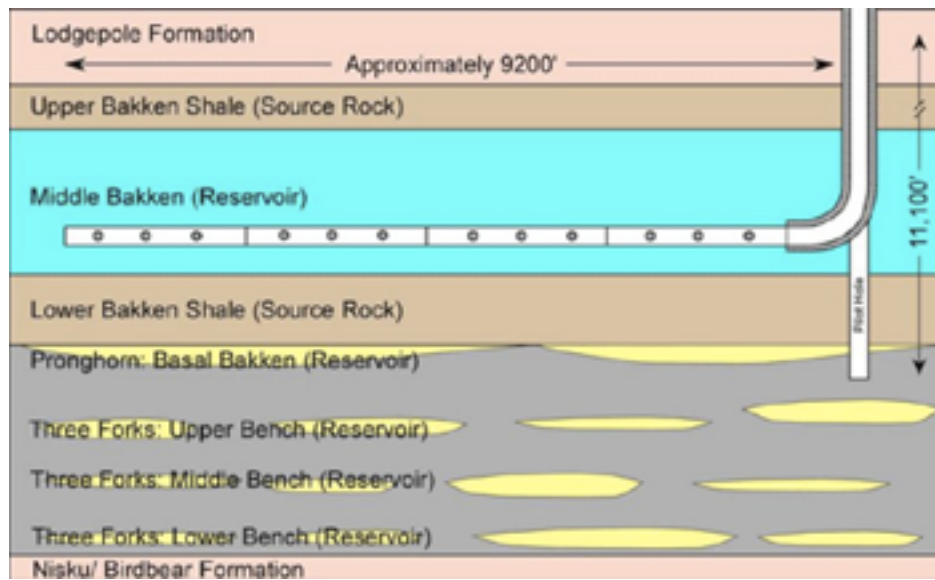


First discovered in 1951 in North Dakota, the Bakken formation (about 200,000 square miles, or about 520,000 square kilometers²) was too costly to develop for many decades. Only at the beginning of the 2000s did the small Lyco Energy Co. and giant Halliburton attempt a combination of horizontal drilling and hydraulic fracturing in a small section of Montana's part of the formation (the Elm Coulee field). The outcome was so promising that, in 2006, it led the independent company EOG Resources to repeat the experiment in an area of the North Dakota section of the Bakken formation (the Parshall field). That was the real beginning of the U.S. shale oil revolution.

Currently, the main productive area of Bakken-Three Forks is estimated to be slightly less than 12,000 square miles, but exploration and production is moving to other areas and going deeper to get oil from a different strata of Three Forks that, so far, have been untouched. In fact, like all shale and tight oil formations, Bakken-Three Forks is made up of several strata—also referred to as “intervals” or “benches”—with different geological characteristics and thickness, as shown in Figure 9.

While the very early stage of Bakken's development relied essentially on the Middle Bakken reservoir, exploration and development is moving also to the lower formations, particularly into the three benches of Three Forks that have a bigger thickness than Middle Bakken.

Figure 9. Bakken-Three Forks stratigraphy



Source: CREDO Petroleum's April 2012 Investor Presentation

As already reported in my “Oil, the Next Revolution,” my estimates of recoverable oil reserves from Bakken-Three Forks is about 45 billion barrels. For a more detailed view of this argument, I refer the reader to that paper.”⁵⁶

Starting from a few thousand barrels in 2007, shale oil production in Bakken Three-Forks reached 550,000 b/d at the end of 2011 and 770,000 b/d in December 2012 (plus an additional 818,152 million cubic feet per day of natural gas).⁵⁷

The rig count is decreasing, after peaking at 218 units on May 19, 2012.⁵⁸ In January 2013, the total rig count figure was 185, all concentrated on oil themes and 95 percent of them targeting Bakken and Three Forks alone.⁵⁹

As we have seen in the first part of this study, the number of new producing wells has increased dramatically on an annual basis over the years, by 2012 exceeding an estimated 1,600. The intensive drilling activity largely explains the steady growth of oil production in the Bakken-Three Forks area despite the steep production decline of shale wells.

According to the NDDMR's estimates based on well completion rates and production responses in November and December 2012, it now takes about ninety new wells a month, or more than 1,000 a year, to maintain December 2012 production levels.⁶⁰ Consequently, the higher the level of production, the higher the numbers of new producing wells needed. It is probable, however, that the more advances made in knowledge and technology, the more there will be a need to bring new wells online as a result of higher recovery rates.

My analysis of the productive pattern of more than 1,400 producing oil wells in Bakken-Three Forks suggests that productivity per well has increased dramatically over time.

The analysis of data by the NDDMR⁶¹ and public information made available by oil companies for the U.S. Securities and Exchange Commission (SEC) and presentations to investors suggests that the average per-well IP30 in the Bakken-Three Forks has more than doubled between 2007 and 2012, escalating from about 4,000 barrels of oil in 2007 to slightly more than 11,000 in 2012 (see Figure 3).

Although the observation period for the wells brought online after 2010 is still too brief, the decline rate recorded so far by the most recent wells seems to follow the general pattern exhibited by the wells brought online before 2010. (See table 1, Section 1). Wells brought online between 2010 and early 2011 have produced on average in excess of 100,000 barrels of crude oil (plus minor volumes of natural gas) during the first year and 155,000 barrels of oil in the first two years.⁶² As I have noted, however, these averages incorporate huge variances.⁶³

On average, in the Middle Bakken and Three Forks formations, a well completed in 2012 costs between \$8.5 million and \$11 million, meaning that the largest share (75 percent) of the wells I tracked fall into range. It is worth noting that in 2010 costs were on average 25 percent to 30 percent higher in nominal terms. To these costs should be added the cash paid upfront to acquire the acreage, going from \$350 an acre for the early entrants to more than \$20,000 an acre. Royalties to be paid to landowners are, on average, 15 percent to 20 percent and operating costs oscillate between \$6 and \$8 per barrel.

Roughly speaking, these numbers suggest that the average Bakken producer needs to sell its oil at about \$60 to \$65 per barrel to get an 8 percent internal return on capital (IRR). It is worth recalling that Bakken crude has been traded at a discount of about \$8 to \$10 for WTI, even if its quality is superior, because of transportation and refining problems.

This spread probably will disappear in the future as soon as new transportation routes, particularly by rail, will allow Bakken-Three Forks crude to reach the East Coast and other U.S. markets. This transition already has occurred in the case of one of the protagonists of the Bakken development, EOG Resources, the first company to use railroads for the majority of its Bakken crude for a Louisiana Light Sweet (LLS)-Brent pricing, e.g., an average of \$10 more per barrel for WTI.⁶⁴

As noted in the first part of this study, the drilling potential of Bakken-Three Forks is big (see Section 5).

Given the oil price scenario I used for this study, I assumed that if the number of Bakken's new producing wells increases progressively by 12–20 percent a year from 2013 on, the play may reach a crude oil production of 1.8 mbd by 2017.

3. EAGLE FORD

The Eagle Ford Shale in the Western Texas Basin stretches more than 300 miles (480 kilometers) from the Mexico border south of San Antonio to northeast of Austin. The play is composed of three hydrocarbon “windows”: dry gas (southern section), gas liquids (central section), and oil (northeastern section), as shown in Figure 10.

