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TROPHY HUNTING VS. MANUFACTURING ENERGY: THE PRICE-RESPONSIVENESS OF SHALE GAS

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ABSTRACT

We analyze the relative price elasticity of unconventional versus conventional natural gas extraction. We separately analyze three key stages of gas production: drilling wells, completing wells, and producing natural gas from the completed wells. We find that the important margin is drilling investment, and neither production from existing wells nor completion times respond strongly to prices. We estimate a long-run drilling elasticity of 0.7 for both conventional and unconventional sources. Nonetheless, because unconventional wells produce on average 2.7 times more gas per well than conventional ones, the long-run price responsiveness of supply is almost 3 times larger for unconventional compared to conventional gas.

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Over the past decade, technological developments have driven increased natural gas and oil extraction by opening access to resources stored in shale and other "tight" formations. These unconventional technologies and resources have allowed drillers to extract from significantly larger subsurface acreage using fewer wellbores and with much higher production per well. The combination of hydraulic fracturing and horizontal drilling techniques has underpinned this unconventional supply and the resulting shale gas boom.[1] Supported initially by high natural gas prices during much of the 2000s, the United States has experienced significant increases in natural gas and oil production.

The shale revolution has fundamentally changed how gas and oil are produced in the United States. In the words of one industry expert,[2] conventional oil and gas investments resemble high-risk/high-reward, "big game trophy hunting," which involves drilling many dry holes in search of a few highly productive ones. This stands in stark contrast to modern unconventional extraction from shale, which is commonly said to resemble a "manufacturing process" in that operators have much more flexible and certain control over their production levels.

Multiple features of unconventional gas lead to this flexibility. First, industry operators have better information about the location and scale of shale resources than they do for conventional formations; the obstacle is extracting them. As one industry analyst stated, "[w]e knew the shale formations were there but we didn't

[1] Conventional wells tap porous and permeable resources that flow to the wellhead naturally once the well is drilled. Unconventional wells require hydraulic fracturing, where tight shale resources are artificially stimulated with high-pressure water causing fissures that are propped open to allow the gas and oil to flow to the wellhead. The process requires more time and at a higher cost to complete the well.

[2] Rob Jacobs, Caird Energy, personal communication.

have the technology to extract from them."[3] Second, shale resources produce a much larger amount of resources quickly, suggesting a tighter relationship between drilling effort and realized production. Altogether, experts have suggested that these factors make unconventional gas and oil more responsive to prices.[4]

To the extent that unconventional gas is more price responsive, the shale boom has likely "flattened out" the U.S. natural gas supply curve, thereby reducing price volatility. Indeed, following the boom in shale gas, prices have been significantly less volatile compared to the early 2000s. To the extent that unconventional gas is responsible for this diminished volatility, continuation would help reduce uncertainty for policymakers and businesses considering investments that are highly sensitive to gas prices. For example, compliance with regulations reducing carbon dioxide emissions from power plants may involve higher reliance on natural gas-fired generation, both as a substitute for coal and as backup for intermittent renewable power. The economic benefits of investments in LNG export infrastructure also depend on stable natural gas prices, as do the benefits of domestic investments in energy-intensive manufacturing and chemical production.

Given the differences in geology and changes to drilling technology, this research seeks to disentangle the differences in operators' price-responsive behavior between conventional and unconventional gas. We consider different aspects of the production process to assess the differences between unconventional and conventional wells at each stage of the supply function, beginning with the decision to drill the well, complete the well, and produce gas over time. We estimate these

[3] Jodi Shafto, "Dry gas well drilling economics improved by drilling technology advancements," May 31, 2013, SNL Daily Gas Report.

[4] For example, *The Economist*, "The economics of shale oil: Saudi America," February 15, 2014.

relationships using econometric models that appropriately describe each stage of well development and execute the analysis using detailed data from approximately 62,000 gas wells drilled in Texas between January 2000 and September 2015.

We find that the important margin for production responses to price changes is drilling investment, whereas neither production from existing wells nor the time from drilling to first production respond strongly to price changes. We estimate a long-run drilling elasticity to prices of approximately 0.7 and find no clear evidence that this elasticity is different for unconventional compared to conventional gas drilling. While unconventional wells take somewhat longer to reach production, they produce much more gas per well than conventional wells and have less risk associated with variation in well productivity. This faster flow rate per well turns out to be the primary margin by which aggregate supply from unconventional gas production is more price responsive than conventional production.

We use these econometric results to conduct a simulation of the effect of an exogenous 10 percent price shock on wells drilled and gas supplied over time, providing a time-varying price response. We find that unconventional gas production responds more strongly to price changes (nearly 3-fold in the long-run) than conventional production does. These are the first econometric estimates to isolate the differences in supply response between shale gas and conventional gas.

I Literature

The paper spans several literatures related to the economics of the oil and natural gas industry and more generally to non-renewable resource extraction. We contribute to a nascent but growing area of research on the effects of greater accessibility to shale gas (Joskow 2013). The study also contributes to understanding of price formation in fossil fuel markets (e.g., Hamilton 2009; Kilian 2009). Specifically, we analyze the separate phases of energy development and isolate the industry decisions that are responsive to changes in natural gas and oil prices, effectively estimating a supply elasticity in a much more disaggregated manner than is typical in past work.

The resource extraction literature seeks to characterize firms' optimal extraction decisions and depletion rates (Nystad 1987; Adelman 1990; Davis and Cairns 1998; Cairns and Davis 2001; Thompson 2001; Smith 2012; Cairns 2014; Kellogg 2014). Our paper empirically tests the degree to which natural gas production decisions are sensitive to shocks in prices and whether there are differential effects for conventional versus unconventional resources and technologies. Using more disaggregated, well-level data applied to gas (rather than oil), we find similar evidence to Anderson, Kellogg and Salant (2014) that the quantity produced from already-producing wells is not elastic or price sensitive.

