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EFFECTS OF LOW OIL PRICES ON U.S. SHALE PRODUCTION: OPEC CALLS THE TUNE AND SHALE SWINGS

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Effects of Low Oil Prices on U.S. Shale Production: OPEC Calls the Tune and Shale Swings

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Introduction

Emerging data on U.S. oil drilling and output show that U.S. shale producers appear to be among the first to respond to the collapse in global crude oil prices. Sharp declines in new production are evident in high-cost plays, while growth in some low-cost unconventional production appears virtually unaffected.

Oil prices shed around half of their value between June and December 2014, falling precipitously after OPEC's November decision to maintain constant oil production. Saudi oil minister Ali al-Naimi declared that OPEC would defend its share of global crude oil markets from upstart producers, including U.S. shale operators. Two months later, OPEC's actions appear to be generating the desired effect. New oil production in some U.S. shale plays appears to have been curtailed, especially since November. Signs include shrinking numbers of drilling rigs in operation, fewer wells being drilled, and reductions in the volumes of new oil production coming onstream.

The clearest evidence of decline has emerged from the Permian Basin of Texas and New Mexico. There were steep drop-offs in the number of rigs in operation and in the drilling of vertical wells. As a result, projected new oil flow, especially from vertically drilled wells, has decreased.

The picture is far from universal, however, and important counter-cases bear mention. Perhaps the most contrarian is South Texas' Eagle Ford shale, where data from the Austin-based analytics firm Drillinginfo show rising numbers of wells drilled and increasing volumes of oil produced, even between the months of November 2014 and January 2015, as bad news spread across the global oil sector.

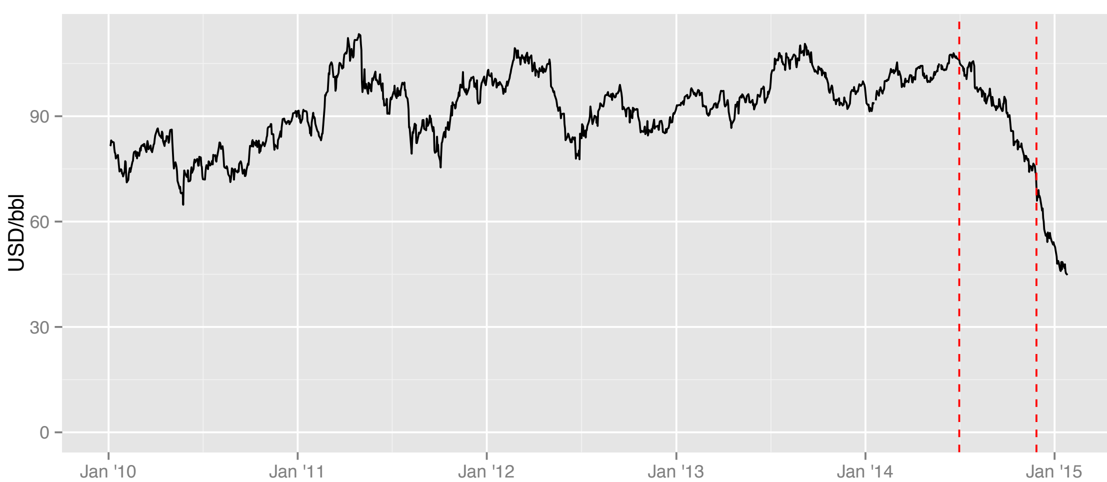
It bears emphasizing that the slowdown in growth, where it applies, does not mean that overall U.S. oil production has decreased. It means that production growth is occurring at a decreasing rate.

Significance

The Drillinginfo data appear to confirm speculation that some of the first reductions in worldwide oil production would take place in the U.S. shale sector. The shale industry is now revealing itself as a nimble and price-responsive producer at a time when OPEC member-states have refused to squelch their own production, thereby rejecting their customary market-balancing role. The International Energy Agency (IEA) expects other high-cost producers such as Canada and Colombia to join in the cuts in production, but investment momentum and price hedging often mean that oil output continues to rise in the near term.[1] The U.S. Energy Information Administration (EIA) forecasts that overall U.S. oil production will increase until the third quarter of 2015 for similar reasons.[2] Long-planned conventional projects, including those offshore, continue to bring new production online.

A number of analysts predicted that market dynamics would force shale producers to assume a portion of the swing producer role formerly held by Saudi Arabia.[3] As is now well known, OPEC members announced at their Nov. 27 meeting that member-states would maintain a constant level of production, refusing to reduce oil flowing to an oversupplied global market. The drop in oil prices accelerated immediately after Nov. 27 (see Figure 1).

Figure 1. West Texas Intermediate spot price



Source: Energy Information Administration
July 1 and Nov 27 indicated by dashed lines

Al-Naimi blamed rising non-OPEC production for OPEC's divergence from past practices, arguing that any OPEC cut would be quickly annulled by production increases from emerging competitors.

"Why did we decide not to reduce production? I will tell you why," al-Naimi said in December. "If I reduce, what happens to my market share? The price will go up and the Russians, the Brazilians, U.S. shale oil producers will take my share."[4]

To date, however, there has been little quantitative evidence of a non-OPEC supply response. Anecdotal reports have described declining investment, job cuts, and dropping numbers of drilling rigs in operation. Missing from these reports were figures detailing numbers of actual wells drilled, whether levels of new oil production had declined, and, if so, which basins bore the brunt of those declines. This paper intends to bridge that gap by leveraging previously unreleased data provided by Drillinginfo that sheds light on these important shortcomings.

The Drillinginfo index reveals reduced investment in some shale formations—both in terms of number of wells and the overall production potential of these investments—and opposite effects in others. What emerges is an illustration of the diverging fortunes of an industry that appears to be shifting into a low-price mode in which retrenching firms set aside drilling plans in less-productive zones and focus efforts on their most productive acreage and highest efficiency extraction techniques. These revelations portend a new paradigm in an industry where decades-long investment horizons have typically led to over- or under-shooting market needs, contributing to price volatility.

The enhanced price-responsiveness of shale extends from a key difference with conventional oil exploration and production, in which shale resembles a manufacturing process. Exploration is generally unnecessary because locations of oil-rich shale basins are already known. However, constant levels of production require constant rates of well drilling, due to steep decline curves on well productivity. If drilling declines, production tends to follow.

Methodology

We combined two primary sources of data to tell this story. First, we were given access to previously unreleased monthly data from Drillinginfo, a company that compiles diverse ground-level data on oil and gas production. Second, we examined those data alongside rig count data from Baker Hughes, which has been a standard data source for analysts tracking industry investment trends.

The Drillinginfo index tracks new onshore wells that have been drilled ("spudded") across most of the lower 48 U.S. states since March 1, 2014.[5] The index assigns each well a predicted peak production volume, which is calculated as the average peak production of nearby wells of a similar type. The index is computed on a monthly basis, and wells are tracked down to precise latitude and longitudes. Thus, the index provides an indication of the level of investment and drilling activity at a precise geographical location, as well as a useful estimate of expected initial production. These data are provided for the previous calendar month, a shorter time frame than those of other public reports.

It is important to interpret the Drillinginfo production index carefully. The index estimates the maximum monthly new oil production likely to flow from a given well drilled in a given month. The data do not show when or whether the wells are completed or connected to gathering infrastructure. Peak production normally occurs at least a month after the well and its production are counted in the index. Further, new production covered in the index is a fraction of overall U.S. oil production. The index captures a future marginal increase in total production from new wells. Thus, even if the index showed zero new production for January, production could still continue to rise as wells drilled earlier in the year come online.

Our second data source, the rig count data from Baker Hughes, details the number of rigs "actively exploring for or developing oil or natural gas" on a weekly basis in each U.S. county. The dataset tags each rig as horizontal or vertical (an indicator of whether the well is unconventional or conventional) as well as whether the well is targeting oil or natural gas. The data are similar to the DI Index in that they provide an indicator of the level of new upstream investment.