Figure 10. The Eagle Ford Shale: The three “Windows”



Source: Energy Information Administration

Eagle Ford contains a much higher carbonate shale percentage that makes it more brittle and “frack-able.”⁶⁵ So far, the main productive area, in terms of oil and liquids, is estimated to be about 6,000 square miles.

The emergence of the play dates to 2008, when Petrohawk, an American exploration and production company, drilled the first horizontally fractured well in the area, which turned out to be rich in natural gas. Because of the global financial crisis and the contemporary boom of other shale gas plays, there was little action until 2010, when new discoveries, particularly in the oil-rich section of the play, and unexpected recovery rates similar to those in the Bakken finally attracted an eager crowd of independent oil and gas companies.

Since then, the pace of growth of Eagle Ford has been astonishing.

According to Wood MacKenzie,⁶ Eagle Ford oil production, including NGLs, has skyrocketed from virtu-

⁶ Wood MacKenzie, along with IHS, possesses the largest database of oil and gas wells in the world.

ally zero in 2009 to 700,000 barrels of oil equivalent (boed) in December 2012 (of which about 560,000 b/d are crude oil), and it now ranks as the second shale play in the United States in terms of liquid production after Bakken, and first in terms of overall oil and natural gas production, which topped 1 mboed in 2012.⁶⁶ The same source stated that Eagle Ford shale now ranks as the largest single oil and gas development in the world, based on capital expenditures that will reach \$28 billion in 2013. Wood Mackenzie expects capital expenditure in the Eagle Ford from 2012 through 2015 “to surpass the projected capex of the entire Kashagan project in Kazakhstan, the world’s most expensive stand-alone energy project” that will require a total capital investment of \$116 billion.⁶⁷

These figures, however, contrast with the more conservative ones released by the RRC, according to which oil and condensate production in Eagle Ford was about 425,000 b/d in January 2013.⁶⁸

This divergence between two highly authoritative sources gives a sense of how complicated is the most basic elements of the shale sector. My own estimate is that Eagle Ford was producing more than 500,000 b/d of crude oil by the end of 2012, and it has been doing even better afterwards.

The number of drilling permits has increased dramatically between 2010 and 2012, jumping to a cumulative 5,230 permits at the beginning of 2013 as against a total of ninety-four in 2009, as shown in Table 1 in the first part of this study. After 2010, drilling permits for shale gas have plummeted, reflecting a major shift to drilling in the shale oil-rich section of Eagle Ford.

Overall, there were 232 active drilling rigs at the beginning of 2013 as against 229 a year earlier, even though the number peaked at more than 260 units during 2012. Most of the active rigs in January 2013 were used in horizontal drilling (216 in January 2013), while the number of gas rigs continued to decrease (sixty-six).⁶⁹ In fact, the decreasing number of drilling rigs, as compared with the peak in 2012, stems from plummeting gas activity and higher drilling efficiency.

It is not easy to obtain precise data on all completed oil wells in Eagle Ford Shale in the absence of a specific database. I have tracked more than 1,600 primarily oil wells that came online since 2010, 700 of which were completed in 2012 alone, and this is certainly incomplete. Given the much more rapid wells completion time, Eagle Ford is probably in the process of outpacing the activity of Bakken-Three Forks.

Per-well productivity varies significantly across the areas of the play, generally identified according to the different counties that lie in its heart. They are Atascosa, DeWitt, Dimmit, Gonzales, Karnes, La Salle, Live Oak, Maverick, McMullen, and Webb.

Table 7 reports average per-well production data of 1,041 wells across the different counties in the first 30 days of production, as calculated by geologist Gary Swindell as of February 2012.⁷⁰

My own analysis (as of March 2013), on which I based the data reproduced in Figure 5 in the first part of this study, are slightly higher than this.

Table 7. Per-well first month productivity in different Eagle Ford Shale counties

County	Average peak oil production month (bbl)	Average peak gas production month (Mcf)
Atascosa	8,390	9,689
DeWitt	21,551	123,873
Dimmit	7,430	37,772
Gonzales	13,475	10,635
Karnes	14,329	66,037
La Salle	5,195	128,891
Live Oak	17,184	107,657
Maverick	2,567	9,192
McMullen	9,363	86,218
Webb	5,271	119,458

Decline curves in Eagle Ford seem to be steeper than in Bakken during the first year of production, indicating a 55 percent loss of the IP30 after the first twelve months of production. Eventually, they tend to follow the same yearly decline of Bakken.

Swindell's analysis is much more pessimistic than mine, indicating a per-well average ultimate recovery of 206,779 barrels of oil equivalent (including gas), of which 115,282 are barrels of oil. Most companies suggest average EUR numbers higher than 600,000 barrels of oil and gas per well.

I tend to believe that Swindell is too pessimistic whereas oil companies are too optimistic.

True, in the case of Eagle Ford and the Permian Basin, it remains highly complicated to calculate the actual production of wells because of the absence of a detailed state database such as that of the NDDMR. This requires relying much more on data from companies. However, by comparing RRC data and those of the oil companies, it is possible to make the conservative assumption that the average well in Eagle Ford produced about 95,000 barrels of oil and liquids during the first year of production, of which 80,000 barrels was crude oil, or about 219 b/d, plus additional natural gas. Considering the average decline rates of Eagle Ford, this implies a per-well estimated ultimate recovery that is much higher than Swindell's.

In the Eagle Ford Shale, depths are much lower and rock is less formidable than in Bakken. Further, the length of laterals required to get the best productivity so far has turned out to be much shorter (maximum 5,000–6,000 feet) than in Bakken. Consequently, well drilling and completion cost is significantly cheaper than in the North Dakota formation, varying in 2012 between \$5.5 million and \$7.5 million (in 2010, costs were on average 30 percent higher in nominal terms). Royalties to be paid to landowners average 20 percent and operating costs vary between \$4 and \$6 per barrel. Acreage lease expenses are comparable to those of Bakken.

Without considering the additional revenues from NLGs and natural gas, therefore, the average Eagle Ford producer needs to sell its oil at about \$55 per barrel to get an 8 percent IRR. Yet producers in DeWitt and Live Oak counties may get such returns even with an oil price lower than \$40.

As noted in the first part of this study, the drilling potential of Eagle Ford is huge (See Section 5). These

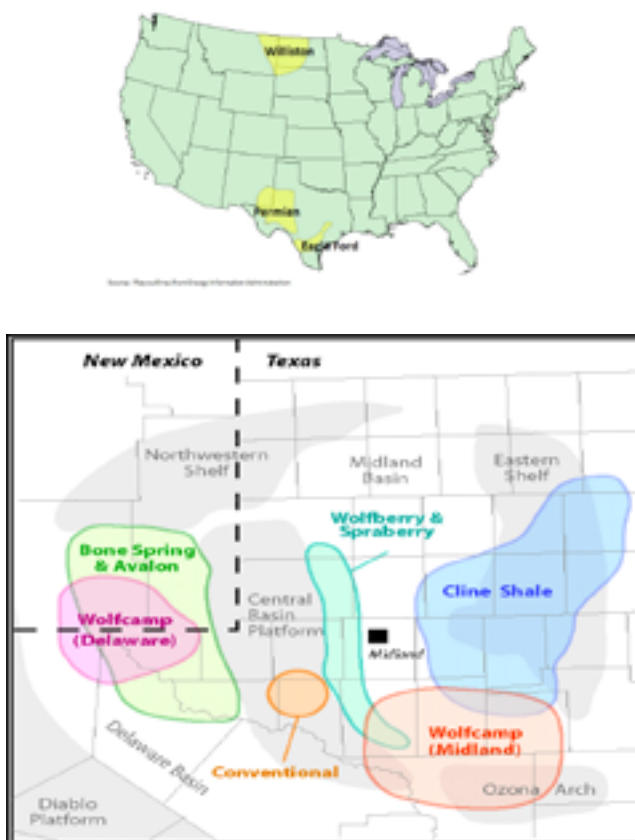
features could explain why the Eagle Ford Shale has become the single largest investment venture in the global oil sector as of today.

