

What Could Lower Prices Mean for U.S. Oil Production?

By Nida Çakır Melek

Oil prices have declined sharply since the summer of 2014, raising questions about whether the boom in oil and gas production can continue. Since 2005, U.S. oil and gas production has increased more than 50 percent. The share of oil and gas in private fixed investment increased from 2.9 percent in 2005 to 5.8 percent in 2013. With oil prices at about half their summer 2014 level, will the investment continue to be profitable and boost production?

The dramatic increase in production post-2005 became possible when high and rising energy prices allowed two complementary but expensive technologies—multistage hydraulic fracturing and horizontal drilling—to be applied on a large scale for the first time. Energy producers were able to access previously untapped reservoirs using the newly profitable technologies, first in shale gas fields such as the Barnett field of east Texas, and then in tight oil fields such as the Bakken in North Dakota. Since 2011, over 95 percent of the growth in U.S. oil and gas production has come from these unconventional sources. To continue this growth, however, energy prices must remain high enough to justify the costs of extraction. Shale fields require significant drilling activity and thus significant ongoing capital investment to increase, much less

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maintain, production levels. Moreover, the cost of an unconventional well could be as high as five times the cost of a conventional well.

The recent sharp decline in oil prices and drop in oil rig counts have called into question whether oil production will continue to increase in 2015. This article estimates that, despite highly productive new wells and an increase in the number of wells drilled per rig, U.S. oil production could decline from 0.7 to 8 percent in 2015, due in part to the significant decline in rig counts and depletion in existing wells. While the 0.7 to 8 percent range appears wide, it reflects uncertainty regarding productivity gains in the sector over a one-year period as well as how much further rig counts could decline. For production to increase in 2015, rig efficiency and initial well production would need to increase markedly or the decline in rig counts would need to halt.

Section I reviews the key technologies driving the recent boom and describes tight oil and shale gas field characteristics. Section II investigates the trends in energy prices and production in the U.S. oil and gas sector since 1990. Section III examines the implications of the recent oil price decline for drilling activity and U.S. oil production.

I. Tight Oil and Shale Gas

The recent growth in U.S. oil and natural gas production reflects a move toward shale gas and tight oil extraction. Shale gas is natural gas trapped deep within shale formations, while tight oil is oil produced from low-permeability source rocks deep within the earth. Horizontal drilling and hydraulic fracturing have made these fields accessible (see Box for a description of these technologies). In 2000, shale gas provided only 1 percent of U.S. natural gas production; in 2010, it provided over 20 percent.

Although companies have only recently developed horizontal drilling and hydraulic fracturing on a large scale, the technologies have existed for over 50 years. When U.S. oil and gas production started to decline in the 1970s, producers searched for other sources of domestic production.¹ A combination of private and government funding contributed to improvements in the late 1970s.² Output nearly stabilized in the 1990s as a result of both management and technological advancements in the oil and gas sector (Bohi).³

Box

Overview of Key Technologies

The key technologies that contributed to the oil and gas boom are horizontal drilling, hydraulic fracturing, and pad drilling.

Horizontal wells typically start vertically and then curve to horizontal at depth to follow a particular reservoir (Hughes 2013a). The first horizontal oil well was drilled in 1929, but the commercial application was not developed until the 1980s. The development of supportive technologies—including three-dimensional seismology, measurement-while-drilling (MWD), and steerable drilling motors—played an important role in the process. Three-dimensional (3D) seismology information, obtained by sensors sent into the earth, is used to determine where to locate a well, how many wells to drill, and how to drill the well for maximum production (Wang and Krupnick). An MWD package, or downhole instrument package, transmits sensor readings of the drill bit location to the surface. Additional sensors in the drill string also provide real time information on the downhole environment and physical characteristics. Using the data from the MWD package, the direction of the hole can then be controlled with a steerable motor.

Hydraulic fracturing (“*fracking*”) is the process of inducing fractures in reservoir rocks through the injection of fluids, chemicals, and solids under very high pressure. A mixture of sand and other granular materials creates or holds open fractures in the rock to allow the hydrocarbons to flow freely to the well. The first experiments with hydraulic fracturing took place in 1947 and marginal developments followed. Mitchell Energy began large-scale testing of the technology in 1978 with the Department of Energy’s support (Wang and Krupnick). The knowledge developed during that test was then transferred to other unconventional areas. As with horizontal drilling, 3D seismology supported hydraulic fracturing by giving developers a better understanding of the geology of the reservoir and how best to stimulate it.