Rig counts fail to capture productivity differences in terms of number of wells drilled or expected volumes of production from those wells. However, the Baker Hughes rig count is available for a longer time horizon (since early 2011). Changes in the rate of upstream investment will appear sooner in Baker Hughes' weekly rig counts than in the monthly Drillinginfo index.

Five Places Where Production is Dropping

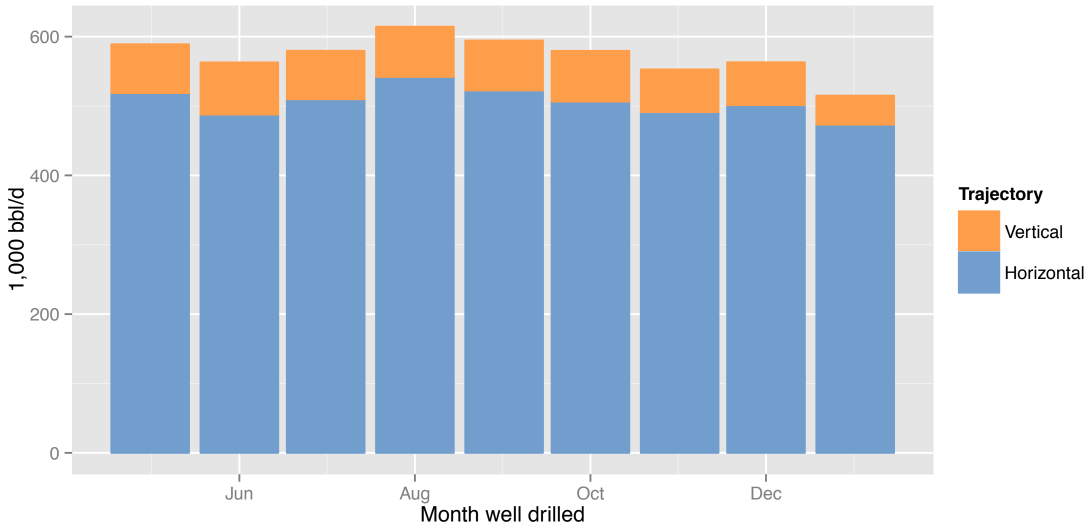
National

Across the continental United States, data from Drillinginfo show a gradual 13% decline in new oil production brought onstream in a given month, from about 600,000 barrels per day (bbl/d) in May 2014 to just under 525,000 bbl/d in January 2015. Although new production rises and falls throughout the period, it appears significant that levels in January—after falling oil prices became a concern—are the lowest of any of the months shown.

New oil-directed[6] well starts showed greater declines, dropping by 32%, from 1,967 in May to 1,338 in January. Oil drilling dropped by the largest amount, 24%, between December and January, as oil prices hit their lowest levels.

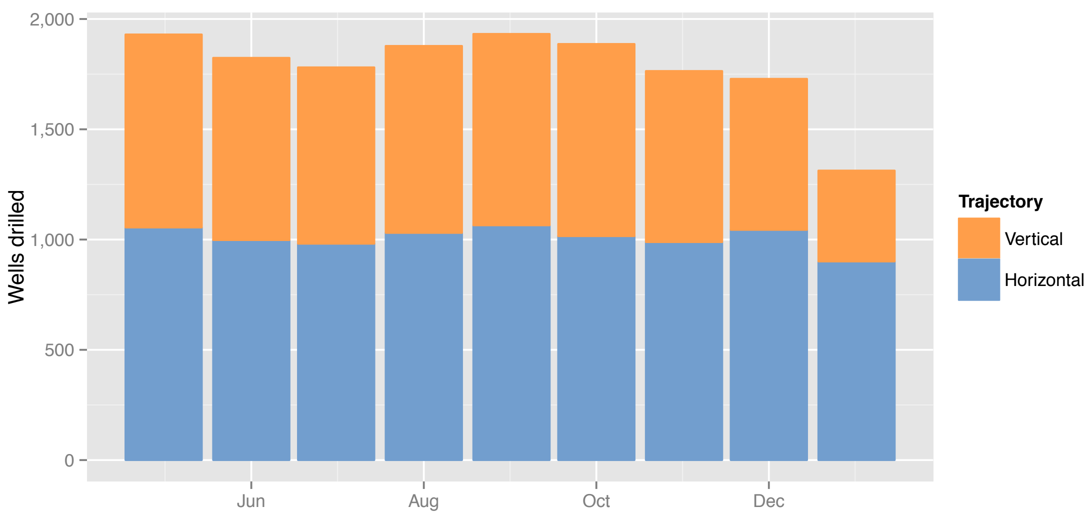
Geographically, the biggest declines appear to be affecting North Dakota's Bakken formation, while in technological terms, the largest declines concerned vertically drilled wells.

Figure 2. New U.S. liquids production from all wells drilled in the month indicated, by well trajectory



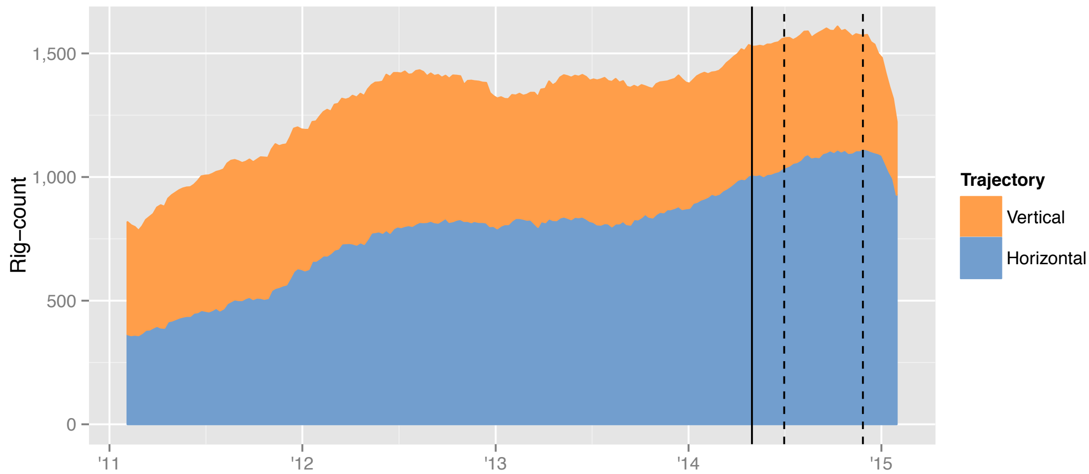
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 3. New U.S. oil wells drilled in the month indicated, by well trajectory



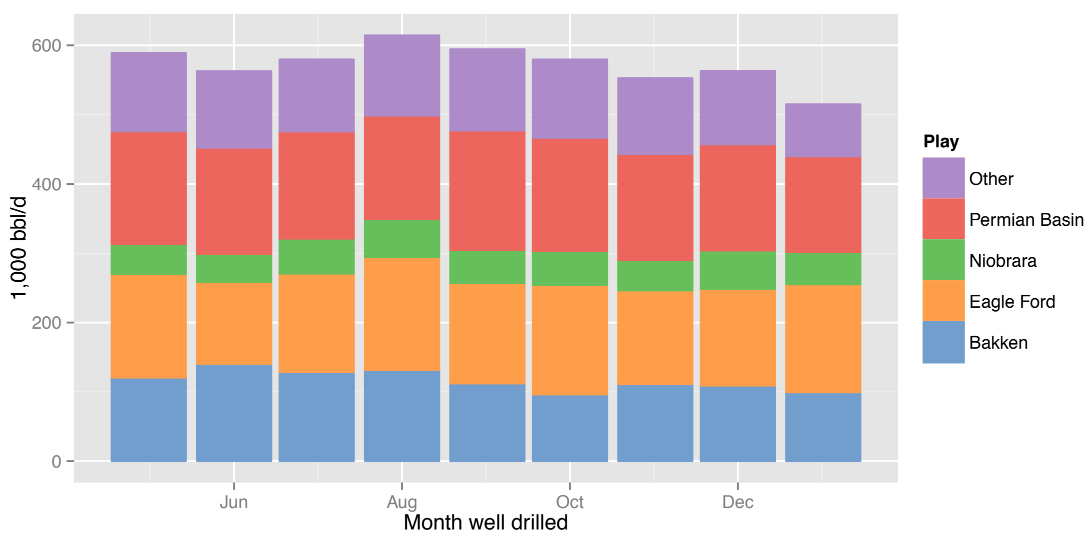
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 4. Active oil-directed rigs in the month indicated, by well trajectory



Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

Figure 5. New U.S. liquids production from wells drilled in the month indicated, by formation



Source: Drillinginfo; Scaled to compensate for number of days in month.

