All the DUCs in a Row: Natural Gas Production in U.S.

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ABSTRACT

Using data from seven shale gas regions in the United States, we examine natural gas production in terms of drilling rig activity and well completion rates. Our objective is to examine the determinants of well completion decisions in the U.S. natural gas production. We observe that in recent years, the explanatory power of drilling rig count has declined. On the other hand, the number of producing wells remains a significant factor for explaining the variation in gas production. We find that an increase in the number of drilled but uncompleted wells (DUCs) plays a significant role in natural gas supply. The number of DUCs depends on drilling rig activity and futures prices of oil and natural gas. Also, our results indicate that well completion decisions and the duration of DUC status depend on oil and gas prices, pipeline capacity, producing well type and well depth.

Keywords: Natural Gas Production, Rigs, Drilling, Completion, Pipelines, Prices.

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1. INTRODUCTION

Understanding the determinants of natural gas supply is important because of its significance for the U.S. power sector (Peters and Hertel, 2017; Stephens, 2018) and U.S. economic activity in general (Arora and Lieskovsky, 2014; Melick, 2014; Weber, 2012; Joskow, 2013).[1] Previous academic literature relied on drilling rig activity (the count of actively drilling rigs) as the primary determinant of oil and gas production because of the simplicity, availability, and global applicability of drilling rig count as an indicator (Apergis, Ewing and Payne, 2016; Melek, 2015). The oil and gas industry also has been relying on the rig count as a measure of oil and gas production activity.[2] However, as Figure 1 illustrates, natural gas production in the U.S. increased even though drilling activity has declined in recent years (EIA, 2019a).

With the growth in the use of hydraulic fracturing and horizontal drilling technologies, market analysts, researchers and government agencies have noted the increase in the inventory of drilled but uncompleted wells (DUCs) in the U.S. (Hegarty, 2017; EIA, 2013; EIA, 2019b; Dunning, 2016; Srinivasan, Krishnamurthy and Kaufman, 2019; IHS, 2016; Piotrowski, 2016). However, little or no systematic information is available on the growth of DUC inventory and the implications

1. Large number of studies document the relationship between energy in general and economic growth (See Hamilton, 2013).

2. Baker Hughes has been reporting rig count since 1944 (Baker Hughes, 2019).

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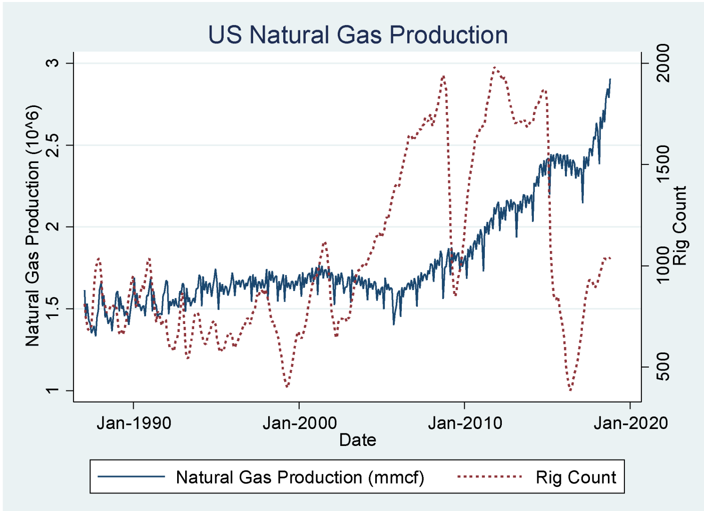
Fig 1: U.S. Rig Activity and Natural Gas Production



for natural gas production. This paper examines the determinants of DUC inventories and the impacts of drilling rig activity and well completion on natural gas output in the U.S.

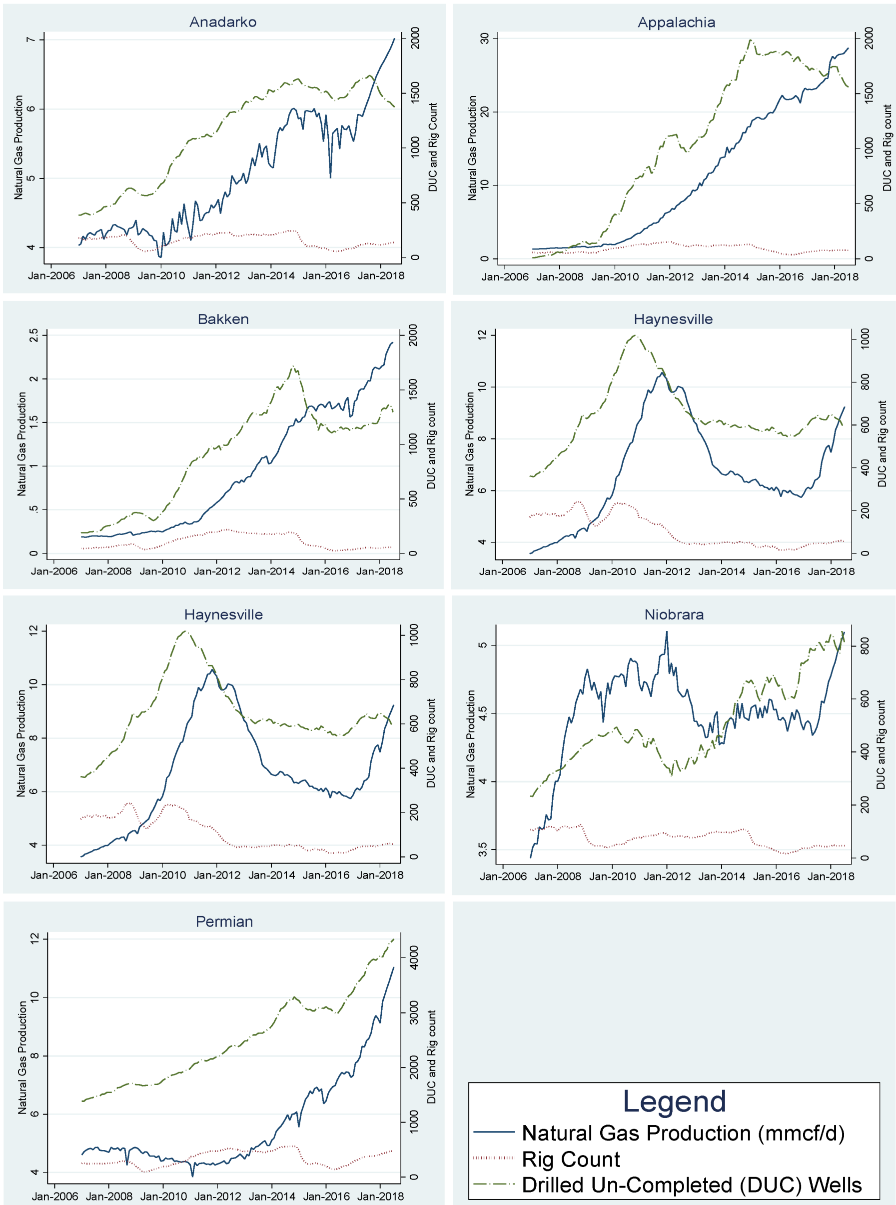
Technological developments in unconventional oil and gas (UOG) production have transformed the U.S. gas industry. According to the U.S. EIA, domestic production of gas from the UOG industry grew by more than 100% from 2000 to 2010. Data from the EIA (2016a) also indicate that the daily production of U.S. dry shale increased from 2.5 in 2002 to 43 billion cubic feet in 2016, with most of the new production coming from the Northern Appalachian basin (Marcellus and Utica shale units). Substantial gains in productivity continue through advances such as super pads (which can include up to 20 wells), extended horizontal laterals (reaching up to 20 thousand feet[3]) and improved drilling and fracturing technologies. The share of horizontally drilled wells increased from 3% in 2008 to 12% in 2017 (EIA, 2018). As a result, although the number of drilling rigs fell since 2014, natural gas production continued to grow (Figure 1) (EIA, 2019a).

