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The Shale Gas Boom in the US

Productivity Shocks and Price Responsiveness

Yan Chen and Jintao Xu

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The Shale Gas Boom in the US: Productivity Shocks and Price Responsiveness

Yan Chen and Jintao Xu

Abstract

The shale gas boom in the United States has been reforming the world energy market. The supply response of shale gas to productivity shocks and relative price changes, however, has not been adequately studied. We analyze the change in price responsiveness of shale gas drilling using well-level data covering all major producing reservoirs in the United States. Shale gas drilling becomes more responsive to energy prices after the major productivity shock in 2009. Oil price elasticity increases from -0.32 (statistically insignificant) in period I (2000Q1-2008Q3) to 1.09 (significant) in period II (2009Q1-2016Q2). Gas price elasticity increases from 0.42 (insignificant) in period I to 0.59 (significant) in period II. These changes in elasticities can be attributed to the increase in natural gas condensate production of new wells, the increase in gas productivity during the shale gas boom, and the difficulties in transporting gas to the global market.

Key Words: shale gas, elasticity, oil price, gas price

JEL Codes: Q32, Q41, D24

Contents

The Shale Gas Boom in the US: Productivity Shocks and Price Responsiveness

Yan Chen and Jintao Xu*

1. Introduction

Shale gas production has been changing the energy outlook of the United States and reshaping the world energy flow map since the beginning of this century. The rapid increase in local supply, combined with difficulty in transporting the product globally, has led to relatively low natural gas prices in the United States after 2009. Correspondingly, the number of newly drilled shale gas wells has declined from its peak in 2011 back to the level in 2000. Because production from a shale gas well declines quickly in the first few years, total production will not rise – or might even decline – if not enough new wells are drilled to replenish productivity. Therefore, the response of new well drilling to energy prices is important to forecast natural gas supply, which, in turn, is of significance to forecast gas prices and make decisions on facility construction and import/export policies. However, given the relatively short history of shale gas development and its fast development, the economic behavior of shale gas supply is still not well understood.

This paper focuses on the change in price responsiveness of shale gas drilling from 2000 to 2016 and examines the mechanism behind the phenomenon. We use well-level drilling data of the major producing shale gas plays in the United States and play-specific price data to build a panel econometric model, which allows us to control for individual effects for each play. Our analysis shows that shale gas drilling activities became more responsive to oil and natural gas prices after 2009, with the oil price elasticity changing from -0.32 (statistically insignificant) in period I (2000Q1-2008Q3) to 1.09 (significant) in period II (2009Q1-2016Q2) and the gas price elasticity changing

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from 0.42 (insignificant) in period I to 0.59 (significant) in period II. The changes in price responsiveness are due to productivity shocks caused by technology improvement and expansion in the United States. The increase in oil price elasticity is directly related to the increase in the yield (oil-to-gas ratio) of new shale gas wells drilled after 2009, which reflects the shifting of the industry focus to more liquid-rich wells. The reason behind this is the increase in the relative price of oil and gas caused by the rapid increase in natural gas supply from the shale gas boom and the limitations in transporting gas to the global market.

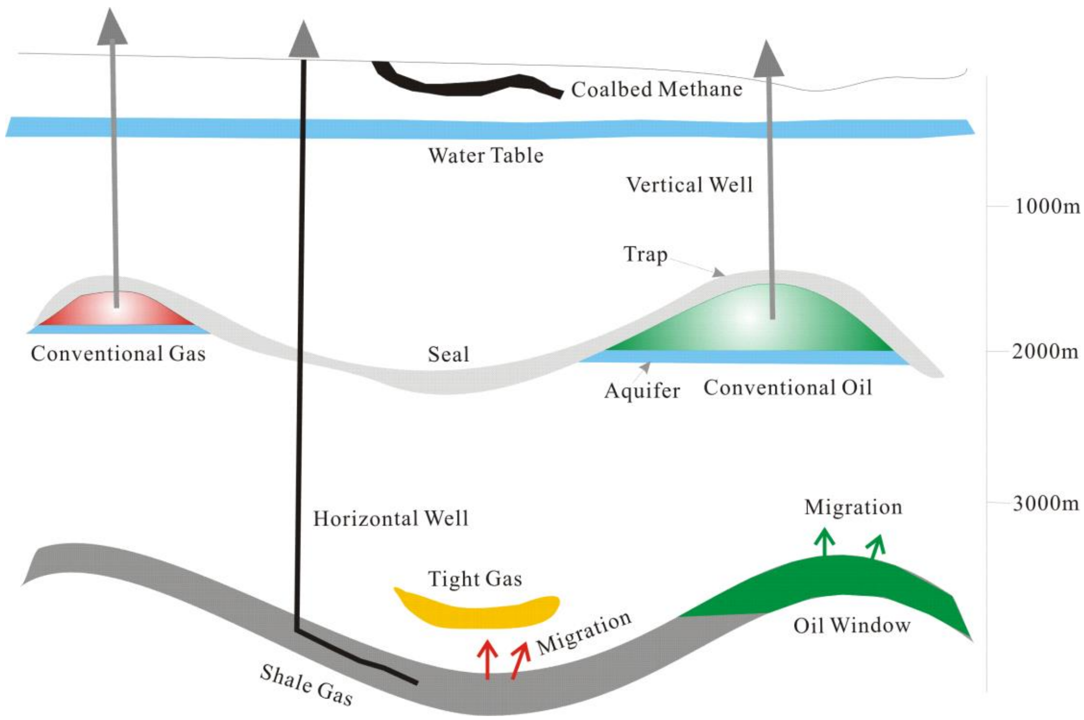
The remainder of the paper is structured as follows: Section 2 provides an introduction to industry fundamentals and a comprehensive literature review; Section 3 contains a description and summary statistics of data used in the paper; Section 4 describes our econometric estimation strategy with basic results; Section 5 discusses the estimation results and Section 6 concludes.