Permian Basin

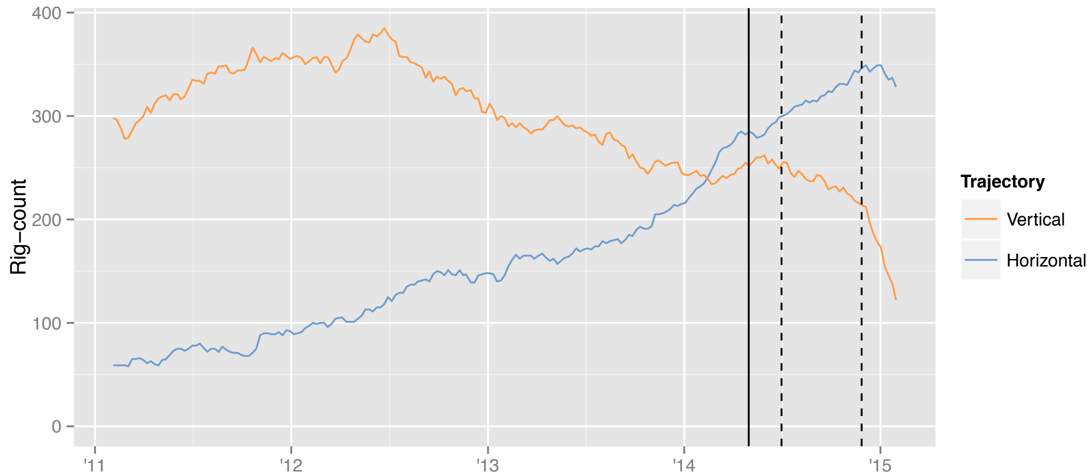
Among the major U.S. oil formations, the clearest signs of price-influenced changes in production are seen in the Permian Basin, where, after evidence of a long surge in investment and vertical and horizontal drilling since 2011, new production was down by almost 16% between May 2014 and the end of January 2015. However, the decline in predicted peak production appears to be tied mainly to a reduced number of vertical wells. New production from vertical wells plummeted by 46%, from 36,000 bbl/d in May 2014 to just under 20,000 bbl/d in January 2015. The steepest fall-off coincides with the OPEC announcement in late November. Predicted production of about 30,000 bbl/d in December tumbled by 36% to just under 20,000 bbl/d in January. Many of these vertical wells are in the eastern Permian's Midland Basin where production is linked to vertical "infill" wells drilled in mature fields. Vertical infill wells are relatively simple and inexpensive to drill, which allows producers to pull back production when prices drop.

For horizontal wells in the Permian, which are more heavily concentrated in its western Delaware Basin, the case is different. Drillinginfo data show predicted new production remaining relatively constant from May through January at roughly 125,500 bbl/d. In fact, there was virtually no change in new production from horizontal wells between November—prior to the oil sector lapsing into panic mode—and January, well after that period was underway.

Another strong indicator of producers reacting to falling oil prices came in the form of a sharp increase in the average productivity of horizontal wells in the Permian, which jumped by 11%, from an average of 458 bbl/d per well in December to 507 bbl/d in January. Rising well productivity conforms to expectations that firms would shift away from low-producing wells in non-core areas and concentrate on drilling horizontal wells in their most productive acreage. The Drillinginfo data appear to bear out these predictions.

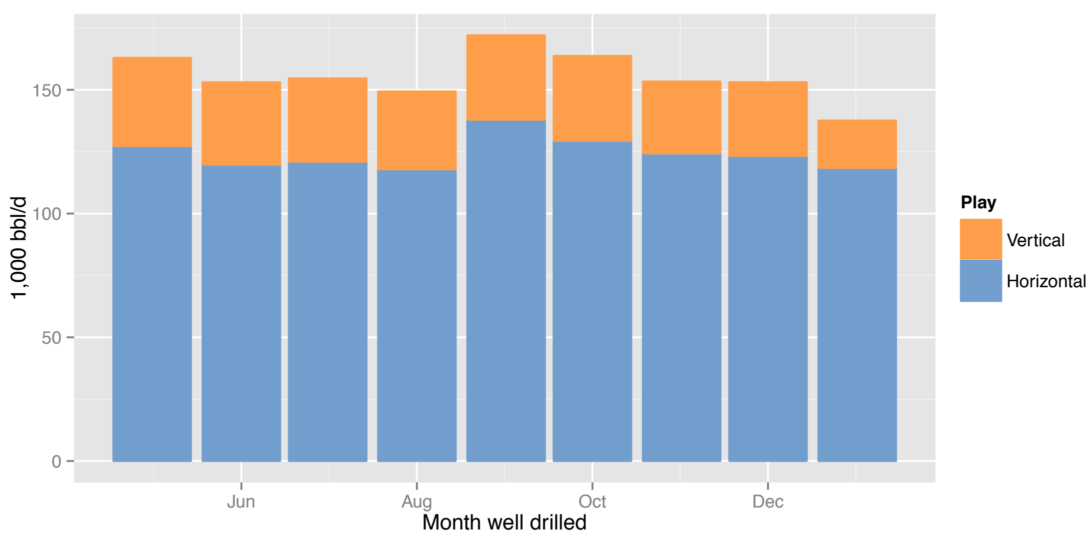
Finally, the Baker Hughes rig count data corroborates these findings. Rigs drilling oil-directed vertical wells in the Permian declined from a peak of 385 in June 2012—well before the current slump in global oil prices—to a low of 122 at the end of January 2015. Figure 6 below shows a steep rig decline after the November OPEC meeting, illustrated by the vertical dotted line on the right-hand side. The rig count for horizontal drillers also shows a decline, albeit a smaller one. After reaching a peak of 349 on December 5 (where it stayed until January 2), rig counts fall to 328 by the end of January 2015.

Figure 6. Rig-count in Permian Basin, by well trajectory



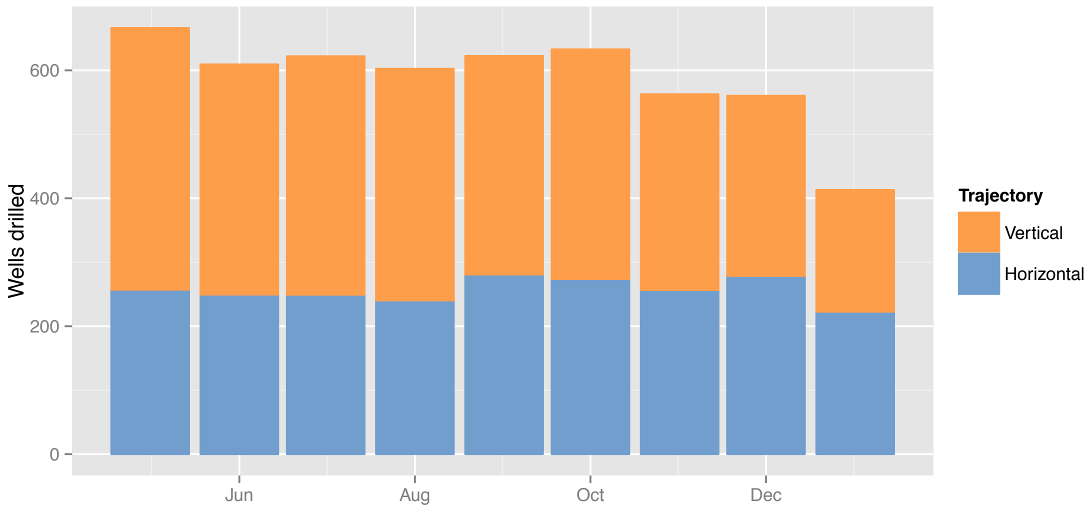
Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

Figure 7. New Permian Basin liquids production from wells drilled in the month indicated, by well trajectory



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 8. New Permian Basin oil wells drilled in the month indicated, by well trajectory



Source: Drillinginfo; Scaled to compensate for number of days in month.

