



*Independent Statistics & Analysis*

U.S. Energy Information  
Administration

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# Drilling Productivity Report

Report Background and Methodological  
Overview

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## Introduction

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The Drilling Productivity Report (DPR) is a computer model (“DPR model”) that estimates recent and future oil and gas production for seven specific regions (“DPR Regions”), based on the number of active drilling rigs that are reported within each DPR Region. Each DPR Region encompasses a specific set of counties, and is not limited to the formation name used for the region. The DPR model parameters are based on the historical relationship between Baker Hughes drilling rig counts and production, as determined using local regression (LOESS) statistical estimation techniques.

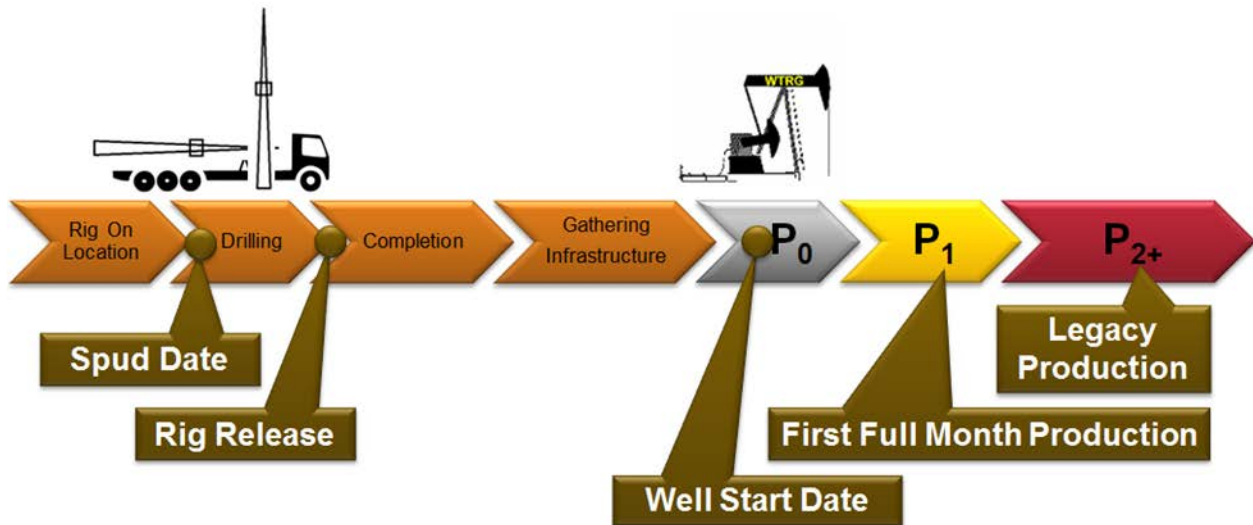
A dramatic increase in horizontal drilling and hydraulic fracturing in shale and "tight" formations with very low permeability has resulted in record increases in oil and natural gas production. Since 2008, tight oil production alone had increased 325% by January 2013, reaching a total U.S. production level of 2.3 million barrels per day.

The DPR methodology is based on two aspects of oil and gas production dynamics:

1. Oil and natural gas production in a play simultaneously increase as a result of the drilling and completion of new wells, while the production from existing wells declines as the resource in place for the existing wells is depleted.
2. Oil and natural gas are often coproduced from a single well, so the drilling rig classification of being either oil- or natural gas-directed can be misleading. Moreover, tight oil wells typically produce between 15 to 25% of the total hydrocarbon liquids as gas, because the gas’s expansion in the formation is required to drive the oil to the wellbore. Consequently, the DPR model estimates: a) the time delay between the start of the drilling of a well and that well’s initial production, b) the amount of oil and natural gas expected to be produced from the new wells, and c) the volume of production decline for the existing wells.

The design of the DPR model was dictated by the limited availability of real-time data that either explicitly or implicitly measure the rate at which new oil and gas wells are being drilled and completed, along with the production volumes coming from those new wells. Because Baker Hughes reports the number of drilling rigs on a weekly basis, at the state and county level, these Baker Hughes drilling rig data are used within the DPR model as the sole measure and input variable that determines the number of new wells being drilled and completed. Thus, the DPR model estimates the historical relationship between the active rigs, the new wells completed, and the incremental oil and gas production volumes coming from those new wells. Estimates of recent and projected new wells and the production of oil and gas coming from those wells, in conjunction with projections regarding the rate of decline of production from existing wells, allow the DPR to project recent and future oil and gas production levels. Figure 1 generalizes a well’s development lifecycle, from drilling to production, that the DPR model seeks to represent in its model structure and parameters.

Figure 1. Drilling process flow chart



### Purpose & use

The DPR model was designed to project short-term oil and natural gas production volumes for seven of the most significant U.S. tight oil and shale gas formations as part of an effort to develop EIA's *Short-Term Energy Outlook* projections for total domestic oil and gas production. The DPR model is also used to develop estimates of recent historic oil and gas production, as reported in EIA's *Weekly Petroleum Status Report* (WPSR), and monthly charts of tight oil and shale gas production by formation.

The estimation of the DPR model parameters also provides additional insights into drilling rig efficiency and well productivity trends. The DPR model generates the rig efficiency and well productivity trends reported in EIA's monthly Drilling Productivity Report.

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## DPR Model Regions

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The DPR model estimates recent historical production and short-term future production for the following seven Regions (Figure 3), which are labeled as:

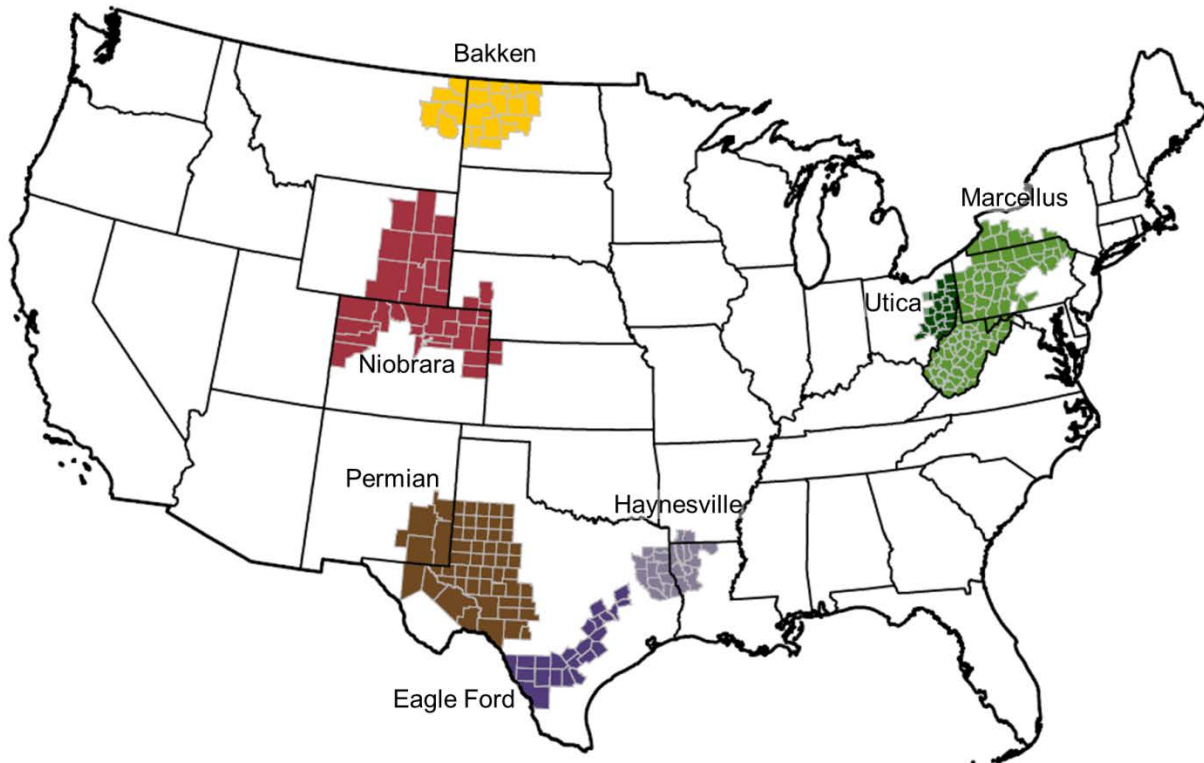
1. Bakken Region
2. Eagle Ford Region
3. Haynesville Region
4. Marcellus Region
5. Niobrara Region
6. Permian Region
7. Utica Region

Each DPR Region encompasses a specific set of counties (for list of counties, see downloadable Excel file at [www.eia.gov/petroleum/drilling](http://www.eia.gov/petroleum/drilling)). The DPR Regions are delineated along county lines, rather than geologic formation boundaries, because each of the DPR model input datasets has a data field that identifies the county in which the drilling rig, well, and production is located.

The DPR Regions are based on the county-level geography encompassing the key oil and natural gas production formations in each region. Identification of the formation boundaries comes from prior and ongoing shale gas and tight oil research at EIA. Although five of the seven DPR Regions are identified by the geologic formation that produces the greatest volume of oil and natural gas within that region (the Permian Region encompasses the Permian Basin, which includes a number of individual formations which produce oil and natural gas), all of these Regions include other geologic formations that also produce oil and natural gas. Some of these other formations have produced oil and gas for many decades and will continue to do so into the foreseeable future. Thus the data used by the DPR, along with the DPR estimates of current and future oil and gas production for all seven Regions, include not only the production from the “headline” formation (e.g., Bakken), but also the production coming any other formations within that region. For example, the Bakken Region’s oil and natural gas projected production includes the oil and gas produced by the other Williston Basin formations, such as the Three Forks.

Historical oil and gas production and the number of active drilling rigs are aggregated up to the regional level, consistent with DPR model production projections being estimated for the entire region. Historical production within DPR Regions includes all production reported from all wells within a Region’s counties. While not all producing wells within the play boundaries are producing from the specifically named geologic formation, the implication is that DPR expects new wells being drilled to target that play, and to follow the production characteristics of the play over time.

Figure 2. Map of DPR model Regions

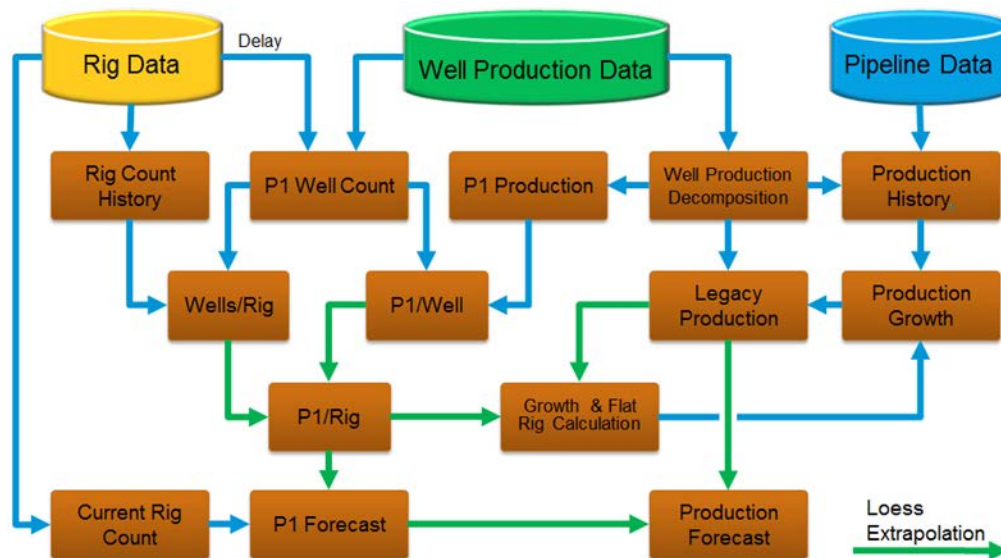




## Overview of Methodology

The DPR model is rerun every month as new monthly data become available for 1) drilling rig activity, 2) individual well oil and wet gas production, and 3) gas pipeline throughput. The new monthly data are used to recalibrate the model's parametric relationships for estimating oil and natural gas production, according to the flow pattern shown in Figure 3. The DPR model information flow progresses from data inputs at the top of the figure to the production forecast at the bottom right. The blue arrows in the chart below are data flow pathways, while the green arrows in the chart depict intermediate variable projections that are determined by parameters estimated by the LOESS data smoothing technique.

**Figure 3. DPR model flow chart**



### LOESS data-smoothing procedure

The DPR model was designed to provide estimates of recent historical oil & gas production and projections of future oil & gas production on a monthly basis. As such, the model parameters must reflect the long-term technological trends regarding the configuration of the drilling rig fleet, the rate at which new wells are drilled and completed, and the design of new tight oil and shale gas wells. All three trends collectively change the rig efficiency and the well productivity.

The long-term trends can best be discerned by removing the random fluctuations in the monthly data using a polynomial data-smoothing routine, known as LOESS.<sup>1</sup> The LOESS smoothing procedure is used within the DPR model for those DPR model linkages shown by the green arrows in Figure 3.

