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The shale gas boom in the US: Productivity shocks and price responsiveness

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ABSTRACT

Many studies have been focusing on the impact of the shale gas boom on our society, but the reverse relationship is not well documented. The objective of this paper is to examine the impact of oil and gas prices on shale gas drilling activities. We analyze the well-level production data from all major producing shale gas plays in the United States (US) and identify a major productivity shock in 2009. We then estimate the price elasticity of shale gas drilling using the econometric methods. Our results show that the oil price elasticity increases from insignificant in the pilot stage (2000–2008) to 1.1 (significant) in the expansion stage (2009–2016), and the gas price elasticity increases from insignificant in the pilot stage to 0.6 (significant) in the expansion stage. This is the first quantitative estimation of shale gas drilling responsiveness to oil and gas prices based on near-full-sample well-level drilling data while taking account the structural break. The change in price elasticities indicates that the shale gas drilling becomes more responsive to oil and gas prices after the major productivity shock around 2009. The high oil-price elasticity after 2009 shows the importance of natural gas condensate in supporting shale gas drilling. The estimated oil and gas elasticities are important to forecasting shale gas supply and economic impacts in the new normal.

1. Introduction

The fast increase in shale gas production is one of the major events in the oil and gas industry. Although discovered as early as 1825 (Milam, 2011), the large amount of hydrocarbon resources in shales had long been regarded unrecoverable due to the very low permeability of the host rock. It is the integration of horizontal drilling and hydraulic fracking technology that has released the bound energy since the early 2000s. From 2000 to 2016, the share of US shale gas production increased from about 3% to 48% of the total natural gas production (calculated using the natural gas production data from the US Energy Information Administration, EIA, 2018a, 2019). This productivity shock has a deep influence on global energy markets, local economies, and the environment. The rise of US shale gas production has changed the international natural gas market structure by directing the supposed US liquefied natural gas (LNG) imports to the Asian markets (Medlock, 2012). It also causes the change in cointegration and correlation status of the liquefied petroleum gas (LPG) prices, oil prices, and natural gas prices (Caporin and Fontini, 2017; Oglend et al., 2015), and decrease in real West Texas Intermediate (WTI) oil price (Liu and Li, 2018). The rapid increase in local supply, combined with the difficulty in transporting the product globally, has led to low natural gas prices in the United States after 2009.

Compared to the large amount of literature studying the impacts of shale gas boom, the reverse is quite limited. Newell et al. (2019) examine the influence of oil and gas prices on the drilling of new gas wells and natural gas production. The empirically estimated oil price elasticity is 0.6 and gas price elasticity is 0.7 for both shale gas wells and conventional gas wells drilled in 2000–2015. The study uses aggregated time series data and does not consider the structural change caused by the shale gas boom. The similar price elasticities for both shale gas and conventional gas drilling are counter-intuitive because of the different geological properties and development strategies between the two gas resources. Mason and Roberts (2018) estimate the gas price elasticity of all natural gas wells drilled in 1994–2012 in Wyoming. The estimated gas price elasticity is 0.6–0.7. The authors divide samples into two subgroups using the year 2003 as a structural breakpoint to identify the effect

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of new technology. The gas price elasticity increases from 0.45 in the first period to 0.65 in the second. The study does not distinguish conventional and unconventional wells. Therefore, the results reflect the overall responsiveness of all natural gas drilling activities in Wyoming. Although the authors take the structural break into consideration, the breakpoint used is different from that identified in other studies (e.g., Arano et al., 2018; Oglend et al., 2015). Hausman and Kellogg (2016) estimate the gas price elasticity for all natural gas wells drilled in 2002–2010 in the US using aggregated time series data. The computed long-run gas price elasticity is 0.81. This study does not distinguish conventional and unconventional wells either.

Besides the above studies related to shale gas supply, there are several papers studying tight oil supply. Smith and Lee (2017) estimate the price elasticity of tight oil reserves using the discounted cash flow method. The responsiveness of tight oil reserve to oil price (elasticity) is 0.3–0.5 and the responsiveness of economically viable drilling sites to oil price is twice this number. Kleinberg et al. (2018) discuss the tight oil market dynamics qualitatively and examine the factors influencing tight oil supply.

In addition to the limited studies on unconventional oil and gas supply, there is a large literature about the supply of conventional oil and gas. Studies estimating the price elasticity of oil supply include Fisher (1964), Griffin (1985), Walls (1994), Kaufmann and Cleveland (2001), Krichene (2002), Askari and Krichene (2010), etc. Papers examining the price elasticity of natural gas supply include Erickson and Spann (1971), Pindyck (1974), MacAvoy and Moshkin (2000), Boyce and Nøstbakken (2011), etc. The methods and models used in these papers are carefully referred to during the work of our research.

In summary, the shale gas boom has big impacts on the energy markets. Knowledge about its supply law is important for predicting natural gas supply in the US, forecasting natural gas prices, and making energy policies. However, existing studies about shale gas supply is limited. The behavior after the structural break caused by the shale gas boom is not fully evaluated. And the individuality of different shale plays is not considered. The objectives of this paper are to 1) identify the major structural breakpoint from the shale gas supply side, and 2) estimate the influence of oil and gas prices on shale gas drilling activities and production—the price elasticities—before and after the structural break. Our study contributes to the existing literature by clearly quantifying the changes in price responsiveness of shale gas drilling due to shale gas productivity shocks. The high-resolution, play specific data allows us to use fixed effect panel data modeling approach to control unobserved heterogeneity across the plays and obtain more accurate estimates.

2. Data description and analysis

2.1. Drilling data

We obtain well-level drilling data from Drillinginfo (2017), a company providing oil and gas upstream data service. This dataset has been used by the US Energy Information Administration (EIA) and other researchers. We compile a list of unconventional plays from various sources (e.g., EIA, 2014a; 2016a; NGI, 2017) and download the well data of each play from Drillinginfo's database using the “approximate string match” technique. The technique is adopted to include all wells of the same play. One play may have multiple names because operators use different abbreviations. Typos also occur when the data is reported. For example, if you type in “barnet” in the reservoir filtering window, a list of reservoirs would appear including “BARNETT SHALE”, “BARNETT”, “BARNET” and etc., among which the “BARNETT SHALE” with 22224 wells is the play name used by most companies, although other names also exist. We select all possible wells first and then examine the coordinates to confirm their formation belonging. We exclude wells other than the gas type, such as water disposal, oil, injection, and observation wells. Samples from the Utica and Point Pleasant reservoirs are grouped together because they are partially interbedded and share similar characteristics.

For each play, we examine its lithology, the change in well type (vertical or horizontal), the spud date (the start date of drilling) and first production date, and production history to ensure that all wells are extracting from shale plays. Since shale gas is defined by the rock containing it rather than the well type, we include all well types as long as they are producing from a shale play. This is different from the methodology used by Newell et al. (2019), who exclude vertical shale gas wells. We delete wells with workover history and having the spud date later than the first production date, and wells missing spud and first production date. Shale plays with limited gas wells (not gas production) are also excluded, such as the Bakken formation, which produces a significant amount of associated gas from tight oil wells. Our final dataset contains 50,510 wells drilled between January 2000 and June 2016 in eight shale plays and ten states (Fig. 1).

Table 1 summarizes the basic characteristics of each play over the period of 2000–2016. The well number in column two shows the total number (after data screening) of shale gas wells drilled in each play. Barnett is the most extensively drilled play with 18,820 wells. Wolfcamp and Utica have only about 1500 wells. The peak gas condensate productivity (IPOD) and the peak natural gas productivity (IPGD) represent the average well-level initial condensate and gas productivity, respectively. The initial productivity is closely related to a well's estimated ultimate recovery (EUR) and lifetime revenue. The average IPOD and IPGD values in column three and four show that the well productivity of different shale gas plays varies significantly. IPOD and the yield value (Yield) in column six show that Eagle Ford is rich in gas condensate whereas Fayetteville produces little liquid. Other characteristics like measured depth (MD) and perforated interval (Perforation), all indicate the heterogeneity of shale gas plays. Models using aggregated time series data are not able to take account the play-level heterogeneity.