2. Industry Fundamentals and Literature Review

2.1 Conventional versus Unconventional

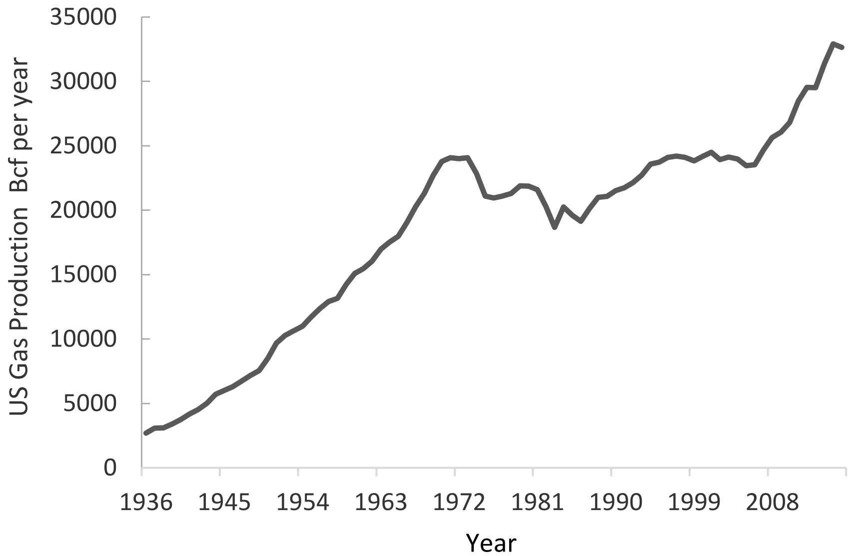
Conventional oil and gas are hydrocarbons that exist in porous and permeable rocks, which form discrete accumulations and are in pressure equilibrium with bounded aquifers (SPE et al., 2018; Figure 1). The high permeability allows petroleum to flow freely into wellbores without the need of special treatment, such as fracking or heating. In contrast, unconventional resources exist in continuous accumulations that are pervasive in a large area and not significantly influenced by aquifers (SPE et al., 2018). Examples of unconventional resources include coalbed methane, natural bitumen, natural gas hydrate, and shale gas. Due to the relatively higher cost of developing unconventional resources, most of the petroleum resources we have been using are extracted from conventional reservoirs. However, given the exhaustibility of fossil fuels, the amount of remaining conventional resources is declining. Therefore, when natural gas production in the United States (mostly from conventional reservoirs) peaked in the early 1970s, the US government started R&D programs to develop unconventional natural gas from tight sand, shale, and coal (NETL, 2007). After more than twenty years' experimentation, a technology breakthrough was finally achieved within the Barnett shale in the early 2000s, and has been quickly applied to other shale gas plays. US natural gas production has been increasing since 2008 and is higher than the first peak reached in the early 1970s (Figure 2).

Figure 1. Illustration of Typical Petroleum Reservoirs



Shale is a type of sedimentary rock with very low permeability. Shales that are rich in organic matter become the source rock for generating hydrocarbons when they are buried during the diagenesis process. When the pressure within a rock increases due to the formation of oil and gas, part of the generated petroleum moves out of the source rock (the shale), migrates into a porous rock, and accumulates in a structure (i.e., a geometrical form to trap petroleum; Figure 1) to form a conventional reservoir. Because of very low permeability, the expelled petroleum is only a small part of what has been generated, and there is still considerable oil and gas remaining in the source rock, which could not be extracted economically until the application of horizontal well fracking technology. The new technology of developing shale gas has substantially increased the amount of economically and technically recoverable natural gas in the world.

Figure 2. Natural Gas Production in the United States from 1936 to 2016

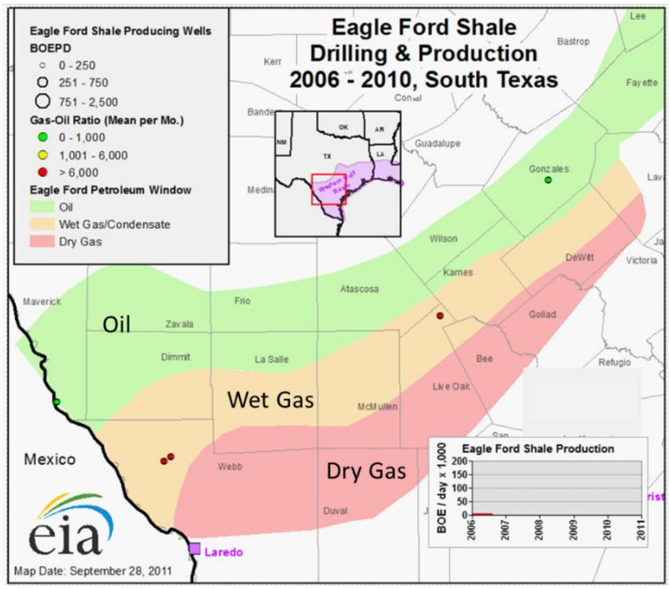


2.2 Maturity of Petroleum

When the bodies of living things are buried with sediments, which compact to form black shales during the diagenesis process, the rock temperature increases with the buried depth, and the organic matter cracks to form hydrocarbons. This process is the maturity of petroleum, which is measured using the vitrinite reflectance value (Ro%). With increasing Ro, the density of hydrocarbon generated is declining. Therefore, we have heavy oil, light oil, wet gas, and dry gas in sequence with increasing maturity (Hyne, 2012, p151; Dow, 1977). Wet gas reservoirs contain short-chain hydrocarbons that are gas phase under reservoir pressure and temperature conditions but liquid phase at surface conditions (Hyne, 2012, p11; SPE et al., 2018). The liquid produced from gas reservoirs is gas condensate (or simply condensate). Natural gas that lacks condensate is dry gas (Hyne, 2012, p12). The gas generating window is about 100 ~ 220 ℃ (Pepper & Corvi, 1995). At higher temperature, organic matter is cracked to form graphite carbon.

A shale play usually covers a wide geographic region, and due to different burying depth, it can have different maturity (Figure 1). The Eagle Ford play is an example showing a spectrum of gas, wet gas and oil windows (Figure 3). The Rail Road Commission of Texas classifies wells as either oil or gas (RRC, 2018), and a gas well is defined as a well producing from non-associated gas reservoirs and with the gas-to-oil ratio (GOR) greater than 100,000 scf/bbl (RRC, 2013). Therefore, gas wells include both dry gas and wet gas wells by classification. The amount of gas condensate produced depends on the reservoir GOR, which varies with time and location.

Figure 3. Distribution of Petroleum Windows in the Eagle Ford Shale Play



2.3 Literature Review

A large number of studies have (empirically) studied conventional oil and gas supply since 1964, when Fisher (1964) used econometric methods to analyze the price elasticity of newly discovered oil reserves. His "drilling-success rate-discovery size" model became a standard way of studying reserve elasticities and has been modified by adding or re-defining variables in later studies (e.g., Erickson & Spann, 1971; Pindyck, 1974; Eyssell, 1978). Khazzoom (1971) simplifies the Fisher-type model by analyzing the relationship between price and reserve directly instead of using three sub-models. Another type of model assumes a certain stochastic distribution of the exploration process and integrates economic factors with geological processes (e.g., Uhler, 1976; Cleveland & Kaufmann, 1991; Walls, 1994). The estimated reserve elasticities vary from very inelastic to very elastic, with the own-price elasticity of oil reserves ranging from 0.03 to 4.2 (e.g., Fisher, 1964; Erickson & Spann, 1971; Cox & Wright, 1976) and gas reserves from 0.69 to 2.4 (e.g., Erickson & Spann, 1971; Pindyck, 1974).