The demand and supply elasticity literature often compares short and long-run results, typically finding that gas and oil supply elasticities are inconsequential once wells have been drilled and that supply is less responsive in the short run than in the long-run. Papers analyzing oil extraction elasticities include Griffin (1985); Hogan (1989); Jones (1990); Dahl and Yücel (1991); Ramcharran (2002); and Güntner (2014). There is very little published econometric evidence on natural gas supply elasticities (Erickson and Spann 1971; Dahl 1992; Krichene 2002), much of which is dated and none of which focuses on the impact of the recent shale gas revolution.

Our paper is specifically focused on estimating the heterogeneous responses for unconventional compared to conventional drilling decisions, centered on the recent shale gas boom occurring in states such as Texas, Pennsylvania, Louisiana, and Arkansas. Hausman and Kellogg (2015) estimates aggregated supply and demand elasticities to capture welfare impacts of the shale boom across industrial sectors and producers, and heterogeneous effects across space.

Our study also contributes to understanding decline curves for unconventional wells, which has important implications for the inertia and cyclicality inherent in gas and oil markets. Decline curves from conventional wells are commonly modeled using the "Arps equation," which nests exponential, hyperbolic, and harmonic decline curves. By contrast, Patzek, Male and Marder (2013) argue that unconventional gas wells in the Barnett shale formation follow a fundamentally different functional form: proportional to 1 over the square root of time for the first few years, and then exponential after that. This same functional form is also used in Browning et al. (2014), among other studies. While we explore functional form in this paper, we ultimately focus on a non-parametric approach to decline paths.

II Industry Background and Data

II.A Industry Structure

Unconventional drilling describes the technological combination of more advanced hydraulic fracturing and horizontal drilling techniques that are used to extract natural gas and oil from tight-shale formations. Unconventional gas and oil reserves are stored in these tight-shale formations where the resources are difficult to extract unless the shale is artificially stimulated using a technique like hydraulic fracturing.

Further, large quantities of shale resources are located beneath more densely populated regions of the country, and these resources can now be accessed through horizontal drilling techniques, with laterals extending from the vertical well for thousands of feet in any horizontal direction. Combined with advancements in seismic and surveying technologies, these extraction methods increase the accessibility to otherwise inaccessible natural gas and oil.

As a result, unconventional gas and oil production differs from conventional methods in several ways across the stages of development, which are described in the following subsections. In particular, the process can be broken down into the following stages: leasing and permitting; spudding a well (i.e., commencing drilling); well completion and stimulation; and production over time.

II.A.1 Leasing and Permitting

Before obtaining a permit to drill a well, a firm signs leases with the mineral rights holders of acreage from which the firm wants to extract natural gas and/or oil, and these mineral rights holders may be private landowners or government entities. Once the mineral rights are leased, firms apply for a permit to drill a well from the relevant state regulatory agency. During the term of the lease, the lessor (landowner) retains the ownership and use of the surface estate while the lessee (firm) has the right to extract and sell the resources stored in the sub-surface mineral estate. In return for the right to extract, the lessor is paid a lump-sum bonus, land rental payment, and royalty on the value of the extracted resources.

Currently, shale-based hydrocarbons are extracted from onshore reserves where, in the United States, the mineral rights are typically privately held. In these cases, a firm privately contacts and negotiates leases with landowners, which is in contrast to first-price sealed bid auctions that allocate government-owned offshore rights.[5] In the state of Texas, where we focus this empirical analysis, the Texas Railroad Commission is the state regulator tasked with issuing and maintaining oil and natural gas permits along with monitoring well activity once drilling begins.

While we investigated estimating the permitting stage explicitly, this stage did not add significantly to the analysis so we did not include it in our model. Permitting tends to be quick and low-cost, in contrast to drilling and completion which require significantly larger investments. For further research on the leasing decision see Porter (1995); Libecap and Smith (2002); Fitzgerald (2010); and Vissing (2015).

II.A.2 Drilling

Once mineral acreage is leased and a well is permitted, drilling can commence, and while drilling unconventional wells results in greater oil and natural gas production per well, it is also more technically challenging and expensive than conventional onshore extraction. An unconventional well is drilled both vertically and then horizontally as compared to a conventional well that is drilled in only the vertical direction. The vertical segments typically reach 4,000 to 13,000 feet in depth and the horizontal segments typically extend 2,000 to 7,000 feet. The horizontal segment of an unconventional well allows firms to extract more natural gas from a larger subsurface mineral acreage using a single wellbore. Drilling begins at the date a well is "spudded." The firm that owns the well typically does not drill it itself. Rather, drilling is typically contracted out to specialized oilfield service companies (e.g.,

[5] Offshore leases are typically awarded through competitive bidding in first-price sealed bid auctions (where the bid is the up-front "bonus payment", and royalty rates are fixed).

Schlumberger and Halliburton) that charge daily rates to rent their drilling rigs and services. These rig rates are on the order of $15,000 per day.[6]

II.A.3 Well Completion and Stimulation

Following the drilling phase, a well must be completed. Completion primarily involves casing, perforating, and possibly stimulating the well. A casing is a large diameter pipe cemented into the wellbore, and it prevents the well from caving in and protects groundwater from contamination. The horizontal part of the casing in the shale formation is perforated using perforating guns containing explosive charges so that gas and/or oil can flow into the casing and up to the surface.

Permeable conventional reservoirs have natural pressure that causes the resource to flow easily to the surface without any additional work. However, the impermeability of tight-shale formations requires that the well be artificially stimulated, generating fissures in the rock that allow the gas and oil to flow freely up to the wellhead. Shale wells are artificially stimulated through large-scale hydraulic fracturing techniques. This process injects millions of gallons of water mixed with sand and chemicals into the well at a high pressure. The pressure causes the rock to fracture, generating fissures in the rock that are propped open by the sand in the fracturing fluid. Once the fracturing fluid returns to the surface, the newly propped fissures allow the gas and oil to flow more easily up to the wellhead.