Fig. 2 plots the key characteristics in 2000–2016. The number of new wells drilled in each quarter increases from 83 in 2000Q1 to 1534 in 2008Q3, drops below 1000 during the economic crisis, quickly rebounds back to the peak level, and then decreases back to the 2000 level in 2016Q2 (Fig. 2A). Unlike the up and down history of the well number, the average perforated interval as well as the measured depth increase steadily since 2002 (Fig. 2B), when Michell Energy and Devon Energy merged (Wang and Krupnick, 2015). The length of the perforated interval should be proportional to the well productivity, ceteris paribus. The smooth up-trending curve of the perforated interval indicates that the technique of horizontal drilling improves steadily from 2002 and is not interrupted much during the 2008 economic crisis. However, the average initial well productivity, an important indicator of EUR, follows a different path. Both the initial natural gas productivity and condensate productivity increase sharply in 2009 (Fig. 2D). Since the average productivity is influenced by the improvement of technology as well as the development of new plays, we take a further step to analyze the individual productivity profile. Fig. 3A shows that the development of the high-productivity Haynesville play around 2009, the development of Marcellus and Eagle Ford, and the productivity increase of Woodford and Wolfcamp all contribute to the sharp increase of natural gas productivity in 2009.

The average natural gas condensate productivity starts to increase in the middle of 2009 and exhibits a different pattern from natural gas productivity (Fig. 2D). A closer look at the individual

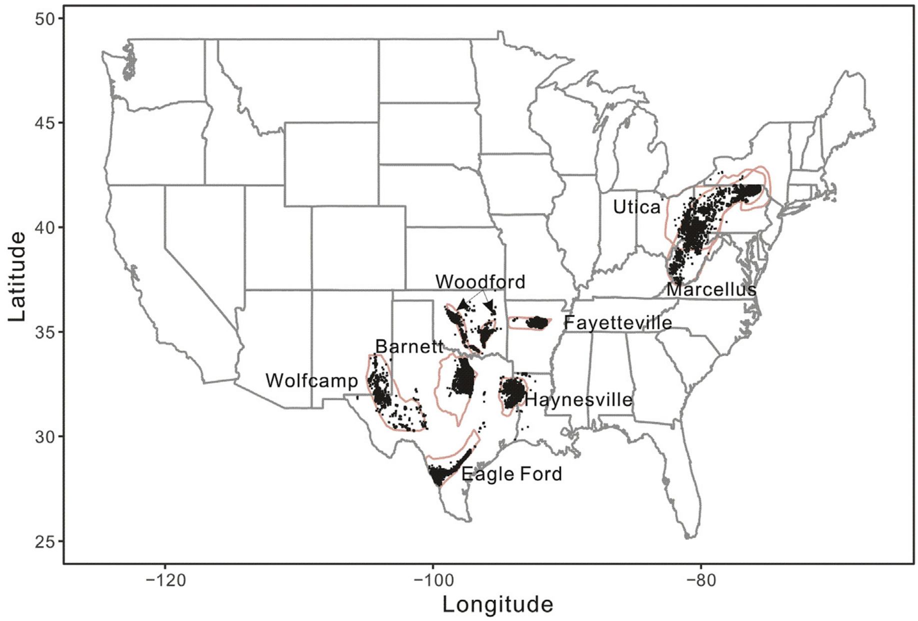

Fig. 1. The location of shale gas wells drilled in 2000Q1-2016Q2. The outline of shale gas plays (pink lines) is from EIA (2016b). Surface coordinates of shale gas wells (black dots) are from Drillinginfo (2017). (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Table 1
Summary statistics of all shale gas plays.

Reservoir	Well Number	IPOD	IPGD	MD	Yield	Perforation
	2000–2016	bbl/d	mcf/d	ft	bbl/MMcf	ft
Barnett	18820	13	1439	10080	25	2477
Eagle Ford	5344	248	2748	15717	127	5245
Fayetteville	5669	0	2130	8653	0	–
Haynesville	3956	2	7707	16623	2	4307
Marcellus	10551	11	3780	11289	5	4002
Utica	1585	104	4376	15547	66	6498
Wolfcamp	1527	115	1884	11391	94	2336
Woodford	3058	30	2547	13666	24	3842
Total	50510	42	2808	11710	31	3506

Notes: Well number: number of wells drilled between January 2000 and June 2016; IPOD: peak daily condensate production; IPGD: peak daily gas production; MD: measured depth; Yield: barrel oil production per million cubic feet of natural gas; Perforation: the length of wellbore perforated. bbl/d: barrels per day; mcf/d: thousand cubic feet per day; ft: feet; bbl/MMcf: barrels per million cubic feet.
Source: Calculations based on well-level data from Drillinginfo (2017).

productivity profile (Fig. 3B) shows that the condensate productivity of most plays has increased since 2009, while some plays remain constantly low. The production of natural gas and natural gas condensate is correlated for a specific play. The coefficient characterizing this relationship is called yield, which is the ratio of condensate and natural gas produced simultaneously, usually measured in barrels per million cubic feet (bbl/MMcf). The yield value varies among different plays or structures. The average yield increases from approximately 10 bbl/MMcf in 2009 to 60 bbl/MMcf in 2013 (Fig. 2C), which indicates that the drilling targets shift from dry gas structures into wet ones. A facet plot of individual play shows that Fayetteville, Haynesville, and Marcellus are dry gas plays (Fig. 4). Barnett, Wolfcamp, and Woodford have both dry and wet gas windows. Eagle Ford and Utica have short development histories and most wells drill into wet gas structures.

The distinct features of well productivity, yield, and well number before and after the transition period of 2008–2010 show that the factors and mechanisms influencing the drilling of shale gas may change over time and econometric analysis needs to take this into account.

2.2. Oil and gas price data

The US natural gas market is under a gas-on-gas pricing system, which indexes the natural gas price to a competitively determined spot price (EIA, 2014a). The spot price at Henry Hub, Louisiana, is the benchmark for US natural gas. Henry Hub is also used as the delivery point by the New York Mercantile Exchange (NYMEX) for its natural gas futures contracts. Despite the popularity of Henry Hub price, natural gas prices are not uniform across the country. The price at local hubs is more close to the well-head price received by producers. In order to better characterize the drilling behavior in each shale gas play, it is better to use the local gas price specific to each play rather than using the Henry Hub price. In our analysis, we use the shale price indices (SPI) from Natural Gas Intelligence (NGI, a company providing natural gas price data) to represent the delivered-to-pipeline spot prices of each shale play from 2010 to 2016. Because the SPI is from September 2010 on, we compute synthetic shale gas prices for the period from 2000 to 2010 using selected conventional gas prices that are used for shale gas price indices estimation by NGI. We take an average of the daily gas prices in a calendar month to upgrade the daily price data into monthly data. We then convert it to real price data in US dollars as of January 2016 using the producer price index (PPI) from the US Bureau of Labor Statistics (BLS). Real monthly data is further upgraded to quarterly price. By comparing the synthetic prices with the NGI-reported SPI, we find a good fit for most plays, except the later period of Utica and Marcellus (Fig. 5). However, since companies take the conventional gas price at the time being as a reference to form price expectations, we believe that using the synthetic price of conventional natural gas is appropriate when SPI is absent. Fig. 6A plots the price of all eight plays, which shows significant differences among them. The actual difference varies over time; therefore, it would be arbitrary to use a constant percentage differential from the Henry Hub price as a substitute.