Supply response is either directly estimated on production (e.g., Griffin, 1985; Jones, 1990; Dahl & Yücel, 1991) or estimated using the number of development wells (e.g., Kaufmann et al., 1994; Boyce & Nøstbakken, 2011). Oil production is found to be very inelastic (usually less than 0.3, sometimes negative), whereas the elasticity of gas production has various results (-0.73~0.8).

Studies of the supply of unconventional oil and gas are very limited. Smith & Lee (2017) study the price elasticity of shale oil reserves using the discounted cash flow method and find that the reserve elasticity is 0.3~0.5 and the elasticity of economically viable drilling sites is twice this number. Hausman & Kellogg (2015) estimate the total natural gas drilling elasticity using aggregated time series data from the United States, which yields a long-run gas price elasticity of 0.81. The elasticity is an overall estimation of both conventional and unconventional gas drilling, not specific to shale gas. Newell et al. (2016) examine the differences between conventional and unconventional gas wells, based on the belief of experts that unconventional oil and gas should be more price responsive than conventional resources, but find no significant difference in drilling elasticity of either oil or gas prices (~ 0.65 for gas price and 0.58 for oil price). The authors use average well depth and lateral lengths to control cost, which may not be appropriate because the lateral lengths are always increasing, while the upstream costs fluctuate over time (EIA, 2016b; Figure 6C).

In summary, studies about the economic behavior of shale gas drilling are still limited. The influence of technology shocks on the industry includes not only single-well productivity increases, but also gradual expansion to new reservoirs with different characteristics. Aggregate time series data of one state in the US may not be representative of the whole country and does not allow for characterization of individual effects. Our study contributes to a better understanding of shale gas development by using panel data to examine the impacts of productivity shocks on all major shale plays in the United States.

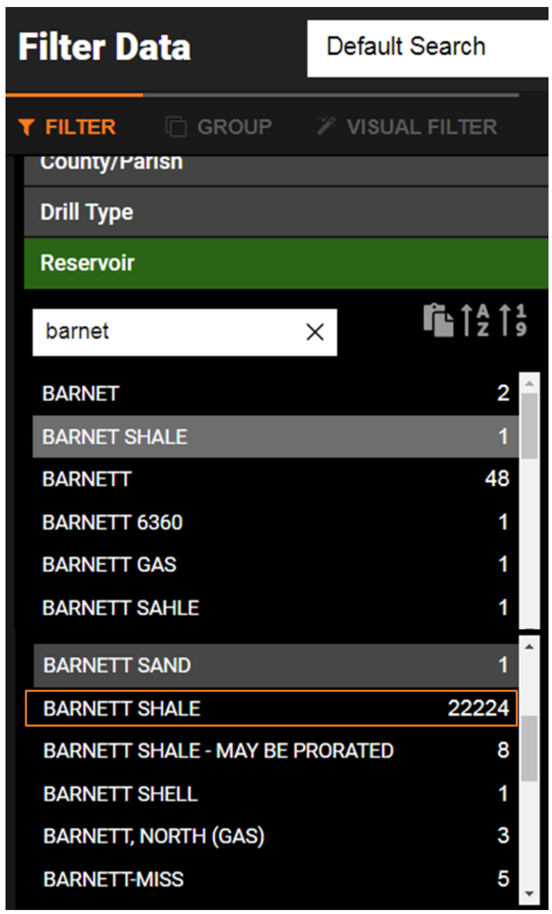
3. Data Description and Analysis

We use well-level drilling data, gas and oil price data, an upstream cost index and a housing price index in our study. The data sources, preliminary data processing methods, and summary statistics are described in following sub-sections.

3.1 Drilling Data

We obtain well-level drilling data from Drillinginfo (2017), a company providing oil and gas upstream data service, whose data is used by the US Energy Information Administration (EIA) and other researchers. Before downloading, a list of unconventional reservoirs is created from various sources (e.g., EIA, 2014, 2016; NGI, 2017). Based on this list, well data for each reservoir is selected from the database using the "approximate string match" technique to include all wells of the same reservoir[1]. 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 reservoir name used by most companies, although other names also exist (Figure 4). Wells from all these reservoirs are selected and further examined for well locations to ensure that they come from the same reservoir. Wells other than the gas type are excluded, 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.

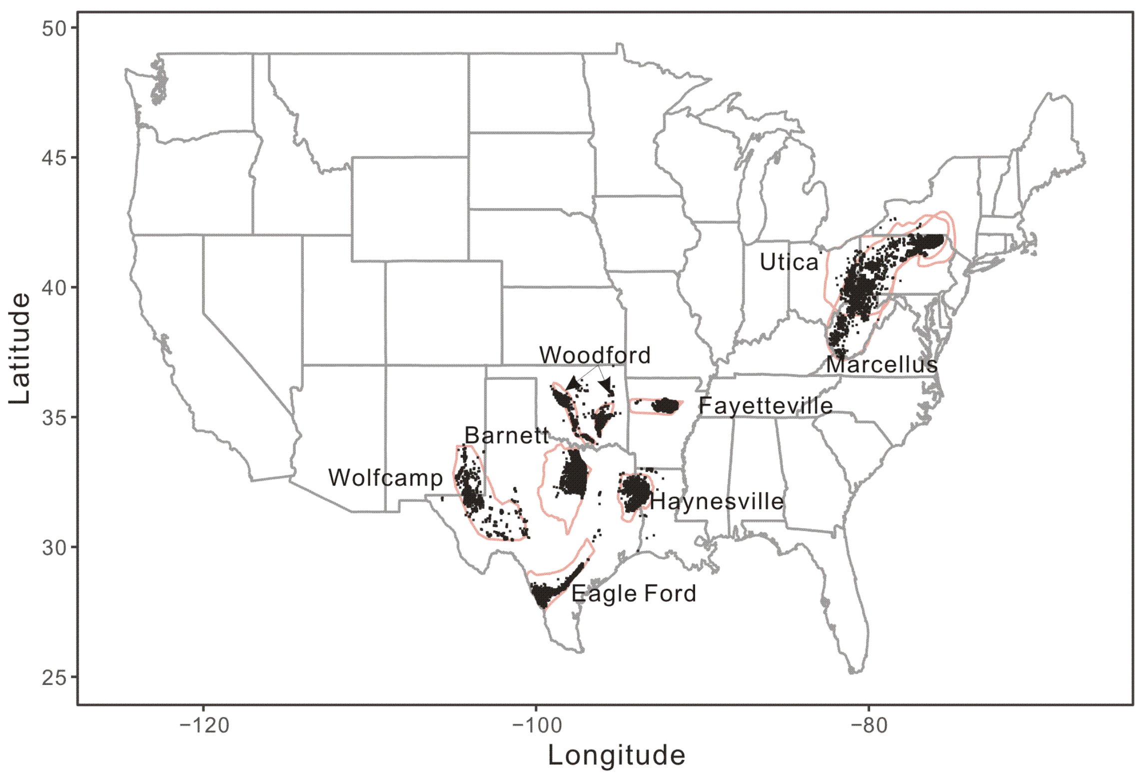
Figure 4. The Drillinginfo Database and Illustration of the Approximate String Match Method



[1] The same reservoir may have different names because different operators use different abbreviations. Typos also occur when the data is reported.