Other Areas of Onshore Oil Production

Decreases in oil production and drilling frequency are also in evidence in some smaller and lesser-known tight oil plays, as well as areas that lie outside the geographical boundaries of the major shale formations. Though the decline in activity has been sharp, these plays represent a smaller segment of upstream investment in terms of oil-directed wells (34% of national for May 2014 to January 2015), rig counts (44% of national for the same time period), and predicted peak production (19% of national). Thus, the aggregate impact of investment declines here will be minor at a national level. Again, this finding is consistent with predictions that production would be maintained in core basins and acreage where high flow rates and other factors allowed for lower unit costs. Forecasts likewise suggested that drilling and production would fall in non-core areas where higher break-even prices were needed to support continued investment and extraction.

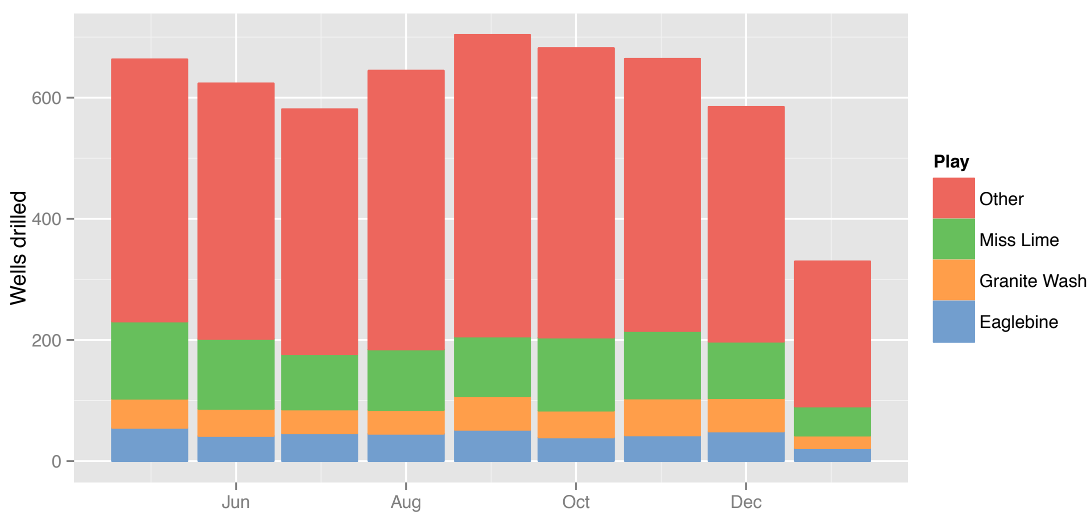
Four areas in particular underwent sharp declines in both new wells drilled and new oil production, Drillinginfo data show. Those were the Eaglebine formation in East Texas, the Mississippian Lime formation in Kansas and Oklahoma, the Granite Wash in Oklahoma and Texas, and areas denoted on the figures below by "other," which include locations outside of defined formations. Combined, these four areas saw new oil production drop by 33% between May 2014 and January 2015, with a pronounced 29% drop from 108,000 bbl/d in December to just under 77,000 bbl/d in January.

Slipping new production coincides with a declining well count. The number of oil-directed wells drilled in these four areas shrank from 676 in May to 336 in January, which includes a 44% drop between December and January.

Figure 9. New liquids production in smaller plays from wells drilled in the month indicated, by play

Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 10. New oil wells in minor plays drilled in the month indicated, by play



Source: Drillinginfo; Scaled to compensate for number of days in month.

The Bakken Formation

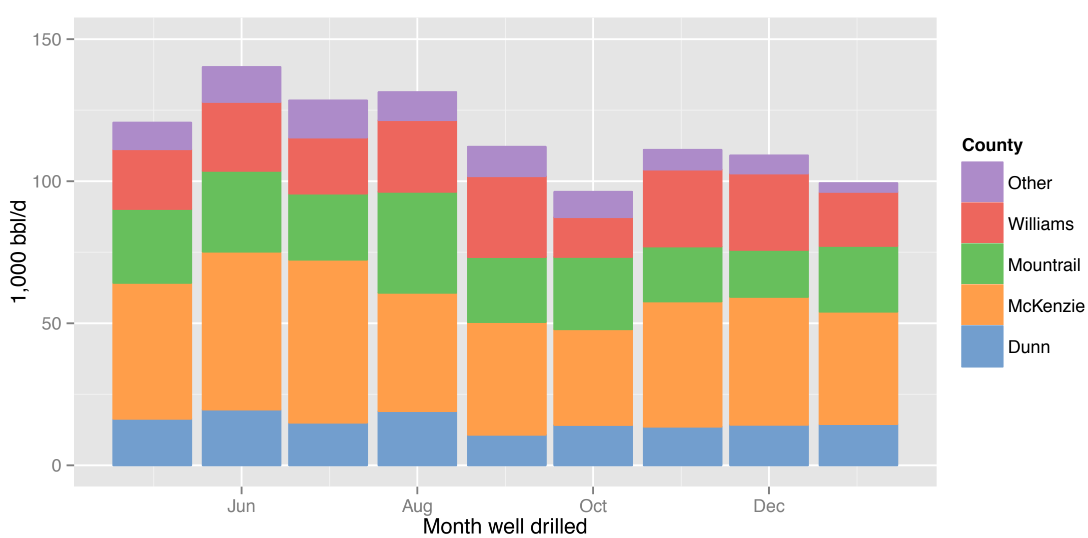
The story in the Bakken Formation, concentrated in North Dakota and spilling into Montana and southern Saskatchewan, is more equivocal. Data from Drillinginfo show predicted production dropping by 18% from around 123,000 bbl/d in May to around 101,000 bbl/d in January. However, new oil production brought onstream actually crept upward in November and then slipped modestly afterward.

Similarly, total wells drilled in the Bakken declined from 215 in May to 185 in January, with the largest drop (–122) occurring in April 2014. This period comes well before falling oil prices began to sour the investment climate in the oil patch. Declines in drilling and new production have been more modest since November.

Baker Hughes' rig count data show a less dramatic drop in oil-directed rigs operating in the Bakken during most of 2014, with numbers holding steady at just under 200 and then dropping from 190 (November 26) to 146 on January 30 after the November 27 OPEC decision.