[6] However, this is a small piece of the total cost of developing a well. For example, according to one industry expert, the overall cost of developing a well has been on the order of $4-12 million, whereas payments to drillers may make up only $0.5 million of this (30 days at $15,000 per day).

II.A.4 Production over Time

Once a well is completed, it often produces oil and natural gas for many years, even several decades in some cases. The largest quantity of production is realized in early periods because of the higher reservoir pressure. Production from existing wells involves little marginal cost, so firms' incentives are to produce the resources to recover their drilling and completion costs quickly. The flow rate of oil and natural gas to the surface is therefore a direct function of the quantity of resources remaining in the ground. As more hydrocarbons are extracted, there is less natural pressure pushing what remains to the surface, reducing the flow rate.

As a result, the production rate of a typical well decreases quickly. In our data, gas production typically decreases more than 60 percent from its peak after only one year. In addition, in the first year of production, conventional and unconventional gas wells realize 35 percent and 34 percent, respectively, of their total gas production. In the first five years, they realize 78 percent and 77 percent of total production, respectively. Further, because the marginal cost of production from an existing well is fairly low, many wells continue to be kept in production even after their flow rates asymptote to zero. Firms also have alternative extraction methods to increase the flow rate in later periods, including reservoir stimulation methods and pumps (for oil only). However, we do not directly observe whether firms have employed these secondary and tertiary extraction techniques to increase flow rates.

II.B Data Sources

We use well-level data aggregated by Drillinginfo, a company that provides information services on upstream oil and natural gas activity. We focus on wells drilled in the state of Texas because of the superior quality of the data from that state.[7] Texas onshore wells account for approximately 30 percent of total U.S. natural gas production, and it has accounted for more than 40 percent of the growth in production since 2000.[8] In Texas, Drillinginfo collects onshore well data from the Texas Railroad Commission. The data include natural gas wells going back many decades, but we focus on wells drilled between January 2000 and September 2015. We downloaded the Drillinginfo dataset on June 9, 2016.

The dataset describes characteristics of each well that do not vary over time including the wells' important dates (spud and first production dates), the geographical location of the well, the direction the well is drilled (horizontal versus vertical), and the reservoir into which the well was drilled. The dataset also includes the time series of each well's natural gas and oil production for each month over the well's productive lifetime. In Texas, natural gas production is measured at the well level, while oil production is measured at the lease level. Drillinginfo allocated oil production to individual wells using well test data.

We drop apparently duplicated observations and observations with missing or invalid dates (e.g., the first production date is reported to occur before the well is reported to be completed).[9] We focus on natural gas wells, ignoring oil wells. We

[7]The data for other regions tend to be inferior because certain variables are unavailable, defined differently, or reported less frequently. For example, in New Mexico, drilling direction is not reliably tracked; in Pennsylvania, production is reported at the annual level, compared to monthly in Texas.

[8]`http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_a.htm`.

[9]These occasional inconsistencies are primarily due to the way Drillinginfo updates data on re-entered wells. For example, a well that initially began production in 1995, but was later re-worked and re-completed in 2010, would have a first production date of 1995, but a 2010 completion date. In these cases, the original completion date would be overwritten in Drillinginfo's data by the more recent 2010 completion. We also drop some wells because they report beginning production more than 24 months after their spud date. These are likely data errors because permits generally expire after two years, and leases typically expire if production does not begin within three to five years.

also compute the length of horizontal well "laterals" using the geodesic distance between the well's surface hole and bottom hole.

We categorize a well as unconventional if it is drilled in a low-permeability or shale reservoir using horizontal or directional drilling techniques. Reservoirs were classified using a dataset provided by the Energy Information Administration (EIA) that maps labels field and reservoir names as either "conventional," "low permeability," or "shale."[10] Correspondingly, a conventional well is defined as a well that is drilled vertically into a conventional reservoir.[11]

Unless otherwise noted, we use the simple average of the next 12 months of futures prices for natural gas price (Henry Hub) and oil (WTI). Each price is the average of daily prices collected from Bloomberg and adjusted to 2014 dollars using the CPI All Urban Consumer (All Items) index.

II.C Data Description

The cleaned dataset includes approximately 62,000 gas wells drilled between 2000 and 2015. For unconventional wells, we only include wells drilled in 2005 or later, as this is the period when the shale gas revolution began in earnest. Figure 1 shows a map illustrating the location of the wells in our data along with depictions of

[10]Approximately half of the wells matched perfectly to EIA's dataset. The remaining wells were matched using the most similar reservoir name according to the Levenshtein distance between the two text strings, which equals the number of character changes required to obtain a perfect match. 78 percent of the wells matched perfectly after changing no more than 1 character in the reservoir name; 93 percent matched perfectly after changing no more than 4 characters. Many such matches are either misspellings, abbreviations, or spelling variants (e.g., "Barnett shell," or "Eagle Ford" versus "Eagleford") or alternatively include extra unneeded information (e.g., "Helms Barnett shale"). Inspection of the results suggests the match performs well. For example, very few wells classified as "shale" appear before 2000.

[11]"Mixed" wells (i.e., a vertical well in a shale reservoir, or a horizontal/directional well in a conventional reservoir) are dropped from the analysis, although there are relatively few of these.

selected shale plays. Table 1 reports the summary statistics for conventional and unconventional gas wells,[12] along with summary statistics for our price data.