The LOESS procedure gives the analyst a heuristic tool for smoothing out monthly data variation so as to identify the underlying long-term well productivity trends developing within each of the DPR Regions. The DPR model's LOESS curve shape and the number of data points evaluated by the LOESS smoothing

<sup>1</sup> Background information on the LOESS technique: <http://peltiertech.com/WordPress/loess-smoothing-in-excel/> and [http://en.wikipedia.org/wiki/Local\\_regression](http://en.wikipedia.org/wiki/Local_regression)

function are developed through a trial and error process in which the analyst compares the function's output to the long-term drilling and completion trends that are readily identifiable on a qualitative basis.

For example, hydraulic fracturing technology has evolved over the last decade in its application to shale gas and tight oil wells. Specifically, the use of shorter-length hydraulic fracturing stages along with an increasing injection of proppant volume has resulted in increased well productivity for a standard length of lateral. This information is generally reported anecdotally in company presentations and other public documents, but is not reported to any agency in a systematic fashion that permits a statistical estimation relating changes in hydraulic fracturing techniques to changes in individual well productivity. In the absence of specific data that permit the creation of statistically estimated relationships, the analyst experiments with alternative LOESS smoothing function parameters in order to identify those parameters that best reveal the underlying long-term well productivity trends inherent in well production data.

The DPR model uses a LOESS locally-weighted smoothing technique using the VBA function in Excel, which requires an exogenous bandwidth selection. For each observation in the series, the local data points are assigned weighting factors using a tricube weight function. The LOESS function then uses the weighted local data points to estimate the "smoothed" data point. This technique is useful since the output array can be larger than the X and Y input arrays; the LOESS function makes sample estimates which are informed by the most recently available data. The LOESS smoothing function thus gives the analyst a less noisy data series that takes into account all observations.

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## DPR Model Input Data

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### Rig count data

[Baker Hughes, Inc. North America Rig Count](#) (BH rig count):

The publicly available North America Rig Count Pivot Table reports the number of active drilling rigs by location at the county level. The Baker Hughes rig data are updated every week. The weekly rig data are converted into a monthly rig count number by calculating an arithmetic average of the rigs reported for each week in each month. According to Baker Hughes, “the rig count does not include rigs that are in transit from one location to another, rigging up, being used in non-drilling activities, including production testing, completion and work over, and are not expected to be significant consumers of drill bits.”

### Oil and natural gas well production data

DrillingInfo, Inc. (DI) Production Database:

The DIP database reports cumulative monthly oil and natural gas production volumes either for individual wells or for individual leases. The DIP database also reports a host of other data including the number of active wells, the county in which the well/lease is located, the number of producing wells on a lease, the date of initial production, etc. The cumulative monthly oil and gas volumes are reported on a calendar-month basis; consequently, the DIP production volume reported for new wells, during the month in which production was initiated, is less than a full month of production. Moreover, the production reported during a well’s first calendar month can be constrained by the flowback of hydraulic fracturing fluids, and is therefore not as representative of that well’s full productive potential as is the production data that are reported for the production that occurs during a well’s first full calendar month.

### Interstate natural gas pipeline flow data

Ventyx Velocity Suite Daily Natural Gas Receipts Database:

This is a subscription database of aggregated Federal Energy Regulatory Commission (FERC) interstate gas pipeline flow data by state and county. Aggregate receipts into the interstate pipeline system do not include receipts into intrastate gas pipelines, so the data’s predictive value is the greatest for those DPR Regions where most of the natural gas flows on interstate natural gas pipelines; such Regions include the Marcellus Region, Bakken Region, Niobrara Region, and Haynesville Region. In contrast, the Eagle Ford Region and Permian Region have considerable volumes of natural gas transported on intrastate natural gas pipelines, and so the Ventyx database provides a less reliable measure of the change in those Regions’ net natural gas production.

The gas pipeline gross inflow and outflow data as reported by Ventyx on a county basis are used in the DPR model to calculate a net outflow of gas from each DPR region. This net regional outflow is used as a surrogate measure of the percentage change in DPR region natural gas production. Because a small volume of natural gas is consumed during the production, processing, and transportation of natural gas, a DPR region’s net pipeline gas flow does not provide an exact measure of the total volume of natural gas produced within each DPR region.

Monthly estimates are calculated as arithmetic averages of the daily gas pipeline receipts.

## Key Data Series and Model Calculations

### Rig count history

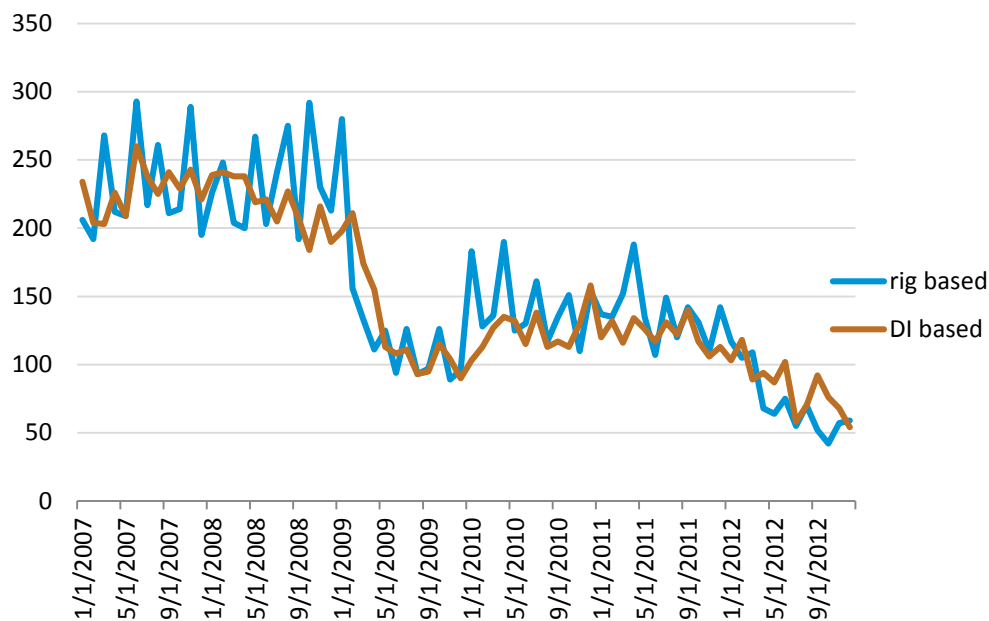
The average DPR regional rig count is calculated each month using the weekly Baker Hughes rig count by state/county play definition.

### Estimating the new wells drilled and completed each month

Using the LOESS estimation procedure, the DPR model each month estimates the historical relationship between the number of active drilling rigs located in a DPR region and the new wells that are drilled, completed, and put into production in that region.

The chart below (Figure 4) shows new well counts in Haynesville, estimated based on historical rig data and DI production data.