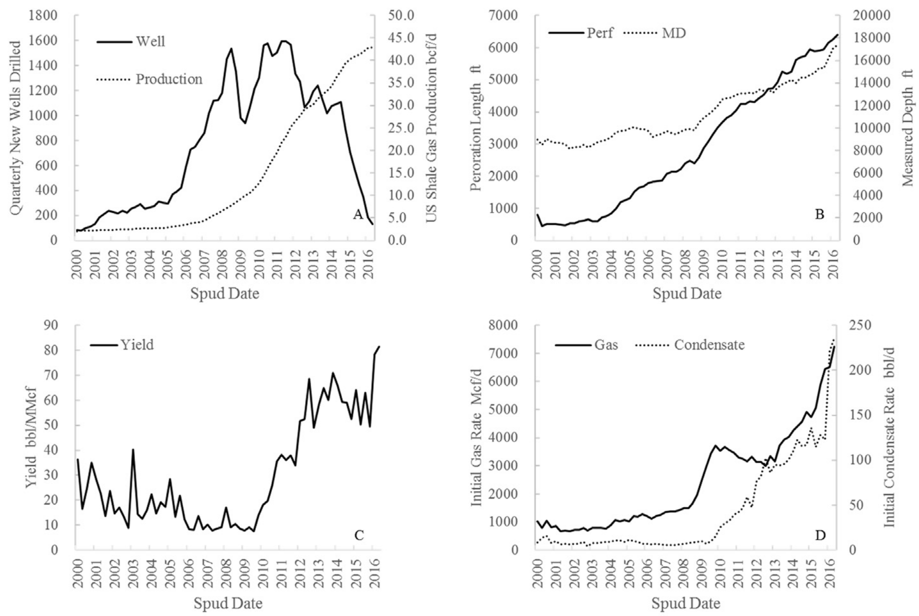

Fig. 2. Quarterly profile of new wells drilled and total shale gas production in the United States (A), the average of perforated interval and measured depth (B), the average yield (C), and the average of initial natural gas and condensate productivity (D).

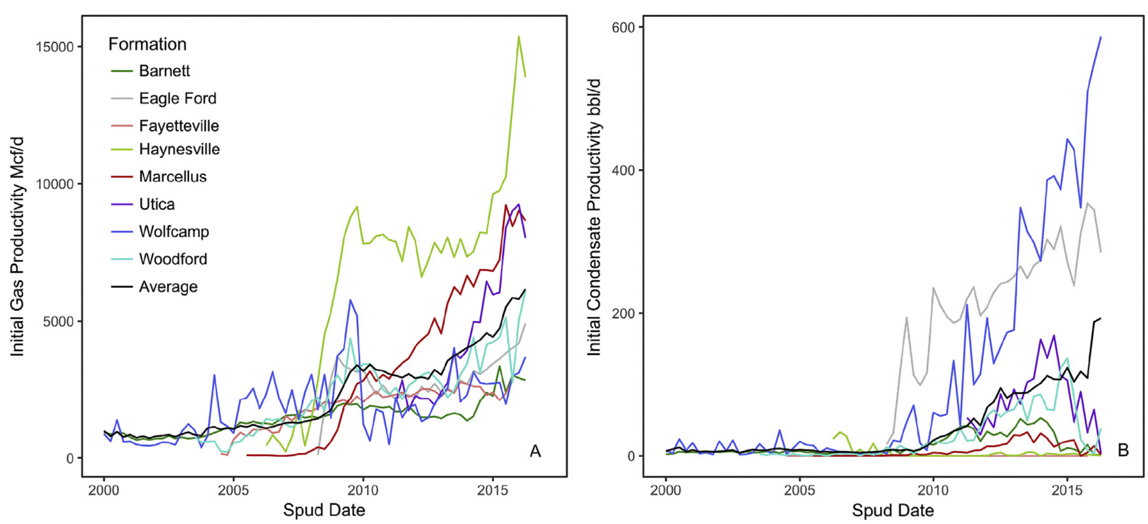

Fig. 3. Quarterly profiles of the average initial natural gas productivity (A) and average condensate productivity (B) for each shale gas play (legend is the same for both plots).

The price of natural gas condensate depends on the exact composition of the products. The price of pure condensate end products in Mont Belvieu (a major natural gas condensate fractionation and distributary hub in the Gulf Coast area) falls between the price of natural gas and crude oil, with the lighter component correlating more with gas price and the heavier product correlating more with oil price (EIA, 2014c). Because the exact composition and gas condensate prices are not available for each shale play, we use the condensate price from Enterprise Products Partners L.P. (a company with business in oil and gas pipelines, natural gas processing, and hydrocarbon liquid import/export in the United States) and EIA's first purchase price of crude oil in different states to calculate substitutes for the condensate price. Fig. 6B plots the calculated price for the eight shale gas plays, which show similar trends, but with different values.

2.3. Production data

We use play-level dry shale gas production data (EIA, 2018a) to analyze the influence of oil and gas prices on shale gas production. This data includes gas production from legacy wells and new wells. It also includes the associated gas production from tight oil wells drilled in the same shale play. Although it would be ideal to distinguish the gas production from different sources, the available production data does not support such analysis. However, since the dry shale gas production is the marketed gas supply from shale plays, it is meaningful to examine the price responsiveness of it. We take the average of the original monthly data to obtain quarterly production data.

The total shale gas production increases from 1.3 bcf/d (billion cubic feet per day) in early 2000 to 40.8 bcf/d in mid-2016 (Fig. 2A). The production is generally low before 2008 and increases rapidly

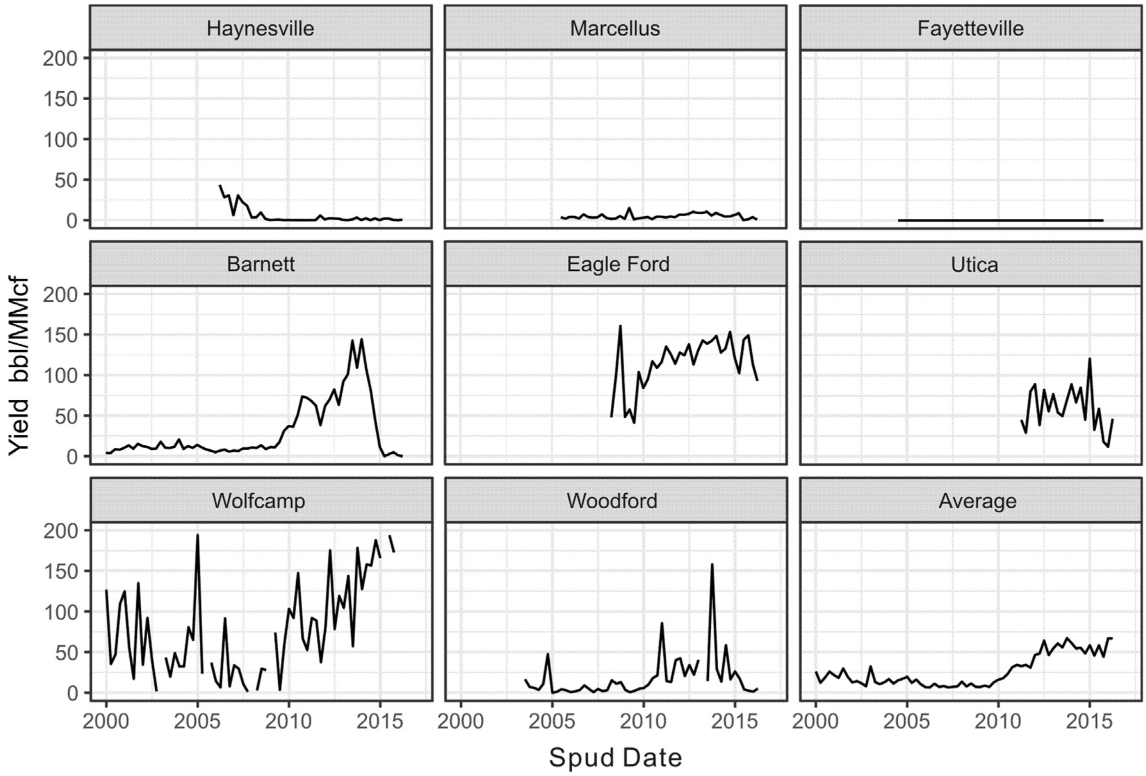

Fig. 4. Facet plot of the average yield value of each shale gas play.