Given the oil price scenario I used for this study, I assumed that if the number of Eagle Ford's new producing wells increases progressively by 15–25 percent a year from 2013 on, this shale formation could reach a crude oil production of 1.5 mbd by 2017

4. THE PERMIAN BASIN

The Permian Basin stretches northwest of the Eagle Ford Shale, between west Texas and southeastern New Mexico and comprises several basins. The largest is the Midland Basin, followed by the Delaware Basin. The smallest is the Marfa Basin. In turn, each of these basins comprises different shale plays that sometimes are dealt with autonomously according to their emerging importance. They are the Cline Shale, the Wolfcamp (Midland), the Wolfberry, the Bone Spring & Delaware, and the Wolfcamp (Delaware).

Figure 11. Permian Shale



Source: Author Elaboration on Devon Energy presentation (April 2, 2012)

An additional problem is that there are also multiple formations that are stacked on top of each other in a single basin or a single play. For example, the Wolfberry Shale includes several plays, such as Spraberry, Dean, and Leonard. Figure 11 offers a simplification of this complicated picture.

The Permian Basin area has a long history of conventional oil and natural gas production that dates to the

1920s. Its conventional hydrocarbon supply peaked in the early 1970s and eventually faced a steady decline. In 2010, before the beginning of its shale plays' early development, it produced on average 740,000 b/d of oil in its Texas section, partly through extensive use of enhanced oil recovery technology and hydraulic fracturing of vertical wells.

The Texas section of the basin had produced over 29 billion barrels of oil and 75 trillion cubic feet of natural gas as of the end of 2011. Industry experts estimate it still contains recoverable oil and natural gas resources exceeding what has been produced over the last ninety years.⁷¹

Horizontal drilling and hydraulic fracturing combined on the Permian shale oil plays are more recent than in Eagle Ford, having started between 2010 and 2011. Their advent, however, brought an escalation of drilling activity, as reflected by the number of total drilling permits and rig count shown in Table 8.

Table 8. New drilling permits issued and rig count in the Permian Basin (Texas)

Year	Drilling Permits	Rig Count
2005	4,459	129
2006	4,738	158
2007	4,703	191
2008	6,178	218
2009	3,369	103
2010	6,928	237
2011	9,347	355

Source: Texas Railroad Commission

Rig count exceeded 400 in 2012 and then declined to 378 at the beginning of 2013, with the vast majority (364) concentrated on oil activity. Most rigs, however, still were drilling vertical wells in conventional, mature formations, even if the number of those drilling horizontal wells has grown substantially, jumping from sixty-four to 102 over the same period.⁷²

The complexity of the Permian Basin shale formations bears a significant heterogeneity of production.

Data concerning the different shale plays in the area are still very limited and somehow confusing. Yet, even at this very early stage of development, some shale plays are emerging as potential world class producing fields.

I have analyzed more than 600 horizontally-fractured wells made available by different oil companies. All data point to a bright near future for the Permian Basin shale formations. This stems from some peculiar features of its shale formations that are taking shape:

- On the basis of assessments by several companies of limited areas of single plays in the Permian Basin, the combined recoverable oil of the basin could be in excess of 50 billion barrels, mostly from shale formations.
- So far, several horizontally fractured wells in shale plays such as Cline, Wolfcamp, Wolfberry, and Spraberry have shown an IP30 higher than 20,000 boed—70 percent oil on average—that is higher than the average IP30 of both Bakken and Eagle Ford. Assuming a decline curve slightly

better than Eagle Ford's (see Table 1), this implies per-well oil production in the first year averaging 120,000 boed. Because of the limited set of data I had, however, I assumed conservatively an estimated 70,000 barrels of crude oil per day as the basis for my forecast.

- The plays that could deliver the bulk of oil production cover an area that is much larger than Eagle Ford's oil window, or about 9,000 square miles.
- At this early stage, per-well costs are generally lower than in Bakken but higher than in Eagle Ford, varying between \$7 million and \$9 million. As with other shale plays, however, costs probably will decline once the different formations are better understood and characterized.
- The Texas section of the Permian Basin has the highest concentration of drilling rigs in the world, with more than 400 active rigs in 2012 (more than 500 including the New Mexico section). Though most of these rigs are still used to perform conventional drilling, others are now used in projects of vertical hydraulic fracturing while a growing number has shifted to horizontal hydraulic fracturing.

As the number of vertical and horizontal shale wells brought online grows year by year, the production of Permian Basin shale formations could skyrocket.

For the purpose of this study, I assumed that, from 2014 on, the number of new producing wells would increase by 25 percent a year, allowing the Permian Basin shale crude oil production to exceed 1.3 mbd by 2017.

The timing I considered also takes into account the need to resolve two primary problems that several shale-rich Permian areas present: lack of housing and adequate infrastructure, particularly transportation.

5. OTHER SHALE OIL PLAYS

In addition to the Big Three U.S. shale oil formations developed so far, there are additional shale oil plays that have attracted the interest of oil companies and are now in different stages of exploration, characterization, or development.

The very early stage of activity on these plays, or the mixed results they have delivered thus far, do not allow for a reasonable assessment of their future potential. Here is a very brief presentation of some of them. This is far from being exhaustive in that it focuses only of those plays that have already shown consistent clues of significant oil potential.