**Figure 4. New wells each month in Haynesville Region**



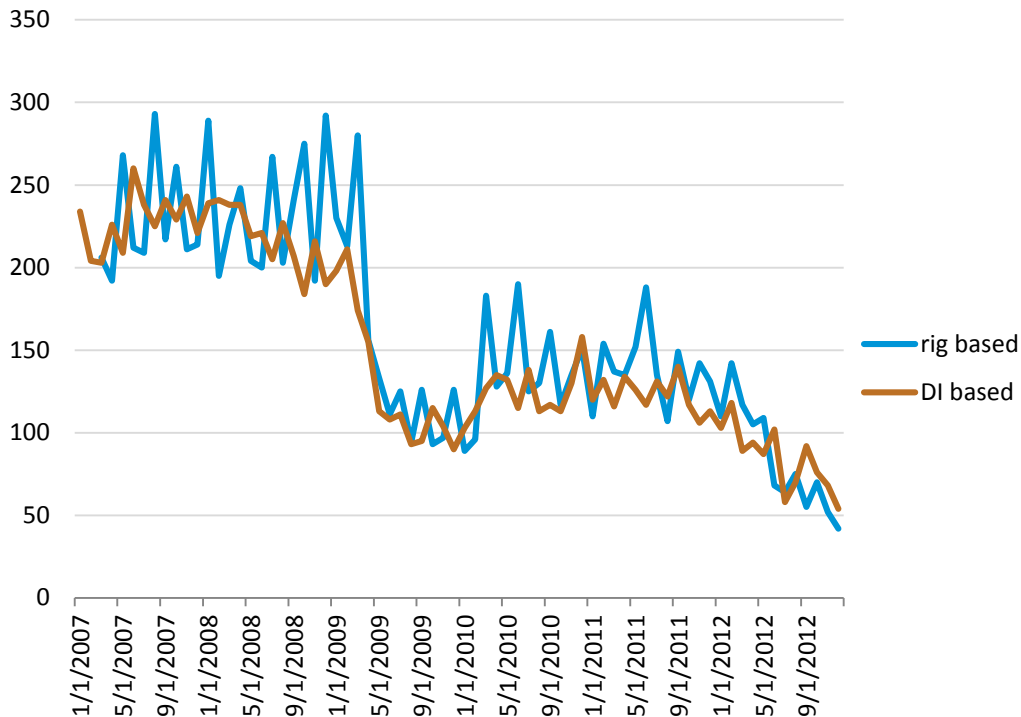
### Estimated rig count to new well count delay time

In the DPR model, this variable approximates the time delay from drilling to first production, as observed between the rig database well count and the production database well count. The chart below shows that lagging the rig-based well count by two months in the Haynesville Region causes the two lines to match more closely. Because the DPR model uses monthly data, the rig-production delay time must be specified in whole months.

A 2-month delay time is used for all the DPR Regions and mirrors the average amount of time required to drill, complete, and hook up a well to transportation and processing infrastructure. Often new surface field equipment must be constructed in a DPR region to bring all the new wells into full production. The DPR model's 2-month time lag best represents the observed delay, on average, that

typically occurs between initiating the drilling of a new well and bringing it into full production. So in the DPR model, two months after a change in a region's rig count occurs, a commensurate change in that region's well count occurs.

**Figure 5. New well counts in Haynesville Region, Rig-Based well count lagged two months**



### Well production time-period categorization

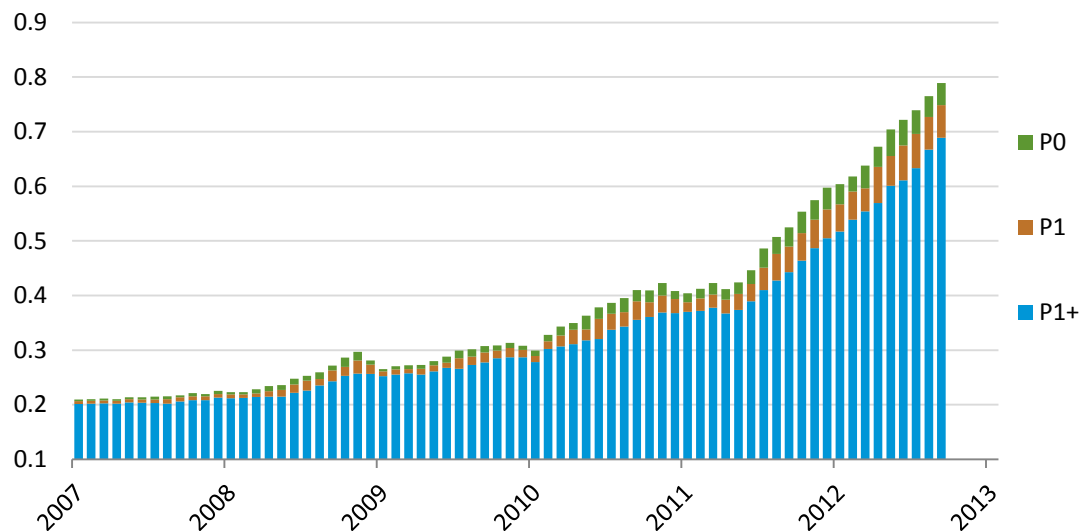
In the well production data, wells are separated into three categories, based on the number of months that they have been in production:

1. **P0 Wells (P-Zero):** The P0 well production category consists of those wells that have been producing for up to one month, have production reported for only one month, and for which there is no earlier monthly production data. During the first week of production a well often produces at less than its full productive capacity because hydraulic fracturing fluids are flowing back into the wellbore, which inhibits the flow of hydrocarbons. Consequently, these partial-month production data are not representative of a well's productivity, and therefore are not used anywhere within the DPR model. However, the number of P0 wells is tracked over time within the model to specify the relationship between the number of active rigs in a DPR region and the new wells created by those rigs.
2. **P1 Wells (P-One):** The P1 well category contains the wells which have two and only two consecutive production data points. P1 production is a well's first full calendar month of production, and is critical because it is the first consistently measurable data point for "initial production."

3. **P2+ Wells (P-Two-Plus):** The P2+ category includes all wells which have more than two months of reported production. For example, a well which started producing in January 2013 would be categorized as P0 in January 2013, P1 in February 2013, and P2+ in March 2013 and beyond. As such, a well “rolls” from one group to the next over the first three months of reported data. The graphic below shows the breakdown of total monthly production in the Bakken Region each month by well category.