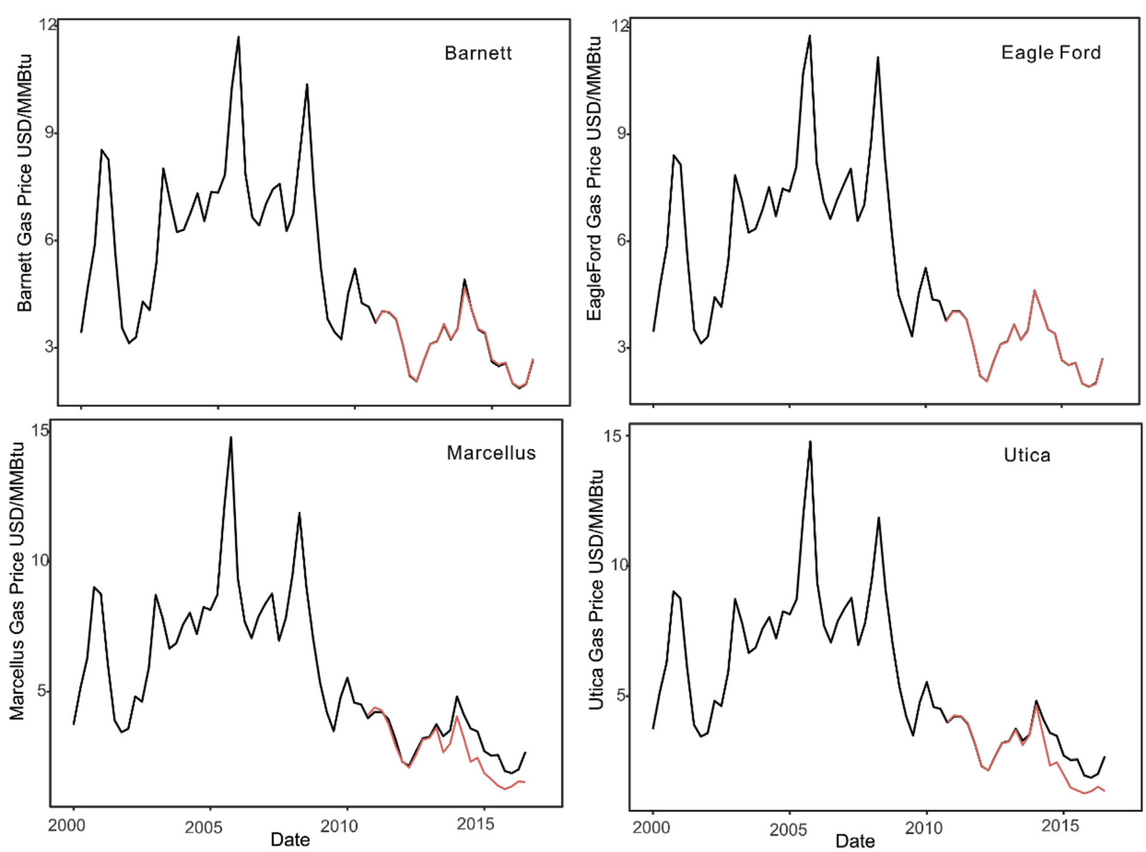

Fig. 5. Synthetic natural gas prices (black) and NGI-reported SPI (red) for selected shale gas plays. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

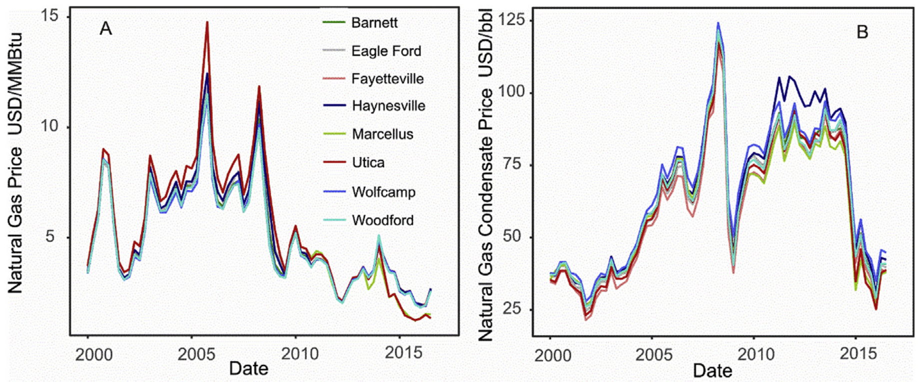

Fig. 6. Quarterly profiles of the natural gas price (A), and gas condensate price (B) for each shale gas play. Legend is the same for both plots.

after 2009. An inflection point occurs around 2009 (Fig. 2A). The production history of individual play varies significantly. Barnett contributes to most of the shale gas increase before 2009 (Fig. 7). Its production had been the highest until 2010, when surpassed by Haynesville. The production of Marcellus is close to zero before 2009, but increases to 16 bcf/d in 2016. It accounts for 40% of the total shale gas production in 2016.

2.4. Other data

We use the upstream cost indices for shale gas plays provided by iHS (a company providing intelligence services for the petroleum industry) in our analysis. This data is a quarterly cost index evaluating the trends of drilling, completion, facilities, and operation cost of different shale plays. We convert their nominal index into real terms using the quarterly PPI value published by the Organisation for Economic Co-operation and Development (OECD) to the 2016Q1 base. Fig. 8A plots the real cost indices of the eight shale gas plays, which show a generally increasing trend before 2009 and a decreasing trend after 2009.

We use the house price index (HPI) data from the Federal Housing Finance Agency (2018) to control the effect of the economic crisis on shale gas development. The index tracks the movement of single-family house prices since 1991. We convert the seasonally adjusted nominal data into real price index as of 2016Q1 using the Consumer Price Index (CPI) data from the Federal Reserve Bank (FRED, 2018). Since the HPI data is reported by states, we calculate weighted average HPI for each play using the number of wells drilled in each state as the weight. Fig. 8B plots the computed quarterly HPI profiles for shale gas plays. The plots show that 1) the influence of economic crisis varies geographically; 2) the general trends are similar in different plays; and 3) the house prices in different plays are substantially different.

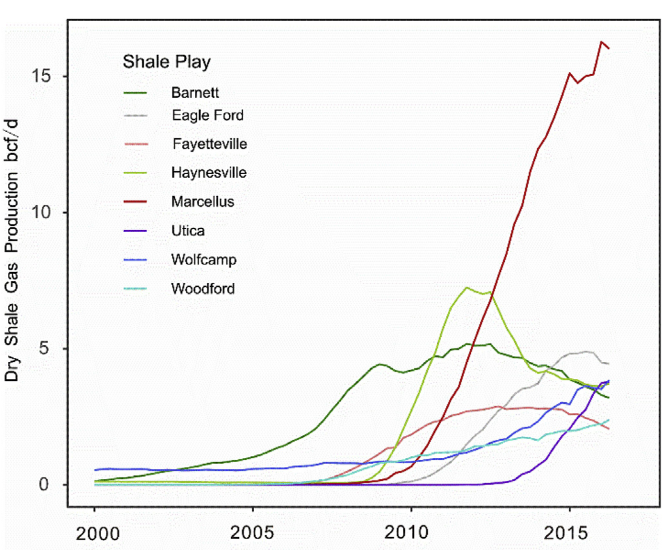

Fig. 7. Dry shale gas production by play. Data source EIA (2018).

3. Methods

We use an econometric method to quantitatively estimate the influence of energy prices on shale gas supply. Our model builds on the method of Newell et al. (2019) and other empirical studies on conventional oil and gas supply (e.g., Cleveland and Kaufmann, 1991; Fisher, 1964).

We use the quarterly number of new wells drilled and the dry shale gas production in each play as the dependent variables. The number of new wells drilled is a direct measure of the drilling activity. It is fully responsive to human behavior and is closely related to natural gas production. The price responsiveness of the drilling activity is helpful to evaluate the influence of oil and gas prices on the upstream activities. It is also useful to forecast the effect of energy prices on natural gas production. Therefore, using the number of new wells as the dependent variable has been popular in empirical studies (e.g., Hausman and Kellogg, 2016; Newell et al., 2019).

The dry shale gas production is a direct measure of the actual shale gas supply. However, due to its complexity, the relation between shale gas production and energy prices is not stable over time and difficult to model. Here we include it as a comparative study to show the reason for analyzing drilling activity rather than production directly.