DJ Niobrara-Codell

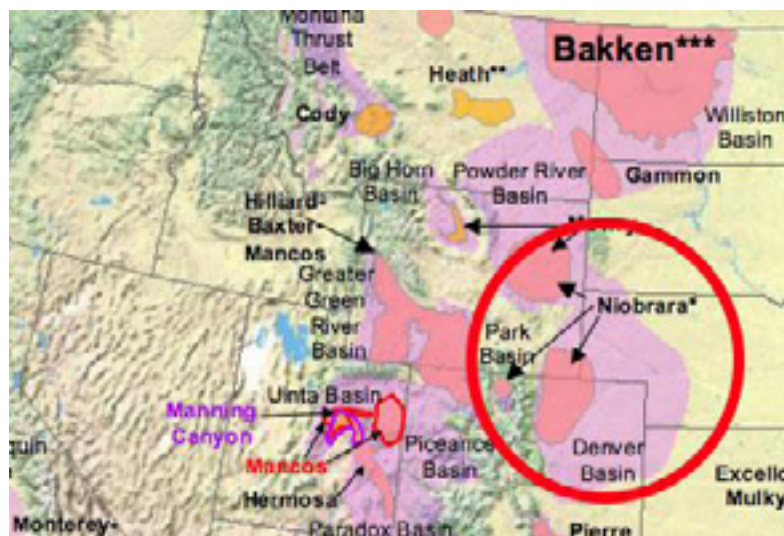
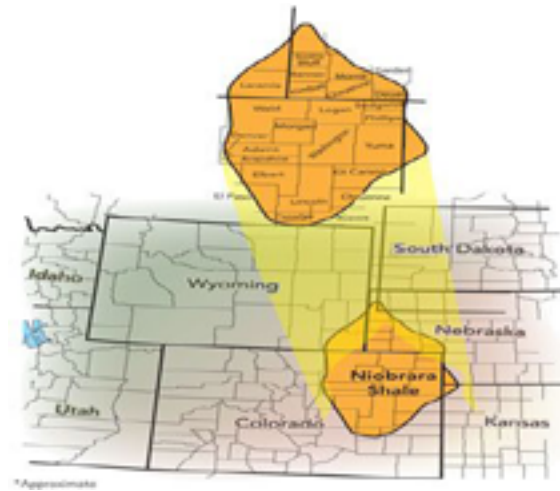
The Niobrara shale formation spans northeast Colorado, northwest Kansas, and parts of Nebraska and Wyoming. It is located in the Denver-Julesburg Basin, which has long been a major U.S. oil and gas province in the twentieth century. Because of its passage through the Denver-Julesburg basin and its often equal reckoning with the underlying and prospective Codell sandstone, the multihorizon play is known interchangeably as the DJ-Niobrara and the Niobrara-Codell play.

The basin encompasses an area of more than 70,000 square miles. Although it crosses four states (Figure 12), so far the overwhelming drilling activity has centered in Colorado and, to a much lesser degree, Wyo-

ming (around the Silo field). Weld County, Colorado, is home to the rich Wattenberg field⁷³ that is also the source of the Niobrara horizontal shale oil play, where 95 percent of the drilling activity occurs.⁷⁴

Niobrara holds crude oil, natural gas and NGLs, with crude oil representing between 30 percent and 40 percent of production. Hydrocarbons are found anywhere between 3,000 feet and 14,000 feet, with most of the oil located about 7,000 feet to 8,000 feet down. The biogenic natural gas is at depths of about 3,000 feet. The formation has a thickness of 200 to 400 feet, which makes it thicker than the Eagle Ford formation.

Figure 12. The Niobrara shale



Source: EIA

Horizontal hydraulic fracturing in Niobrara started in 2008–2009 and triggered a wave of high optimism as high initial flow rates in 2010 and 2011 seemed to suggest that the formation could be another Bakken-style play. However, the astonishing performance of Bakken after 2011 and the eventual mixed results from Niobrara, particularly in 2012, led to more cautious optimism.

Despite these setbacks, many of the operators continue to increase their acreage positions (Anadarko, EOG, Noble), while at the same time geophysical investigations continue to get a better understanding of the Niobrara and the underlying Codell formations.

Drilling activity is growing substantially, albeit at a much slower pace than in the Big Three U.S. shale oil plays, as shown in Table 9.

Table 9. Drilling activity, DJ-Niobrara Colorado (horizontal wells)

Year	Permits	Wells Drilled	Comment
2009	18	11	
2011	765	235	
2012	914	541	
<i>Total</i>	<i>1697</i>	<i>896</i>	<i>(394 Completed & Actively Producing)</i>

Source: Colorado Oil and Gas Conservation Commission⁷⁵

Unfortunately, the Colorado Oil and Gas Conservation Commission does not separate either production rates by basin and formation or by drilling type (vertical or horizontal); rather, it provides total production rates by county.

The commission released a presentation in September 2012 detailing the annual oil production of DJ-Niobrara shale showing that, starting from virtually zero in 2008, it jumped to more than 5.3 million boe in 2011, or less than 15,000 b/d. In the first five months of 2012, it had already doubled on a daily basis, reaching 26,000 b/d (or more than 3.9 million barrels cumulatively in the first five months).⁷⁶

It grew even more by the end of 2012.

Oil production reported by one of the largest Wattenberg players, Anadarko Petroleum, showed that, in the fourth quarter of 2012, the company sold an average 40,000 b/d of crude oil plus 16,000 b/d of NGLs of the field production. About half of that came from its horizontal fracking program.⁷⁷ According to my own estimates, oil production in the whole DJ-Niobrara-Codell exceeded 40,000 b/d at the end of 2012 and is heading upward.

The lack of an adequate dataset impedes reaching a clear view of the average IP30 for most wells in my sample (sixty-seven, a number that was very difficult to round up, given the difficulty in separating the horizontal from vertical wells and Niobrara from other formations).

In general terms, per-well production in Niobrara is much lower than in the Big Three shale oil plays, with initial peaks over the first 24 hours of production that rarely exceed 1,000 oil barrels, while the aver-

age seems to fall in the range of 200–300 b/d. Moreover, wells brought online in the last three years show a production decline of about 60 percent after the first twelve months.

However, well costs (drilling and completion) are generally lower in Niobrara than in the Big Three shale oil plays, ranging on average between \$4.5 million and \$7 million in 2012. Also, Anadarko now calculates an estimated ultimate recovery of about 350,000 boe from its average Wattenberg well, which, albeit discretionary, represents a significant improvement as compared with a few years ago.

Utica-Point Pleasant Shale

Utica-Point Pleasant shale is a huge shale rock formation that lies below the Marcellus shale. The epicenter of its development is now in Ohio, but the whole formation stretches under eight states, from Tennessee to New York and across the border into Quebec.

According to the Ohio Department of Mineral Resources (ODMR), the formation's oil and liquids richest area is in the interval where Utica and Point Pleasant shales abut (with the Point Pleasant immediately below the Utica), forming a two-level rock layer that is from eighty-seven feet to 350 feet thick.⁷⁸ According to the Ohio Geological Survey, the Ohio section alone of Utica Point Pleasant may hold 8.2 billion of recoverable oil and gas barrels considering a 5 percent recovery rate, of which about 5.5 billion barrels is oil.⁷⁹

Rich in carbonate content, Utica shale is particularly well-suited for hydraulic fracturing, which breaks carbonate rocks more easily. Like Eagle Ford shale, the Utica shale has three separate hydrocarbon windows—oil, wet gas, and dry gas.

The ODMR recently released updated drilling statistics for the Utica shale emphasizing that 205 horizontal wells were drilled since late 2010 with forty-seven currently producing, most of them (twenty-seven) in Carroll County.⁸⁰ Production data are still too poor. In particular, on its website, the ODMR offers production data related only to 2011 concerning nine producing wells, whose production is mainly natural gas with minor volumes of oil.⁸¹

An updated rig count, however, shows companies are now shifting to potential oil targets. Twenty-nine rigs were active on average in the first two weeks of January 2013 in Ohio's section of the play compared with fifteen during the same period of 2011. Most of those rigs (twenty-six of the twenty-nine) were drilling for oil (compared with only six in the same period of 2011) and twenty-five were targeting horizontal strata.⁸²

Oil activity is thus increasing, but the very early state of development of the play does not allow for any reasonable assessment of its future potential production.

Monterey Shale

A huge shale formation that could emerge as a major shale oil play is the Monterey/Santos shale in California.