In general, UOG production involves two stages. The first stage involves drilling, casing the well with multiple strings of steel pipe, and cementing the pipe. In the second stage (completion), the steel casing is perforated, and the well is stimulated via hydraulic fracturing to initiate gas flow from fractured formations. Completion, which can be significantly more expensive and time consuming than the first stage activities, can be delayed indefinitely. However, interrupting the flow from a producing well can be prohibitively costly in terms of foregone income (Kleinberg et al., 2018). Hence, production timing decisions take the form of drilling and completion decisions corresponding to stages one and two, respectively (Mason and Roberts, 2018). Wells drilled (stage one), but not hydraulically fractured or completed are labeled as drilled but uncompleted wells (DUCs).

Figure 2 shows that the aggregate number of DUCs has increased since 2007 across all regions. From November 2016 to the end of 2017, the number of DUCs rose 37.4% to 7,493 (DI, 2016). EIA's (2019a) drilling productivity report shows more than 8,700 DUCs as of November 2018. Growth in DUCs varies by region, with the largest increase observed in the Permian Basin. The reasons for the delays in well completion, and consequent growth in the DUC numbers, may

3. See Eclipse Purple Hayes well at 20,803 feet. https://www.hartenergy.com/exclusives/super-laterals-going-really-really-long-appalachia-31209.

Figure 2: Rig Count, Drilled and Un-Completed Well Count, and Natural Gas Production Trends from 2007–2018



include: shortage of hydraulic fracturing equipment and teams, contractual lease obligations that require active well development in stage one, pipeline capacity bottlenecks, and operators' timing decisions to take advantage of favorable prices (EIA, 2019b; Kleinberg et al., 2018).

One implication of the increase in DUCs is that aggregate natural gas production depends less on drilling rig activity and more on well completion rates. As a result of growth in unconventional production, and associated two-stage production technology use, drilling rig counts no longer directly correspond to the number of producing wells. Hence, the number of completed wells may be increasingly important for modeling natural gas production. Though the drilling rig count remains an important factor in natural gas production, supply growth is achieved with fewer drilling rigs given improvements in drilling technology and despite the backlog of DUCs (EIA, 2019a).

Importantly, for the production to grow, the productivity of new wells must offset declines in productivity of legacy wells (Boyce and Nøstbakken, 2011). Therefore, this paper considers both the number of producing wells and the number of newly completed wells as drivers of natural gas output. The objectives of this study are threefold. First, we examine the role of well completion rates in explaining natural gas production. Second, we examine the determinants of DUC numbers, which represent the gap between drilled and completed wells. Third, we identify the factors that influence the length of time that operators take to complete the unconventional wells.

The literature on the determinants of natural gas production is limited. Iledare (1995) uses a supply model for natural gas reserve additions in West Virginia to study the responsiveness of drilling effort and gross reserve additions to changes in the expected wellhead price, taxes, resource depletion and reserve life index. He concludes that drilling activity shifts across geological formations in response to varying geologic conditions and economic incentives. Boyce and Nøstbakken (2011) show a positive correlation between output prices and drilled wells, considering a significant decrease in the cost of drilling. Chen and Linn (2017) examine the effects of oil and gas futures prices on drilling activity in the U.S. and the rest of the world. They show that drilling activities respond to futures prices more than spot prices. This is consistent with the industry practice of hedging gas production. Gülen et al. (2013) also document the sensitivity of drilling new wells to changes in natural gas prices. Similar results with a positive association between oil rig activity and crude oil prices have been documented by Ringlund, Rosendahl and Skjerpen (2008), Apergis et al. (2016), Anderson, Kellogg, and Salant (2018) and Khalifa, Caporin and Hammoudeh (2017).

Mason and Roberts (2018) examine the sensitivity of well level natural gas production in Wyoming to geologic and economic factors. They show that geologic factors affect intra-well production variation (well productivity) while prices affect inter-well production changes (number of producing wells) via producer drilling decisions. They conclude that after a well has started producing, prices have limited effect on well-level production. Instead, geologic and engineering factors determine well productivity. However, prices have a significant effect on aggregate supply due to the elasticity of producers' drilling decisions. The authors show that at lower prices, only the most productive wells are drilled, while higher prices enable drilling of less productive wells. They also observe that the elasticity of drilling decisions in Wyoming increased following the growth in the use of horizontal drilling and hydraulic fracturing technologies. Ikonnikova and Gulen (2015) also examine the effect of prices on drilling activities in Barnett, Haynesville, and Fayetteville shale units. They show that at lower prices, producers in some locations may find it more profitable to rely on low-cost infill[4] wells to minimize capital costs as opposed to drilling relatively more productive but costlier wells in new locations.

None of the previous studies examine growth in the DUC numbers and the relationships between gas production, drilling rig activity and well completion across shale regions in the U.S. We disentangle these variables, which allows us to present a more nuanced account of production activities given the recent growth in the number of drilled but uncompleted wells. Our results document greater explanatory power of the number of producing wells relative to the count of active rigs for modeling natural gas production.[5] We also show that changes in oil and gas futures prices

4. Infill wells are drilled and completed next to the existing wells as opposed to new locations. Infill wells are less productive but require lower upfront capital costs by taking advantage of existing infrastructure and existing lease arrangements.

5. Although the principles addressed in this study are applicable to both oil and gas production, we focus the analysis on unconventional gas production and reserve the analysis of oil production to future studies. We acknowledge that in some cases

and drilling rig activity affect DUC numbers and the length of time that operators take to complete individual wells.

2. DATA

Unconventional shale gas production makes up more than 50% of all-natural gas produced in the U.S and its contribution continues to increase with most of the production coming from seven major shale regions (EIA, 2017). This study is based on the data from Anadarko, Appalachia (Marcellus and Utica), Bakken, Eagle Ford, Haynesville, Niobrara and Permian regions.