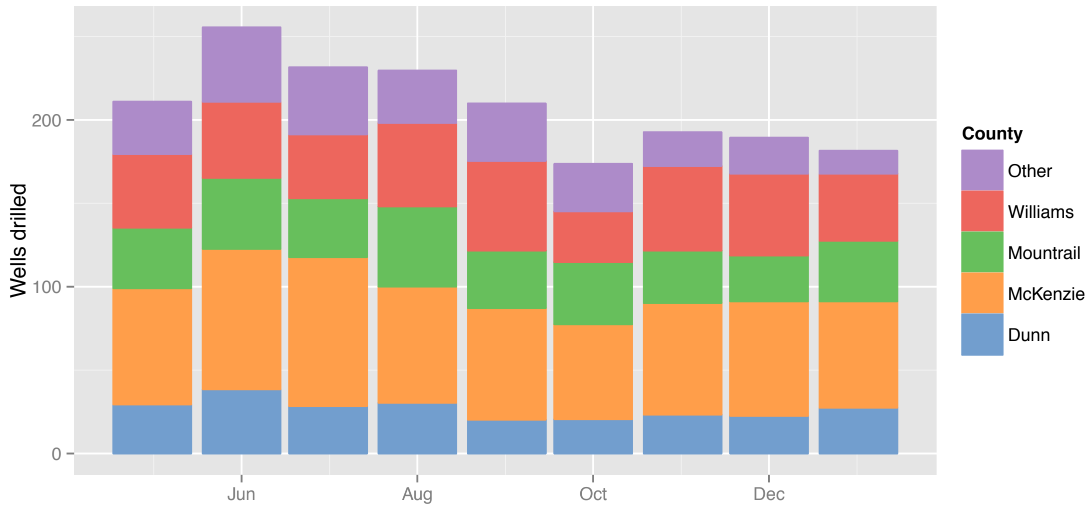
The North Dakota Department of Mineral Resources' January report also describes an atmosphere of continuing decreases in the number of operating rigs and well completions, which fell from 145 in October to an estimated 39 in November. "Oil price is by far the biggest driver behind the slowdown," the report states. "Operators report postponing completion work to avoid high initial oil production at very low prices ..."[7]

Figure 11. New Bakken liquids production from wells drilled in the month indicated, by county



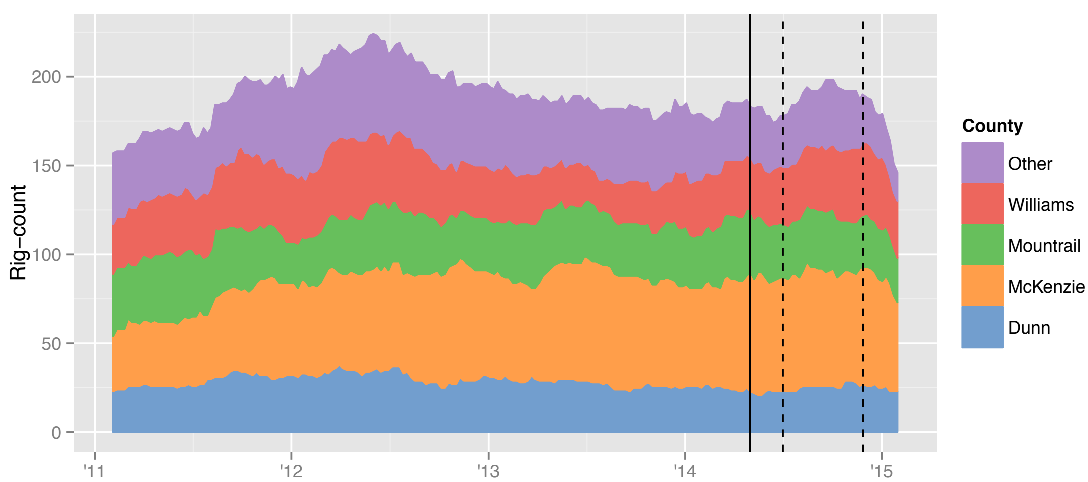
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 12. New Bakken oil wells drilled in the month indicated, by county



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 13. All active rigs in the Bakken, by county

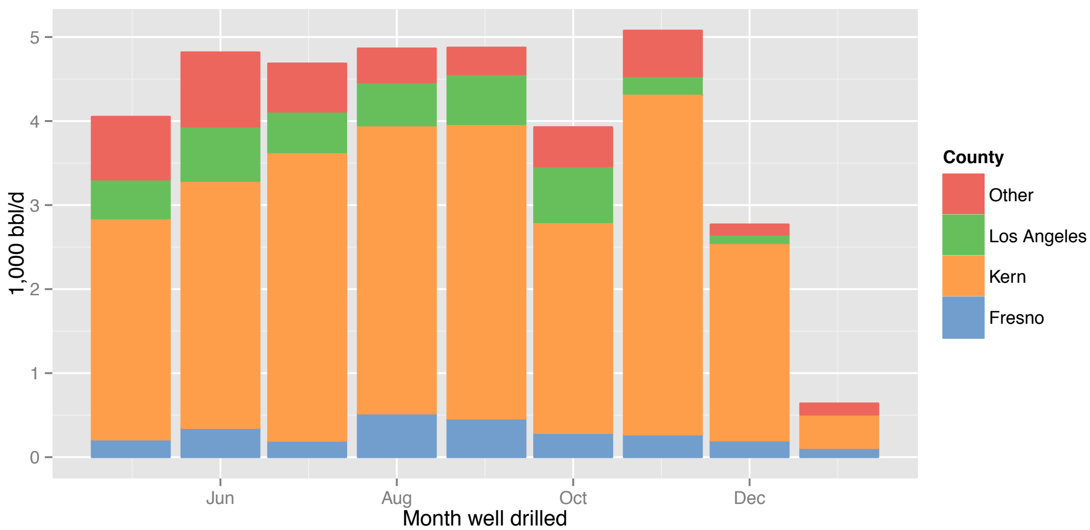


Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

California Heavy Oil

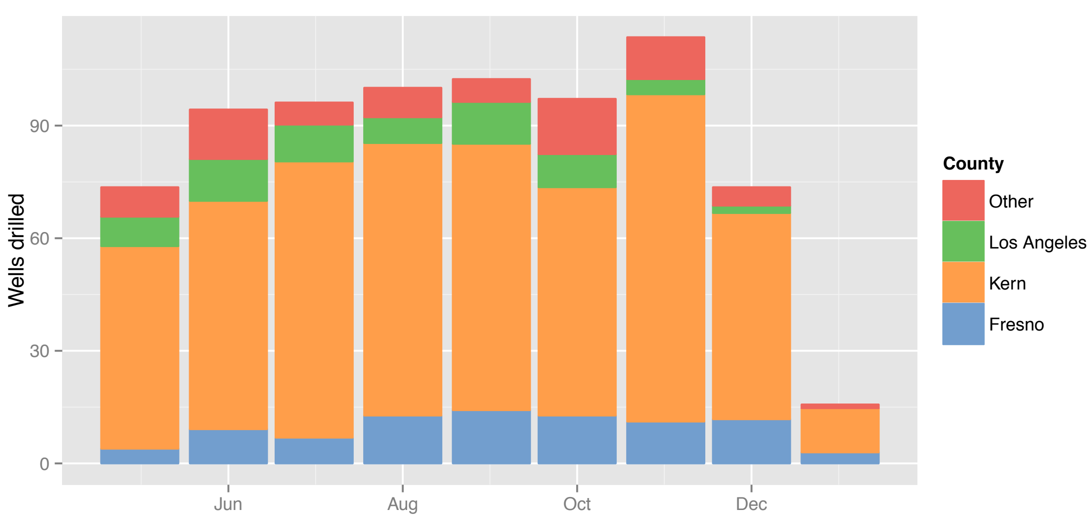
Outside of U.S. shale plays, another casualty of declining oil prices emerged in the heavy oil operation in and around Kern County and Bakersfield, California. Drillinginfo data show that new production in Kern County fell from just under 2,700 bbl/d in May to 400 bbl/d by January. The biggest monthly declines occurred in December (40%) and January (another 83%). New heavy oil production in Fresno County, never large, also slowed significantly, while that of Los Angeles County producers tracked by the company appears to have stopped altogether. Drillinginfo's production data parallels a similar decline in the number of wells drilled, which fell to 16 in January from 113 in November; Baker Hughes' data reveal a similar idling of rigs in the California heavy oil patch (see Figure 16). Besides halting production, plunging global oil prices also lie behind a financial crisis in Kern County, which declared a fiscal emergency in January.[8] The national impact of this decline will be relatively minor. Total new oil production brought onstream in a given month is over 500,000 bbl/d for the nation, but California's share tops out less than 1% of this.