Pad drilling is another technique that has been used intensively along with hydraulic fracturing and horizontal drilling since

Box continued

2006. It allows drilling multiple wellbores from a single surface location, so rig operators can drill groups of wells more efficiently. Improved rig mobility saves time and expense that otherwise would be spent on packing and moving the rig and preparing a new drilling site.

Experiments with horizontal drilling date back several decades, but the development of complementary technologies—such as 3D seismic surveying methods—made horizontal drilling more practical. In 1991, the first horizontal well was drilled in the Barnett Shale field. In 1997, hydraulic fracturing was successfully applied to shale formations. Together, these technologies have changed the energy sector significantly: the most productive tight oil and shale gas fields accounted for more than 95 percent of growth in oil and gas production from 2011 to 2013, due largely to extensive use of hydraulic fracturing and horizontal drilling (U.S. EIA 2014b).

Production in tight oil and shale gas fields depends on several factors, such as initial well production, production decline rates, and extraction costs. These factors have led to considerable and continued drilling activity and investment in oil and gas extraction in recent years, without which U.S. production would have fallen quickly.

Initial production

Oil and natural gas production in shale formations depends heavily on the initial production (IP) of unconventional wells—that is, their production rate when first drilled. For a few high-quality wells, IP can be significant, but for the majority of wells, IP is considerably lower.⁴ For example, 2 percent of gas wells in the Haynesville field of east Texas and west Louisiana have an IP over 7,300 million cubic feet per year. However, as shown in Table 1, the field's average IP is much lower at around 2,993 million cubic feet per year. In the Eagle Ford tight oil field of south Texas, about 10 percent of oil wells have an IP of more than 365 thousand barrels per year, but the average IP is around 160 thousand barrels per year (Hughes 2013a). Nevertheless, these lower

Table 1
Average Well Production by Field

| Tight oil field | Average well production (1,000 bbl) | Average initial well production (1,000 bbl) | Shale gas field | Average well production (million cubic feet) | Average initial well production (million cubic feet) |
|-----------------|--|--|-----------------|---|---|
| Bakken | 45.3 | 146.0 | Haynesville | 910.0 | 2,993.4 |
| Eagle Ford | 61.3 | 159.5 | Marcellus | 470.9 | 710.7 |
| Permian | 7.1 | 30.4 | Woodford | 226.3 | 836.6 |
| Niobrara | 1.7 | 9.2 | Granite Wash | 112.4 | 759.2 |

Source: Hughes (2013a).

average IP rates are still significantly higher than average well production, a measure which includes all operating wells both new and old. Average well production is only 61 thousand barrels per year in Eagle Ford.

Production decline rates

Unconventional wells have steeper production decline rates than conventional wells. In conventional oil fields, annual production decline rates typically range from 5 to 10 percent (Hook and others). A conventional well can go through a longer period of steady, flat production between its peak and decline. In unconventional wells, however, production falls rapidly in the first three years and then enters a sustained period of low production. As a result, new and high-producing wells have to be drilled constantly to maintain steady production across unconventional fields.

In shale gas and tight oil formations, production typically declines sharply in the first year (Table 2). In the next couple of years, production continues to fall fairly rapidly. For example, production in an average gas well in the Marcellus shale gas field of Pennsylvania and western Virginia declines around 47 percent in its first year. In three years, the overall decline averages around 80 percent. Similarly, in the Haynesville shale gas field of eastern Texas and western Louisiana, production declines 68 percent in the first year and nearly 90 percent over the first three years. The average three-year decline rate across the top five shale gas fields is over 80 percent.

In the Bakken, one of the top tight oil fields in North Dakota and Montana, production in an average well declines 69 percent in its first

Table 2

First Year Well Decline Rates

| Tight oil field | Decline rates (percent) | Shale gas field | Decline rates (percent) |
|-----------------|-------------------------|-----------------|-------------------------|
| Bakken | 69 | Haynesville | 68 |
| Eagle Ford | 60 | Marcellus | 47 |
| Permian | 66 | Woodford | 58 |
| Niobrara | 79 | Granite Wash | 78 |

Source: Hughes (2013a).