We use monthly regional data from January 2007 to July 2018 to examine cumulative natural gas production and DUC counts, and daily well level data from 2000 to 2018 to estimate hazard ratios.[6] The data summary is presented in Table 1. Rig count and natural gas production[7] (million cubic feet - mmcf) data are obtained from the EIA. Well completion data obtained from DrillingInfo (now Enverus) include a monthly cumulative number of producing wells. Rig count data (disregarding the differences in rig requirements across regions due to geological characteristics) are provided by Baker Hughes.

Rig activity in this study reflects only the number of actively[8] drilling rigs. Figure 2 presents data trends for drilling rig counts, DUCs, and gas production. Since 2007, natural gas production has been increasing significantly in most regions, except in Niobrara and Haynesville. Substantial increase in production can be attributed to significant gains in productivity enabled by recent technological improvements. Haynesville lies deeper than the shale reservoirs in other regions making supply sensitive to price variation. Drilling rig activity in this region went down significantly and in 2016 drilling rig count dropped to 20.

To examine the growth in the number of DUCs, we use estimated monthly count of DUCs from January 2007 to July 2018.[9] Figure 2 shows that the numbers of DUCs have been increasing since 2007, with greater increases observed in Permian, Niobrara, and Anadarko regions. However, in Appalachia and Eagle Ford regions, the numbers of DUCs have decreased since 2014. The declines in the numbers of DUCs in Appalachia and Eagle Ford imply that completion has been outpacing drilling of new wells.

To explain the variation across regions and over time, we control for pipeline capacity, drilling rig count, and futures prices of natural gas (measured in dollars per thousand cubic feet)

oil and gas production is joint. For example, unconventional production in the Permian basin is primarily aimed at oil with associated gas production.

6. Natural gas production and DUC count analysis covers 2007 to 2018 because EIA data on monthly rig count and production per region are available only starting from January 2007. We used an expanded sample time frame in the survival analysis from January 2000 to July 2018 based on DUC duration data availability.

7. EIA estimates natural gas production using data reported by various industry sources. In this study, we use up to date natural gas production numbers as reported by the EIA.

8. The rig is active if it is drilling at least 15 days during the month. This measure excludes rigs involved in non-drilling activities like workovers and production testing. This definition is consistent with EIA (2019a) and Baker Hughes (2019).

9. Estimates of DUC numbers can vary depending on methodologies, assumptions, and availability of data. EIA counts a drilled well to be uncompleted after 20 days' post spudding (EIA, 2016b). EIA started providing DUC count as of December 2013. To increase the sample size, we estimate DUCs using DrillingInfo well level data from January 2000 to July 2018 following the EIA methodology. Comparison of EIA DUC data and our estimated DUC numbers after 2013 reveals insignificant mean difference at 5% significance level in most regions except Appalachia and Permian. In these regions, the difference is insignificant at 1% level. The comparisons are available upon request. The minor difference in some regions can be due to the estimation method. Our computations account for DUCs drilled since 2000. On the other hand, EIA excludes wells drilled prior to December 2013.

Table 1: Descriptive Statistics

Region	Variable	N.	Mean	Std. Dev.	Min.	Max.
All Regions	N.Gas Futures price ($/mcf)**	6,787	4.91	2.29	1.35	14.74
	Oil Futures price ($/b)**	6,787	62.41	27.20	14.06	145.90
Anadarko	Pipeline Capacity (10^3 mmcfd)**	139	16.3	2.7	13.3	19.3
	N.Gas Production (10^3mmcf)/month*	139	5.1	0.8	3.9	7.0
	Rig Count/month*	139	155	55	55	247
	DUC Count 10^3/month*	139	1.1	0.4	0.4	1.7
	Producing Well Count 10^3/month*	139	16.2	2.7	9.8	19.7
	DUC Duration[a] (Days)**	14,840	88	121	1	1,778
	UOG Well Measured Depth[b] (10^3Ft)**	14,781	13.4	3.8	0.1	38.9
Appalachia	Pipeline Capacity (10^3 mmcfd)**	139	40.1	11.1	29.7	59.8
	N.Gas Production (10^3mmcf)/month*	139	11.2	9.1	1.3	28.7
	Rig Count/month*	139	90	33	36	154
	DUC Count 10^3/month*	139	1.1	0.7	0.01	2.0
	Producing Well Count 10^3/month*	139	47.6	7.2	20.5	54.9
	DUC Duration (Days)**	14,649	317	249	1	1821
	UOG Well Measured Depth (10^3Ft)**	14,529	12.6	3.8	0.04	40.0
Bakken	Pipeline Capacity (10^3mmcfd)**	139	7.7	0.4	7.2	8.1
	N.Gas Production (10^3mmcf)/month*	139	0.9	0.7	0.2	2.4
	Rig Count/month*	139	105	64	24	218
	DUC Count 10^3/month*	139	0.9	0.5	0.2	1.7
	Producing Well Count 10^3/month*	139	6.2	4.7	0.5	13.2
	DUC Duration (Days)**	15,738	142	153	1	1656
	UOG Well Measured Depth (10^3Ft)**	15,705	18.8	3.4	1.9	27.2
Eagle Ford	Pipeline Capacity (10^3 mmcfd)**	139	5.5	1.5	3.7	7.8
	N.Gas Production (10^3mmcf)/month*	139	4.2	2.2	1.5	7.4
	Rig Count/month*	139	134	87	30	279
	DUC Count 10^3/month*	139	1.3	0.6	0.3	2.4
	Producing Well Count 10^3/month*	139	7.4	2.9	3.0	11.6
	DUC Duration (Days)**	25,230	149	204	1	1,821
	UOG Well Measured Depth (10^3Ft)**	25,225	14.9	3.2	0.4	39.4
Haynesville	Pipeline Capacity (10^3 mmcfd)**	139	38.4	6.0	30.4	46.8
	N.Gas Production (10^3mmcf)/month*	139	6.7	1.9	3.6	10.6
	Rig Count/month*	139	104	73	16	244
	DUC Count 10^3/month*	139	0.6	0.2	0.4	1.0
	Producing Well Count 10^3/month*	139	15.7	3.0	8.1	18.7
	DUC Duration (Days)**	7,965	116	137	1	1,728
	UOG Well Measured Depth (10^3Ft)**	7,949	14.9	3.6	1.1	39.9
Niobrara	Pipeline Capacity (10^3 mmcfd)**	139	21.2	6.4	10.6	27.3
	N.Gas Production (10^3mmcf)/month*	139	4.5	0.3	3.4	5.1
	Rig Count/month*	139	72	30	16	127
	DUC Count 10^3/month*	139	0.5	0.2	0.2	0.9
	Producing Well Count 10^3/month*	139	2.5	0.7	1.2	3.3
	DUC Duration (Days)**	11,872	133	150	1	1,821
	UOG Well Measured Depth (10^3Ft)**	11,373	11.5	3.6	0.4	40.0
Permian	Pipeline Capacity (10^3 mmcfd)**	139	16.6	2.5	13.3	20.2
	N.Gas Production (10^3mmcf)/month*	139	5.7	1.7	3.8	1.0
	Rig Count/month*	139	335	132	92	565
	DUC Count 10^3/month*	139	2.5	0.8	0.4	4.3
	Producing Well Count 10^3/month*	139	109.3	21.8	30.4	136.9
	DUC Duration (Days)**	36,513	132	182	1	1,822
	UOG Well Measured Depth (10^3Ft)**	36,486	13.1	4.1	0.4	40.0

Note: **Data is from 2000- 2018 and *Data is from 2007–2018.