Figure 14. New California liquids production from wells drilled in the month indicated, by county



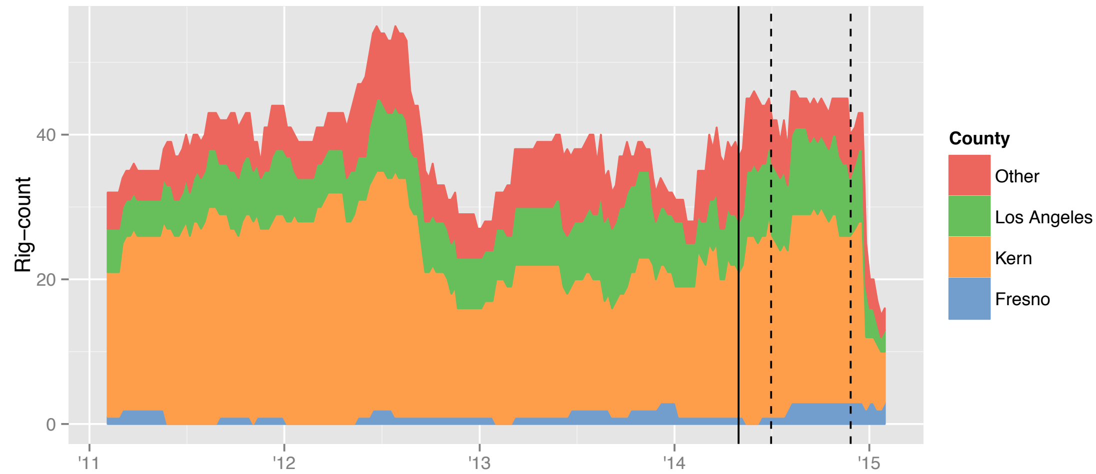
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 15. New California oil wells drilled in the month indicated, by county



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 16. Active oil-directed California rigs, by county



Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

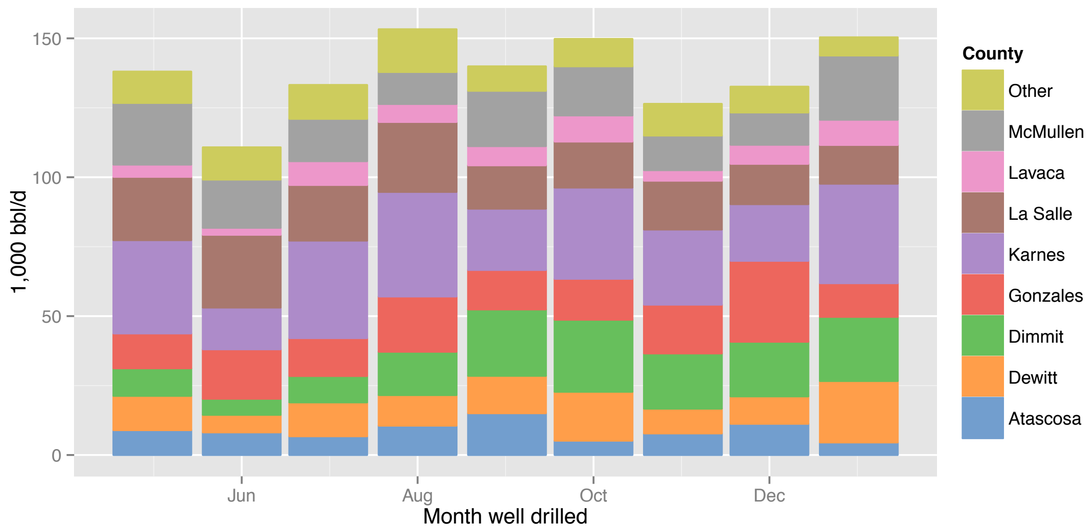
Two Places Where Production is Flat or Rising

As mentioned above, the declining new production in some areas contrasts with flat or increasing output from other formations. In addition to western areas of the Permian Basin, regions managing to resist the downward pressure include the Eagle Ford and Niobrara formations.

Eagle Ford Formation

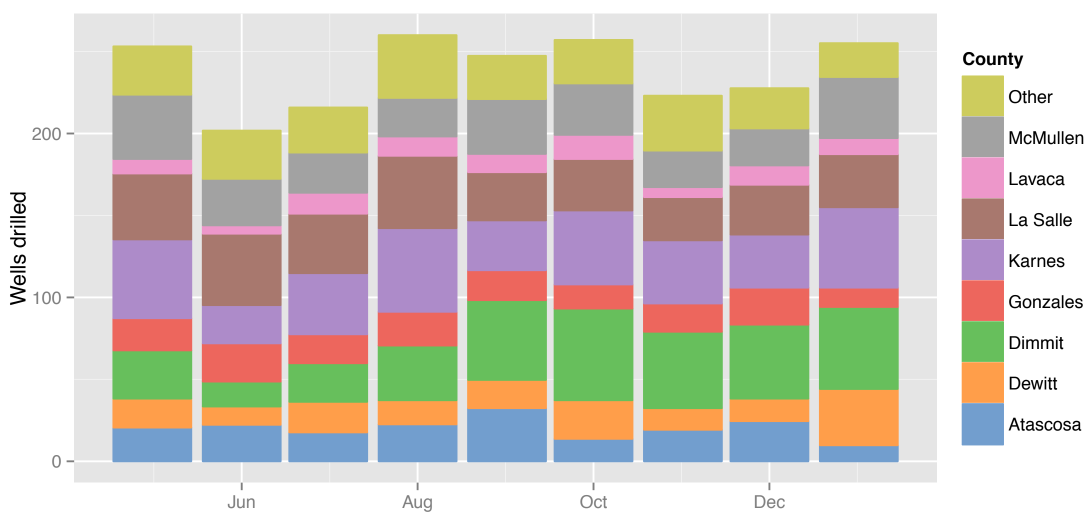
The Eagle Ford shale of South Texas was always advantaged by its close proximity to transport infrastructure and demand centers, including the Gulf Coast refinery sector. Drillinginfo predicts that new oil production actually increased in the formation, surging even during the worst hit months of December and January, when other regions were beginning to pare back. New oil wells[9] in the Eagle Ford jumped from 220 in November to 260 in January, while predicted production from these wells rose from about 133,000 bbl/d in November to about 159,000 bbl/d in January. It was unclear from the data whether this increase was a reaction to price signals or a more random event in a basin where new monthly production has risen and fallen over the short term, while remaining roughly constant since May.[10] Baker Hughes' rig data show a contrasting picture, with oil-directed rigs in operation declining immediately after the OPEC meeting in late November, from a 2014 high of 214 to 161 by January 30.[11] Rig departures could be a sign of a coming decline in oil production in the Eagle Ford.

Figure 17. New Eagle Ford liquids production from oil wells drilled in the month indicated, by county



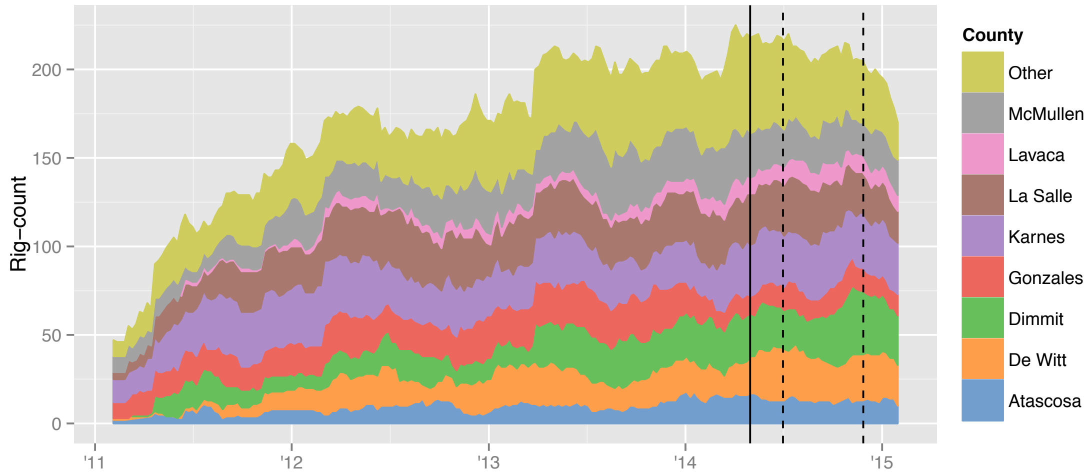
Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 18. New Eagle Ford oil wells drilled in the month indicated, by county