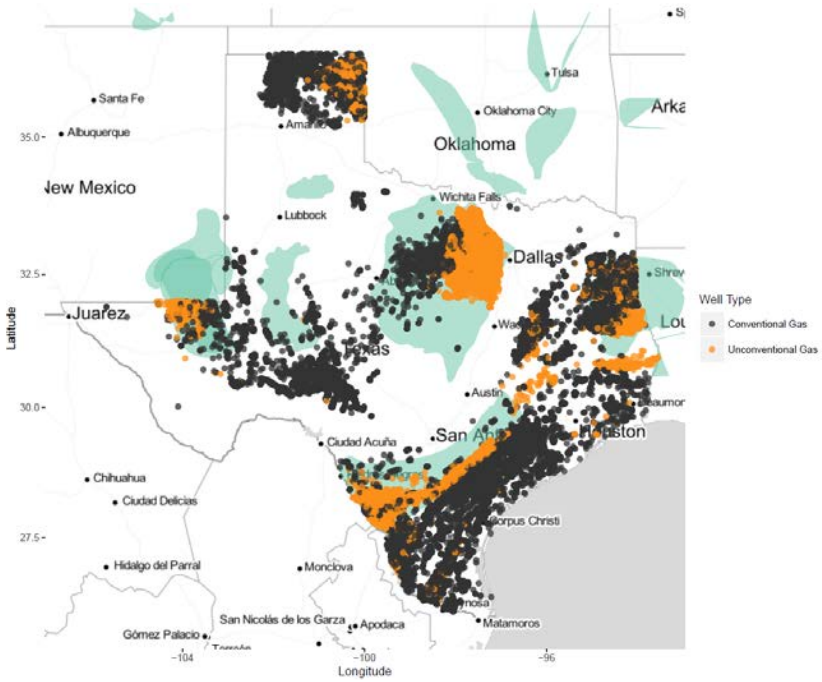

Figure 1: Location of Gas Wells in Data by Well Type and Selected Shale Plays

Sources: Well locations are from Drillinginfo data. Classifications based on EIA dataset. Map is from Stamen.com via the `ggmap` package for R developed by Kahle and Wickham (2013). The indication of shale formations is based on EIA's shapefile for low permeability oil and gas play boundaries in the Lower 48 States, available at `https://www.eia.gov/maps/maps.htm#geodata`.

Unconventional wells are much more productive than their conventional counterparts. On average, an unconventional gas well in our data produced nearly 70,000 thousand cubic feet (mcf) of natural gas in its first full month,[13] compared to ap-

[12]Decline rates represent decline from peak production, which is not necessarily the first full month. Means, medians, and standard deviations are taken over relevant subsets of the data. For example, wells that produced no oil are excluded from the calculation regarding oil decline rates.

[13]Initial production is measured as production during its first full month of production, meaning the second calendar month during which production is reported. It is standard to focus on the second month because a well is typically only producing for a fraction of its first calendar month.

proximately 30,000 mcf from a conventional gas well, meaning on average over this sample period (2000-2015 for conventional and 2005-2015 for unconventional), unconventional wells are 2.3 times as productive. However, this average masks trends in productivity (shown below in Figure 4); per-well productivity has been rising substantially for unconventional wells and falling slightly for conventional wells. Over the 2010-2014 period,[14] the average initial production for unconventional wells was 80,000 mcf per month (not shown in table), 2.7 times as productive as the average conventional well (30,000 mcf over 2000-2015, as shown in Table 1).

Comparing the averages and medians illustrates the greater predictability of unconventional wells by capturing the relative skewness of conventional drilling. Many conventional wells end up producing relatively little, but the occasional "gusher" compensates for the unproductive ones. The average and median production values are more similar for unconventional wells (mean of about 68,000 mcf versus a median of about 50,000 mcf), the mean being about 37 percent higher than the median, compared to conventional wells, for which the mean is more than twice as large as the median (about 30,000 mcf versus 14,000 mcf).

[14] We exclude 2015 from this computation because that rise is potentially due to temporary refocusing of efforts on "sweet spots" during low oil and gas prices, rather than persistent innovation.

Table 1: Summary Statistics

	(1)	(2)	(3)	(4)	(5)	(6)
		Conventional			**Unconventional**	
VARIABLES	Mean	Median	Std. Dev.	Mean	Median	Std. Dev.
Well Data						
Initial Gas Production (first full month, mcf)	30,261	14,214	55,055	68,244	49,918	68,183
First 12 Months' Total Gas Production (mcf)	217,060	106,619	397,392	493,399	371,878	463,673
Gas 3-Month Decline Rate (%)	47.9	46.8	23.2	43.4	40.6	20.5
Gas 12-Month Decline Rate (%)	70.8	72.9	19.7	68.3	68.1	16.6
Gas 24-Month Decline Rate (%)	80.5	83.0	16.1	78.8	79.4	13.6
Initial Oil Production (first full month, barrels)	344	0	1,347	2,245	0	5,050
First 12 Months' Total Oil Production (barrels)	2,311	150	8,770	14,503	253	32,140
Oil 3-Month Decline Rate (%)	70.3	72.7	26.6	64.6	63.7	26.8
Oil 12-Month Decline Rate (%)	86.0	92.4	17.7	84.3	87.4	16.0
Oil 24-Month Decline Rate (%)	91.5	97.9	13.1	91.1	94.3	11.2
Horizontal Well Length (ft)				4,003	4,009	1,836
Total Vertical Depth (ft)	8,963	9,250	3,287	12,414	11,780	3,066
Months Between Spud Date and First Production	2.53	2.00	3.08	4.73	4.00	3.64
Number of Wells		36,093			26,017	
Price Data (Monthly, 2000-2015)	Mean	Median	Std. Dev.			
Henry Hub Natural Gas Price - Prompt Month Future ($/MMBTU)	$5.95	$5.02	$2.71			
Henry Hub Natural Gas Price - 12-Month Future ($/MMBTU)	$6.31	$5.63	$2.64			
WTI Oil Price - Prompt Month Future ($/barrel)	$70.90	$73.12	$27.12			
WTI Oil Price - 12-Month Future ($/barrel)	$71.15	$76.13	$27.72			

Sources: Authors' calculations based on data from Drillinginfo, EIA, and Bloomberg

This greater predictability of unconventional wells is also demonstrated by the standard deviation of their initial gas production relative to conventional wells. The coefficient of variation (the standard deviation divided by the mean) is much smaller for unconventional gas wells (1.0), compared to conventional wells (1.8).