[a] DUC duration variable measures the length of time in days from end of drilling (spud date plus 20 days) to well completion or to first production for only completed unconventional wells. Minimum DUC duration of 1 day indicates that every region has at least 1 well which was completed in 21 days after spudding. Maximum DUC duration reflects maximum duration before the DUC is treated as "dead". For the purpose of this study, outlier wells (wells drilled and not completed within the period of 5 years) are treated as "dead" DUCs and they constitute about 0.3% of our data.

[b] Well measured depth is the borehole and horizontal length of unconventional wells (horizontal and directional). We do not have access to the information on lateral length, number of fracking stages and proppant intensity. Such data likely would have improved the accuracy of our DUC duration analysis.

and oil (measured in dollars per barrel). Following Chen and Linn (2017), we compute average futures prices of natural gas and oil using all available, *m*, futures contracts from the trading floor of the New York Mercantile Exchange (NYMEX). We define futures price (F_t) at time *t* as a function of the contract prices such that $F_t = \frac{1}{n}(\sum_{m=1}^{n} C_{t,m})$, where $C_{t,m}$ denotes the price of the m-th contract at time t. Contract prices and natural gas pipeline capacity data are obtained from the EIA. Pipeline capacity measures outflow volume of pipeline infrastructure expressed in million cubic feet per day (mmcf/d). Table 1 indicates that pipeline capacity increased the most in the Appalachian region with more than 30,000 mmcf added between 2007 to 2018. On the other hand, Bakken experienced the least expansion in pipeline capacity with less than 1000mmcf added over the same period. In Eagle Ford, Niobrara, Haynesville, Anadarko and Permian capacities increased by 4,141mmcf, 16,708mmcf, 16,386mmcf, 5,968mmcf and 6,920mmcf respectively.

In the time-to-event (survival) analysis of DUC duration status, we use individual well level data from January 2000 to July 2018. DUC duration status for an individual unconventional well is the number of days between the end of stage one[10] and completion. Completion date in our analysis is the earliest of the reported well completion date or the date of first reported production.[11] Summary statistics of DUC duration are presented in Table 1.

3. EMPIRICAL STRATEGY

Our empirical strategy includes: a) the analysis of natural gas production in terms of drilling rig counts and producing wells using linear fixed effects and vector autoregressive models, b) the analysis of DUC Counts within and across regions using linear fixed effects regressions, and c) the analysis of individual DUC duration status using survival analysis technique.

Natural gas production

We first use a linear regression model in double log form to explore the effect of (lagged) rig count (RC) and producing wells (PW) on natural gas production (NGP) individually and in combination. Next, we estimate autoregressive models as a robustness check. We test for unit roots using Phillips-Perron (Phillips and Perron, 1988), Augmented Dickey-Fuller (Dickey and Fuller, 1981) and panel Levin-Lin-Chu (Levin, et al., 2002) statistics. Subsequently, we conduct a panel cointegration analysis to determine the long-run relationship between natural gas production, rig count, and the number of producing wells.[12] The Pedroni's heterogeneous panel cointegration test is used to test for the group and bivariate cointegration relationships. We compute four panel and three group statistics following Neal (2014) based on the 'within' and the 'between' dimensions respectively (Pedroni 1999, 2004). We also test for cointegration within each region using the Johansen test (Johansen, 1988, 1995a, b). We proceed with estimating a panel VAR with generalized methods of moments (Abrigo and Love, 2016). Next, we estimate each region's VEC (vector error correction) model to account for cointegration within regions (Engle and Granger, 1987). The VEC model is specified as follows:

10. Following EIA methodology, we assume that stage one takes 20 days on average.

11. Many wells are completed/fractured more than once, and the data do not indicate whether a specific completion date corresponds to first completion or a recompletion. Therefore, we use the earlier of the first production or completion dates to avoid re-completion entries.

12. Following Liew (2004), Hannan-Quinn criterion (HQC) (Hannan and Quinn 1979) is used to determine the appropriate lag length for each series in each region.

$$\Delta Y_{kt} = \alpha_k + \delta\eta_{kt-1} + \sum_{i=1}^{p} \beta_{ki} \Delta Y_{kt-i} + \sum_{i=1}^{p} \Phi_{1ki} \Delta X_{1kt-i} + \ldots$$
$$\ldots + \sum_{i=1}^{p} \Phi_{jki} \Delta X_{jkt-i} + \varepsilon_{kt} \qquad (1)$$

where Δ is the first difference operator; Y_{kt} is natural gas production in log form in region k and period t; X_j is the j-th explanatory variable in log form; η are the residuals from the cointegration vector; p is the optimal lag length; α_k is the intercept, i is the lag length, and ε_t is the error term. δ, β and Φ are the parameters.

DUC counts

To examine the growth in the number of DUCs, we use regional fixed effects regression models in log-log form with and without time fixed effects,[13] with first differences, and standardized variables. The independent variables include pipeline capacity, drilling rig count, natural gas and oil futures prices. Futures prices (FP) rather than spot prices are used following Chen and Linn (2017) who showed that futures prices have a more significant effect on natural gas production than spot prices. The futures prices (FP) are lagged to account for the time that it takes the operators to initiate production in response to price movements (Osmundsen et al., 2015). We use standardized variables obtained by subtracting the mean (across regions and within regions) and pipeline capacity expressed in first difference to estimate the fixed effects regression model.[14] Standardization approach reduces the scale of variables but preserves the interpretation of the regression coefficients to represent the mean change in the DUC given a unit change in the independent variable.

DUC Duration

In this analysis, we are interested in examining the factors that influence the length of time that operators take to complete the drilled wells. Time to event (duration/survival) analysis (see Sy and Taylor, 2000; Box-Steffensmeier and Zorn, 2001; Fleming and Harrington, 2011; Hernandez and Dresdner, 2010) is used to analyze DUC duration data. We define a random variable ***T*** with a continuous probability distribution function $f(t)$ to represent DUC duration, or the number of days from the end of drilling to completion. The probability that a drilled well is completed in t days is given by $F(t) = Prob(T < t)$**.** Correspondingly, the survival function, or the probability of a drilled well not being completed in t days, is $S(t) = 1 - F(t)$**.** The hazard rate ($\lambda(t) = f(t)/S(t)$), is the probability that a drilled well will be completed at time, *t***,** given that it was not completed prior to *t*. We use semi-parametric[15] Cox proportional hazard model (equation 2) (Cox, 1972) to represent the hazard function in the DUC duration analysis (Stogiannis et al. 2011).

$$\lambda(t \mid x, \beta) = \lambda_0(t) exp(X' \beta) \qquad (2)$$

where β is a vector of unknown parameters of X covariates**,** $\lambda_0(t)$ is the baseline hazard function when $\lambda(t \mid x = 0) = \lambda_0(t)$ and can take any form as a function of t. The effects of covariates can be represented in various specifications of the hazard function.