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 19. Active oil-directed rigs in the Eagle Ford, by county

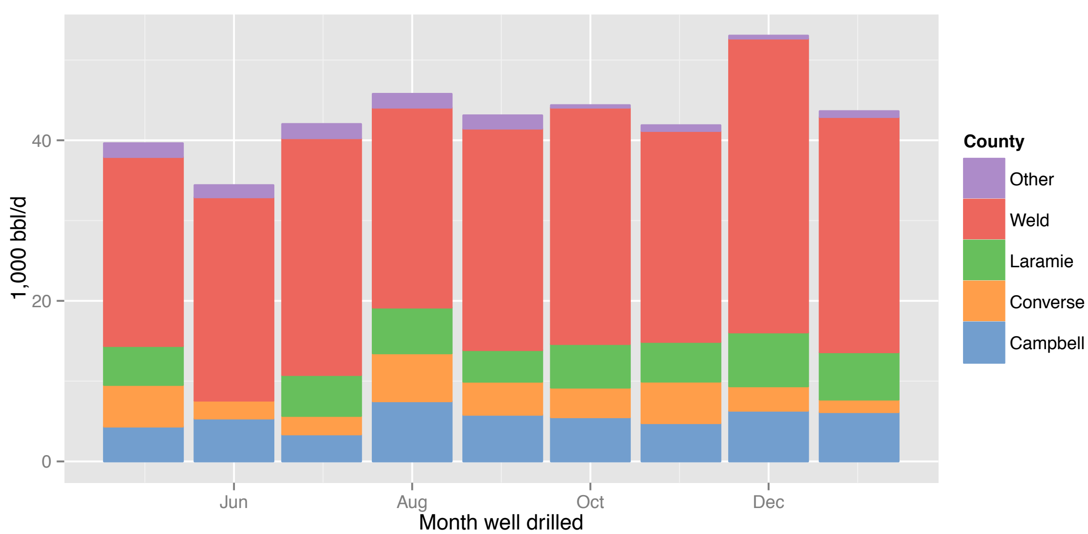


Source: Baker Hughes
May 1, July 1 and Nov 27 indicated by lines

Niobrara Formation

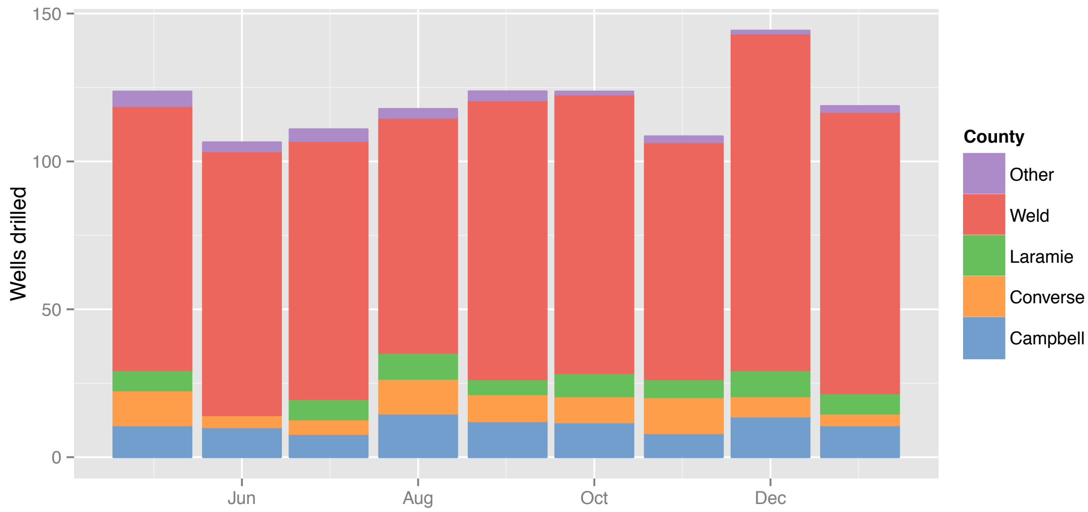
In Colorado's Niobrara chalk formation, predicted production and drilling frequency have remained relatively constant since May, including during the November-to-January period of steep declines in the oil price. Most of the activity in what Drillinginfo defines as the Niobrara has taken place in Weld County, northeast of Denver.

Figure 20. New Niobrara liquids production from horizontal oil wells drilled in the month indicated, by county



Source: Drillinginfo; Scaled to compensate for number of days in month.

Figure 21. New Niobrara horizontal oil wells drilled in the month indicated, by county



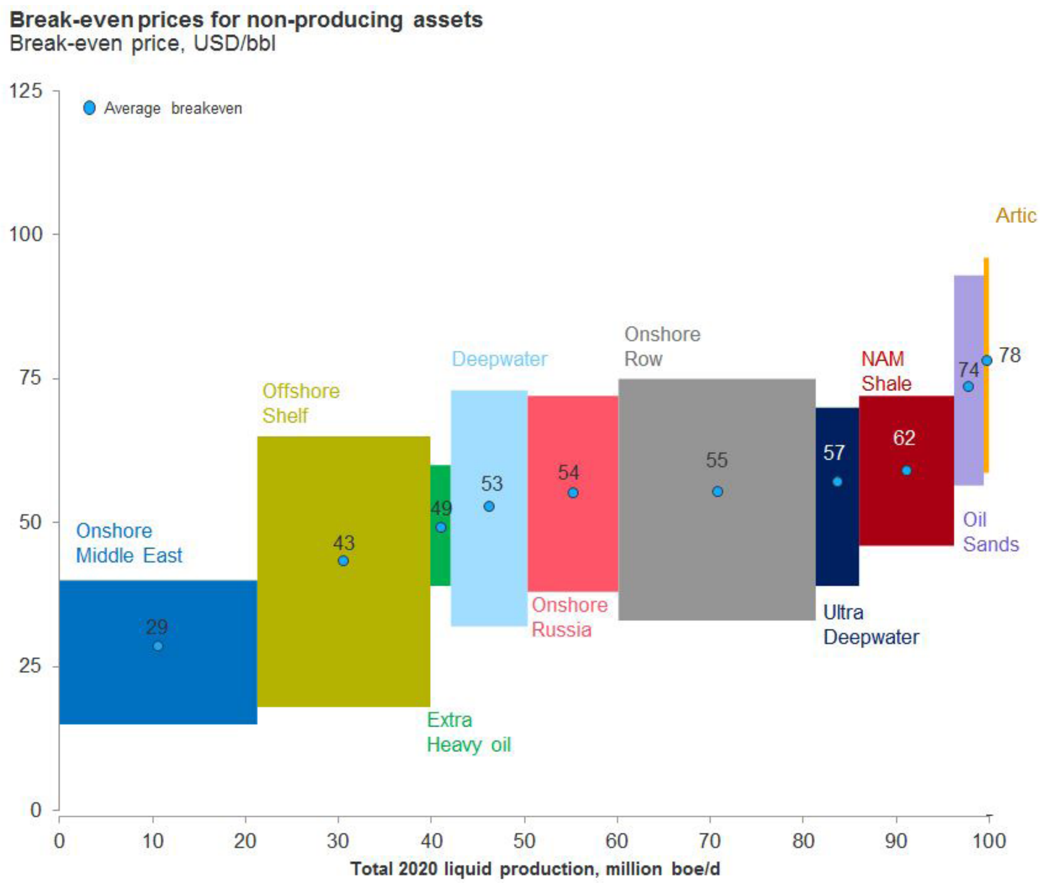
Source: Drillinginfo; Scaled to compensate for number of days in month.