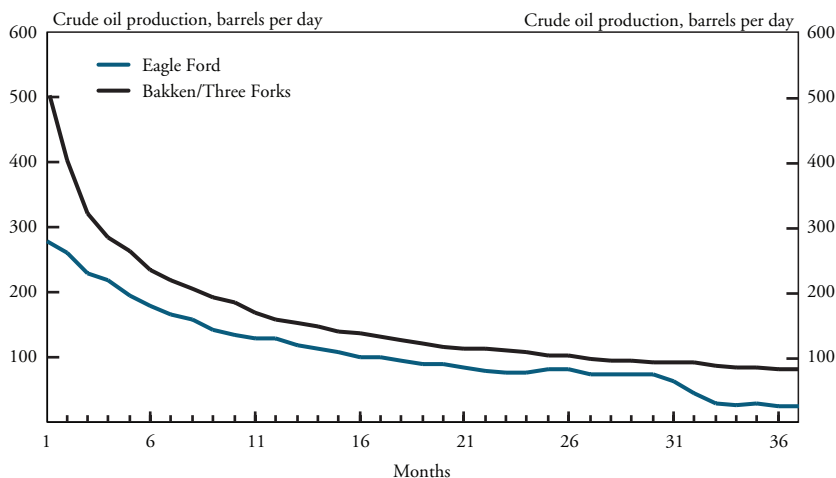
year and more than 85 percent in its first three years. In the Eagle Ford tight oil field of south Texas, production in an average well declines 60 percent in its first year and more than 90 percent over its first three years. Chart 1 shows the well decline curves for oil production in the Bakken/Three Forks and Eagle Ford.⁵ Although initial production is high in these fields, the steep decline rates mean that drilling, and thus investment in the oil and gas sector, must remain at high levels to increase production.

Extraction costs

A third factor in oil and natural gas production is the high cost of drilling in tight oil and shale gas fields. An unconventional well can cost from \$5 million to \$9 million. In 2012, the average cost of a new well across the top 10 tight oil fields was about \$8.3 million (Table 3).⁶ In 2013, a well in the Eagle Ford cost about \$6 million (Xu). Similarly, wells in the Permian and Bakken fields cost, on average, \$5.5 million and \$8 million, respectively. In contrast, a conventional vertical well can cost from \$1 million to \$3 million (Barker).⁷

Due to the high cost of unconventional wells, energy companies had little incentive to broadly employ sophisticated, expensive, and capital-intensive drilling techniques when prices were low. However, rising energy prices in the 2000s made these technologies profitable for commercial oil and gas production. As a result, the share of horizontal rigs in total rigs has increased from 9 percent in 2002 to 81 percent in 2014 (Chart 2).

Chart 1
Bakken/Three Forks and Eagle Ford Oil Well Decline Curves



Source: Hughes (2013b).

Table 3
Approximate Well Costs

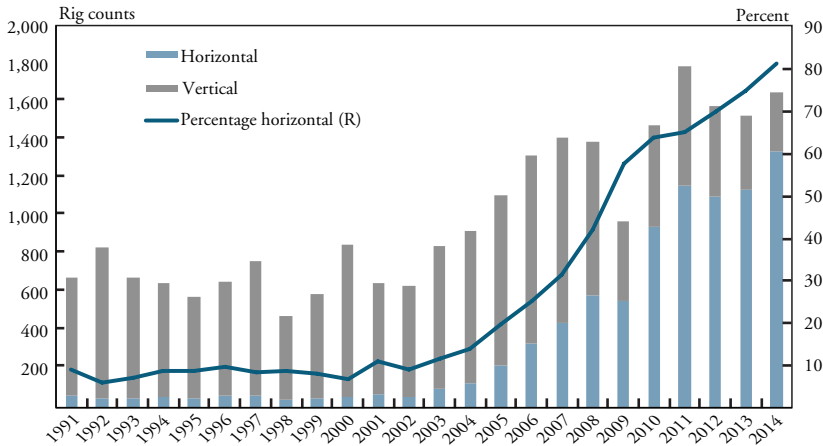
| Tight oil field | Average approximate well cost (million \$) | Shale gas field | Average approximate well cost (million \$) |
|-----------------|--|-----------------|--|
| Total | 8.3 | Total | 5.9 |
| Top 5 | 8.7 | Top 5 | 5.75 |
| Bottom 5 | 4.9 | Bottom 5 | 7.17 |

Notes: Bakken, Eagle Ford, Bone Spring, Niobrara, Granite Wash, Permian, Barnett, Austin Chalk, Spraberry, and Monterey-Tremblor are the oil fields considered. Bakken, Eagle Ford, Bone Spring, Austin Chalk, and Granite Wash are the top five according to their average IP, and the rest are the bottom five. The first row presents average values across 10 fields. All statistics presented are weighted average values where the weights are shares of these fields in total tight oil production. Haynesville, Marcellus, Barnett, Fayetteville, Eagle Ford, Woodford, Granite Wash, Bakken, and Niobrara are the gas fields considered. Haynesville, Marcellus, Barnett, Fayetteville, and Eagle Ford are the top five according to their average IP, and the rest are the bottom four. The first row presents average values across nine fields. All statistics presented are weighted average values where the weights are shares of these fields in total shale gas production.