13. Hausman test (Chi2(5) =78.04; Prob>Chi2=0.00) indicted superiority of Fixed Effects regression over a Random Effects model. Joint F test results (F (135, 820) =1.92 Prob>F=0.00) suggest including time fixed effects.

14. After standardization all VIFs were less than 5 with mean of 2.81 (Hair, Anderson, Tatham, and Black, 1995).

15. We also estimate parametric specifications including exponential, Weibull and Gompertz functions. These results are available on request.

4. RESULTS

We start with examining the difference in the relationship between natural gas production and rig count (RC) before and after February 2009.[16] In addition to the expansion in unconventional gas production, this breakpoint is also close to the economic downturn and to the beginning of the new U.S. administration. Each of these factors could have contributed to the structural break timing. Nevertheless, we believe that our breakpoint adequately reflects the changes in natural gas production series and enables meaningful comparison of production pre and post 2009.

Table 2: Split Sample Regional Fixed Effects Results for Aggregate NGP

Dependent–NGP	Before Feb 2009	After Feb 2009
Rig Count$_{t-1}$	0.212 (0.04)***	–0.048 (0.03)
Constant	13.55 (0.17)***	15.54 (0.15)***
R-sq	0.17	0.010
Observations	n=7, T=25, N=175	n=7, T=113, N=791

Note: Significance values 1%***, 5%**, 10%*; Standard errors in parenthesis.

The results from regional fixed effects regression models with lagged RC are presented in Table 2. These results show a significant change in the explanatory power of lagged RC for natural gas production (NGP). The rig count is positively correlated with natural gas production prior to February 2009. However, after February 2009 RC has a statistically insignificant relationship with natural gas production and a weaker explanatory power. A similar loss of explanatory power of RC is found with heterogeneous break point dates across regions (see Table A1 in the online Appendix).

4.1 Determinants of Natural Gas Production (NGP)

Table 3 shows regression results with region fixed effects and logged NGP as the dependent variable. Three model results are presented. R-squared values show that models 2 and 3, which include producing wells (PW) explain more of the variation in NGP than model 1 (with only RC). The marginal contribution of producing wells as an explanatory variable relative to the rig count is significant, as revealed by the difference in R-squared values between models 1 and 2. Comparison of models 2 and 3 illustrates that although rig count is statistically significant and remains to be a meaningful determinant of NGP, its marginal contribution to explaining the variation in natural gas production is smaller relative to the number of producing wells. These results are robust under heterogeneous break period specification across producing regions (see online Appendix Table A2).

To explore the relationship at the regional scale, we estimate models 1, 2 and 3 for each region individually. The results presented in Table 4 are consistent with the results in Table 3, with all but two of the regions showing statistically significant effects of producing wells (PW). In some of the regions, rig count has a negative coefficient as natural gas production increased despite the declining number of active rigs. The estimated adjusted R-squared varies among regions and between models. However, in all cases, models 2 and 3, which include the number of producing wells, show

16. We test for the presence of a structural break using Wald-type tests (Vogelsang, 1997; Andrews 1993; Andrews and Ploberger 1994) in the linear regression of natural gas production (NGP) and rig count (RC). We estimate a linear regression model and compute the S-wald test statistic for an unknown break. This method is also used to identify the breaks (B_i) for each region independently. The results show May 2010 for Anadarko, August 2012 for Appalachia, December 2012 for Bakken, February 2013 for Eagle Ford, February 2009 for Haynesville and January 2014 for Niobrara and Permian.

Table 3: Region and Time Fixed Effects Results for Aggregate NGP

NGP-Dep	**Model 1**	**Model 2**	**Model 3**
Rig Count$_{t-1}$	0.332 (0.03)***		0.274 (0.03)***
Producing Wells		0.524 (0.04)***	0.468 (0.03)***
Feb 2009	1.413 (0.22)***	1.044 (0.22)***	1.093 (0.21)***
Constant	12.94 (0.22)***	9.906 (0.41)***	9.132 (0.41)***
R-sq	0.58	0.61	0.64
Observations	Balanced Panel n=7, T=138, N=966		

Note: Significance values 1%***, 5%**, 10%*; Standard Errors in parenthesis; Data from 2007–2018.

Table 4: Regional Regression Results (Determinants of NGP)

Region	**Model 1**	**Model 2**	**Model 3**
Anadarko			
Rig Count$_{t-1}$	–0.003 (0.03)		0.002 (0.02)
Producing Wells		0.894 (0.07)***	0.908 (0.07)***
Feb 2009	0.202 (0.03)***	–0.126 (0.03)***	–0.126 (0.03)***
Adj R-sq	0.230	0.633	0.630
Appalachia			
Rig Count$_{t-1}$	–0.663 (0.19)***		–0.521 (0.16)***
Producing Wells		3.978 (0.50)***	3.874 (0.49)***
Feb 2009	2.222 (0.20)***	0.596 (0.22)***	0.915 (0.24)***
Adj R-sq	0.482	0.621	0.642
Bakken			
Rig Count$_{t-1}$	–0.264 (0.09)***		–0.083 (0.03)**
Producing Wells		0.896 (0.03)***	0.884 (0.03)***
Feb 2009	1.571 (0.15)***	–0.318 (0.08)***	–0.245 (0.09)***
Adj R-sq	0.436	0.916	0.919
Eagle Ford			
Rig Count$_{t-1}$	0.152 (0.06)**		0.153 (0.02)***
Producing Wells		1.525 (0.05)***	1.530 (0.04)***
Feb 2009	0.838 (0.12)***	–0.235 (0.05)***	–0.337 (0.04)***
Adj R-sq	0.379	0.931	0.937
Haynesville			
Rig Count$_{t-1}$	0.077 (0.02)***		0.160 (0.03)***
Producing Wells		0.177 (0.14)	0.771 (0.17)***
Feb 2009	0.653 (0.05)***	0.490 (0.08)***	0.391 (0.07)***
Adj R-sq	0.587	0.571	0.638
Niobrara			
Rig Count$_{t-1}$	0.011 (0.01)		0.010 (0.02)
Producing Wells		–0.023 (0.03)	–0.028 (0.03)
Feb 2009	0.122 (0.02)***	0.136 (0.02)	0.138 (0.02)***
Adj R-sq	0.363	0.382	0.203
Permian			
Rig Count$_{t-1}$	–0.006 (0.05)		–0.121 (0.04)***
Producing Wells		1.255 (0.12)***	1.390 (0.13)***
Feb 2009	0.172 (0.06)***	–0.387 (0.07)***	–0.408 (0.07)***
Adj R-sq	0.051	0.457	0.497

Note: Significance values: 1%***, 5%**, 10%*; Standard errors in parenthesis; Data from 2007–2018.

better fits compared to model 1. The rig count is a significant indicator for natural gas production in some regions. However, in most regions the rig count is not as informative as the number of producing wells, which accounts for well completions. Similar conclusions are reached in the models with heterogeneous break points across regions (see Table A3 in the online Appendix).