**Figure 6. Bakken Region oil production, by well production category**

million barrels per day

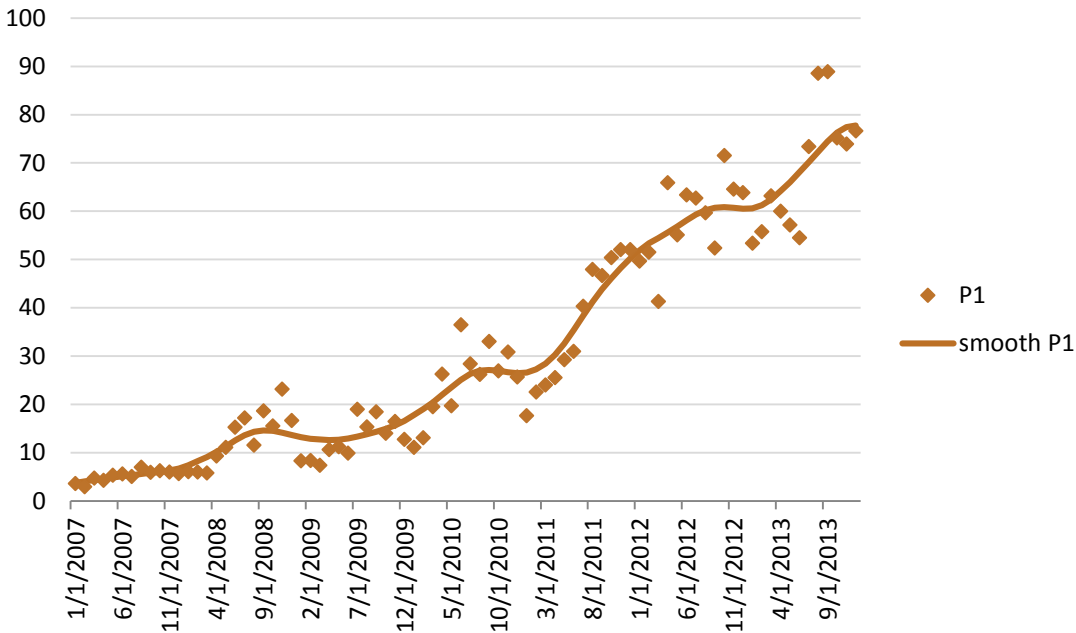


### New well production (P1 production)

For each month, the DPR model calculates the total volume of both oil and natural gas produced from all wells in their first full calendar month of reported production (P1). The first full month of production is a proxy for initial production because it is the first complete month of production that is measured. In contrast, P0 is an inconsistent measurement of initial production, because the exact number of days that the well has been in production during the initial month is unknown; thus, it is not possible to calculate an average daily production rate for a specific fixed timeframe (e.g., 30 days). Figure 7 below shows scattered P1 data points and the LOESS function-smoothed estimates as a line.

**Figure 7. Bakken Region first full calendar month of reported oil production (P1)**

thousand barrels per day



### Production-pipeline flow ratio

Average daily interstate natural gas pipeline flows generally track a region's average daily production. However, a region's monthly pipeline flow rate is generally less than the aggregate wellhead gas production rate, due to the consumption of natural gas at the lease and at nearby processing plants. Because the DI production database is incomplete for the most recent months due to state reporting delays, the FERC interstate pipeline flow data, which are available on a daily basis up to the day prior to the most current day (i.e., yesterday), are used as a surrogate for estimating recent-month wellhead gas production.

The DPR model calculates the ratio of natural gas pipeline flow to production for each DPR region, using the most current complete month of complete DI production.

$$\text{pipeline ratio} = \frac{\text{reported production}}{\text{pipeline receipts}};$$

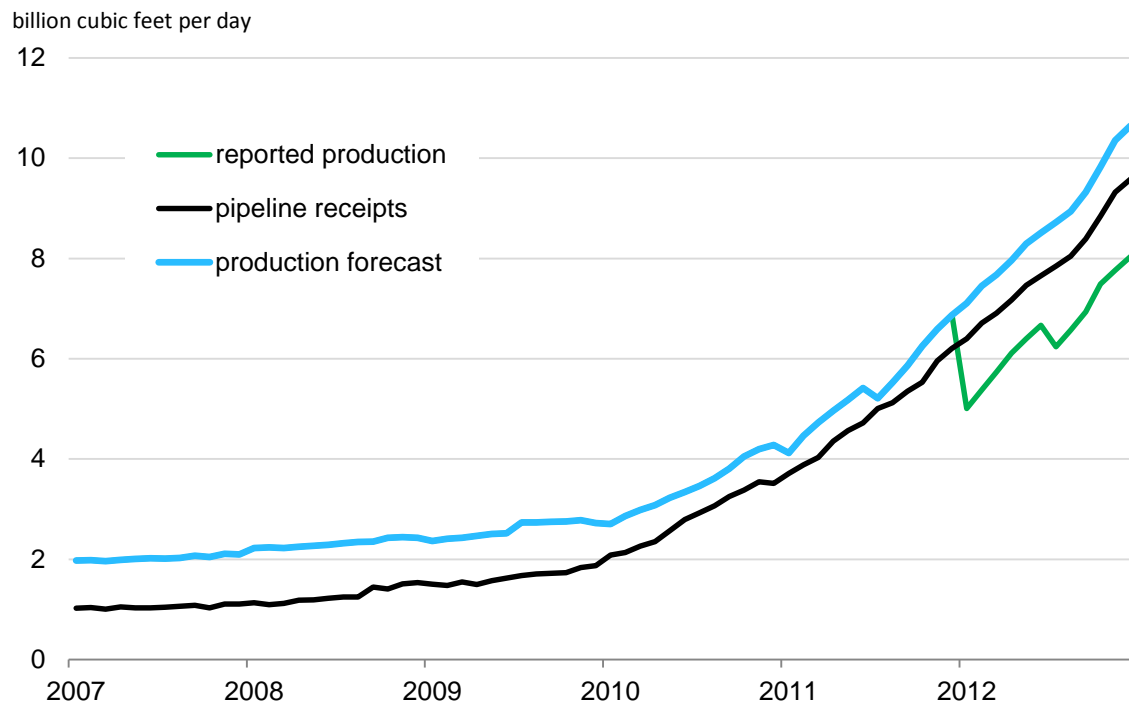
$$\text{pipeline ratio}_F = \text{Trend forecast of ratio};$$

$$\text{production forecast} = \text{pipeline flow} \times \text{ratio}_F;$$

where

*Reported production* = DI production data, million cubic feet per day (MMcf/d);

*Pipeline receipts* = Daily natural gas pipeline receipts, MMcf/d.