Sources: Hughes (2013a) and author's calculations.

Chart 2

U.S. Rig Counts: Horizontal vs. Vertical



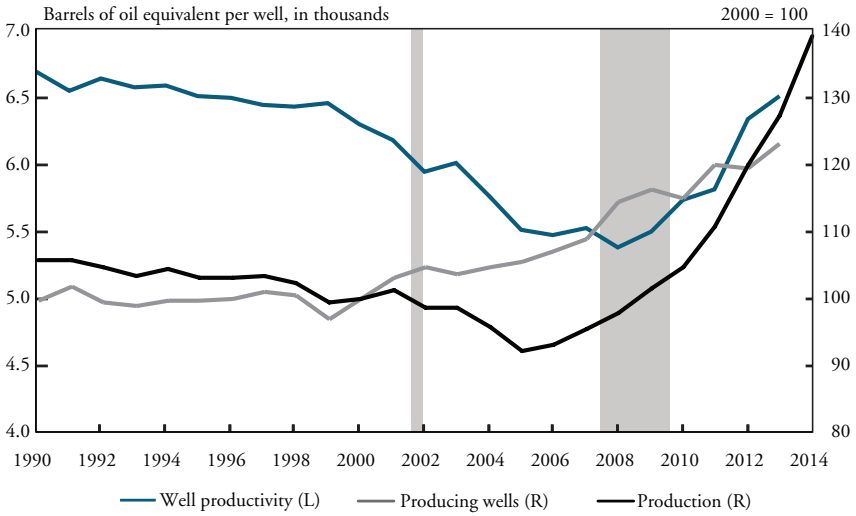
Source: Baker Hughes.

II. Trends in Energy Prices and Production since 1990

Past trends in the energy sector may help explain the path of future production growth. The 1990s to the early 2000s was a period marked by low prices, slowly declining oil and gas production, and a generally stable number of producing wells. As a result, well productivity—that is, output per producing well—declined slightly in the 1990s, from 6.7 thousand barrels of oil equivalent per well in 1990 to 6.5 thousand barrels of oil equivalent per well in 1999 (Chart 3). Low energy prices in the 1990s meant firms had little incentive to invest and to drill new wells, and the capital stock in the oil and gas sector declined slightly in the early 1990s and stayed flat the rest of the decade (Chart 4).

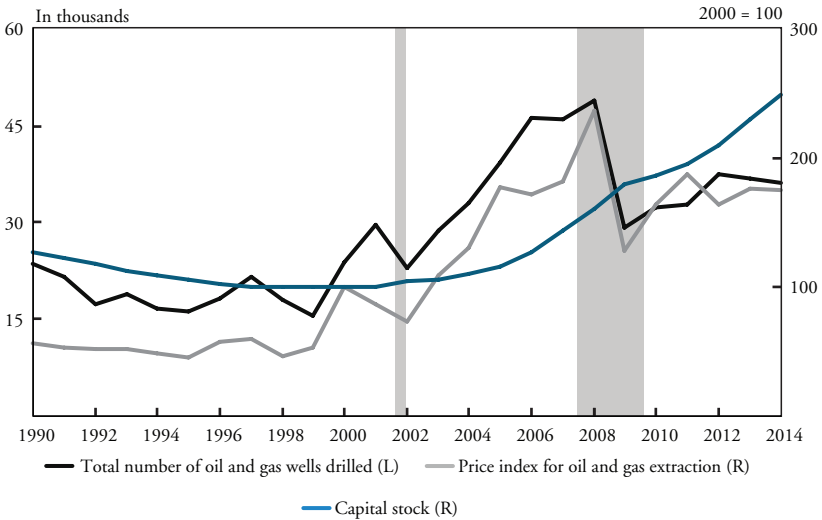
Oil and gas prices rose from early 2000 to the beginning of the Great Recession. With rising prices, previously unprofitable technologies—in particular, hydraulic fracturing and horizontal drilling—became more economical. Not only were previously unprofitable wells developed, but the number of exploratory wells also increased.⁸ Chart 4 shows both the number of oil and gas wells drilled and the capital stock in the sector increased significantly in the 2000s, with the number of gas wells nearly tripling from the 1990s to the beginning of the Great Recession in 2008. Although increased drilling eventually led to a significant increase in output, initially the number of wells grew faster.

Chart 3
U.S. Oil and Gas Sector Indicators



Note: Gray bars denote NBER-defined recessions.
 Sources: EIA, Baker Hughes, and author's calculations.