We use three lags of natural gas and condensate prices as independent variables. The price should be a company's expected future price at the time of decision making. A survey of the literature shows that there are several methods used to estimate expected prices, such as the average of past prices (Macavoy and Pindyck, 1973), spot price (Fisher, 1964), random walk price (Walls, 1994), and futures price (Newell et al., 2019). Nixon and Smith (2012) compare several expected prices with the realized data and concluded that none of them is better than the others. In this paper, we use the spot price at the time of decision as the proxy for the expected price. The number of lags is selected to reflect the industry normal. Following a decision, companies need to file for permits, contract rigs, build roads and well pads, etc. before

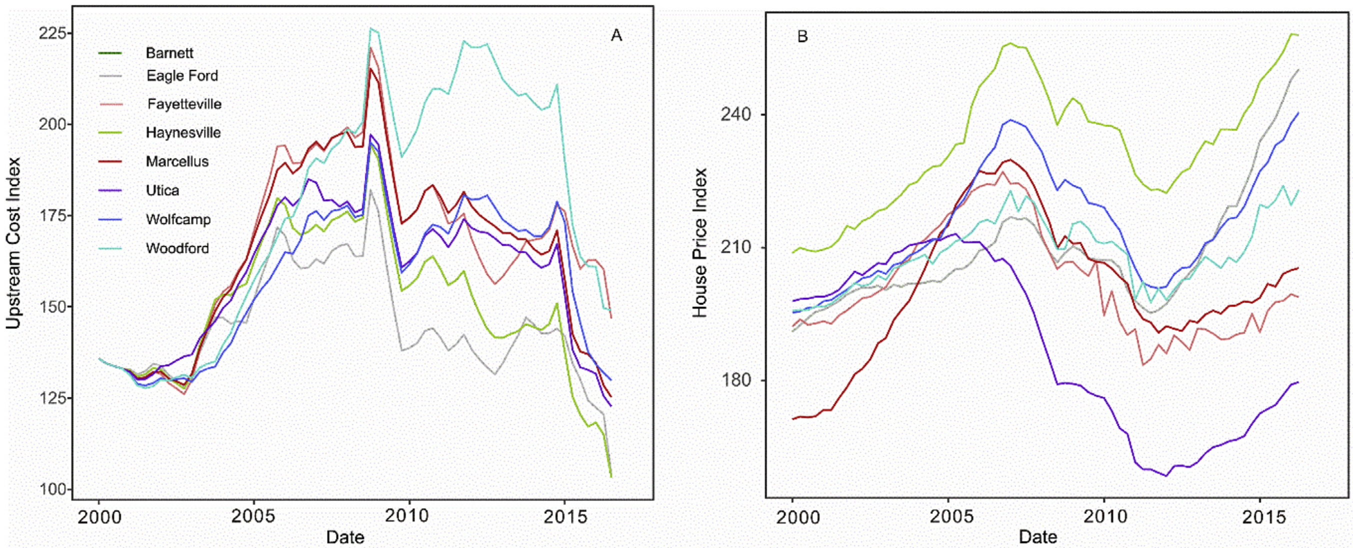

Fig. 8. Quarterly profiles of the upstream cost index (A), and house price index (B) for each shale gas play. Legend is the same for both plots.

spudding a well, all of which takes several months to complete. In addition, the drilling plan of different companies varies between quarterly, semi-annually, and annually. To cover these variations, we assume that the wells drilled at quarter t are decided at quarter t-1, t-2, and t-3. We also assume that companies can adjust their drilling plans within one year's time.

We include the upstream cost and the house price index data as independent variables to control the influence of cost and economic crisis on shale gas supply.

Unit root tests using the CIPS method of Pesaran (2007) indicate that the level values of the drilling data, the gas prices, and the condensate prices are nonstationary, whereas the first differences of these data are stationary (Table 2). A cointegration test using the VAR method of Johansen (1991) indicates that the number of wells drilled is not cointegrated with energy prices. In addition, price and well number are not in the same units; therefore, we transfer the level data into percent changes to achieve stationarity and calculate price elasticity. To incorporate the individual characteristics of each reservoir, we estimate a fixed effect model of the following form:

$$y_{it} = \beta_i + \sum_{m=1}^{3}\left[\beta_{1,m}p^{g}_{i,t-m} + \beta_{2,m}p^{o}_{i,t-m}\right] + \gamma' X_{i,t-1} + \varepsilon_{it} \quad (1)$$

where the subscript i refers to reservoir i, t refers to time, m equals to 1, 2, 3, and.

y_{it} is the percent change of new wells drilled or dry shale gas production in reservoir i during period t;

$p^{g}_{i,t-m}$ is the percent change of shale gas price in reservoir i during period t-m;

$p^{o}_{i,t-m}$ is the percent change of natural gas condensate price;

$X_{i,t-1}$ is the percent change of control variables, such as the upstream cost index and the house price index;

$\varepsilon_{i,t}$ is the random error.

Table 2
Unit root test results.

	Lag 2	Lag 3	Lag 4
Level			
Well	−1.6	−1.4	−1.3
Gas Price	−2.4	−2.3	−2.2
Condensate Price	−1.8	−2.0	−1.9
First Difference			
Well	−3.4***	−2.9***	−2.5**
Gas Price	−5.6***	−3.3***	−2.7***
Condensate Price	−3.4***	−3.2***	−2.4**

Notes: The CIPS method of Pesaran (2007) is used. The lag number is the order used for Dickey-Fuller augmentation. *** Significant at the 1 percent level. ** Significant at the 5 percent level.

We count the number of new wells drilled in each quarter according to the spud date, from 2000Q1 to 2016Q2 for each play. We also compute the corresponding average initial gas and condensate production rates, measured depth, perforated interval, and second-month yield. Analysis of the quarterly profile of productivity, yield, and drilling number indicates a structural break around 2009. The timing of the breakpoint is similar to the result of Oglend et al. (2015), who identify a structural break in the oil and gas price relationship at the end of 2008. Therefore, we divide the shale gas development history into two phases. The first phase is from 2000 to 2008, when the hydraulic fracking technology and horizontal drilling is integrated and experimented in extracting shale gas. At this stage, the well-level productivity is still low (Fig. 2D) and the development is confined to the Barnett play (Fig. 9). We name this phase the pilot stage. The second phase is from 2009 to 2016, when the drilling and completion technology is advanced. The well-level productivity increases significantly (Fig. 2D) and the shale gas development expands to more plays (Fig. 9). We name this phase the expansion stage. Regression modeling is conducted for the two phases respectively. We test different time divisions for the exact breakpoint and also divide the shale gas plays into a wet group and a dry group according to the condensate content.

4. Results

We report the regression results as follows: section 4.1 is the results for shale gas drilling responsiveness to oil and gas prices, section 4.2 is the results for shale gas production responsiveness to oil and gas prices, and section 4.3 is the robustness and sensitivity check of the results.

4.1. Drilling responsiveness

Table 3 presents the regression results based on all eight shale plays. Cases (1) to (3) include both cost and housing price indices as

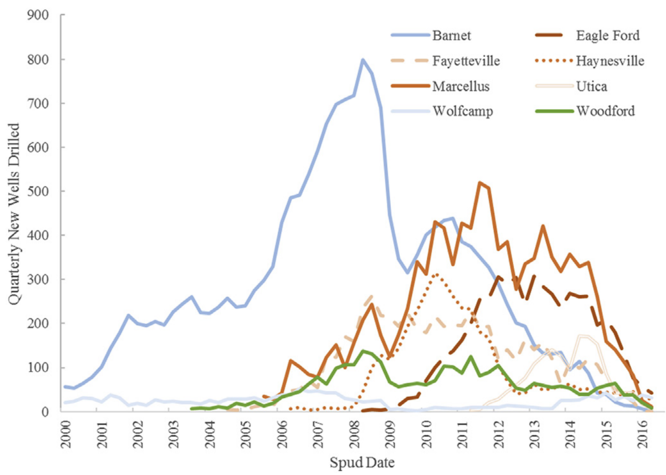

Fig. 9. The number of new wells drilled in each quarter.

control variables and correspond to the periods of I (2000Q1-2008Q3), II (2009Q1-2016Q2), and "Full" (2000Q1-2016Q2). Cases (1) and (2) are our preferred base scenarios. Cases (4) and (5) are designed to examine the effect of control variables. Only the result of period II is shown for illustration. Cases (6) to (8) are designed to examine the effect of different time divisions for periods I* (2000Q1-2008Q2), II* (2008Q3-2016Q2), and II** (2010Q1-2016Q2). Coefficients of the three lags of each variable are added to get the long-run elasticity, following the method in Newell et al. (2019).