In Table 5 we show the results from the regression where new wells are separated from older (legacy) wells. In this model, new wells represent cumulative number of wells that started producing up to three months ago. New well completions reflect the effect of higher initial productivity of new wells and have a statistically significant effect.[17] The new wells contribute to total gas production only after completion, which can be delayed indefinitely after drilling. The delays in completion weaken the correspondence between drilling rates and aggregate gas production. Hence, well completion decisions have a significant impact on aggregate natural gas production following the growth in UOG production. The conclusions are robust with regards to heterogeneous breakpoints across regions (see Table A4 in the online Appendix).

Table 5: Region and Time Fixed Effects Results (NGP and New Wells)

Dependent–ΔNGP	Log-log form
Legacy Wells	–0.012 (0.00)***
New Wells	0.009 (0.00)***
Feb 2009	0.042 (0.02)***
Constant	0.070 (0.03)**
R-sq	0.26

Note: Significance values 1%***, 5%**, 10%*; Standard Errors in parenthesis.

Next, we turn to the panel vector autoregressive models. First, we perform several diagnostic tests. Unit root tests indicate that all variables are non-stationary in levels at the regional and aggregate scales. However, we reject the null hypothesis that the differenced variables contain a unit root at 1% significance level (see Table A5 in the online Appendix for the first-differenced variables, with and without a trend). We use a lag length of four as determined by the HQC test (see Table A6 in the online Appendix). The Pedroni's heterogeneous panel cointegration test is used to determine the long-run relationships between variables (see Table A7 in the online Appendix), and indicates that panel rho-statistic, panel PP statistic, group rho-statistics and group PP-statistics fail to reject the null hypothesis of no cointegration at the 0.1 significance level.[18] However, panel ADF t-statistic and group ADF-statistics reject the null hypothesis at the 0.05 significance level. Conversely, the Johansen test for cointegration (Johansen, 1988, 1995a, b) reveals cointegration within regions between some of the variables in our specifications (see online Appendix Table A8). Therefore, we reject the null of zero co-integrating vectors within regions using the trace statistic and conclude that there is at least one co-integrating vector in our specifications, which include natural gas production (NGP), rig count (RC) and producing wells (PW).

The results for the panel vector autoregressive models with regional fixed effects are presented in the appendix (see online Appendix Table A9). The rig count is statistically not significant in the first three models. On the other hand, the lagged number of producing wells is significant. We also estimate the Vector Error Correction model with NGP as a function of RC and PW for each region. Results are presented in the appendix section (see online Appendix Table A10). The rig count has a statistically insignificant effect in three of the seven regions. In Bakken, Eagle Ford, Niobrara

17. We also estimated the model where new wells include those that have started producing longer than three months ago. The results, available upon request, confirm declining productivity after approximately a year.

18. The panel VEC estimation follows two steps. First is the estimation of long run relationship using the following model, $Y_{k,t} = \alpha_k + \delta_k t + \sum_{i=1}^{n} \beta_i X_{i,k,t} + \varepsilon_{kt}$, to obtain the estimated residuals ε_{kt} which form the error correction term in the panel VEC model (see Jiang and Liu, 2014). In the second step, equation 1 is estimated as a panel VAR with the error correction term.

and Permian regions, the rig count has a negative and significant coefficient indicating growth in natural gas production despite a declining number of active rigs. This is consistent with our previous results and with the report by the Federal Reserve Bank of Dallas (2019). These results suggest that well productivity and the number of producing wells, which depends on well completion rates, are important determinants of natural gas production.

Overall, the results show that there is a significant relationship between the cumulative number of producing wells and natural gas production. However, the strength of the relationship differs across regions. In comparison, the drilling rig count is statistically weaker in explaining natural gas production. Delays in unconventional well completions, and growth in the number of DUCs, have introduced an additional layer of disparity between drilling rig count and natural gas production. We examine the determinants of the number of DUCs in the next section.

4.2 DUCs Analysis

Region and time fixed effects models are used to examine the number of DUCs as a function of pipeline capacity (Cap), rig count (RC), and natural gas and oil futures prices (FP). The results in Table 6 are consistent with expectations. We observe that futures prices of natural gas and oil have statistically significant and negative effects on the number of DUCs. When futures prices are high, more wells are completed, and DUC numbers decline. This result is consistent with operators selling at favorable prices to cover well completion costs by taking advantage of high initial well production rates. With futures and forward contracts locked in, the operators attract investors to front the money needed for well completion. This result supports the insight that operators defer well completions, leading to high DUC numbers, in anticipation of better oil and natural gas prices (Andrien, 2016; Kleinberg, 2018).

Region fixed effects regression results show that pipeline infrastructure is not a statistically significant factor in explaining DUC numbers.[19] Statistical insignificance of pipeline capacity in these models can be due to a lack of variability in pipeline capacity within each region over time. The individual region results in Table 7 confirm the results from the aggregate analysis where rig count and futures prices have positive and negative effects on DUC numbers, respectively. The results also show that, as one would expect, an increase in drilling activity, measured in terms of the number of active drilling rigs, has a statistically significant and positive effect on the number of DUCs. All else constant, greater drilling activities lead to a greater number of DUCs.

4.3 DUC Duration Status Analysis

Next, we examine the length of time that operators take to complete each unconventional well. We use the well level DUC duration status data to examine completion timing. Non-parametric survival functions are presented in Figure 3 using data from 2000 to 2018. The Kaplan-Meier survival curves show the proportion of wells that remain uncompleted over time. Most wells (about 90%) are completed within a year. An insignificant number of outlier DUCs (about 0.3%) remain uncompleted after five years. In this study, such wells are treated as "dead"[20] DUCs and are excluded from the regression analyses.

19. We also estimated a regional and time fixed effects regression model using first differences of the explanatory variables. The results show significant negative effect of oil and gas futures prices on DUC growth. However, pipeline capacity and drilling activity are not significant. These results are available on request.

20. Example of such definition can be found in Andrien (2016) where "dead" DUCs are defined as wells which fail to be completed even at better oil and gas prices.