Chart 4
Energy Prices, Capital Stock, and Wells Drilled



Note: Gray bars denote NBER-defined recessions.
 Sources: EIA, BLS, BEA, Baker Hughes, and author's calculations.

As a result, U.S. oil and gas productivity (output per producing well) fell, dropping from 6.3 thousand barrels of oil equivalent per well in 2000 to as low as 5.4 thousand barrels of oil equivalent per well in 2008 (Chart 3).

Not surprisingly, the Great Recession caused a break in the energy sector. In particular, prices—and therefore oil and natural gas drilling activity—collapsed in 2008 before rebounding in 2009. The number of natural gas wells drilled decreased by 44 percent from 2008 to 2009 and kept declining due to low prices. Natural gas production, however, continued to increase.⁹

After their fall, oil prices began increasing again in 2009. As a result, oil exploration and development rebounded strongly, with the number of oil wells drilled doubling from 1990s levels. The increase in the number of oil wells represented a significant increase in investment in the oil and gas sector. The share of oil and gas in total U.S. capital investment jumped from just 1.9 percent in the 1990s to 5.8 percent in 2013.¹⁰

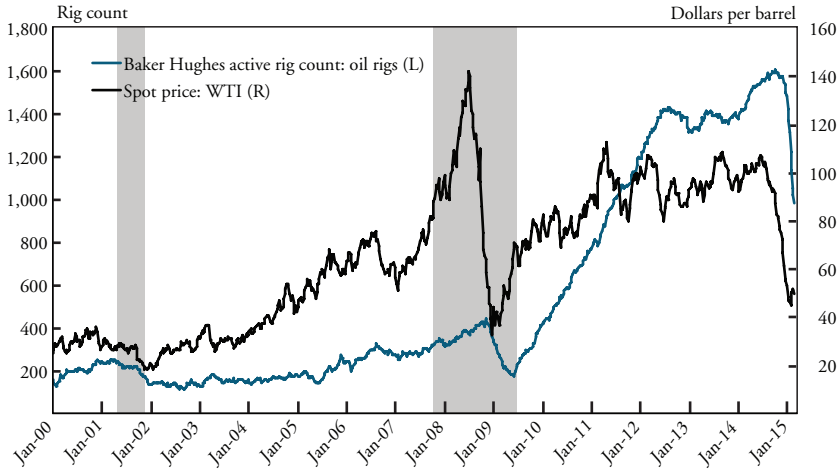
The resulting increase in the capital stock led to an increase in production and well productivity. In 2013, well productivity was almost 6.5 thousand barrels of oil equivalent per well, up more than 20 percent from its 2008 low. In 2014, oil and gas production reached 7.7 billion barrels of oil equivalent per well, 43 percent higher than its 2008 level.

III. Implications of the Recent Oil Price Decline for U.S. Oil Production

This section narrows the article's focus from developments in the oil and gas industry to the effects of lower oil prices on oil production. The analysis projects 2015 oil production based on reasonable assumptions about rig counts, the number of new wells drilled, and rig and well efficiency.

The sharp decline in oil prices since the summer of 2014 has led to a subsequent decline in oil rig counts—that is, the number of drilling rigs actively exploring for or developing oil (Chart 5).¹¹ Oil prices declined around 55 percent from their peak in June 2014 to the end of March 2015. The decline in oil prices reflects a combination of changes in demand and supply factors including lower-than-expected oil demand from China, Japan, and Europe; continued faster-than-expected

Chart 5
Weekly U.S. Oil Rig Counts and WTI Spot Price



Note: Gray bars denote NBER-defined recessions.

Sources: Baker Hughes and *The Wall Street Journal*.

U.S. production; and Libyan output returning to the market. In addition, Saudi Arabia, the biggest oil producer within the Organization of the Petroleum Exporting Countries (OPEC), publicly announced its intention to maintain production in the face of falling prices. OPEC subsequently decided on Thanksgiving Day 2014 not to cut production.

Oil rig counts in the United States began to decline in October, and fell sharply after Thanksgiving. In particular, weekly oil rig counts declined more than 49 percent from their peak in October 2014 to the end of March 2015, and could decline further if projected prices are not high enough to make continued drilling profitable.

To determine the effect of the recent oil price decline on oil production in 2015, the analysis considers two hypothetical cases: oil rig counts declining by 50 percent from 2014 to 2015 and oil rig counts declining by 60 percent over the same period. Under these assumptions, oil rig counts would fall from 1,527 in 2014 to 763 and 611 in 2015, respectively. Falling rig counts, however, do not necessarily imply falling production. The relationship between changes in rig count and changes in oil production is not simple because rigs drill wells, but wells pump the oil. For example, even though rig counts have declined over the past four months, U.S. oil production has continued to increase.