The data is examined carefully on the well type (vertical or horizontal), the spud (drilling) and first production date, production history, and formation lithology 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, which is different from the Newell et al. (2016) methodology[2]. Wells with workover history and having the spud date later than the first production date, and wells missing spud and first production date, are excluded. The lithology of all formations is examined to exclude tight gas and coalbed methane (CBM) plays. 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 shale oil wells. Our final dataset contains 50,510 wells drilled between January 2000 and June 2016 in 8 shale plays and 10 states (Figure 5).

Figure 5. The Location of Shale Gas Wells Drilled in 2000Q1-2016Q2



[2] Newell et al. (2016) excludes vertical shale gas wells. Non-horizontal wells (vertical, directional, and unknown) comprise about 19% of the data in our analysis, which is not negligible.

Table 1 summarizes the basic characteristics for each reservoir over the period of 2000-2016, including the number of new wells drilled, average single-well peak production of condensate and natural gas, measured depth, second-month yield (oil/gas ratio), and perforated interval. It is obvious that reservoirs are distinct in well productivity, geology, and the number of wells drilled. Models using aggregated data may overlook these individual characteristics.

Table 1. Summary Statistics of All Shale Plays

Reservoir	Well Number 2000-2016	IPOD bbl/d	IPGD mcf/d	MD ft	Yield bbl/MMcf	Perforation 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 MMcf 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.

Figure 6 plots the quarterly profiles of the key characteristics. The quarterly number of new shale gas wells drilled increases from 83 in 2000Q1 to 1,534 in 2008Q3, drops below 1,000 during the economic crisis, quickly rebounds back to the peak level, and then decreases back to the 2000 level in 2016Q2 (Figure 6A). Unlike the up and down history of the well number, the average perforated interval as well as the measured depth increase steadily since 2002 (Figure 6B), when Michell Energy and Devon Energy merged (Wang & Krupnick, 2013). Horizontal drilling is one of the major techniques that enables the development of shale gas and the length of the perforated interval should be proportional to 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 (estimated ultimate recovery), follows a different path, which has a sharp increase in 2009 (Figure 6D). The average productivity is influenced by the improvement of technology as well as the development of new plays. A closer look at the individual productivity profile (Figure 7A) shows that the development of the high-productivity Haynesville reservoir 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 in 2009.

The average natural gas condensate productivity starts to increase in the middle of 2009 and exhibits a different pattern from the profile of natural gas productivity (Figure 6D). A closer look at the individual productivity profile (Figure 7B) shows that the condensate productivity of most plays has increased since 2009, while some plays remain constantly low. The productivity of natural gas and natural gas liquid is usually correlated for a specific reservoir structure and the coefficient characterizing the relationship is called yield, which is the ratio of condensate per unit of natural gas produced, usually measured in barrels per million cubic feet (bbl/MMcf). The yield value remains constant for one structure over time, but it varies among different plays or structures. The average yield increases from approximately 10 bbl/MMcf in 2009 to 60 bbl/MMcf in 2013 (Figure 6C), which indicates that the drilling targets shift from dry gas structures into wet ones. A facet plot of individual formations shows that Fayetteville, Haynesville, and Marcellus are dry gas plays (Figure 8). Barnett, Wolfcamp, and Woodford have both dry and wet gas structures. 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.

Figure 6. Quarterly Profile of New Wells Drilled and Total Shale Gas Production in the United States (A), Average of Perforated Interval and Measured Depth (B), Average Yield (C), and Average of Initial Natural Gas and Condensate Production (D)

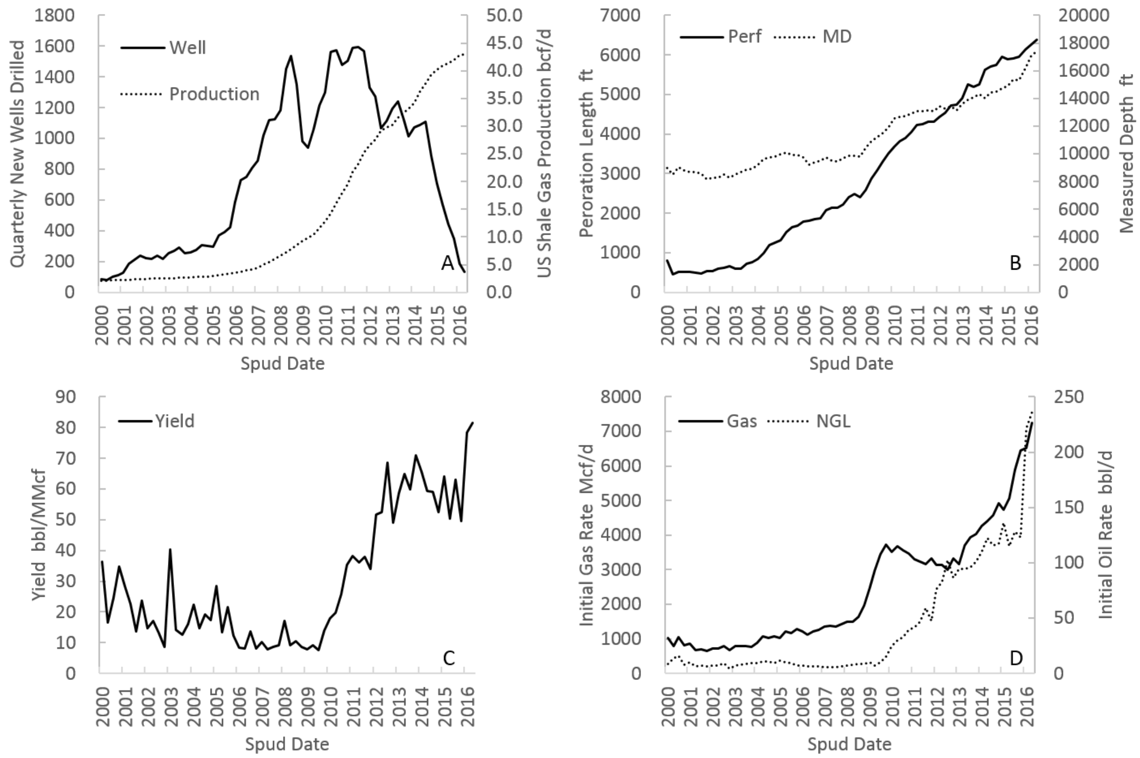


Figure 7. The Quarterly Average of Single-Well Initial Productivity of Natural Gas (A) and Condensate (B) (legend is the same for both plots)