Regression results in the base case show that the long-run oil and gas price elasticities are insignificant in period I but significant in period II. The long-run gas price elasticity is 0.59 and the long-run oil price elasticity is 1.09 in period II (case 2). The full-time gas price elasticity is insignificant but the oil price elasticity is 0.62 (significant) in period II (case 3).

A key finding from the all-play regression is that the drilling activity responds more to oil price after 2009. Given the high average yield value in period II (Fig. 2C) and the different yield characteristics shown in Fig. 3, we divide the shale plays into two sub-groups: the dry gas group including Fayetteville, Haynesville, and Marcellus; and the wet gas group including Barnett, Wolfcamp, Woodford, Eagle Ford, and Utica.

Regression results in Table 4 show that the drilling activities in the dry shale gas group respond only to natural gas price. The oil price elasticity is insignificant in all three sampling periods (cases 9, 10, and 11). The gas price elasticity is insignificant in period I (case 9), but significant with an elasticity of 1.05 in period II (case 10). On the other hand, drilling activities in the wet gas group respond to oil price only. The oil price elasticity is insignificant in period I (case 12) and is 1.93 (significant; case 13) in period II. The gas price elasticity is insignificant in all three periods (case 12, 13, and 14).

The regression results imply that well drilling is influenced by the profit from its products. The dry gas plays can only produce lean natural gas; therefore, they respond little to oil price and more to gas price. The wet gas plays produce both natural gas and gas condensate in period II. The drilling in wet gas plays should respond to both oil and gas prices. However, because the profit from gas condensate is higher than that from natural gas, the influence of oil price is higher. In the all-play regression, the estimated oil and gas price elasticity lies in between the two end members. The general higher oil price elasticity than gas price elasticity (1.09 vs 0.59 in case 2) reflects the importance of gas condensate production in supporting shale gas drilling at the low natural gas price market after 2009. Because operators own different assets and have different decision-making mechanism, their responses to

Table 3
Drilling responsiveness using samples from all eight shale plays.

Dependents	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	I	II	Full	II	II	I*	II*	II**
lag(GasPrice, 1)	−0.04	0.24	0.14	0.22	0.22	−0.05	0.18	0.17
	(0.27)	(0.15)	(0.14)	(0.15)	(0.15)	(0.28)	(0.16)	(0.16)
lag(GasPrice, 2)	0.52	0.28**	0.32**	0.29**	0.29**	0.62**	0.18	0.26
	(0.27)	(0.14)	(0.13)	(0.14)	(0.14)	(0.29)	(0.15)	(0.15)
lag(GasPrice, 3)	−0.06	0.06	−0.17	0.03	0.01	−0.12	−0.05	−0.01
	(0.27)	(0.15)	(0.14)	(0.15)	(0.14)	(0.28)	(0.16)	(0.17)
lag(OilPrice, 1)	−0.59	0.44**	0.45***	0.51***	0.53***	−0.43	0.34	0.49**
	(0.49)	(0.21)	(0.17)	(0.19)	(0.18)	(0.52)	(0.18)	(0.21)
lag(OilPrice, 2)	0.11	0.44**	0.02	0.49***	0.48***	0	−0.03	0.46**
	(0.48)	(0.17)	(0.16)	(0.17)	(0.16)	(0.50)	(0.16)	(0.22)
lag(OilPrice, 3)	0.16	0.21	0.15	0.22	0.21	0.39	0.11	−0.02
	(0.47)	(0.17)	(0.17)	(0.17)	(0.16)	(0.51)	(0.17)	(0.23)
lag(Cost, 1)	2.61	−0.41	1.06	−0.24		1.43	−0.46	0.04
	(2.80)	(0.87)	(0.80)	(0.86)		(3.01)	(0.94)	(1.07)
lag(House, 1)	−5.22	−1.97	−2.6			−5.92	−4.16	−1.98
	(5.82)	(2.01)	(2.02)			(6.02)	(2.11)	(2.16)
Sum.GasPrice	0.42	0.59**	0.29	0.55**	0.53**	0.45	0.31	0.41
	(0.47)	(0.26)	(0.24)	(0.25)	(0.25)	(0.49)	(0.27)	(0.28)
Sum.OilPrice	−0.32	1.09***	0.62**	1.22***	1.22***	−0.03	0.42	0.93**
	(0.83)	(0.32)	(0.29)	(0.31)	(0.30)	(0.88)	(0.30)	(0.38)
F	1.23	4.83	4.22	5.39	6.3	1.3	2.49	2.99
p-value	0.29	0	0	0	0	0.26	0.01	0
R-Squared	0.09	0.17	0.09	0.16	0.16	0.1	0.09	0.13
Adj-R^2	−0.03	0.1	0.05	0.1	0.11	−0.03	0.02	0.05
N	111	207	345	207	207	105	221	179

Notes: Sum.GasPrice, etc. are the total of coefficients of three lagged variables; Standard error in parentheses. I: 2000Q1-2008Q3; II: 2009Q1-2016Q2; Full: 2000Q1-2016Q2; I*: 2000Q1-2008Q2; II*: 2008Q3-2016Q2; II**: 2010Q1-2016Q2.
*** Significant at the 1 percent level.
** Significant at the 5 percent level.

Table 4
Drilling responsiveness for the dry and wet shale gas plays.

Dependents	Dry Gas Group			Wet Gas Group		
	(9)	(10)	(11)	(12)	(13)	(14)
	I	II	Full	I	II	Full
lag(GasPrice, 1)	−0.23	0.55***	0.39	0.02	0.03	0.02
	(0.98)	(0.18)	(0.28)	(0.20)	(0.21)	(0.16)
lag(GasPrice, 2)	1.35	0.25	0.51	0.26	0.29	0.23
	(0.97)	(0.17)	(0.26)	(0.20)	(0.19)	(0.15)
lag(GasPrice, 3)	1.35	0.25	−0.22	−0.03	−0.04	−0.17
	(1.18)	(0.20)	(0.29)	(0.19)	(0.21)	(0.15)
lag(OilPrice, 1)	−3.25	0.05	0.47	−0.31	0.70**	0.45**
	(2.01)	(0.24)	(0.32)	(0.38)	(0.31)	(0.20)
lag(OilPrice, 2)	1.39	0.39	0.1	0.15	0.54**	0.01
	(1.84)	(0.21)	(0.29)	(0.37)	(0.25)	(0.19)
lag(OilPrice, 3)	1.14	−0.47**	−0.25	−0.42	0.69***	0.37
	(1.43)	(0.20)	(0.32)	(0.37)	(0.24)	(0.20)
lag(Cost, 1)	8.75	−0.46	3.04	0.55	−0.6	0
	(9.44)	(1.14)	(1.62)	(2.11)	(1.18)	(0.89)
lag(House, 1)	−18.55	−2.44	−1.41	−2.95	−0.99	−3.21
	(18.48)	(2.16)	(3.39)	(4.70)	(3.22)	(2.55)
Sum.GasPrice	2.47	1.05***	0.68	0.25	0.28	0.09
	(1.81)	(0.32)	(0.48)	(0.35)	(0.36)	(0.27)
Sum.OilPrice	−0.72	−0.04	0.32	−0.58	1.93***	0.84**
	(3.07)	(0.38)	(0.54)	(0.64)	(0.47)	(0.34)
F	1.51	3.23	2.12	0.51	4.07	2.84
p-value	0.22	0	0.04	0.84	0	0.01
R-Squared	0.38	0.27	0.13	0.06	0.22	0.1
Adj-R^2	0.06	0.17	0.05	−0.08	0.14	0.05
N	31	81	124	80	126	221

Notes: Sum.GasPrice, etc. are the total of coefficients of three lagged variables; Standard error in parentheses. I: 2000Q1-2008Q3; II: 2009Q1-2016Q2; Full: 2000Q1-2016Q2.
*** Significant at the 1 percent level. ** Significant at the 5 percent level.

individual lagged oil and gas prices are different. Future analysis of companies' asset and structure can help to explain the detailed underlying mechanism.

Our full-period oil price elasticity in case (3) (i.e., 0.62) is very close to the result of Newell et al. (2019), which is 0.59 for unconventional wells in the period of 2005–2015 (although not significant). This confirms that ignoring the structural change around 2009 leads to commingled elasticity values; such estimation overlooks important market changes during the development of shale gas.