To estimate oil production in 2015, the analysis first estimates the effect of a decline in rig counts on the number of wells drilled. Then, it estimates the effect of a decline in the number of wells drilled on oil production. Under reasonable assumptions, the analysis suggests oil production could decline in 2015 from 0.7 to 8 percent. However, oil production could increase by around 5 percent in 2015 if efficiency increases significantly and rig counts decline by slightly less than 50 percent.

The effect of a decline in rig counts on the number of wells drilled

The effect of a decline in rig counts on the number of oil wells likely to be drilled in 2015 depends on both rig counts and rig efficiency—that is, the number of wells that can be drilled by a rig. For example, if the number of rigs falls but each rig can drill more wells, the number of wells could increase or decrease. An average rig can drill more wells today than in the past due to pad drilling, and most shale wells today are drilled from pads (see Box). Since one rig drills many wells from the same surface location without demobilizing or remobilizing, drilling has become more efficient. Moreover, the most inefficient rigs are expected to be removed first when prices fall, contributing to a potential disconnect between rig counts and production.¹²

In 2014, the average rig could drill around 22 wells, an efficiency increase of 11 percent from 2011 (or about 3.5 percent per year).¹³ Individual fields saw sharp efficiency gains. For example, the average drilling rig efficiency rose around 50 percent in the Bakken field from 2011 to 2013, or about 22 percent per year (U.S. EIA 2014c). Rig efficiency in Eagle Ford rose 38 percent from 2012 to 2014, or about 18 percent per year.¹⁴

Given the wide range of estimates of the improvement in rig efficiency and uncertainty about whether these rates of improvement can persist, this article considers two alternative production scenarios slightly higher than recent gains but lower than gains in the most productive fields: rig efficiency rising by 5 percent and by 10 percent in 2015. In other words, rig efficiency, which was 22 wells per rig in 2014, is assumed to increase to 23 (in the first scenario) and 24 (in the second scenario) in oil fields in 2015.

The analysis in this section focuses on oil production, and therefore considers the number of oil wells drilled. The EIA provides estimates

Table 4

U.S. Oil Drilling and Production Estimates, 2015

Panel A: 50 percent decline in oil rig counts

| Improvement in rig efficiency | Number of oil wells drilled | Improvement in rig efficiency + IP | Oil production (million barrels) |
|-------------------------------|-----------------------------|------------------------------------|----------------------------------|
| 5% | 15,605 (-47%) | 5% (rig) 5% (IP) | 3,147 (-0.7%) |
| 10% | 16,348 (-45%) | 10% (rig) 15% (IP) | 3,322 (+4.9%) |

Panel B: 60 percent decline in oil rig counts

| Improvement in rig efficiency | Number of oil wells drilled | Improvement in rig efficiency + IP | Oil production (million barrels) |
|-------------------------------|-----------------------------|------------------------------------|----------------------------------|
| 5% | 12,484 (-58%) | 5% (rig) 5% (IP) | 2,909 (-8%) |
| 10% | 13,078 (-56%) | 10% (rig) 15% (IP) | 3,049 (-3.8%) |

Sources: Hughes (2013a), EIA, Baker Hughes, and author's calculations.

for the total number of wells drilled, but does not distinguish between oil and gas wells. To estimate the number of oil wells drilled using the EIA's total number of oil and gas wells drilled estimates, the ratio of oil wells to oil and gas wells is set at 82 percent.¹⁵ About 11 percent of total wells are assumed to be dry holes, and are thus excluded.¹⁶ Given these estimates, the 41 thousand oil and gas wells drilled in 2014 translate into an estimated 29.6 thousand oil wells drilled in 2014.

Table 4 shows estimates of the number of oil wells drilled under each efficiency scenario and for both hypothetical rig count declines. Panel A shows that under the first scenario, a 50 percent decline in oil rigs implies a 47 percent decline in the number of oil wells drilled in 2015, from 29.6 thousand to 15.6 thousand.¹⁷ Under the second scenario, a 50 percent decline in oil rigs implies a 45 percent decline in the number of oil wells drilled, from 29.6 thousand to about 16.4 thousand. With a 60 percent decline in rig counts, the decline in oil wells drilled is significantly larger. Panel B shows that under the first scenario, a 60 percent decline in oil rigs implies a 58 percent decline in the number of oil wells drilled, from 29.6 thousand to about 12.5 thousand. Under the second scenario, a 60 percent decline in oil rigs

implies a 56 percent decline in oil wells drilled, from 29.6 thousand to 13.1 thousand.