Table 6: Drilled and Un-Completed Well Analysis Regional Results

	Region Fixed Effects	Region and Time Fixed Effects		
DUC –dependent	A. Log-log	B. Log-log	C. Variables standardized across regions	D. Variables standardized by region
Pipeline Capacity	1.668 (0.86)		0.329 (0.17)	0.232 (0.24)
ΔPipeline Capacity	—	2.274 (1.73)	—	—
Rig Count$_{t-1}$	0.448 (0.10) ***	0.585 (0.14) ***	0.485 (0.11) ***	0.412 (0.09) ***
NG Futures price	–0.213 (0.14)	–2.337 (0.69) **	–0.636 (0.16) ***	–1.493 (0.73)*
Oil Futures price	–0.031 (0.15)	–4.112 (1.01) ***	–0.765 (0.16) ***	–1.841 (0.86)*
Time	0.007(0.00)**			
Constant	–11.75 (8.71)	24.34 (4.48)***	–0.218 (0.13)	–1.008 (0.39)**
Adj R-sq	0.717	0.735	0.792	0.721
Observations	966	966	966	966

Note: Significance values 1%***, 5%**, 10%*; Robust standard errors in parenthesis; Data from 2007–2018.

Table 7: OLS Log-log Results for DUC Well Analysis per Region

Dependent- DUC	Anadarko	Appalachia	Bakken	Eagle Ford	Haynesville	Niobrara	Permian
ΔPipeline Capacity	–0.832	0.767	–0.861	–0.544	0.374	–0.081	–0.781
	(0.35)	(2.00)	(1.45)	(1.47)	(1.17)	(0.26)	(1.95)
Rig Count$_{t-1}$	0.281***	0.462*	0.278***	0.510***	0.247***	0.180***	0.354***
	(0.07)	(0.24)	(0.07)	(0.05)	(0.02)	(0.05)	(0.03)
NG Futures price	–1.089***	–2.949***	–1.363***	–0.934***	–0.666***	–0.262***	–0.391***
	(0.08)	(0.31)	(0.12)	(0.10)	(0.06)	(0.07)	(0.06)
Oil Futures price	0.079	0.646	0.158	–0.121	–0.295***	–0.234***	–0.382***
	(0.10)	(0.41)	(0.17)	(0.12)	(0.05)	(0.08)	(0.08)
Constant	6.735***	5.747***	6.624***	6.442***	5.035***	8.302***	7.937***
	(0.35)	(0.89)	(0.46)	(0.35)	(0.18)	(0.27)	(0.23)
R-sq	0.740	0.747	0.728	0.831	0.634	0.532	0.720
Observations	138	138	138	138	138	138	138

Note: Significance values 1%***, 5%**, 10%*; Standard errors in parenthesis; Data from 2007–2018.

We use linear regression and time-to-event (survival) models to obtain statistical estimates for the factors that explain the length of time taken to complete drilled wells. The generalized linear model is used to illustrate the general baseline relationship between DUC duration and the explanatory variables. However, survival analysis is more appropriate to represent the duration data adequately and to provide a more detailed account using both the survival and hazard functions. The survival function represents the probability that a well remains uncompleted at any given time, while the hazard function gives the probability that a well will be completed in a given period assuming that it has not yet been completed.

The Results for the generalized linear (column A) and semi-parametric Cox proportional (columns B and C) models with logged days of DUC duration status are presented in Table 8. Cross region variation is captured using dummy variables with Anadarko as the base category. Generalized linear model results show that all variables are statistically significant with expected signs. Pipeline capacity, natural gas and oil futures prices have statistically significant and negative effects on the duration of the DUC status.[21] On the other hand, well depth has a positive effect on DUC duration. Interpretation of the coefficients in the Cox proportional survival model (column B) should be oppo-

21. Pipeline capacity limitations have been especially prominent in the Permian basin leading to negative natural gas prices and increase in the number of DUCs (Addison, 2018; Surran, 2019).

Figure 3: Kaplan-Meier Survival Curves

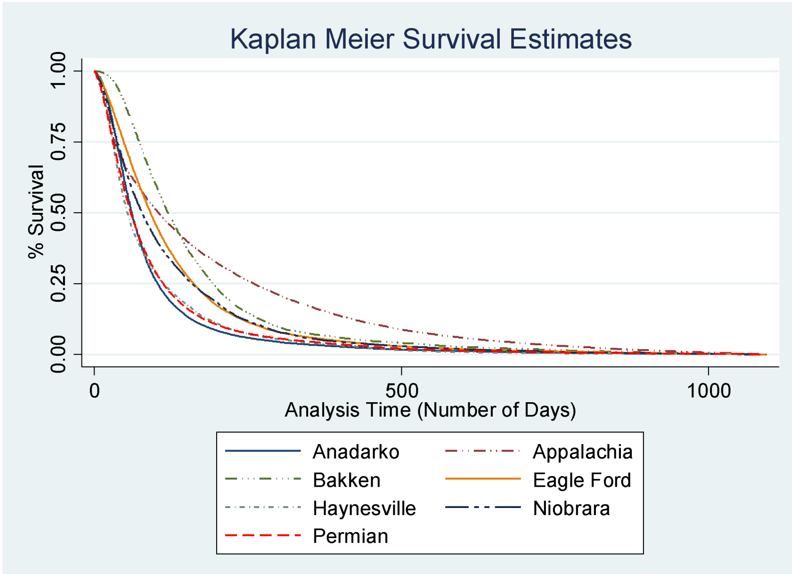


Table 8: DUC Duration Analysis Results

Variables	Generalized linear model	Semi-Parametric Cox Proportional Model	
Dep-DUC Duration	A. Coef.	B. Coef.	C. Hazard Ratio
LL	–139760	–1346626	–1401168
LR Chi2(12)		20062 (0.00)	20062 (0.00)
NG Futures price	–0.041 (0.01)***	0.052 (0.01)***	1.053 (0.01)**
Oil Futures price	–0.051 (0.01)***	0.118 (0.01)***	1.126 (0.01)***
Pipeline capacity	–0.502 (0.03)***	1.013 (0.05)***	2.753 (0.13)***
Gas Well[a]	0.232 (0.01)***	–0.269 (0.01)***	0.764 (0.01)***
Well depth	0.498 (0.01)***	–0.350 (0.01)***	0.705 (0.00)***
Time	0.0001(0.00)***	–0.0002(0.00)***	0.999 (0.00)***
Appalachia	1.477 (0.03)***	–1.960 (0.04)***	0.141 (0.01)***
Bakken	–0.320 (0.03)***	0.651 (0.04)***	1.917 (0.08)***
Eagle Ford	–0.225 (0.03)***	0.594 (0.05)***	1.811 (0.09)***
Haynesville	0.544 (0.03)***	–1.061 (0.04)***	0.346 (0.02)***
Niobrara	0.621 (0.01)***	–0.869 (0.02)***	0.419 (0.01)***
Permian	0.288 (0.01)***	–0.411 (0.01)***	0.663 (0.01)***
Observations	126,048	127,627	127,627
Number of Completions	126,048	126,048	126,048

Note: Significance values 1%***, 5%**, 10%*; Standard errors in parenthesis; Data from 2000–2018.
[a] Gas well is a dummy variable (with 1=Natural Gas producing well and 0=Oil producing well) that captures production type as defined by the operator. Wells are classified based on their gas/oil ratio (GOR).

site of the estimated signs (see Teachman and Hayward, 1993 for interpretation of hazard models). A positive coefficient indicates a negative effect on the probability that a well remains uncompleted (longer DUC duration). For example, our results show that an increase in natural gas and oil futures prices decreases the probability that a well will remain uncompleted at any given time, which implies a decrease in the DUC duration status. On the other hand, the length of the unconventional well has a positive effect on the duration of DUC status. Similarly, we observe that from 2000 to 2018, the probability that an unconventional well remains uncompleted at any given time has increased.