On average, we do not observe a substantial difference in decline rates between unconventional and conventional gas wells—somewhat contrary to conventional wisdom. Decline rates measure the *rate of change* in production levels for a given well beginning with the peak period, typically but not always the first full calendar month of production. Unconventional gas wells extract more natural gas in earlier periods because they are much larger on average. Unconventional gas wells also have more consistent decline rates than conventional wells, as demonstrated by the lower standard deviations for the decline rates for unconventional wells in Table 1.

According to industry participants, unconventional wells are more expensive to drill and complete than conventional wells, so the gain in physical well productivity also comes with higher costs. The primary costs associated with developing an oil or gas well are associated with renting rigs during the drilling and completion stages. These expenses depend on the amount of time the rigs are working on site, which depends in turn on the depth of the well and the length of its laterals, also summarized in Table 1. Average lateral lengths have been rising at a remarkably linear pace over that period (not shown), from about 2,000 feet in 2005 to about 6,000 feet in 2015, with an average of about 4,000 feet over the full sample period. Further, in section III.C we consider the length of time between spudding and first production, which is greater for unconventional wells due to the extra steps required to hydraulically fracture the well: unconventional gas wells begin producing within 4.7 months, on average, compared to 2.5 months for conventional gas wells.

Figure 2 shows the production profiles for two typical gas wells in our data, both of which began producing in 2007. The unconventional well is located in Johnson County, TX, overlaying the Barnett shale play. The conventional well is located in Shelby County, TX, in the East Texas Basin. This graph and Table 1 illustrate that while the level-decline in gas production is larger for the unconventional well, the conventional and unconventional wells have quite similar percentage decline rates. As shown in Table 1, after 12 months of production, the mean unconventional well's gas flow has fallen by about 40,000 mcf from its peak of 68,000 mcf, a drop of 59 percent. In the same amount of time, the mean conventional well's production fell by about 17,000 mcf from its peak of about 30,000 mcf, which is a comparable 56 percent reduction.

Figure 3 describes the number of new spuds each quarter of our data from 2000 to 2015 by well type (conventional versus unconventional gas wells), and the spud

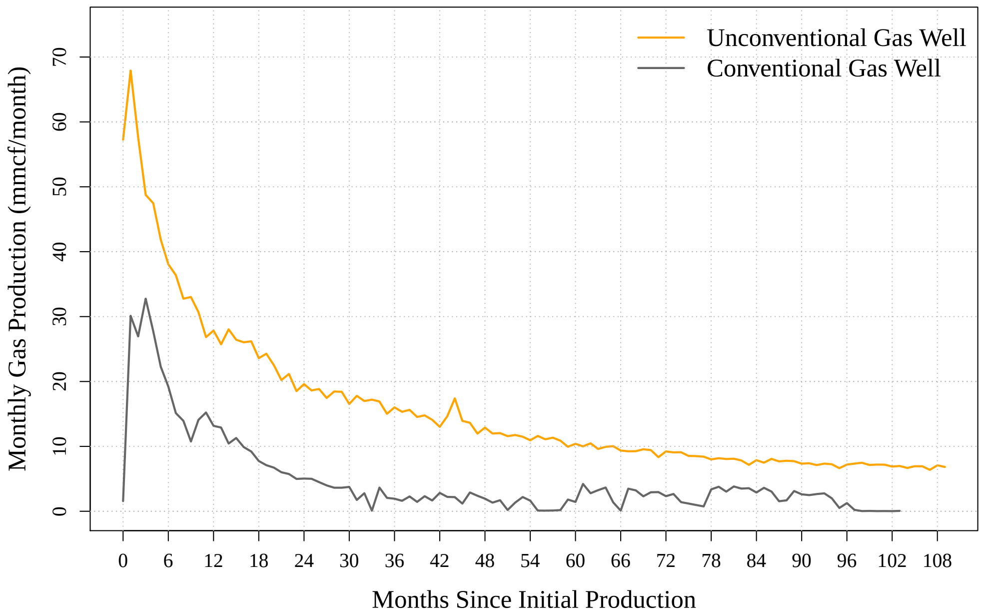

Figure 2: Production Profile of Typical Gas Wells

Sources: Authors' calculations based on data from Drillinginfo and EIA

counts are plotted along with natural gas and oil prices.[15] The figure reveals that the wells we have classified as unconventional are indeed a recent phenomenon, supporting our classification method. Following the massive increase in unconventional drilling and collapse in gas prices, conventional gas wells have all but disappeared.

As shown in the figure, gas drilling fell dramatically after the collapse of gas prices in 2008. Natural gas prices continued to decline in the subsequent years, during which the number of conventional gas wells drilled fell by 70 percent, while

[15]Oil prices represent West Texas Intermediate (WTI) prices, divided by 5.8 to convert to dollars per million British thermal units. Both oil and gas prices are the simple average of the next 12 months of futures prices in real 2014 dollars.

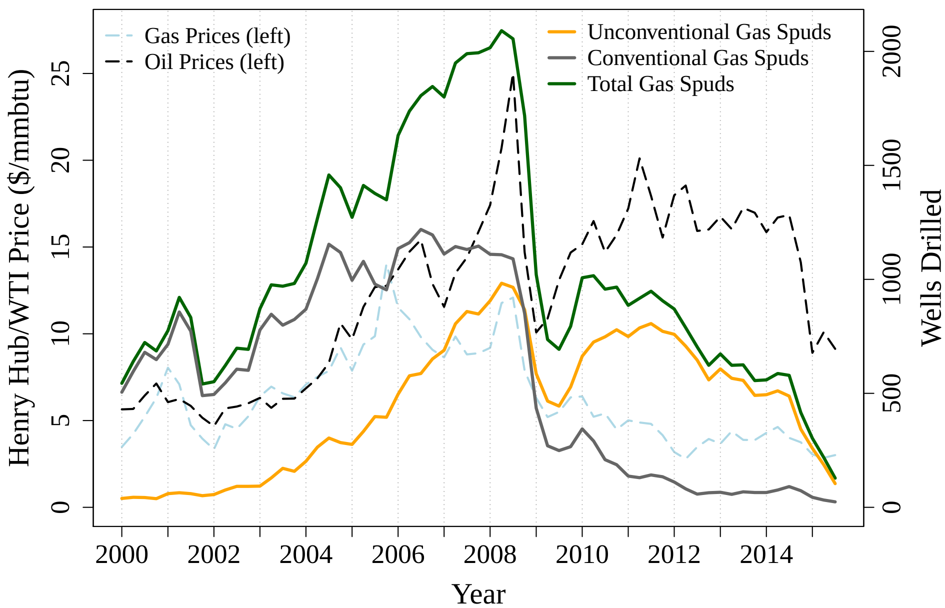

Figure 3: Number of Spuds by Well Type (right axis) and Oil & Gas Prices (left axis), 2000-2015, Quarterly