The effect of a decline in the number of wells drilled on 2015 oil production

The effect of a decline in the number of wells drilled on oil production can be obtained using estimates of production coming from existing wells (old production) and from newly drilled wells (new production). These estimates depend on annual overall field decline rates, the average IP of a well in U.S. tight oil fields, 2014 annual U.S. crude oil production, the number of oil wells drilled, and U.S. well count data by basin.¹⁸

Production from existing wells declines due to resource depletion in existing wells. A field's average production decline rate provides an estimate of how much production would be lost from 2014 to 2015. The average annual field decline rate across the top 10 fields is about 38 percent.¹⁹ With 3,168 million barrels of oil produced in 2014, a 38 percent decline rate means 2015 production from existing wells would be around 1,960 million barrels (3,168 times $(1-0.38)$).

Production from wells drilled in 2015 depends on a well's average IP. The IP of a well varies significantly across and within regions. Statistics provided by Hughes (2013a) are used to estimate the average IP of a well in U.S. tight oil production. Since rigs in less productive areas would be removed first, drilling is assumed to continue in the most productive areas. Using the average IP of a well in the most productive U.S. fields—the Bakken, Eagle Ford, Permian, and Niobara—an overall average IP estimate for U.S. oil production of 72.6 thousand barrels per year is obtained.²⁰ This estimate is assumed to increase in 2015, due in part to continued efforts by oil companies to enhance well stimulation, and the analysis considers well productivity gains of 5 percent or 15 percent over a one-year period.²¹ Assuming a 50 percent decline in oil rigs, a 5 percent rise in rig efficiency and a 5 percent rise in IP, new oil production in 2015 is estimated to be 1,190 million barrels (that is, approximately 15.6 thousand oil wells times 76.3 thousand barrels per year). If rig efficiency increases 10 percent and IP rises 15 percent, then new oil production in 2015 will be higher, around 1,365 million barrels. However, if oil rig counts decline 60 percent, then new production will be much less: 952 million barrels and 1,092 million barrels, respectively.

Table 4 combines production from existing wells and new wells to present 2015 production estimates. Panel A shows production estimates assuming a 50 percent decline in oil rig counts. Under this assumption, if rig efficiency increases by 5 percent and well productivity rises by 5 percent, then production will decline by around 0.7 percent, from 3,168 million barrels in 2014 to 3,147 million barrels in 2015. If rig efficiency increases by 10 percent and IP increases by 15 percent, however, production will increase by around 5 percent, from 3,168 million barrels to 3,322 million barrels. That is, even with a 50 percent decline in rig counts, improvements in efficiency could increase production in 2015. A near 7 percent increase in IP, along with a 5 percent increase in rig efficiency, could be enough to keep production steady. However, if rig counts decline 60 percent, then even improvements in rig and well efficiency of 10 and 15 percent, respectively, would not be enough to increase production (Panel B). Under this assumption, production could decline as much as 8 percent. In order to keep production steady from 2014 to 2015, IP would need to rise more than 27 percent to around 92.6 thousand barrel per year, even with a 10 percent rise in rig efficiency.

IV. Conclusion

Developments in shale gas and tight oil formations created a boom in the U.S. oil and gas extraction sector over the past decade which significantly expanded drilling activity and the capital stock. High initial productivity but fast production decline rates have required increasing investment and drilling over time in shale fields. However, the recent sharp decline in oil prices has put the drilling activity necessary to continue shale production at risk. Using two hypothetical cases, this article finds U.S. oil production in 2015 could decline from 0.7 to 8 percent from 2014 levels despite production taking place in the most productive fields with efficiency gains. For production to stay the same or increase, efficiency would need to increase markedly or the decline in rig counts would need to halt.

Endnotes

¹These technologies were primarily developed to find new oil and gas sources to deal with the energy crises facing the United States in the 1970s, including the 1973 oil embargo and the decline in domestic gas production.

²The private sector, some argue, had little financial incentive to invest in research and development programs, thus spurring government involvement. The Department of Energy spent \$137 million (in 1999 dollars) on the Eastern Gas Shales Program from 1978 to 1992 (Wang and Krupnick). Private companies then took that expertise and further developed it for their use.

³Bohi suggests major companies responded to the decline in oil prices after 1986 by changing their management structure, moving from hierarchical to team decision-making.

⁴Highly productive shale gas and tight oil fields are not widespread, and production can vary considerably within fields. “Sweet spots”—the most productive portions of shale gas and tight oil fields—are relatively scarce. Current production mostly occurs in sweet spots, and output per well in these regions has recently shown signs of improvement. As these spots are exhausted, however, production must move to less-productive areas—requiring significant capital investment and additional wells to offset high decline rates—unless new productive fields are found or well productivity increases significantly (Hughes 2013a).