**Figure 8. Marcellus Region natural gas production forecast from pipeline receipts**

### Wells per rig

This variable measures each region's average drilling rig efficiency. The rig count series is lagged by 2 months, since the BH rig count only identifies a new well once the rig has left the location, and on average the rig would have been observed on the location two months prior to its inclusion in the BH rig count. The wells drilled and completed per rig is calculated by dividing a month's number of new wells by the two-month lagged value from the data series of rig counts.

$$WpR = \frac{W}{R_{(-2)}}$$

where:

$WpR$  = Number of wells drilled per rig per month

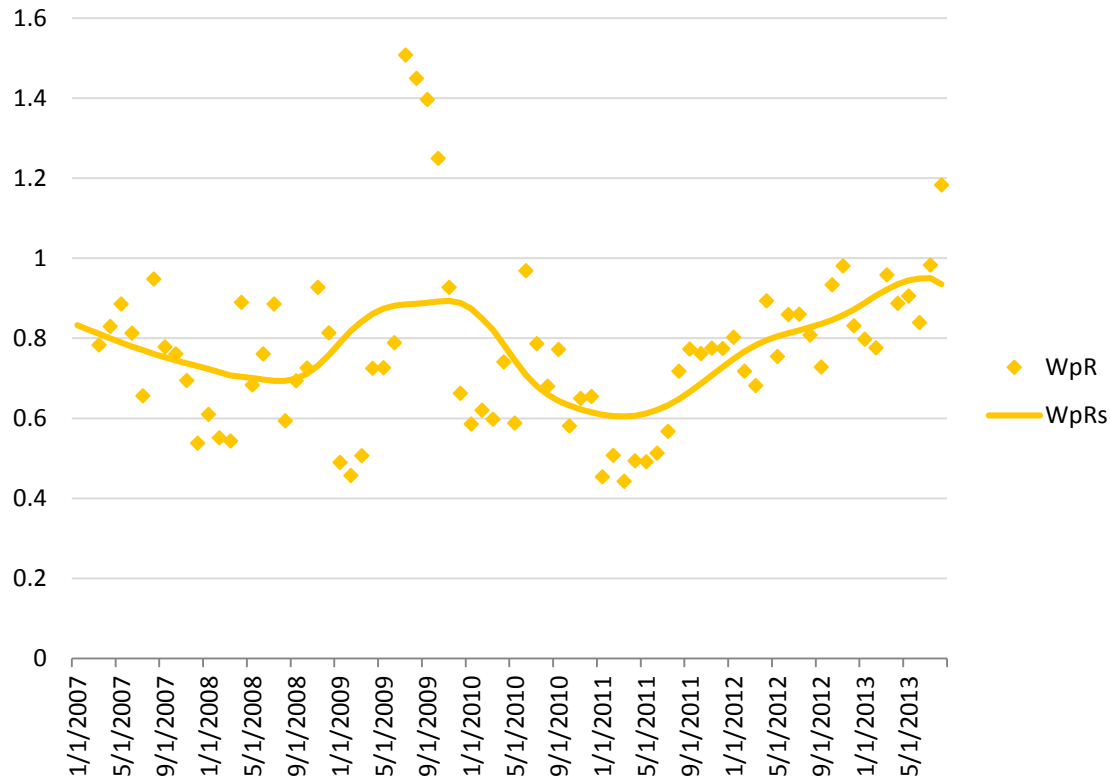
$W$  = New well count from DI rigs (including possible dry holes, which slow average drilling efficiency)

$R_{(-2)}$  = Two-month-lagged rig count



**Figure 9. Average Bakken Region drilling speed**

new wells per rig each month



### Initial production per well

The average oil and gas production rate all P1 wells equals total P1 production rate divided by the number of P1 wells.

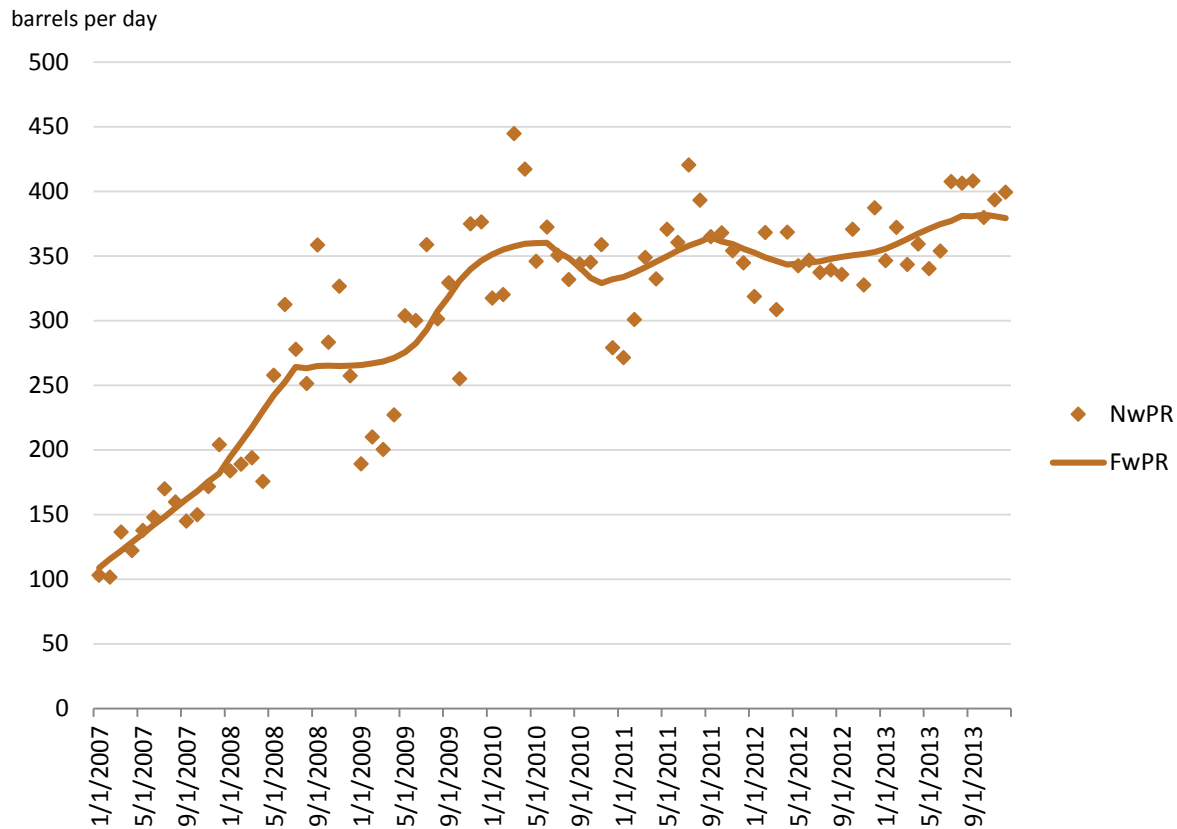
$$NwPR = \frac{NPR}{Nw}$$

where:

$NwPR$  = New well production rate

$NPR$  = P1 production rate

$Nw$  = Number of wells in the P1 group from DI production database

**Figure 10. Bakken Region P1 natural gas production per well**

### Production change

Overall change in production from the prior month.

$$\Delta PR = PR - PR_{(-1)}$$

where:

$\Delta PR$  = Month-to-month change in production rate

$PR$  = Total production rate (from Pipeline Flow Production History for natural gas, DI production database for oil)

### Legacy (P2+) well production change

This variable measures the total month-to-month change in the oil and gas production from all P2+ wells. Typically, the legacy well production rate declines each month as well reservoir pressure declines over time. Occasionally the legacy well production change can be positive, given external factors such as re-completions or additional takeaway infrastructure. The change in production from the prior month for all “legacy” wells is calculated by subtracting the P1 production rate in the current month from the overall change in production from the prior month.

$$DPR = \Delta PR - NPR$$

Where:

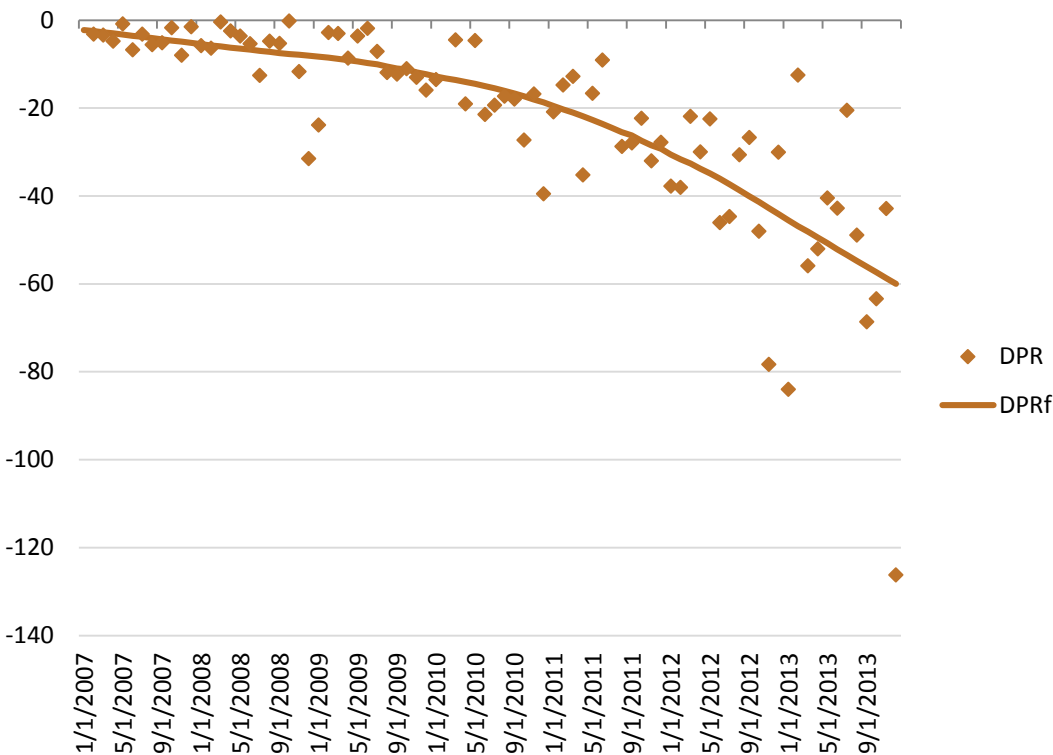
$DPR$  = Legacy production change

$\Delta DPR$  = Month-to-month change in production volume of P2+ wells

$NPR$  = P1 production rate

**Figure 11. Legacy oil production change**

thousand barrels per day



### February 2016 update to legacy production change

The procedure for estimating legacy production changes has been revised as of February 2016 to enable earlier detection of legacy change inflection points, as illustrated in Figure 12.

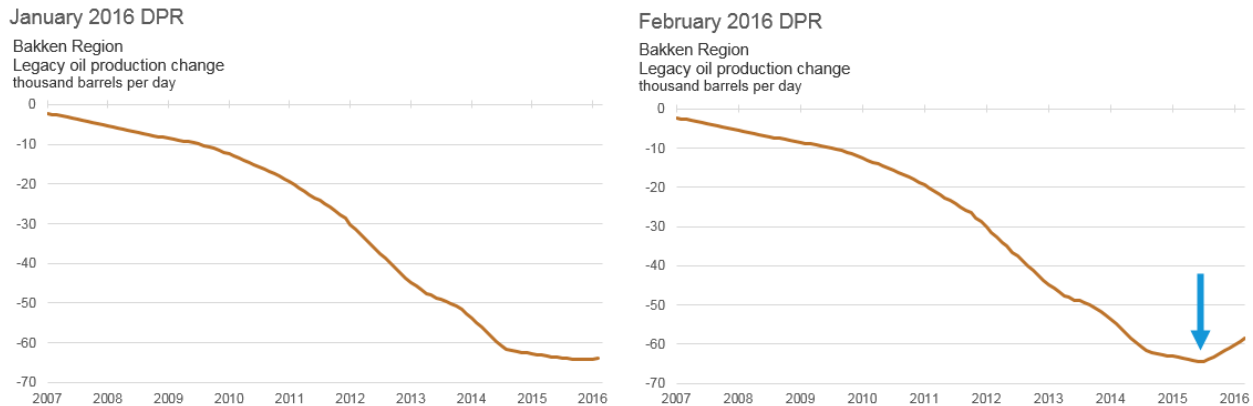
The estimated legacy oil production change is now based on the number of producing wells and the age distribution of those wells. A higher concentration of new wells will result in a greater negative legacy change because new wells may decline as much as 70% from the previous month's production, while an older well may decline less than 5%. Previously, only a trend line was used to project changes in legacy production. Trend lines will identify inflections points only with a long lag.

At times when drilling activity is significantly below its prior level, as it is currently the case, new well production is not sufficient to compensate for legacy production change. With production in decline, the well age distribution is changing, resulting in lower declines, but only with a modest change in the ratio of legacy production change to total production. The Haynesville Region went through a similar

phenomenon in 2011, and the ratio of legacy gas production change to total gas production remained relatively stable.

In order to better account for the legacy production changes during the most recent months, DPR now projects the ratio of legacy production change to total production as an initial step and then derives a final estimate for the legacy production change. In figure 12 the results of this approach is shown for the Bakken region.