Sources: Authors' calculations based on data from Drillinginfo, EIA, and Bloomberg

unconventional wells drilling fell by about 8 percent.[16] We explore the reasons for this asymmetric relationship in detail in section III.

Figure 4 shows trends in the productivity of unconventional and conventional gas wells from 2000 to 2015 (2005-2015 for unconventional, as explained at the beginning of this subsection), measured by the average first full month of production of all wells drilled in the prior two quarters.[17] The figure shows the increase in average unconventional well productivity, which has nearly doubled since 2005.

[16]These numbers are the changes in total wells drilled for each well type in 2012, relative to 2010.

[17]We use a two-quarter average to avoid the noise that would be created by focusing only on wells drilled in individual months, some of which involve small numbers of observations, particularly given the small number of of conventional wells drilled in recent years as illustrated in Figure 3.

This productivity improvement demonstrates how, for a given price of gas, each unconventional well has generated increasing revenue, and thus how focusing solely on gas prices can misstate changes in the revenues gained from drilling.

To conclude, while the data focus on only Texas gas wells, these figures and summary statistics illustrate that our dataset is consistent with commonly-discussed trends in the industry and detailed conversations with industry participants.

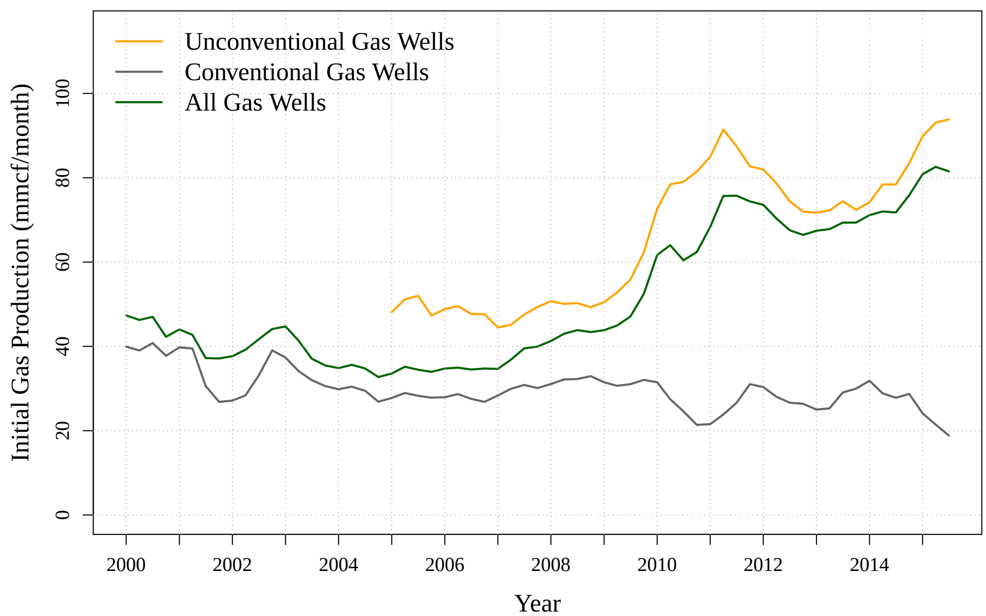

Figure 4: Average Gas Production Per Well During the First Full Month, 2000-2015, Quarterly

Sources: Authors' calculations based on data from Drillinginfo and EIA

III Models and Results

III.A Overview

We divide our analysis of the natural gas production process into three stages: the decision to commence drilling (or "spud") a well, how quickly to complete and start production at a well (conditional on spudding), and how quickly to extract gas from the well (conditional on first producing a well). We describe our analysis of the spud decision in section III.B, the completion and production start decision in section III.C, and the profile of the quantity produced in section III.D. Finally, we integrate the analysis of each of these different stages in section III.E.

III.B Stage 1: Commence Drilling (Spud) a Well

III.B.1 Drilling Estimation Method

Our empirical specification represents drilling activity as a log-linear approximation of the expected profits from drilling, which is a function of the expected present value of the future stream of revenues and costs associated with different types of gas wells. Recall that gas wells may produce oil in addition to gas (see Table 1), meaning that oil prices may affect the incentive to drill gas wells.

We estimate the relationship in first differences because both drilling activity and our oil & gas revenue variables are non-stationary time series, while they are stationary after taking first differences. This leads to the following specification for the number of gas wells drilled:

$$\Delta \ln(w_t) = \beta_0 + \sum_{l=0}^{L} [\beta_{1,l} \Delta \ln(\tilde{p}_{gas,t-l} \tilde{q}_{gas,t-l}) + \beta_{2,l} \Delta \ln(\tilde{p}_{oil,t-l} \tilde{q}_{oil,t-l})] + \boldsymbol{\gamma}'(\boldsymbol{\Delta X}_t) + \varepsilon_t \quad (1)$$

where w_t represents the number of wells that are spudded during period t, which is measured in quarters. Expected revenue in each period is equal to a well's expected cumulative output of gas and oil (denoted $\tilde{q}_{gas,t}$ and $\tilde{q}_{oil,t}$ respectively) multiplied by the price ($\tilde{p}_{gas,t}$ and $\tilde{p}_{oil,t}$) expected to be received for each type of output (in present value equivalents). $\boldsymbol{X}_t$ is an optional vector of cost controls for wells drilled in period t (all measured in logs). The primary parameters of interest are $\beta_{1,l}$, which represent the l-lagged elasticity of gas well drilling. We include $L = 2$ quarterly lags of the revenue variables to account for the fact that drilling a well takes time due to the need to obtain mineral rights, drilling permits, contracts with drilling service companies, and transport drilling rigs to well sites. In this specification, the long-run drilling elasticity with respect to gas prices[18] is given by $\sum_{l=0}^{L} \beta_{1,l}$.