According to a report prepared by Intek for the U.S. Energy Information Administration (EIA), the Monterey shale is estimated to hold 15.4 billion barrels of recoverable oil, or much more than Bakken (3.59 billion barrels of shale oil resource) and Eagle Ford (3.35 billion).⁸³

Generally, all evaluations of U.S. shale resources potential have grossly underestimated the U.S. shale oil potential, also because of the use of outdated data. The report published by the EIA, for example, was based on publicly available company data and commercial databases at the end of 2008. So it is quite surprising that it puts Monterey at such relatively high level.

Monterey shale is well known by geologists and the oil industry. It has probably been the source rock of most conventional oil produced in California during the twentieth century, when the state's central coast sometimes had been one of the biggest oil producing areas in the world. It is thus highly probable that it contains huge oil volumes that have yet to be recovered. Nonetheless, the shale formation still needs to be characterized and well understood. Its geology varies dramatically from one area to another and seems to be inconsistent, as experienced by U.S. independent Venoco, which drilled three dry horizontal wells in the shale formation in 2011 as compared with thirteen oil-rich vertical wells between 2011 and 2012 in the same formation.⁸⁴

It will take time before a proper assessment of Monterey shale will be possible and much also will depend on the attitude of once-reluctant California to allow for horizontal fracking (also if most of the vertical oil wells have been already fracked in California, several with vertical acid fracking). That seems about to change now after the state government proposed a regulation in December 2012 that was considered reasonable by the oil industry.⁸⁵

Tuscaloosa Marine Shale

The Tuscaloosa Marine shale stretches between southeastern Mississippi and Louisiana. Independent preliminary evaluations indicate that the Tuscaloosa Marine shale may contain a potential reserve of about 7 billion barrels of technically recoverable oil.⁸⁶

So far, only a few horizontally fracked wells have been drilled in the area, all producing oil in highly significant volumes. In particular, Encana Corp.'s Anderson 17H well (Amite County) averaged an astonishing 933 boe per day, almost all oil, in its first thirty days, from a roughly 7,300-foot lateral and thirty fracking stages and was still producing 300 b/d six months later. By the same token, Encana's Weyerhaeuser 73H-1 well has registered an annual production of 740 boe per day from a 5,000-foot lateral and fifteen fracking stages.⁸⁷

Together with other wells that have produced significant, albeit lower, volumes of oil, these early exploration successes seem in the same league as those in the Big Three U.S. shale plays, thus making the prospect for Tuscaloosa development very encouraging. Per-well costs are still relatively high, now estimated at \$12 million to \$13 million each (with a 7,500-foot lateral and twenty-five fracking stages), but they are down from early estimates of as much as \$19 million.⁸⁸

Woodford Shale

Located in Oklahoma, mostly within the Anadarko Basin, the Woodford shale play attracted a great deal

of interest since the early 2000s as a major natural gas shale play. Only from 2010 on has the attention shifted to its most supposedly promising oil-rich intervals.

The first to emerge was Cana Woodford in 2010, but the attention shifted again in late 2012 toward the South Central Oklahoma Oil Province (Scoop), located south of the Cana field, particularly after important discoveries by the U.S. company Conoco that believes Scoop has six times the reservoir volume of Cana.

Woodford shale covers an area of 3,300 square miles, much smaller than that of the Big Three, but it is also much thicker (150–400 feet), and its oil windows are located at depths higher than 10,000 feet. Coupled with a complex geology that, according to Halliburton (the world leader in hydraulic fracturing), may affect “drilling and completion design, production practices and ultimately well productivity.”⁸⁹ This makes Woodford an expensive play to deal with, especially if one considers that, so far, producing wells in the oil-richest area have shown crude oil to be between 25 percent and 50 percent.

Detailed information about well productivity and decline are not yet available so it is not possible to envisage a reasonable potential production pattern for the next few years.

Summing up

Considering the scarce data available for all U.S. shale oil plays other than the Big Three, I could not model the evolution of their future liquids production.

However, according to a probabilistic method (with a ± 50 percent probability ratio of production, based on yet-to-find discoveries) assuming a number of new producing wells per year growing from 200 to 1,000 in 2017, with an average production of 30,000 b/d of crude oil during the first 12 months, I projected a cumulative crude oil production from all other U.S. shale oil plays of 400,000 crude oil b/d by 2017. This could be a highly conservative estimate, but in the absence of more reliable data, it is not possible to go beyond that hypothetical assumption.

APPENDIX B: DISCLAIMER ON METHODOLOGY

As with all analyses and estimates on shale activity, this one does not claim to be error-free. The inherently fragmented, often opaque universe of data on shale oil carries natural byproducts of ambiguity and uncertainty.

With few exceptions, official data by state agencies tend to be confusing and inadequate. Only the NDD-MR offers a sound and detailed historical series of figures on drilling, well completions, per-well production, etc. Other principal sources of state-level data offer dataset that often do not distinguish between shale and conventional wells or identify the exact share of crude oil, NGLs, and natural gas produced by single wells.

For example, the RRC that presided over the regulation of oil and gas activities in Texas only provides production by lease for oil wells (but per-well production may be inferred on most leases) without specifying how many days a well produced during a month. Even worse, the Colorado Oil and Gas Conservation Commission (COGCC) neither separates production rates by basin and formation or states if wells are vertical or horizontal. The EIA does not cover the gap left by state agencies and commissions, and it is not its mission to do so.

Conversely, oil companies usually offer plenty of data concerning their wells, including first production during the first twenty-four hours, thirty days, ninety days, etc., along with the length of laterals, cost, and much more.

However, the shale universe is fragmented among too many operators and it is still in a manufacturing mode, meaning that each operator still tends to follow its own drilling and development strategy as well as its own models of estimating ultimate recovery and economic returns. This implies that for each single area of a single shale play, well results may differ significantly, adding analytical problems to the difficulty of analyzing shale plays that, per se, present a major variance of geological characteristics across different locations.

There is a mainstream view among observers of the oil industry: Oil companies lie about everything that concerns their activity, particularly in the shale sector. This view may be true for a certain number of companies, but not for all of them. In general terms, the data of companies are much closer to the actual reality of production that is emerging in several U.S. shale plays. They are simply more updated than those released by many state agencies. Major doubts may exist for information from companies about costs, but there are ways to check them.

The first kind of double check consists of comparing the data of different companies operating in the same area. As I have noted, there could be many reasons for actual discrepancies among those data, but, once again, they may offer a proxy of the reality, indicating whether significant discrepancies in cost reporting have no actual explanation.

Another kind of double checking can be made through service companies, e.g., those that provide drilling, completion and other services for oil companies. This exercise is useful in that it may raise a red flag about data supplied by oil companies that is too optimistic but is limited to a few wells. More importantly, data by service companies show, in general terms, if a certain trend, such as a cost decrease in shale activ-

ity, is consistent with the data of companies.

In any case, given the inadequacy of public official data, it is almost impossible to complete up-to-date assessments of the current and future evolution of the U.S. shale oil universe without drawing from the miasma of micro numbers submitted by plenty of independent operators.

For this study, I focused on the widest possible number of reported wells by both state agencies and oil companies, verifying the consistency of per-well data by cross-checking state and information from private companies where possible as well as company-to-company reports on wells situated in the same area of a specific formation.