4.2. Production responisvenss

The influence of oil and gas prices on shale gas production tells a different story. Table 5 shows the regression results using model (1) and using the dry shale gas production data as the dependent variable. Scenario settings are the same as that in Table 3. The results show that shale gas production is not responsive to oil and gas prices in period I (case 1), which is similar to the responsiveness of shale gas drilling in the same period. However, the gas price elasticity is insignificant in period II (−0.03), which is different from the 0.59 value estimated for drilling responsiveness in Table 3. The oil price elasticity is significant 0.76 (case 2), lower than the 1.09 value in Table 3.

Theoretically, the relation between shale gas production and energy prices is hard to model. Shale gas production is from two sources: production from legacy wells and production from newly drilled wells. The production from legacy wells is found to be unresponsive to economic incentives (e.g., Anderson et al., 2018; Mason and Roberts, 2018). The reason behind is the relatively lower operating cost (OPEX) compared to the value of the product. The average operating cost for a Barnett gas well is about 0.5–0.7 USD/Mcf (US dollars per thousand cubic feet; Gülen et al., 2013) whereas the historically low gas price is 1.6 USD/Mcf. Once a well begins production, its profit is usually positive as long as productivity is above the economic limit. Operators usually do not base their decisions to shut in existing wells on the volatility of gas prices. Therefore, the price signal can only influence the gas supply through the drilling of new wells. What is more, the productivity of each well is controlled by many factors: local geology and engineering properties, drilling and completion technology, and other uncontrollable factors. The influence of economic incentives on well drilling is diluted when passed to the total production. This is why the production responsiveness to oil and gas prices is lower than that of the drilling responsiveness.

4.3. Robustness and sensitivity

The estimated price elasticities might be sensitive to model settings. We test several model choices in our analysis. The first test is the selection of time periods. Data analysis in section 2.1 indicates that the structural breakpoint is in 2008–2009. We use each quarter in 2008 and 2009 as the breakpoint and report representative regression results in Table 3. Trials of different sample divisions show that the third quarter of 2008 (i.e., the time of economic crisis) is a breakpoint, which would greatly influence the estimation of price elasticity if included in period II. Case (7) includes the point of 2008Q3 in period II* and the estimated oil and gas price elasticities become insignificant. Moving the endpoints within each period does not change the results substantially as shown in case (6). We also test sample periods 2000Q1-2007Q4 and 2001Q1-2008Q3, which yield similar results. The result in case (8) shows that the oil price elasticity would be lower (0.93 vs 1.09), but not significantly different if the samples in 2009 are excluded.

We test models with different control variables. Case (2) in Table 3 is our base model, which include both cost and house price

Table 5
Production responsiveness using samples from all eight shale plays.

Dependents	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	I	II	Full	II	II	I*	II*	II**
lag(GasPrice, 1)	−0.17	−0.06	-0.18^{**}	−0.07	−0.06	−0.17	−0.1	0.02
	(0.10)	(0.07)	(0.07)	(0.07)	(0.07)	(0.09)	(0.08)	(0.06)
lag(GasPrice, 2)	0.01	0.01	−0.05	0.01	−0.07	0.03	−0.06	−0.07
	(0.09)	(0.06)	(0.07)	(0.06)	(0.07)	(0.10)	(0.07)	(0.06)
lag(GasPrice, 3)	0.06	0.03	0.01	0.01	−0.13	0.04	−0.06	0.07
	(0.09)	(0.07)	(0.07)	(0.07)	(0.08)	(0.09)	(0.08)	(0.07)
lag(OilPrice, 1)	0.13	0.17	0.17	0.21^{**}	0.47	0.18	0.19^{**}	0.13
	(0.17)	(0.09)	(0.09)	(0.09)	(0.08)	(0.17)	(0.09)	(0.08)
lag(OilPrice, 2)	−0.02	0.39	0.15	0.42	0.33	−0.04	0.14	0.24^{***}
	(0.17)	(0.08)	(0.08)	(0.08)	(0.08)	(0.16)	(0.08)	(0.09)
lag(OilPrice, 3)	0.25	0.19^{**}	0.16	0.19^{**}	0.24^{***}	0.3	0.1	0.23^{**}
	(0.16)	(0.08)	(0.08)	(0.08)	(0.08)	(0.17)	(0.08)	(0.09)
lag(Cost, 1)	−1.49	−0.22	0.17	−0.14		−1.59	−0.07	−0.14
	(1.01)	(0.40)	(0.40)	(0.39)		(1.04)	(0.46)	(0.42)
lag(House, 1)	3.54	−0.97	−1.44			3.76	−1.6	−1.17
	(2.07)	(0.91)	(1.00)			(2.04)	(1.03)	(0.84)
Sum.GasPrice	−0.10	−0.03	−0.22	−0.05	-0.26^{**}	−0.11	−0.22	0.03
	(0.16)	(0.12)	(0.12)	(0.12)	(0.13)	(0.16)	(0.13)	(0.11)
Sum.OilPrice	0.36	0.76^{***}	0.47^{***}	0.82^{***}	1.04^{***}	0.44	0.43^{**}	0.59^{***}
	(0.29)	(0.15)	(0.14)	(0.14)	(0.14)	(0.30)	(0.15)	(0.15)
F	1.58	5.92	2.82	6.6	8.54	1.79	2.25	3.56
p-value	0.14	0	0	0	0	0.09	0.03	0
R-Squared	0.12	0.2	0.07	0.2	0.2	0.14	0.08	0.15
Adj-R2	0	0.14	0.02	0.14	0.15	0.01	0.01	0.07
N	106	205	335	205	213	100	217	177

Notes: Sum.GasPrice, etc. are the total of coefficients of three lagged variables; Standard error in parentheses. I: 2000Q1-2008Q3; II: 2009Q1-2016Q2; Full: 2000Q1-2016Q2; I*: 2000Q1-2008Q2; II*: 2008Q3-2016Q2; II**: 2010Q1-2016Q2.
*** Significant at the 1 percent level.
** Significant at the 5 percent level.

indices. Case (4) excludes the house price index, and case (5) excludes both indices. The results show that the oil price elasticity would be higher (1.22 vs 1.09) and the gas price elasticity would be lower (0.55 vs 0.59) if the economic crisis were not controlled. Case (5) indicates that the cost index has a slight effect on price elasticities.

5. Discussion

5.1. The lack of price responsiveness in the pilot stage

The regression results of all shale gas plays and sub-plays show that the drilling of shale gas wells is not sensitive to oil and natural gas prices in the pilot stage (2000–2008). One reason is that the well productivity in this period is too low to make a profit, even with an increase in natural gas prices. The average initial well productivity is less than 1000 Mcf/d before 2008, compared to the value of 7000 Mcf/d in 2016. The productivity of natural gas condensate also increases substantially, from less than 10 bbl/d in period I to more than 200 bbl/d in 2016. It is the advancement in technology that makes shale gas drilling profitable and responsive to market signals.

The second reason is that shale gas development for most plays is in the pilot stage; therefore, some wells are drilled to collect information and conduct experiment for future development. Making a direct or short-term profit is not the major purpose for these wells.

The third reason is that most shale gas development wells are drilled in the Barnett play at this stage (Fig. 9). The spot prices we are using may not be the selling price of operators in Barnett. Mitchell Energy had long-term contracts with the Natural Gas Pipeline Company of America (NGPL), which guaranteed higher natural gas prices than the market price (Wang and Krupnick, 2015). Before 2008, the total shale gas produced in the US was low (Fig. 2A) and the net natural gas imports had been increasing (EIA, 2018b). In the expectation of increasing natural gas demand, and given the confirmed natural gas resources from Barnett, it is possible that operators in Barnett could negotiate a better price with middle stream companies.

In summary, the major reason for the insignificance of oil and gas price elasticities in 2000–2008 is the low profit obtained from shale gas development. Factors influencing the profit – well productivity, energy prices, and cost – all contribute to the result. But the low productivity of shale gas wells at this stage should be the major reason.