The estimates for the hazard rates (the probability that a well will be completed at time *t* given that the well has not been completed prior to *t*) in column C are consistent with the estimates from the linear regression model results (column A) and prior expectations. A hazard ratio greater (less) than one indicates that a unit increase in the covariate is associated with an increase (decrease) in the probability that a well will be completed at any given time *t,* given that it is still in DUC status at time *t*–1. For example, based on the estimates from column C, all else constant, a one dollar increase in natural gas price is associated with 5.3% increase in the hazard rate. Similarly, a unit (10^3 mmcfd) increase in pipeline capacity is associated with 175% increase in hazard rate, on average across regions. This result illustrates the significance of pipeline infrastructure for unconventional well completion decisions. On the other hand, a unit (10^3 ft) increase in the well depth of an unconventional well is associated with 0.295% (1–0.705) decrease in hazard rate.

The results also show that both survival and hazard rates differ significantly across regions and that gas wells are more likely to have lengthier DUC periods than primarily oil producing wells. This result, in combination with the significance of pipeline capacity, is possibly indicative of more pressing pipeline bottlenecks in natural gas supply than in oil. We also observe that well depth has a negative effect on the probability of completion at any given time. These results, in general, suggest that prices, infrastructure, and geologic variables play important roles in operators' decisions to complete unconventional gas wells. This is consistent with the results in recent literature where prices and geologic factors are reported to be significant determinants of unconventional oil and gas production decisions (Mason and Roberts, 2018; Kleinberg et al., 2018; Ikonnikova and Gülen, 2015).

5. CONCLUSION

The U.S. natural gas production industry has experienced tremendous growth in the recent decade due to the developments in unconventional oil and gas extraction technologies. This growth has affected domestic and international energy markets (Oglend, et al., 2016), electricity generation sector (Peters and Hertel, 2017; Logan et al., 2013), industrial manufacturing sectors (Arora and Lieskovsky, 2014) and labor markets (Agerton, et al., 2017). Therefore, it is important to identify key interdependencies in the natural gas industry for appropriate market analysis and effective policy formulation. The objective of this study is to explain the observed variability in the U.S. natural gas output in terms of the drilling rig count, the number of producing wells, and the completion of drilled unconventional wells. We are particularly interested in the observed growth of the number and duration of DUCs in recent years, given a significant increase in unconventional production.

We find that since the expansion in shale gas production, the explanatory power of rig count has declined, while the effect of the number of producing wells remained statistically significant. Therefore, new wells and completion of drilled wells are important deteminants of natural gas output. The decline in the significance of rig counts as a determinant is expected given the nature of UOG production technology, where extraction requires hydraulic fracturing as an additional step, which can be delayed indefinitely. Hence, unless delays in well completion are constant across wells, the explanatory power of rig counts is expected to decline. Indeed, we observe heterogeneity in the delay of well completions and an overall increase in the number of DUCs. As a result, the statistical significance of rig counts has diminished as completion decisions have become important determinants of natural gas output.

Our results show that rig count and futures prices have statistically significant effects on the number of DUCs. Aggregate, as well as region-specific results indicate that an increase in the natural gas futures prices decreases the number of DUCs. This suggests that all else constant, increase in natural gas prices motivates operators to complete existing drilled wells sooner. An increase in the futures price of natural gas decreases the probability that a well remains uncompleted and increases the probability that a well will be completed assuming it has not yet been completed. This result is consistent with producers hedging gas production to take advantage of high initial well productivity. Forward contracts and futures markets with favorable prices enable producers to pay off well completion costs faster and attract needed investment to finance well completion.

The duration model also shows that pipeline capacity has a negative effect on the duration of DUC status. This result confirms the effect of pipeline infrastructure bottlenecks in natural gas markets. While the effect of pipeline bottlenecks on natural gas prices has been recognized (Oliver et al., 2014), we show that pipeline capacity has a direct positive effect on the completion of drilled unconventional wells using data from multiple shale regions. Our results are consistent with the observed negative effects of pipeline constrains on completion rates and associated negative impacts on the demand for sand, water, and fracking fleet capacity as reported in industry outlets (Davis, 2018; Andrien, 2016).

It is important to note that this study does not explicitly address the simultaneity of output, inventories, and prices. This study is the first to draw attention to the role of well completion in unconventional gas production as a factor in aggregate output. Our objective is to point to the diminished power of rig counts and the increased role of completion decisions. We refrain from also addressing the identification issues and from claiming causal inference involving aggregate natural gas supply and prices. Future studies should examine supply of natural gas considering endogeneity of prices and inventory to support a proper causal inference for supply. In our analysis of DUC duration, we include prices as one of the factors affecting the timing of well completion decisions. In the well level analysis, causal inferences pertaining to prices and well level completion decisions are not as susceptible to the inconsistency of estimates that may be caused by price endogeneity. For individual well completion modeling, price can be reasonably treated as an exogenous factor.

The results of this study are important for natural gas operators, energy market analysts, government agencies and other stakeholders in the natural gas industry. Investors, operators, market analysts and policy makers rely on natural gas production information to support investment strategies, facilitate production decisions, improve market analysis, and formulate regulatory policies. Thus, it is important to have access to the best available information about the primary determinants of natural gas production. EIA produces a monthly report (Drilling Productivity Report) which uses data on drilling rig counts, drilling productivity and production in natural gas wells to develop regional forecasts of natural gas production. In this study, we show that the information about drilled but uncompleted wells can be meaningful for improving such projections.

We also show that infrastructure constraints, like pipeline bottlenecks, can have important implications for well completion decisions and natural gas output in the U.S. The implications of such bottlenecks are important for coordinating increasingly interdependent electricity and natural gas markets (Mugabe et al., 2020) considering reliability (Moeller, 2012; U.S. Department of Energy, 2015). Increased availability of shale gas has transformed the U.S. power sector (Mugabe et al., 2020; Kerr, 2010; Rogers, 2011), and future developments in natural gas distribution infrastructure will likely have further implications for U.S. power generation sector (Logan et al., 2013). Future analysis should examine how the U.S. electricity sector will evolve under various natural gas distribution infrastructure bottleneck scenarios.

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