This bottom-up approach allowed me to round up data on more than 4,000 wells that started their production between 2007 and 2012, of which about 280 have been producing oil for more than five years, 590 for four years, and 840 for three years, 1,100 for two years, and 1,350 for one year or less. I used this first set of data to focus on an in-depth analysis on a subset of about 2,000 wells that were representative (when confronted with the broader dataset) of their specific location characteristics and presented a complete set of data concerning their characteristics (depth, length of laterals, water and proppants used for their completions, etc.), productivity over different periods of time (and, consequently, their decline), and costs.

Whereas this exercise gave me a certain degree of confidence as far as the overall productivity of a well over time is concerned, some doubts remains about the precise partition of hydrocarbons (e.g., the share of crude oil, natural gas, and NGLs) produced by many wells. When these data were uncertain, I relied on the average share of hydrocarbons output that I observed in the specific area where an uncertain well was located.

In any case, the subset of 2,000 wells allowed me to extrapolate the figures I have presented in this study.

As far as my bottom-up approach may present pitfalls, I chose it because, in my view, it allows for better grasping of the frantic but still opaque pace of evolution of U.S. shale oil development than an approach based on more consolidated data that tend to be outdated and thus unrepresentative of the actual reality.

For example, in 2012 the EIA projected in its January *Short-Term Energy Outlook* and June *Annual Energy Outlook* that U.S. total crude oil production would average 5.74 mbd in 2012, 5.82 mbd in 2013,⁹⁰ and 6.47 mbd in 2017, with tight/shale oil contributing 1.07 mbd by 2017.⁹¹ By December 2012, U.S. crude production had already surpassed 6.6 mbd, of which over 1 mbd comprised tight/shale oil. Only a month later, the EIA reported that average weekly U.S. oil production had reached 7 mbd, a 1.16 million barrel (20%) increase over the same week a year earlier.⁹²

John Staub, the head of EIA's division of Integrated Analysis and Forecasting, recently explained the agency's continual supply underestimations that "the agency's forecasts lag those of private sector firms in part because its long-term projections were based on data from 2011." He then admitted, "We've been limited in our ability to see how quickly production is growing."⁹³

The problem outlined by Staub, as I tried to convey in this appendix, encompasses not only production, but all of the other data concerning shale oil.

Considering all of the complications of reconstructing a reliable and updated dataset of shale oil activity, I did my best to cross-check all data I had in order to avoid the risk of major mistakes. Wherever possible, I confronted my data with other relevant, bottom-up analyses that I found. This was the case, for example, of Michael Filloon's analysis on Bakken and Gary Swindell's analysis on Eagle Ford.

That said, the result of my own analysis is the best possible approximation I could derive from the huge volume of data I gathered, but it remains an approximation of a complex reality.

NOTES

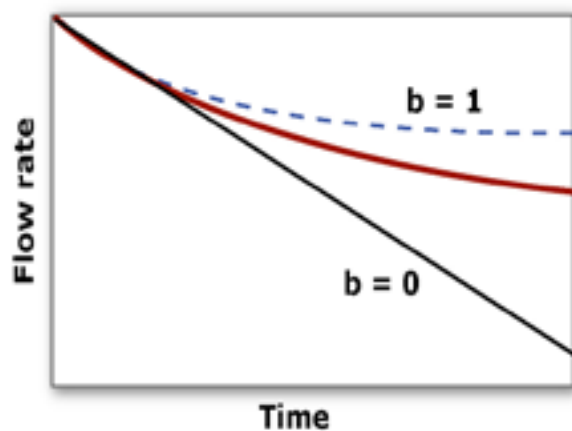
¹ Ibidem. Canada is the second country in the world in terms of drilling intensity. While Canadian well completions data are not available, the IHS-Cera database shows that Canada brought online 3,450 oil and gas wells in 2012.

² In its 2008 assessment of Bakken's reserves, the U.S. Geological Survey assumed a recovery rate lower than 2 percent, implying an estimated 3.0 to 4.3 billion barrels of undiscovered, technically recoverable oil reserves. See: http://pubs.usgs.gov/fs/2008/3021/pdf/FS08-3021_508.pdf

³ See: http://www.usgs.gov/blogs/features/usgs_top_story/usgs-releases-new-oil-and-gas-assessment-for-bakken-and-three-forks-formations/

⁴ The Arps decline curves analysis models the production history and future with the equation of a hyperbola. Locating the hyperbola requires the presence of three variables: the starting point of production, the initial decline rate and an assumed degree of curvature for the model defined as the "b-exponent." The latter generally may vary from zero to one. A b-exponent equal to or higher than one implies an infinite production. In the shale gas and oil arena, the b-exponent tends to be close to one, implying that the curve representing the decline of a shale play tends to flatten out with time, as represented by the red curve in Figure X.

FIGURE X Arps decline curves



The above curve flattening suggests that after a sharp decline, production tends to stabilize around a certain level for a long period of time and register minor decline rates. In any case, new technologies may alter the curvature of the line over time. In the absence of long-term historical data for well production, the choice of b-exponent plays a critical role in assessing the future pattern of production and decline. The Arps model also provides three discrete variables, each of which may serve as foundational points for industry discussion.

⁵ While many experts continue to be skeptical about long-term recovery rates of shale formations, the oil industry continuously updates its EUR projections because of the improvement of its understanding of shale formation and the testing of new techniques and technology for their development. Further, oil companies continue to revise upward their evaluation of the OOP in several shale formations, thus increasing the asset base against which a recovery rate is calculated.

While many oil companies may be overoptimistic, the general trend by 100 operators toward revising upward both recovery rates and OOP is consistent with the improvement of the learning curve of shale oil and actual performance advancement in exploration and production technology.

⁶ Data based on the historical series of the North Dakota Department of Mineral Resources and oil companies data. See, in particular, <https://www.dmr.nd.gov/oilgas/>

⁷ North Dakota Department of Mineral Resources NDDMR, Director's Cut, February 15, 2013, p.1. at: <https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2013-02-15.pdf>

⁸ Texas Railroad Commission, Eagle Ford Shale Drilling permits at: <http://www.rrc.state.tx.us/eagleford/EagleFordDrillingPermitsIssued.pdf>
The 2012 figure is taken by the updated map by the TRR at: <http://www.rrc.state.tx.us/eagleford/images/EagleFordShalePlay201301-large.jpg>

⁹ Data on international oil and gas wells supplied by IHS-CERA to the author on March 1, 2013. The data on international completions may be higher due to limited data from Kuwait, Saudi Arabia, Iran, Libya, Algeria, and Russia.

¹⁰ Continental Resources presentation, March 18, 2013. At: <http://phx.corporate-ir.net/phoenix.zhtml?c=197380&p=irol-EventDetails&EventId=4922417>

¹¹ EOG Resources presentation, March 13, 2013. At: http://www.eogresources.com/investors/slides/InvPres0313_3.pdf

¹² The latter is made possible by the rotary bits' ability to facilitate closer contact with the target production location at a 3-foot radius, a substantial improvement over the 10-foot radius achieved by traditional rotary rigs.

¹³ See: U.S. Unconventional Oil & Gas Centre, DUG Eagle Ford 2012: A Land Of Opportunity, Oct. 24, 2012, at: http://www.ugcenter.com/Eagle-Ford/DUG-Eagle-Ford-2012-Land-Opportunity_108801

¹⁴ See: U.S. Unconventional Oil & Gas Centre, Technology Speeds Shale Play Drilling, Cuts Costs, Nov. 21, 2012, at: http://www.ugcenter.com/Marcellus/Technology-Speeds-Shale-Play-Drilling-Cuts-Costs_109985

¹⁵ See: Pioneer Cuts Costs, Maximizes Recoveries in Eagle Ford Shale, in Oil Daily, Oct. 17, 2012.