⁵The Three Forks shale formation, like the Bakken, is also within the Williston Basin in North Dakota and Montana.

⁶Data on approximate well cost in each field is obtained from Hughes (2013a). Average cost is then calculated as the weighted average cost across 10 fields where the weights represent the share of each field in tight oil production.

⁷Factors such as available locations to drill, locations of wells, fracturing stages, and others also determine production.

⁸For example, from 2003 to 2008, amid rising oil and gas prices, the number of exploratory oil wells increased more than 150 percent.

⁹Natural gas production increased due to production coming from previously drilled wells, efficiency gains, and associated gas produced from oil wells.

¹⁰Share is calculated as private fixed investment in current U.S. dollars.

¹¹To be counted as active, a rig must be on location and be drilling. Active rig counts data published weekly by Baker Hughes are the timeliest data on the status of the U.S. oil industry. For this article, the weekly rig data are converted into monthly and annual rig count numbers by calculating arithmetic averages of the rigs reported.

¹²In addition, a time delay between the start of the drilling of a well and that well’s initial production contributes to the disconnect. The delay between drilling a new well and bringing it into full production can vary from one or two months up to six months. The analysis in this article focuses on annual changes mainly

due to data restrictions on well information. As a result, it assumes that new wells drilled in 2015 will contribute to production during that same year.

¹³The EIA provides data on the number of oil and gas wells drilled each year through 2011 and the EIA's Annual Energy Outlook provides estimates on the total number of oil and gas wells drilled from 2012 to 2014. The average rig efficiency is then obtained by dividing total wells drilled by total rig counts.

¹⁴Rig efficiency for Eagle Ford is calculated as land well count per land rig count by basin (Baker Hughes).

¹⁵An estimate for the number of oil wells drilled is obtained using the monthly seasonally adjusted ratio of oil rig counts to total oil and gas rig counts (Baker Hughes and Haver Analytics). The ratio of oil rig counts in total rig counts has increased significantly since 2011. In 2012, the ratio was 71 percent, and in 2014, it was 82 percent. For this article's 2015 calculations, the 82 percent ratio is assumed to hold.

¹⁶From 2000 to 2011, on average about 11 percent of total oil and gas wells drilled in the United States were dry holes (EIA).

¹⁷In 2014, oil rigs numbered 1,527. A 50 percent decline in rig counts would lead to 763 rigs in 2015. Since 2014 rig efficiency was 22 wells per rig and the first scenario assumes a 5 percent increase in rig efficiency, the number of oil wells drilled in 2015 would be approximately 763 times 22 times 1.05 times 0.89 (excluding dry wells) equals around 16 thousand.

¹⁸Baker Hughes provides quarterly data on U.S. land well count by basin since 2012. The number of wells drilled and oil production are obtained from the EIA. Hughes (2013a) presents 2011 and 2012 estimates of productivity and decline rates for 21 tight oil fields in the United States. Among these fields, the top 10 constitute 99 percent of tight oil production and therefore serve as a proxy for the U.S. oil producing regions. Note that in terms of well metrics, the EIA publicly releases data only on the number of wells drilled in the nation, reported as the sum of their county-level estimates from detailed data on fields at the county/reservoir level. As a result, this analysis uses Hughes' (2013a) estimates for other well metrics.

¹⁹Hughes (2013a) estimates decline rates using production data from all wells drilled prior to 2011 for each of the fields considered. These decline rates across 10 fields are used to calculate the overall field decline rate. The production decline rate for tight oil wells is 38.23 percent on average for the United States, calculated as the weighted average of the 10 top tight oil fields' overall annual decline rates before 2011. Field decline rates in unconventional fields tend to increase over time. As a result, the estimates of this article may be quite conservative.

²⁰Share of land well count by basin in total U.S. land well count is used to weigh IP levels across the four fields, which are then averaged to obtain the U.S. average. In other words, well-count weighted average IP across these four fields is used as a proxy for U.S. IP of a well.

²¹The EIA's periodic study on drilling productivity across top U.S. tight oil fields shows that efficiency, measured as new well production per rig, has

continued to rise in recent years. In the Bakken, efficiency increased on average 30 percent from 2011 to 2014; in the Permian, efficiency increased 22 percent per year over the same period. This efficiency measure, new well production per rig by field, incorporates both rig efficiency and well productivity. Hence, assuming a range of 5 to 15 percent well productivity gains and 5 to 10 percent rig efficiency gains would be reasonable given the EIA's recent drilling productivity data for the most productive fields.

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