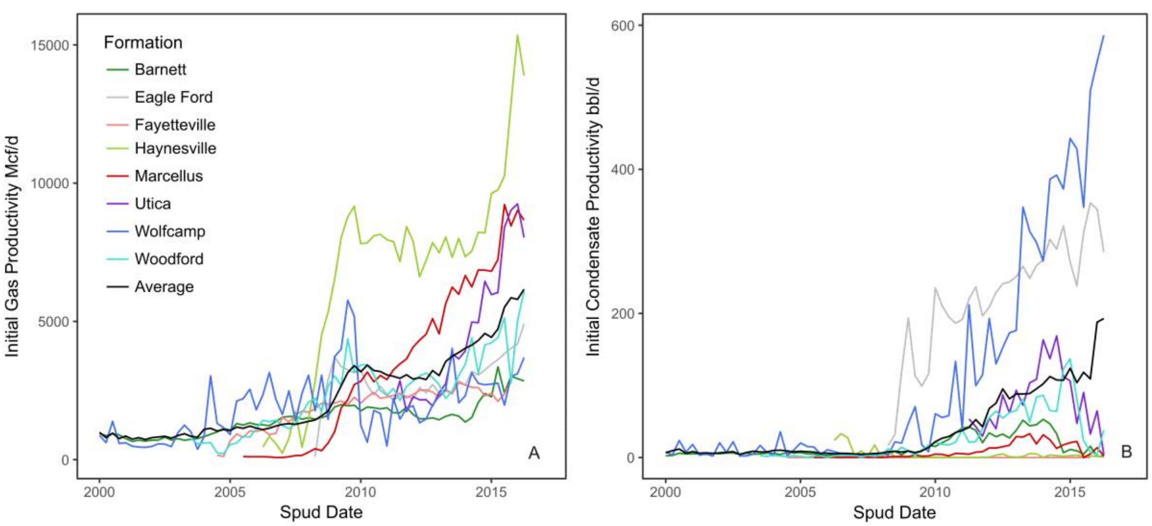
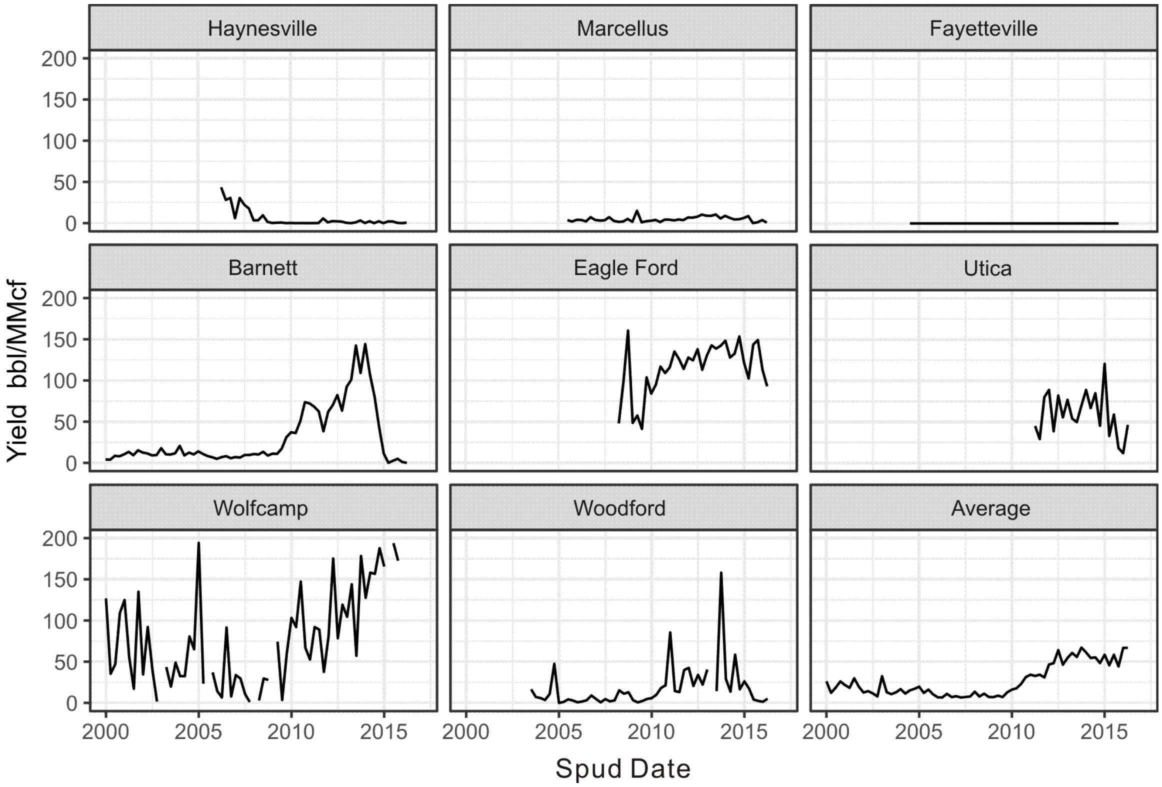