5.2. The increase of price elasticity in the expansion stage

The significant increase in price elasticities across the structural break in 2008 is one of the key findings of this study. An explanation for the increase in elasticity is that the technology breakthrough in the early 2000s continues to advance and fosters shale gas development in other plays. After 2009, there is a major jump in productivity and a drop in development cost, which makes shale gas development profitable at market prices.

The higher oil price elasticity is another finding. The total production of shale gas accelerates since 2007 and, by 2009, it reaches five times the production in 2000 (Fig. 2A). Accordingly, the natural gas price drops significantly after 2009 and the oil-to-gas relative price increases (Fig. 10). Following this sign, investors start to drill high-liquid targets and the average yield increases. When the production of natural gas condensate and thereby profit from condensate increases, the drilling decisions become more responsive to oil price than to gas price.

The increase in oil-to-gas relative price is due to the different physical characteristics of oil and gas. Natural gas has to be

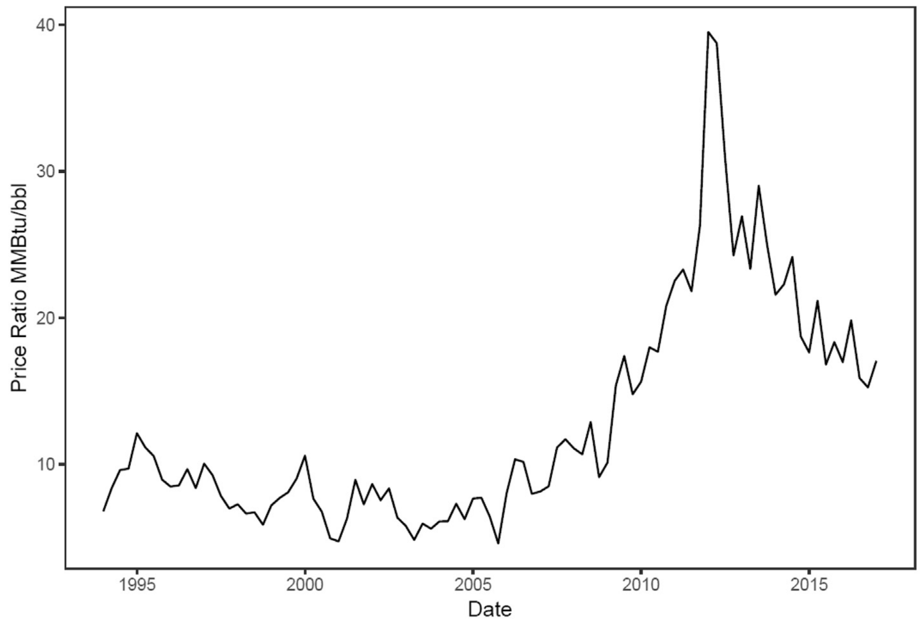

Fig. 10. Price ratio of the WTI oil price and the Henry Hub gas price.

compressed into liquid form to reach global markets, which requires special facilities and induce additional cost. Most of the increased shale gas remains in the United States (EIA, 2017) due to the lack of facilities. Because the demand for natural gas does not increase correspondingly, the natural gas price declines in the US market. Studies show that the prices of three natural gas markets (i.e., the North America, Europe, and Asia markets) were cointegrated before the shale gas revolution, but the US price diverged from the other two after 2009 (Aruga, 2016; Geng et al., 2016). In contrast, crude oil is easier to transport throughout the world and therefore forms one global market with a less geographically variable price. The decrease of the natural gas price in the United States causes an increase of the relative price of oil and gas from about 8 MMBtu/bbl (million British thermal unit per barrel) to as high as 40 MMBtu/bbl (Fig. 10). This market signal transmits quickly to the industry and the drilling targets shift from pure gas wells to liquid-rich wells. In the average new well yield plot (Fig. 2C), we see a clear trend of increase in the yield value after 2009. This is achieved by either increasing the liquid production of existing reservoirs, such as Barnett, or by developing new liquid-rich reservoirs, such as Eagle Ford. The reservoirs that increase yield values are those with both dry and wet gas producing windows over a wide geographic area. However, the pure dry gas reservoirs, such as Haynesville and Marcellus, cannot change their yield value much.

The increasing responsiveness of shale gas drilling activity to oil price is the result of the shale gas revolution itself. However, the relative prices of oil and gas are coming down after reaching their record high in 2012 (Fig. 10). We believe that the export of liquefied natural gas (LNG) and the increase of domestic demand will eventually stabilize the relative price and adjust the drilling elasticity.

5.3. *Significance of the study*

The estimated price elasticities are useful for predicting shale gas drilling activities and the impacts of shale gas development. Considine et al. (2010) estimate the relation between gas price and Marcellus drilling using log-level data and a simple econometric model. They forecast that over 1000 Marcellus wells will be drilled in 2010. But the actual number is over 1500 (Drillinginfo, 2017). The major purpose of their study is to forecast the economic impacts of shale gas drilling in Marcellus. And the drilling price elasticity is an essential parameter for their input-output model. However, since estimating price elasticity is not the major focus, they do not pay much attention to this step. Similar methods are adopted in other welfare or economic impacts analysis (e.g., Hausman and Kellogg, 2016). The elasticity used in these studies is questionable. Our study concentrates on the relation between drilling activities and energy prices. We conduct a comprehensive and detailed analysis to obtain accurate estimates, which can be used by other researchers in their study.

The results are useful for forecasting shale gas production. Energy prices influence shale gas production through the drilling of new wells. The estimated price elasticities can be used in large energy models to forecast shale gas supply. The computed supply elasticities in major energy models vary from 0.2 to more than 2.0 (EMF, 2013). Our study provides a reference for selecting the correct supply elasticity when modeling shale gas production.

Our study reveals an important fact that the response of shale gas drilling and shale gas production to energy prices is different. A decline in the number of drilling wells does not mean a decline in gas production. And lower natural gas prices do not necessarily lead to reduced production in the short run. Energy policies using the price tool should take this into consideration.

6. Conclusion

We analyze the well-level production data from all major producing shale gas plays in the United States and empirically estimate the price responsiveness of shale gas drilling and production using the econometric methods. The study identifies two development phases in the shale gas history and estimates the price elasticities before and after the major productivity shocks for the first time.

Our study is based on a near-full-sample well-level drilling data set, which allows detailed examination of drilling and production characteristics. We compute the data by individual shale gas play and generate panel data for econometric analysis. We conduct rigorous statistical tests to select the proper modeling strategy and transfer the level data into percent change values to reach stationarity. We use a fixed effect panel data modeling approach to estimate the price responsiveness of shale gas drilling and dry shale gas production.

Our main findings are that: 1) a structural break occurs at the end of 2008; 2) shale gas development experiences two phases, the pilot stage of 2000–2008 and the expansion stage of 2009–2016; 3) shale gas drilling activities are not responsive to oil and gas prices in the pilot stage and responsive in the expansion stage; and 4) the estimated gas price elasticity is 0.6 and oil price elasticity is 1.1 in the expansion stage for the drilling activity.

The estimated price elasticities are useful for forecasting shale gas supply and economic impacts related to shale gas drilling. The study contributes to the limited but growing literature of unconventional oil and gas supply. However, the paper has some main limitations. It can not model the influence of energy prices on the shale gas production from gas wells only, which is mainly due to the data limitation. Future studies should examine this problem based on well-level production data. The second limitation is that the influence of cost is not fully modeled, which is also due to data limitation. Future studies combining productivity, prices and cost data would be able to calculate the breakeven price and forecast the profitability of projects.

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Nomenclature

bbl/d	barrels per day
bbl/MMcf	barrels per million cubic feet
bcf/d	billion cubic feet per day
BLS	US Bureau of Labor Statistics
CPI	consumer price index
EIA	US Energy Information Administration
EUR	Estimated ultimate recovery
HPI	house price index
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
mcf/d	thousand cubic feet per day
MMBtu/bbl	million British thermal unit per barrel
NGI	Natural Gas Intelligence
NGPL	Natural Gas Pipeline Company of America
NYMEX	New York Mercantile Exchange
OECD	Organisation for Economic Co-operation and Development
PPI	producer price index
SPI	Shale price indices
US	United States
USD/Mcf	US dollars per thousand cubic feet
WTI	West Texas Intermediate

Declaration of interest

The authors declare no conflict of interest.

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