**Figure 12. Impact of methodology change on estimated legacy oil production change in Bakken Region**



### Initial new well production per rig

Average new well production rate per rig is calculated as the product of the number of wells drilled per rig and the average production per well. This calculation is subject to the Rig Count to Well Count Delay, such that the production per rig for the current month is applicable to the rig count two months prior. Equivalently, the observed rig count today is expected to produce this amount per rig two months from now.

$$NPR = NwPR \times WpR = NrPR \times R_{(-2)}$$

where:

$NPR$  = P1 production rate

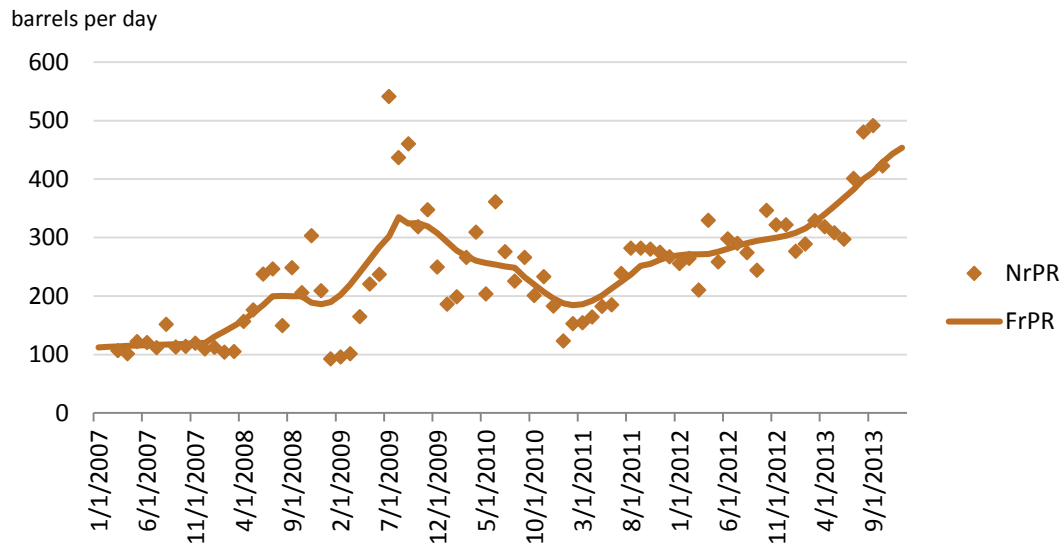
$NwPR$  = New per well production rate for P1 wells

$WpR$  = Wells per rig

$NrPR$  = New initial production from P1 wells

$R_{(-2)}$  = Rig count two months lagged

Figure 13. Bakken Region new-well (P1) oil production per rig



### Rigs needed for flat production

Having estimated the Legacy Production Change, or expected month-to-month decline in production in the absence of any new wells in the play, and Initial Production per Rig, one can calculate how many rigs would be required to bring on the equivalent amount of new production as the decline. Plotted against the rig count, this series gives a quick view into the risk of production declining from one month to the next.

$$FRG = \frac{DPR}{NrPR}$$

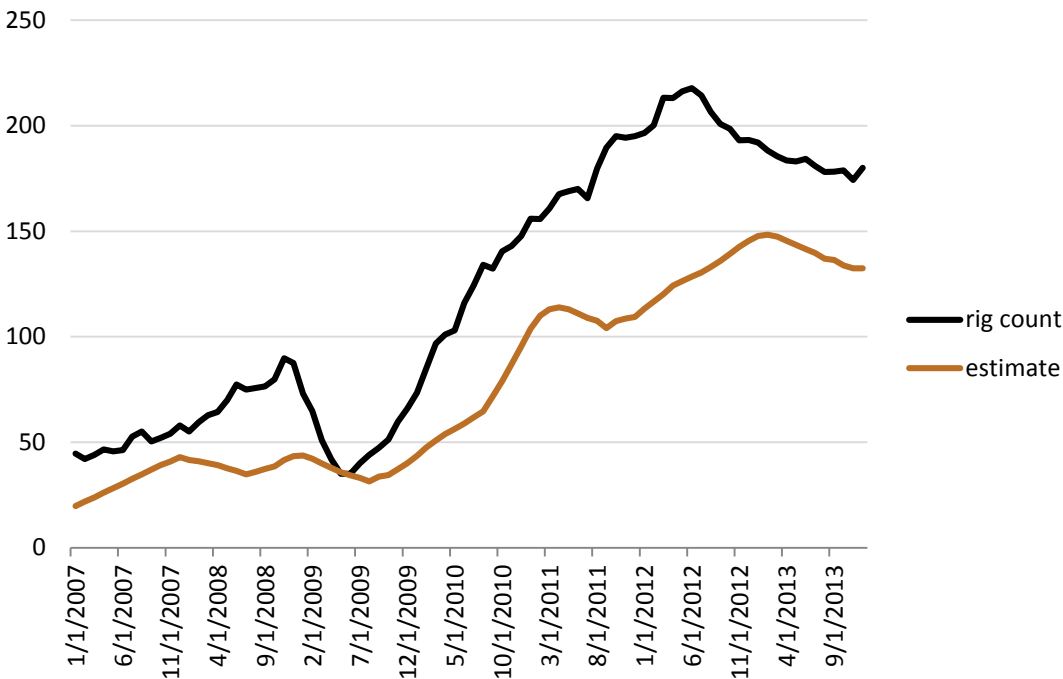
where:

$FRG$  = Rigs needed to maintain flat production rate

$DPR$  = Legacy production change

$NrPR$  = New production per rig

Figure 14. Bakken Region estimated rigs needed for flat oil production



### New well production forecast

Based on the expected new well production rate per rig and the expected future rig count (offset by the two-month Rig Count to Well Count Delay) for a play, the model estimates the expected production from new wells for the current month.

$$NPRf = R_{(-2)} \times NrPR$$

where:

$NPRf$  = Production forecast from new wells

$R_{(-2)}$  = Expected Rig count two months prior to the forecast month

$NrPR$  = New production per rig

### Production net change

The month-to-month change in total expected production is computed as the sum of the New Well Production Forecast and the Legacy Production Change.

$$\Delta PRf = NPRf + DPR$$

where:

$\Delta PRf$  = Forecast month-to-month change in production rate

$NPRf$  = Production forecast from new wells

$DPR$  = Legacy production change

### Production forecast

Finally, the sum of the prior month production rate and the estimated net change in production rate yields the forecast production rate.

$$\begin{aligned} PRf &= PR_{(-1)} + \Delta PRf \\ &= PR_{(-1)} + (R_{(-2)} \times NrPR) + DPR \end{aligned}$$

where:

$PRf$  = Production forecast

$PR_{(-1)}$  = Prior month production rate

$\Delta PRf$  = Forecast month-to-month change in production rate

$R_{(-2)}$  = Rig count two months prior

$NrPR$  = New production per rig

$DPR$  = Legacy production change

**Figure 15. Bakken Region change in total oil production**

thousand barrels per day