Figure 8. Facet Plot of the Average Yield Value of Each Formation



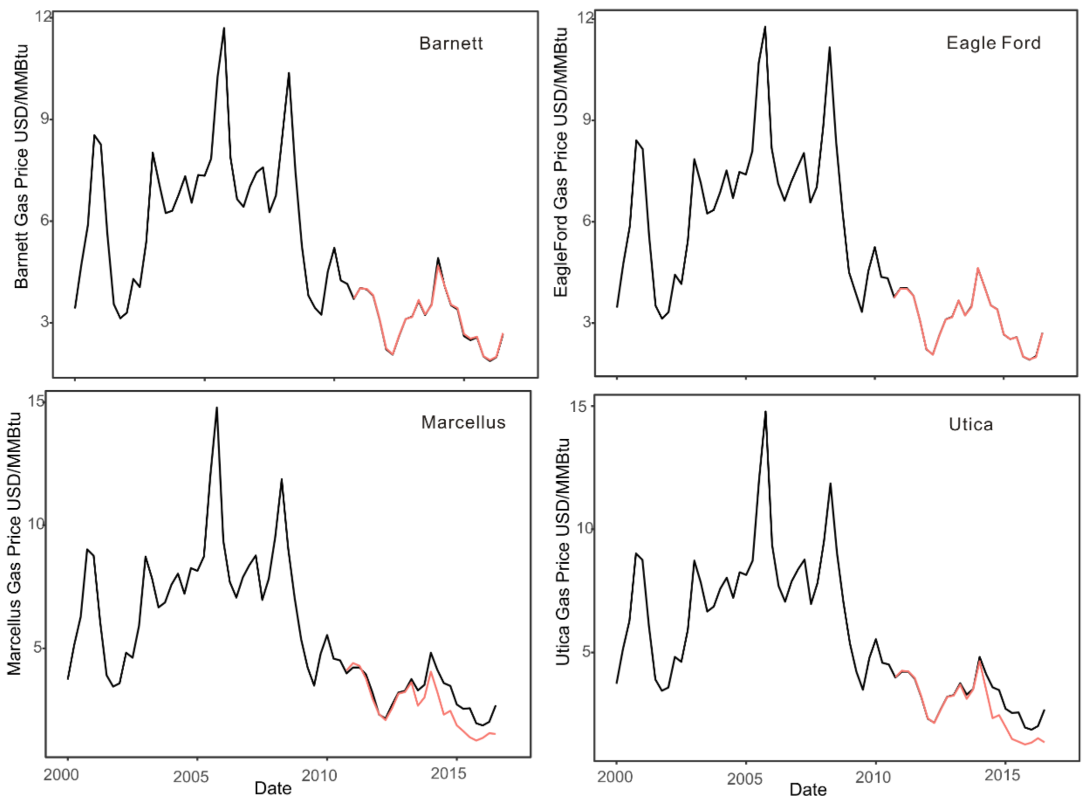
3.2 Price and Cost Data

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, 2014c). The spot price at Henry Hub, Louisiana, is the benchmark for US natural gas and the hub is also used as the delivery point by the New York Mercantile Exchange (NYMEX) for its natural gas futures contracts. However, there are many natural gas hubs on the pipelines and the natural gas price is different in different places (Figure 10). In order to characterize the drilling behavior in the various shale plays, 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)[3] 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 price points that are used for shale gas price indices estimation by NGI. The daily gas price is upgraded to monthly data first and then converted to the real price in US dollars as of January 2016 using the producer price

[3] A company providing natural gas and shale news/market data to the energy industry.

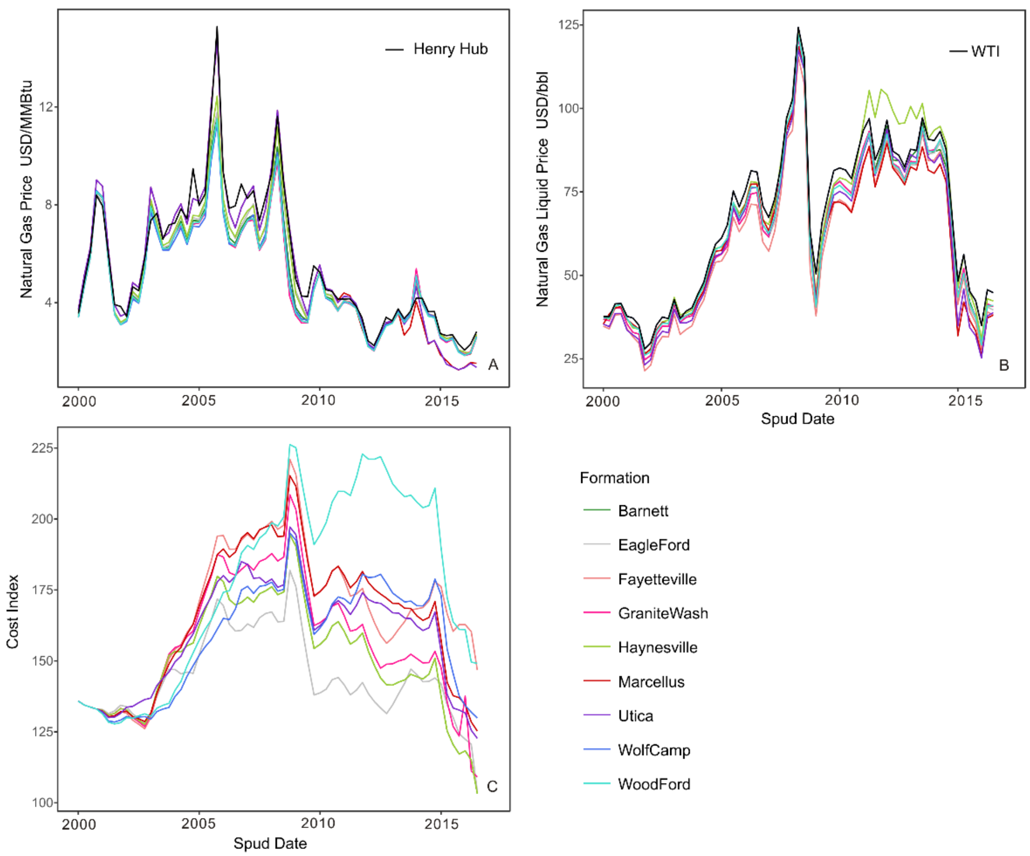
index (PPI) data from the US Bureau of Labor Statistics (BLS). Real monthly data is further upgraded to quarterly price. By comparing the synthetic prices with the NGI-reported SPI, we find a good fit for most reservoirs, except the later period of Utica and Marcellus (Figure 9). However, since companies 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 gas is appropriate when SPI is absent. Figure 10A plots the price of all eight reservoirs, and 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.

Figure 9. Synthetic Natural Gas Prices (black) and NGI-Reported SPI (red) for Selected Reservoirs



The price of natural gas condensate depends on the exact composition of the product and is not transparent in most places. The price of pure condensate end products in Mont Belvieu[4] 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, 2014b). We use the price from Enterprise Products Partners L.P.[5] and EIA's first purchase price of crude oil in different states to calculate substitutes for the condensate price in each shale play. Figure 10B plots the calculated price for the eight shale gas plays, which show similar trends, but with different values.

Figure 10. Quarterly Profile of Natural Gas Price (A), Condensate Price (B), and Upstream Cost Index (C) for Each Formation



The upstream cost indices for shale plays from iHS [6] are used in our analysis. This data is a quarterly cost index evaluating the trends of drilling, completion, facilities, and

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[4] Mont Belvieu is a major natural gas liquids (NGLs) fractionation and distributary hub in the Gulf Coast area, whose NGLs end products prices serve as the benchmarks for NGL products. NGLs include condensate.

[5] Enterprise Products Partners L.P. is a company with business in oil and gas pipelines, natural gas processing, and NGL import/export in the United States.

[6] iHS is a company providing intelligence services for the petroleum industry

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. Figure 10C 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.

4. Econometric Modeling and Results

In this section, we discuss the model building process and display the regression results. Our model is based on the number of shale gas wells and energy prices. The regression results include full play and sub-play estimates.