The advantage of using expected revenue as an explanatory variable, rather than simply gas and oil prices as in many other studies, is twofold. First, it more closely reflects the reality that the incentive to drill a well depends on the well's *total* revenue, which depends in turn on the well's overall productivity rather than the price of one unit of its output. Second, the changes to well productivity contribute an additional source of revenue variation in the data. Intuitively, a 10 percent increase in production has the same revenue impact as a 10 percent increase in output prices.

For the expected future prices of gas and oil $\tilde{p}_t$, we use the simple average of the next 12 months of futures prices for Henry Hub natural gas and WTI oil, adjusted for inflation (see section II.B). This captures the fact that drilling decisions yield a stream of production (and profits) over the course of the coming months into the

[18]We do not distinguish between "revenue" or "price" elasticities since they are equivalent, due to the equality $\beta_{1,l} \ln(\tilde{p}_{gas,t-l}\tilde{q}_{gas,t-l}) = \beta_{1,l} \ln(\tilde{p}_{gas,t-l}) + \beta_{1,l} \ln(\tilde{q}_{gas,t-l})$. Intuitively, a 1 percent increase in prices is equivalent to a 1 percent increase in revenues, holding productivity constant.

future. Due to discounting and the relatively rapid decline in production from oil and gas wells (see Table 1), much of the present value revenue from oil and gas wells depends on prices in the first year or so of production.[19]

Because we do not observe each firm's expectations about well productivity ($\tilde{q}_{gas,t}$ and $\tilde{q}_{oil,t}$), we proxy for it using the measure of recent gas well productivity described in section II.C and plotted in Figure 4.[20] Our preferred specifications do not include controls, but including average well depth and lateral lengths as cost controls has little effect on the results.[21]

Studies of U.S. oil supply elasticities have typically not instrumented for oil prices based on the historically plausible argument that incremental production from the United States (and Texas in particular) is small relative to the global oil market. This argument is less sound for natural gas, which is primarily a North American market and has been strongly affected by the shale gas boom. In addition, the shale revolution has arguably played some role in the drop in oil prices in 2014 and 2015, raising new concerns about the endogeneity of oil prices. For these reasons, we instrument for both of our contemporaneous oil and gas revenue variables.[22]

[19]Conversations with industry participants also confirm that using futures prices is a reasonable approach for two other reasons: producers often look to futures markets for price expectations and/or hedge their output prices (at least for their wells' initial and most productive months).

[20]Specifically, we use the average initial production values (first full month) for wells drilled in the prior two quarters. Because production profiles decline quickly (Table 1), production in the first full month is a fairly reliable indicator of a well's long-term productivity. The correlation between first-month production and first-year production is 0.89, and for mature wells in the data that have produced the vast majority of their output, the correlation between first-month production and cumulative production is 0.72.

[21]The cost measures chosen are intuitive and comport with suggestions from industry operators.

[22]We do not instrument for lagged revenues. For 1- and 2-quarter lagged oil and gas prices to be potentially endogenous, one must argue that traders can anticipate changes in drilling activity and hence production as far as 9 months in advance and for prices to immediately adjust based on those

We use four instruments: U.S. population-weighted heating degree days (HDD), cooling degree days (CDD), lagged U.S. working gas inventories, and copper prices.[23] We include both contemporaneous values and up to three quarterly lags of these instruments, with the exception of gas inventories for which we only use the lagged values because the contemporaneous value is likely endogenous to gas prices.

The first three instruments are standard gas demand shifters. The final instrument, copper prices, is included as a proxy for global commodity demand to instrument for oil prices, inspired by Hamilton (2014). Indeed, the copper and oil prices are highly correlated (0.92 in levels and 0.71 in log-differences during 2000 Q1 - 2015 Q3), suggesting that the price of copper is a reasonable proxy for commodity demand shocks that also affect oil demand. Unless otherwise noted, all results are estimated using two stage least squares (2SLS).

To show the importance of the instruments and of the non-stationarity of the time series, we also present un-instrumented and un-differenced results. We also present estimation results separately for unconventional and conventional gas wells to test whether the drilling response is different for unconventional wells. The sample period begins in 2000 Q1 and ends 2015 Q3, and the unit of observation is one quarter. All standard errors are HAC robust.

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anticipations. Given that we are using quarterly data and that drilling activity is generally considered very difficult to forecast, we find this argument implausible and treat lagged revenues as exogenous.

[23]HDD, CDD, and gas inventory data is from EIA, available at `http://www.eia.gov/forecasts/steo/query/`. Copper prices are the average of the futures strip in 2014 dollars, collected from Bloomberg.

III.B.2 Drilling Estimation Results

Table 2 shows the results of estimating equation (1). The first three rows report the estimated price elasticity of drilling for 0, 1, and 2 quarterly lags of gas revenues. The sum of these effects is the long-run price elasticity (and revenue elasticity more generally), also reported in the middle of the table along with standard errors. Our preferred specification is the simplest one, found in column (1), finding a long-run drilling elasticity of 0.66, significant at the 1 percent level.[24] Column (2) adds cost controls, average vertical depth and lateral lengths, to the specification; these controls have little effect on the magnitude or significance of the long-run elasticity.