¹⁶ While increases in these factors generally have contributed to greater well productivity, additional growth beyond certain thresholds appears to bear neutral to modestly negative impacts on per-well productivity. The specific threshold varies from play to play. In the Bakken, lateral well length has increased from a few thousand feet to the current standard of 9,000 feet to 10,000 feet, involving about thirty fracking stages vs. 12–15 initially. Even more dramatic has been the rise in sand volumes used in fracking, which have catapulted from averaging ~550,000 lbs/well in 2007 to ~2.5 million lbs/well in 2011. By contrast, the most effective lateral well in the Eagle Ford appears to be 5,000 feet to 6,000 feet long, requiring about 4.5 million pounds of sand per well. Together with other emerging factors requiring further study, such as the use of various chemicals in fracking and the size of chokes, the aforementioned

elements have homogenously boosted output across these plays' patchwork quilt of high- and low-productivity areas.

¹⁷ The percentage of oil companies' hedged oil&gas production is usually disclaimed by companies themselves in their Annual Form-F20 and during quarterly presentations.

¹⁸ See: After Shaky Start, South Texas Eagle Ford Soars to Top Play. In: Natural Gas Week, November 7, 2011, p. 13.

¹⁹ The estimates are based on my elaboration of data from the North Dakota Department of Mineral Resources and oil companies. To have an additional countercheck, I used the same areas identified by the best analysis I have found on the same subject, which is by Michel Filloon. Our results are close. See: Michael Filloon. Bakken Update: The Red Queen Is Just A Fairy Tale Part II. Seeking Alpha, October 8, 2012. At: <http://seekingalpha.com/article/909761-bakken-update-the-red-queen-is-just-a-fairy-tale-part-ii>

²⁰ Ibidem

²¹ The estimates are based on my elaboration of data from the Texas Railroad Commission and oil companies. For an additional countercheck for Bakken-Three Forks, for example, I used the same areas identified by the best analysis I found on the same subject, by Gary Swindell, whose results are more pessimistic than mine. See: Swindell, Gary. Eagle Ford Shale: An Early Look at Ultimate Recovery. Society of Petroleum Engineers (SPE), Paper 158207, 2012. At: <http://gswindell.com/sp158207.pdf>

²² Ibidem

²³ North Dakota Department of Mineral Resources, Director's Cut, March 15, 2013, p.1. At: <https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2013-03-15.pdf>

²⁴ Ibidem

²⁵ I've already dealt with those critics in my previous paper "Oil, the Next Revolution", pp.58-63.

²⁶ Texas Water Development Board. 2012 State water plan, Ch. 3, p. 137 (Table 3.3). At: http://www.twdb.state.tx.us/publications/state_water_plan/2012/03.pdf

²⁷ RRC, Eagle Ford Shale Taskforce Report, 2012, p.40. At: http://www.rrc.state.tx.us/commissioners/porter/reports/Eagle_Ford_Task_Force_Report-0313.pdf

²⁸ See U.S. Energy Information Administration statistics of oil and gas wells in the U.S., at: http://www.eia.gov/pub/oil_gas/petrosystem/petrosysog.html

²⁹ Water Sources and Demand for the Hydraulic Fracturing of Oil and Gas Wells in Colorado from 2010 through 2015. A Report Jointly prepared by the Colorado Division of Water Resources, the Colorado Water Conservation Board, and the Colorado Oil and Gas Conservation Commission. At: http://cogcc.state.co.us/Library/Oil_and_Gas_Water_Sources_Fact_Sheet.pdf

³⁰ National Academy of Sciences, National Research Council. Induced Seismicity Potential in Energy Technology. Washington (D.C.), The National Academies Press, 2102. At: https://download.nap.edu/catalog.php?record_id=13355

A 2012 study by University of Memphis seismologist Stephen Horton pointed out that the epicenters of a series of earthquakes in northern Arkansas were located close to wastewater disposal wells.

And research by University of Texas seismologist Cliff Frohlich also showed that a series of low-level earthquakes in the Barnett Shale in North Texas in 2009-11 occurred near wastewater disposal wells.

³¹ Katie M. Keranen, Heather M. Savage, Geoffrey A. Abers, and Elizabeth S. Cochran. Potentially induced earthquakes in Oklahoma, USA: Links between wastewater injection and the 2011 M_w 5.7 earthquake sequence. *Geology*, G34045.1, March 26, 2013. At: <http://geology.gsapubs.org/content/early/2013/03/26/G34045.1.full.pdf+html>

³² Ohio Department of Natural Resources. Preliminary Report on the Northstar 1 Class II Injection Well and Seismic Event in the Youngstown, Ohio, Area. March 2012. At: <http://ohiodnr.com/downloads/northstar/UICReport.pdf>

³³ Maugeri (2012), pp.55-57

³⁴ NDDMR, Director's Cut, March 15, 2013, p.1. At: <https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2013-03-15.pdf>

³⁵ On the "Jones Act", see: Maugeri, "Oil, the Next Revolution" (2012), p.57

³⁶ See: <http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCREXUS2&f=M>

³⁷ See: Meyer, Gregory. US crude oil exports rise sharply, in: *Financial Times*, April 29, 2013, at: <http://www.ft.com/intl/cms/s/0/09ae9bb8-b0f0-11e2-80f9-00144feabdc0.html#axzz2ULJgwu00>

³⁸ See EIA at: http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldpd_a.htm

³⁹ The data are based on Baker Hughes Worldwide Rig Count—Current & Historical Data (Excel), January 8, 2013. Baker Hughes data do not include Russia, the Caspian region, Iran, China onshore, North Korea, and Cuba. See at: <http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-rigcountsintl>

⁴⁰ National Petroleum Council. Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources. Washington, D.C.: NPC, 2011, p.21.

⁴¹ Baker Hughes, Worldwide Rig Count (see note 10).

⁴² <http://www.worldoil.com/December-2012-Whither-Russia.html>

⁴³ See Bakken Shale at: <http://bakken shale.com/news/top-10-bakken-operators-december-2012/>

⁴⁴ RRC. Eagle Ford Shale Taskforce Report, 2012, p.6. At: http://www.rrc.state.tx.us/commissioners/porter/reports/Eagle_Ford_Task_Force_Report-0313.pdf

⁴⁵ <http://www.eia.gov/todayinenergy/detail.cfm?id=2270>

⁴⁶ On this issue, see for example: http://www.energy.psu.edu/swc/sites/default/files/files/SWC_052005_completeOPT.pdf

⁴⁷ Energy Information Administration, *Weekly Petroleum Report*, January 8, 2013. See: http://www.eia.gov/pub/oil_gas/petroleum/data_publications/weekly_petroleum_status_report/current/pdf/highlights.pdf

⁴⁸ Energy Information Administration, *Monthly Energy Review*, Dec. 21, 2012, at: <http://www.eia.gov/totalenergy/data/monthly/#petroleum>

⁴⁹ In particular, I refer to the analysis on the subject made by Citi. See: Citi. Energy 2020: Independence Day, February 2013, at: <https://ir.citi.com/ImTJAzZOYgkNHFGGtKrsIQPBnZS%2BZnqWagrxwWq3b24qyDAfarHKPA%3D%3D>

⁵⁰ *Oil Daily*, “Persistent Price Weakness Plagues Canadian Crude” Dec. 18, 2012. At: http://www.energyintel.com/pages/Eig_Article.aspx?DocId=791352

⁵¹ Blow for oil groups over Canada pipe plan. In: *The Financial Times*, June 1, 2013. At: <http://www.ft.com/intl/cms/s/0/bf560fb8-ca37-11e2-8f55-00144feab7de.html#axzz2V0lYI2mU>

⁵² The Keystone XL pipeline has a capacity of about 800,000 bd. TransCanada, the company that proposed the project, has reserved 200,000 b/d of that capacity to North Dakota oil production, leaving for Canadian oil sands about 600,000 b/d of capacity. Yet Canadian oil sands production might exceed 3.4 mbd by 2020 from 1.7 mbd in 2012.