4.1 Model Building

The future supply of shale gas is composed of two sources: production from legacy wells and production from newly drilled wells. The production from legacy wells is found to be unresponsive to price (e.g., Anderson et al., 2014; Newell et al., 2016), which is explained by the high exploration and development costs before production, but the relatively low operating cost (OPEX) compared to the value of the product (e.g., Adelman, 1995; EIA, 2016b; Kleinberg et al., 2018). The average operating cost for a Barnett gas well is about 0.5-0.7 USD/Mcf (Gülen et al., 2013) and the historically low gas price is 1.6 USD/Mcf. In addition, although shale gas wells have a high decline rate in the first few years, they can maintain long low-decline tails for as many as 20-30 years. Therefore, operators usually do not base their decisions to shut in existing wells on the volatility of gas prices, and the price signal can only influence the gas supply through the drilling of new wells. Following the literature (i.e., Fisher, 1964; Hausman & Kellogg, 2015; Newell et al., 2016), we use the number of new wells drilled as the dependent variable to study the price responsiveness of shale gas supply.

When making drilling decisions, companies make inferences about future prices. Various methods are used in the literature to estimate expected prices, for example, the average of past prices (MacAvoy & Pindyck, 1973), spot price (Fisher, 1964), random walk price (Walls, 1994), futures price (Newell et al., 2016), etc. Nixon and Smith (2012) compared 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 expected price.

There is a time lag between making the drilling decision and taking the action. Following a decision, companies are required to file for permits, and they need to contract rigs, build roads and well pads, etc. before spudding a well, all of which takes several months to complete. In addition, companies have different drilling plans varying between quarterly, semi-annually, and annually. To cover these variations, we assume that the wells drilled at time t are decided at t-1, t-2, and t-3 and we include three lags of the price variables in the model. The number of lags is determined by referring to previous studies (e.g., Newell et al., 2016) and considering the fact that companies adjust their drilling plans according to recent prices.

Unit root tests using the CIPS method of Pesearan (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 translate 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:

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

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 in reservoir *i* during period *t*;

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

$p_{i,t-m}^{o}$ is the percent change of natural gas liquid 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.

Quarterly well number is counted according to the spud date, from 2000Q1 to 2016Q2 for each play. The corresponding average initial gas and liquid production rates, measured depth, perforated interval, and second-month yield are also computed. The upstream cost index and housing price index[7] are used as control variables. Data analysis in Section 3 indicates that there may exist structural changes in the industry according to the quarterly profile of productivity, yield, and drilling number. Therefore, we estimate the samples for two sub-periods 2000Q1-2008Q3 (period I) and 2009Q1-2016Q2 (period II), and the full period 2000Q1-2016Q2. Subsamples using different division time are tested for robustness.

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
NGL Price	-1.8	-2.0	-1.9
	First Difference		
Well	-3.4***	-2.9***	-2.5**
Gas Price	-5.6***	-3.3***	-2.7***
NGL Price	-3.4***	-3.2***	-2.4**

Notes: The CIPS method of Pesearan (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.

4.2 Results

Regressions for the eight shale plays estimate the overall price elasticity of the shale gas drilling, and regressions for the dry gas and wet gas groups examine the individual responsiveness. This section shows results from all-play and sub-play data.

4.2.1 All-Play Result

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

[7]Because the time of the Great Recession coincides with the rapid increase in well productivity, which may produce an identification problem, we use the state housing price index from the FHFA (Federal Housing Finance Agency) to control the effect of the financial crisis on shale gas drilling.

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. (2016).

Regression results in the base case show that the long-run gas price elasticity increases from 0.42 (insignificant) to 0.59 (significant) and the long-run oil price elasticity increases from -0.32 (insignificant) to 1.09 (significant) from period I (case 1) to II (case 2). The full-time gas and oil price elasticities (case 3) are 0.29 (insignificant) and 0.62 (significant), respectively. Case (4) shows 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 the price elasticities.

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. Case (6) shows that the regression result does not change much if we move the end point of period I into an earlier time[8]. 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.

Our full-period oil price elasticity in case (3) (i.e., 0.62) is very close to the result of Newell et al. (2016), which is 0.58 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.

[8] We also tried the division from 2000 to 2007, which gives a similar result.

Table 3. Regression Result of the 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.

4.2.2 Sub-Play Result

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 and the different yield characteristics shown in Figure 8, 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 oil price elasticity of the dry gas group is insignificant in all three sampling periods (cases 9, 10, and 11), while the gas price elasticity is insignificant in period I (case 9) and the full period, but significant with an elasticity of 1.05 in period II (case 10). In the wet gas group, the oil price elasticity increases from -0.58 (insignificant; case 12) to 1.93 (significant; case 13) and is 0.84 (significant) in the full period case (case 14); the gas price elasticity is insignificant in all three periods.

The regression results imply that well drilling is correlated with the profit from the product. 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 more condensate in period II and become responsive to oil price correspondingly. We will discuss the reason behind this phenomenon in the next section.

In summary, our study gives the following results about shale gas development: (1) shale gas drilling activities are not responsive to energy prices in 2000-2008; 2) the drilling activities become sensitive to energy prices, with an oil price elasticity of 1.1 and a gas price elasticity of 0.6 in 2009-2016; (3) the dry gas plays respond to gas price only, with an elasticity of 1.1 in period II; (4) the wet gas plays respond to oil price only, with an elasticity of 1.9 in period II; and (5) the second half of 2008 during the economic crisis should be eliminated during regression.

Table 4. Regression Result of the Dry and Wet Shale Gas Plays

	Dry Gas Group			Wet Gas Group		
Dependents	(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.

5. Discussion

5.1 The Lack of Price Responsiveness in 2000-2008

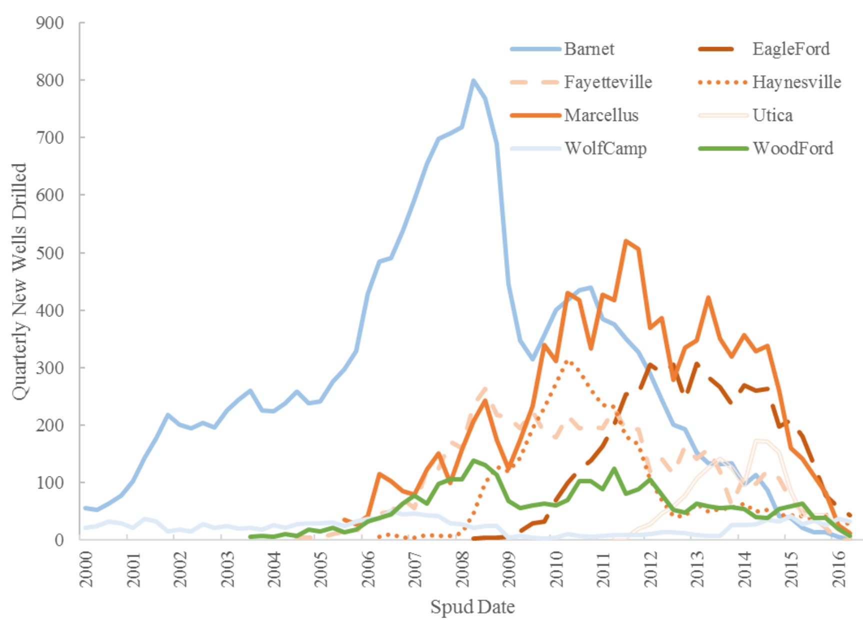
The regression results of all shale gas plays and sub-plays show that the drilling of shale gas wells is not sensitive to oil and natural gas prices in the period of 2000-2008.