Economics Behind Production Variations in U.S. Shale

There are solid economic reasons why North American light tight oil (LTO) is well suited to become a new source of "swing supply" in the global oil market. However, economic rationale also provides reasons why decreases in production might not be as rapid as one might expect, particularly in the most prolific areas.

LTO is relatively high-cost in comparison to most conventional global oil production, as shown in the plot below.[11] Standard economic theory predicts that when prices decline, the high-cost suppliers of a good or service are the first to halt production as price dips below their cost.

Figure 22. Global oil supply curve



Source: Rystad Energy

In the short-run, shale oil production should be able to respond in a much more elastic manner to price changes than large, conventional projects. These typically require years of planning and irreversible capital expenditures. Once these fixed costs are sunk, the firm's interests are best served by proceeding with production. For example, oil sands production in Canada, typically more expensive than LTO on a per-barrel basis, is less responsive to price fluctuations once investment costs are sunk.

Similarly, big startup investments may be accompanied by large shutdown costs, such as in deepwater offshore production. In these cases financial models typically require steady production volumes for many years, and often take into consideration short-term price volatility. By contrast, LTO investments are smaller and faster to execute. Low barriers to entry allowed small, independent producers to rapidly move into the market and start drilling. The same low barriers allow them to exit quickly if investing becomes unprofitable. Finally, shale wells are also characterized by steep decline curves. Hydrocarbons flow at high initial rates but tail off rapidly. Thus, revenues are earned within a much shorter time frame. This means the profitability of a project is more dependent on favorable current prices. Steep decline rates also mean that any halt to drilling implies a fast drop-off in production. In contrast, conventional wells tend to decline much more slowly, so a halt in conventional drilling takes much longer to show up in reduced production volumes.

There are also economic reasons why LTO production may respond more slowly than expected.

Markets for oilfield services and land are both very competitive, with costs dropping as producers drill fewer wells. This is particularly true in "gold rush" areas where supply of these inputs during the boom was constrained and prices were bid up. With lower costs, some producers may still be profitable and stay in business despite lower oil prices. Also, some firms have hedged production or sold volumes in forward markets, which insulates them against price drops and requires that they keep drilling to fulfill these commitments. Likewise, some producers may have already executed procurement plans for upcoming investments. If they have already paid for work (or it is costly to cancel the contracts), it may be most profitable to keep drilling.

Lease terms, which typically specify limited periods for initial drilling, provide another incentive to produce irrespective of price. However, once hydrocarbons are discovered in commercially viable quantities, mineral rights typically become "held by production" in perpetuity. The firm can return at a later date to drill additional wells once prices rise. Signs of such behavior include an increase in average rig transit time between wells as firms focus less on maximizing production and more on holding onto leases.

Finally, wells drilled in different regions of a formation may produce different quantities of oil. Wells in "sweet spots" might be profitable in a low price environment, while wells in less prolific areas are not. We should expect firms to cut their most profitable projects last. Since these "sweet spots" generally produce the highest volumes of oil, the fall in production should be smaller than the fall in the number of wells drilled. In other words, as prices drop average productivity per well should rise.

Conclusion

The picture of U.S. oil production responding to lower prices was just beginning to clarify as this paper was written. What is depicted here is an early snapshot of an industry making initial adjustments in response to a new economic environment.

This paper synergizes a compilation of quantitative evidence from multiple sources that, taken together, suggest that U.S. oil production, and in particular, that of shale oil, will be an early responder to the large drop in oil prices that occurred in late 2014.
Although the actual changes in output are modest, the implications are not. The swing producer role held by Saudi Arabia since the mid-1970s appears to be in flux. At times

when the Saudis decline to adjust production in line with market signals, such as at present, that role may revert to higher-cost areas of production, including some in the United States. In fact, the swing producer role was once an American concern, overseen by the Texas Railroad Commission, which, until the rise of OPEC, maintained similar production quotas aimed at reducing oil price volatility.

This time, however, the response is not being orchestrated by a governing body but by the decentralized actions of many firms responding to price signals. In the case of shale, unique characteristics allow this to happen. These include higher costs, short lead times for investment, low barriers to entry and exit, steep production decline curves, and requirements for continuous drilling to maintain constant production.

U.S. shale will probably be unable, by itself, to assume the mantle of global swing supplier. For one thing, American crude tends to serve domestic markets; producers are prohibited by law from exporting U.S. crude oil. For another, rapid declines in some shales and in vertical drilling contrast with more gradual reductions in the most profitable plays. The Baker Hughes rig counts do show the emergence of a steep, downward trend at the end of January for a number of the big plays, but the average monthly production estimates from Drillinginfo do not. These core areas—the Bakken, the Eagle Ford, the Permian Basin, and the Niobrara—make up the lion's share of new oil production. Since the wells that are drilled will be generally more productive, production should not decline as much as investment.

Shale's price responsiveness bodes well for big conventional oil producers and projects, including those outside North America, which, due to lengthy investment-to-production timelines, cannot respond as quickly. Shale's short-term investment characteristics might also help reduce the duration of the current oil bust, in contrast with the nearly two decades of low oil prices between the mid-1980s and early 2000s, which were exacerbated by the onset of huge projects in Alaska, the North Sea, and the Gulf of Mexico that were not as responsive to oil prices.

The low barriers to entry, which allowed small companies and investors to quickly move into the shale oil business, appear to be complemented by low barriers to exit, which allow them to move away when prices reverse. If OPEC and Saudi Arabia shift away from their prior swing producer roles, the nimble characteristics of U.S. shale producers may provide global markets with alternate and useful source of spare capacity.

Endnotes

1. International Energy Agency, "Oil Market Report," Jan, 16, 2015, https://www.iea.org/oilmarketreport/omrpublic/.

2. U.S. Energy Information Administration, "Short Term Energy Outlook," Jan. 13, 2015, http://www.eia.gov/forecasts/steo/report/us_oil.cfm.

3. For example, see Daniel Yergin, "Who Will Rule the Oil Market?" *New York Times*, Jan. 23, 2015, http://www.nytimes.com/2015/01/25/opinion/sunday/what-happened-to-the-price-of-oil.html.

4. Middle East Economic Survey, "MEES Interview With Ali Naimi: 'OPEC Will Never Plan To Cut,'" Dec. 22, 2014.

5. The Drillinginfo Index excludes wells in Illinois, Indiana, Alaska, and the Gulf of Mexico.

6. Defined as wells where predicted peak gas production in mcf/d was less than 1/6th of oil production (bbl/d).

7. North Dakota Industrial Commission, Department of Mineral Resources, "Director's Cut," Jan. 14, 2015, https://www.dmr.nd.gov/oilgas/directorscut/directorscut-2015-01-14.pdf.

8. Robin Respaut, "S&P: Kern County, Calif., Outlook Negative After Fiscal Emergency," *Reuters*, Feb. 3, 2015; James Nash, "California Oil County Declares Fiscal Emergency as Crude Tumbles," *Bloomberg News*, Jan. 28, 2015.

9. See endnote 6.

10. Well counts and production are choppy in the Eagle Ford, but rig counts appear to have much less variability. This is similar to the Bakken, where flat rig counts with choppy well counts and production appear to have more to do with changes in rig transit time between jobs as drillers move rigs between locations than changes in companies' investment plans.

11. Baker Hughes' definition of the Eagle Ford territory boundary is slightly different than that of Drillinginfo, which could account for diverging data.

12. Rystad Energy, "Global Liquids Cost Curve: Shale is Pushing Out Oil Sands and Arctic, Offshore is Still in the Race," June 12, 2014, http://www.rystadenergy.com/AboutUs/NewsCenter/PressReleases/global-liquids-cost-curve.

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