⁵³ As to the steady growth of world oil production capacity, see: Maugeri, Leonardo. “Oil, the Next Revolution. The Unprecedented Upsurge of Oil Production Capacity and What It Means for the World.” Discussion Paper #2012-10. Belfer Center for Science and International Affairs, Harvard Kennedy School of Government, Harvard University, June 2012. At: <http://belfercenter.ksg.harvard.edu/files/Oil-%20The%20Next%20Revolution.pdf>

⁵⁴ José Graziano da Silva, The U.S. must take action to prevent a food crisis, in: *Financial Times*, August 9, 2012. at: <http://www.ft.com/intl/cms/s/0/85a36b26-e22a-11e1-b3ff-00144feab49a.html#axzz2HnEzyg2v>

⁵⁵ See: Energy Information Administration, *Weekly Petroleum Report*, January 8, 2012, Petroleum Balance Sheet Data, at: http://www.eia.gov/oil_gas/petroleum/data_publications/weekly_petroleum_status_report/wpsr.html

⁵⁶ Maugeri (2012), pp. 47-49

⁵⁷ North Dakota Department of Mineral Resources, Director’s Cut, March 15, 2013, p.1, at: <https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2013-03-15.pdf>

⁵⁸ North Dakota Department of Mineral Resources, Director’s Cut, February 15, 2013, p.1, at: <https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2013-02-15.pdf>

⁵⁹ Ibidem, p.2.

⁶⁰ Ibidem, p.1.

⁶¹ See: <https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp>

⁶² See database of the North Dakota Department of Mineral Resources at: <https://www.dmr.nd.gov/oilgas/bakkenwells.asp> (Select: Middle Bakken and then Three Forks)

⁶³ Ibidem

⁶⁴ http://www.eogresources.com/investors/slides/InvPres_021313.pdf

⁶⁵ For general information about Eagle Ford Shale see the website of the Texas Railroad Commission at: <http://www.rrc.state.tx.us/eagleford/index.php>

⁶⁶ See Wood MacKenzie. Total Eagle Ford capital expenditure to reach US \$28 billion in 2013. At: <http://www.woodmacresearch.com/cgi-bin/wmprod/portal/corp/corpPressDetail.jsp?oid=10950029>

⁶⁷ Ibidem

⁶⁸ See Texas Railroad Commission statistics on oil and condensate production, at: <http://www.rrc.state.tx.us/eagleford/>

⁶⁹ Baker Hughes interactive rig count, week of January 18, 2013, at: <http://gis.bakerhughesdirect.com/Reports/StandardReport.aspx>

⁷⁰ Swindell (2012)

⁷¹ Texas Railroad Commission, Permian Basin, at: <http://www.rrc.state.tx.us/permianbasin/index.php>

⁷² Baker Hughes interactive rig count, week of January 18, 2013, at: <http://gis.bakerhughesdirect.com/Reports/StandardReport.aspx>

⁷³ Wattenberg field production is more than 85 percent from Niobrara with less than 10 percent from the J Sand Formation while the remaining less than 5 percent of production comes from the Sussex, Shannon and D sand formations.

⁷⁴ The Colorado Niobrara shale formation accounted for nearly 87% of the total production from the entire shale play in 2011.

⁷⁵ Colorado Oil and Gas Conservation Commission Staff Report P17, January 7, 2013, at: http://cogcc.state.co.us/Staff_Reports/2013/201301_StaffReport.pdf

⁷⁶ http://geosurvey.state.co.us/energy/Oil/Documents/Niobrara_AAPG_RMS_September_2012.pdf

⁷⁷ See: Anadarko Petroleum, Operation Report, Fourth Quarter 2012, p.5, at: <http://www.anadarko.com/SiteCollectionDocuments/PDF/Operations%20Reports/4Q2012%20Ops%20Report%20Final.pdf>

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- ⁷⁹ Ohio Geological Survey, at: http://www.dnr.state.oh.us/portals/10/energy/Marcellus_Utica_presentation_OOGAL.pdf
- ⁸⁰ Ohio Department of Mineral Resources, at: <http://www.ohiodnr.com/portals/11/oil/pdf/Utica.pdf>
- ⁸¹ Ohio Department of Mineral Resources, at: http://www.ohiodnr.com/portals/11/oil/pdf/Utica_Production_2011.pdf
- ⁸² Baker Hughes, Interactive rig count, at: <http://gis.bakerhughesdirect.com/Reports/StandardReport.aspx>
- ⁸³ Energy Information Administration (EIA), “Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays.” (prepared by Intek), July 2012. At: <http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf>
- ⁸⁴ See: Oil Daily, Venoco Hopes to Start Monterey Shale Production This Year, February 20, 2012, at: http://www.energyintel.com/pages/Eig_Article.aspx?DocId=756133&IsSearchResult=true
- ⁸⁵ See: *Oil Daily*, “California Proposes New Rules on Hydraulic Fracturing,” December 20, 2012, at: http://www.energyintel.com/pages/Eig_Article.aspx?DocId=791688&IsSearchResult=true
- ⁸⁶ For a detailed analysis of the Tuscaloosa Marine Shale formation see: Chacko J. John, Bobby L. Jones, James E. Moncrief, Reed Bourgeois and Brian J. Harder. “An Unproven Unconventional Seven Billion Barrel Oil Resource—the Tuscaloosa Marine Shale.” *BRI Bulletin*, Basin Research Institute, Louisiana State University, Baton Rouge at: <http://www.lgs.lsu.edu/deploy/uploads/Tuscaloosa%20Marine%20Shale.pdf>
- ⁸⁷ Nissa Darbonne, Emerging shale oils: the TMS. Hart Energy U.S. Gas Unconventional Center, January 11, 2013. See: http://www.ugcenter.com/Emerging-Shale/Emerging-Oil-TMS_111659
- ⁸⁸ Ibidem
- ⁸⁹ See: Halliburton, Technical Papers, Woodford Shale, at: <http://www.halliburton.com/ps/default.aspx?navid=2280&pageid=5213>
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⁹³ “Forecasts Suggest US Oil Boom Has Staying Power.” In: *Oil Daily*, September 17, 2012. See: http://www.energyintel.com/Pages/Eig_Article.aspx?mail=PA_TEXT_5_3239&DocId=780562



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