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 in period I is in the exploration and pilot stages for most plays; therefore, some wells are drilled to collect information 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 (Figure 11) and 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 & Krupnick, 2013). Before 2008, the total shale gas produced in the US was low (Figure 6A) and the net natural gas imports had been increasing (EIA, 2018). 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.

Figure 11. Number of New Wells Drilled in each Quarter



In summary, the major reason for the insignificance of oil and gas price elasticities in 2000-2008 is the low productivity of shale gas wells at this stage and the limited number of shale plays under development. Other factors such as higher-than-spot prices may also contribute to the estimated values.

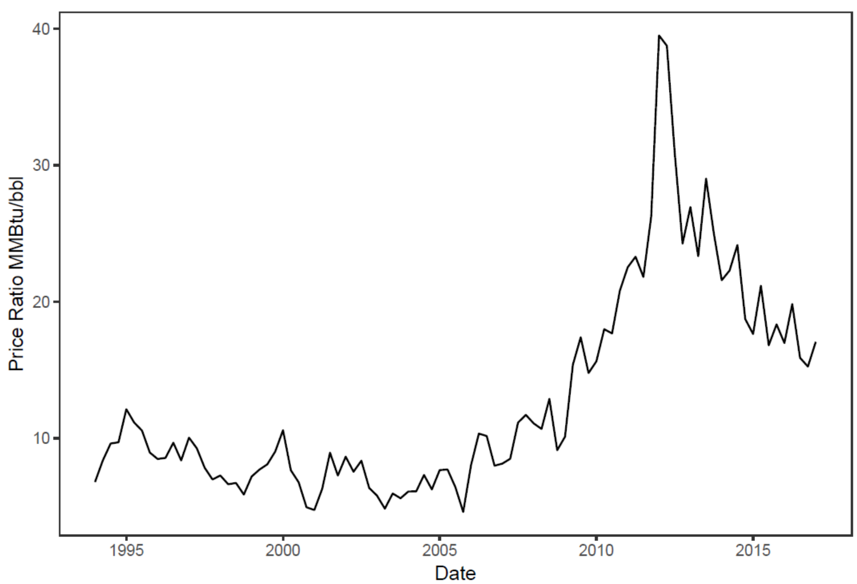
5.2 The Increase of Price Elasticity in 2009-2016

The significant increase in price elasticities from period I to II 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 drop in development cost, which makes shale gas development profitable at market prices. In the meantime, the total production of shale gas accelerates since 2007 and, by 2009, it reaches five times the production in 2000 (Figure 6A). Accordingly, the natural gas price drops significantly after 2009 and the oil-to-gas relative price increases (Figure 12). 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.

Natural gas is not easy to transport, and there are several regional markets in the world with different prices (i.e., the North America, Europe, and Asia markets) (Geng et al., 2016). The shale gas revolution has increased the gross withdrawals of natural gas by 39% from 2006 to 2016 (computed from EIA natural gas gross withdrawals data), and most of the gas remains in the United States (EIA, 2017). Because the demand for natural gas does not increase correspondingly, the price declines. Studies also show that the prices of the three markets were cointegrated before the shale gas revolution, but the US price diverged from the other two after 2009 (Aruga, 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 to as high as 40 MMBtu/bbl (Figure 12). 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 (Figure 6C), 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 (Figure 7). We believe that the export of liquefied natural gas (LNG), the increase of domestic demand, and the decrease of natural gas supply will eventually stabilize the relative price and adjust the drilling elasticity.

Figure 12. Price Ratio of the WTI Oil Price vs. the Henry Hub Gas Price



5.3 Comparison with Results in Previous Studies

Table 5 summarizes the estimated drilling elasticities from various studies. Our study extends the sampling domain in both time and space compared to Newell et al. (2016). Newell et al. (2016) estimate the shale gas drilling elasticity for the period of 2005-2015, finding long-run oil and gas price elasticities of 0.58 (insignificant) and 0.64, respectively. The oil price elasticity is close to our result in 2000-16, whereas the gas price elasticity is close to our result in 2009-2016. Newell's study covers shale gas wells drilled in Texas only, and does not consider play-specific differences. Hausman and Kellogg (2015) estimate the natural gas drilling elasticity for the period of 2002-2010 and give a long-run gas price elasticity of 0.81. Hausman and Kellogg (2015) include both conventional and unconventional gas wells and the time frame overlaps more with our period I, when the shale gas boom had not spread nationwide. Neither of the previous studies consider the structural change around 2009, which produces comingled estimation for two distinct regimes. The high oil price elasticity after 2009 in our study is consistent with EIA's Annual Energy Outlook of 2017, in which natural gas production is highly correlated with oil price.

Table 5. Summary of Regression Results from Difference Sources

	This Study			Newell et al., 2016	Hausman and Kellogg, 2015
Sample Period	2000-2008	2009-2016	2000-2016	2005-2015	2000-2010
Gas Price	0.42	0.59**	0.29	0.64**	0.81
Oil Price	-0.32	1.1***	0.62**	0.58	

Notes: *** Significant at the 1 percent level. ** Significant at the 5 percent level.

6. Conclusion

This study contributes to the limited but growing literature of unconventional oil and gas supply by identifying the change in price responsiveness of shale gas and quantifying the price elasticities before and after the major productivity shocks for the first time. It is also the first analysis to use a near-full-sample well-level drilling data set to conduct play-level econometric analysis, which enables the discovery of a significant price elasticity change and the shift of the industry's purpose in drilling during the shale gas boom.

Our study shows that the drilling of shale gas becomes more responsive to oil and gas prices after the major productivity shock in 2009. The oil price elasticity increases from 0.3 (insignificant) to 1.1 (significant) and the gas price elasticity increases from 0.4 (insignificant) to 0.6 (significant) from period I to II. The advancement and expansion of shale gas development technology are the major reasons for the elasticity change. The increase in oil price elasticity reflects the shift of the industry's focus from dry gas reservoirs to liquid-rich targets due to the increase in the relative price of oil to gas after the shale gas boom. As the world demand for LNG grows and natural gas prices increase, the situation could be different.

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