Columns (3) and (4) show results from re-estimating equation (1) separately for unconventional and conventional gas wells, including computing well productivity and revenues separately for each of these well types.[25] Despite using very different drilling activity and productivity variables (e.g., see Figures 3 and 4), the estimated elasticities (0.64 and 0.65) are very similar to each other and to the result found for both well types combined (0.66) shown in column (1). From this we conclude that there is no meaningful difference between the drilling elasticity for unconventional and conventional gas wells, supporting our preferred specification in column (1).

Column (5) shows the results of estimating the relationship without instruments. The long-run elasticities are somewhat smaller, as would be expected with endogenous gas and/or oil prices. Indeed, the Wu-Hausman tests reject the null of no endogeneity in every specification. Moreover, Sargan tests cannot reject the null

[24]This result is robust to using simple prices instead of our revenue variables. We still prefer to use our revenue variables because we believe they are more accurate depictions of firm incentives.

[25]For column (3)–the unconventional-only estimation–we focus on the 2005-2015 sample period for the reasons described above. Further, the small number of unconventional wells in the early 2000s leads to noisy and unreliable productivity estimates for revenues before 2005.

that our overidentifying restrictions are valid,[26]. This supports the need for and validity of the IV approach and our preference for the specification in column (1).

Columns (6) and (7) show the results of estimating the model in levels, with and without instruments. Given the non-stationarity of the time series, this approach would tend to be biased towards finding a large and spurious relationship, and indeed we find a long-run gas drilling elasticity naively estimated to be approximately 1.6. Ignoring the non-stationarity of the time series thus threatens to significantly overstate the gas elasticity.

In addition, the estimated relationship of gas drilling to oil prices changes sign when estimating in levels. Oil prices were high during the 2009-2014 period, during the time when aggregate gas drilling declined (mostly conventional, arguably due to falling gas prices, see Figure 3), creating a negative correlation between gas drilling and oil prices in levels. Taking differences avoids naively interpreting these diverging, non-stationary trends as causal and identifies a positive relationship between oil prices and gas drilling. Further, the elasticity with respect to oil prices is similar in size to the elasticity with respect to gas prices, consistent with operators being indifferent between the gas-versus-oil composition of their revenue streams.

Our estimate, 0.66, is similar to those derived from other recent sources. Hausman and Kellogg (2015) estimate a long-run drilling elasticity of 0.81 using a different methodology and smaller sample.[27] In addition, the long-run gas supply elasticity implied by the EIA's Annual Energy Outlook 2015 is approximately 0.5.

[26]Based on 2 endogenous variables (gas and oil revenues) and 15 instruments: 0-3 lagged differences of HDD, CDD, and copper prices, along with 1-3 lagged differences of gas inventories.

[27]That paper estimated the relationship in levels, rather than differences, which may in part explain their somewhat higher elasticity. Among other differences between our analyses, they used a different data source that could not distinguish between unconventional and conventional drilling.

In the next two sections we build on the analysis of the drilling decision assessed in this section and consider the subsequent stages of the production process. In section III.C we analyze the amount of time it takes for a well to begin producing once it is drilled. In section III.D we analyze the time profile of wells' gas production.

III.C Stage 2: Spud-to-Production Time

III.C.1 Duration Model

Once a well is spudded, production does not typically begin until at least a month later (see Table 1), and we find that there is considerable variation in how long each well takes to reach initial production. After spudding the well, the time to finish drilling the well depends on factors like well depth and the length of well laterals. The completion stage follows the drilling stage and may require artificially fracturing the well, which also increases the time to production. After completion, the well can begin producing natural gas and oil. Other factors that might influence completion times are fuel prices—whereby operators work faster when prices are higher to achieve revenues earlier—and logistics like renting a completion rig.

Figure 5 shows non-parametric kernel density estimates of the distributions for the spud-to-production time, separately for conventional and unconventional gas wells. Consistent with Table 1, unconventional wells tend to take longer to reach production, due to the additional labor required to horizontally drill and fracture.

To estimate the distribution of spud-to-completion times as a function of prices, we use duration models (i.e., survival time or hazard models) with time-varying coefficients. Denote the hazard function of well i of type j (conventional or unconventional) and beginning production t months after it was spudded by:

Table 2: Drilling Estimation Results

Dep. Var: Log(Wells Drilled)	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Log(Gas Revenues)	0.28	0.26	0.27	0.28	0.14	1.00	0.60
	(0.15)	(0.17)	(0.14)	(0.22)	(0.09)	(0.27)	(0.09)
Log(Gas Revenues), 1 Lag	0.30	0.24	0.33	0.33	0.34	0.00	0.38
	(0.1)	(0.09)	(0.17)	(0.12)	(0.09)	(0.18)	(0.1)
Log(Gas Revenues), 2 Lags	0.08	0.07	0.05	0.04	0.01	0.65	0.55
	(0.13)	(0.11)	(0.15)	(0.13)	(0.09)	(0.1)	(0.04)
Log(Oil Revenues)	0.39	0.45	0.37	0.41	0.19	0.23	0.16
	(0.17)	(0.16)	(0.17)	(0.15)	(0.11)	(0.41)	(0.09)
Log(Oil Revenues), 1 Lag	0.02	-0.02	-0.04	0.02	0.11	-0.21	-0.07
	(0.15)	(0.12)	(0.14)	(0.11)	(0.12)	(0.33)	(0.05)
Log(Oil Revenues), 2 Lags	0.15	0.25	0.25	0.12	0.14	-0.28	-0.35
	(0.15)	(0.16)	(0.18)	(0.12)	(0.16)	(0.11)	(0.07)
Log(Average Vertical Depth)		-2.50					
		(0.85)					
Log(Average Lateral Length)		0.41					
		(0.14)					
Constant	-0.06	-0.05	-0.05	-0.05	-0.05	-6.36	-5.23
	(0.03)	(0.03)	(0.05)	(0.02)	(0.03)	(0.52)	(0.24)
Observations (Quarters)	63	63	43	63	63	63	63
R-Squared	0.37	0.44	0.26	0.44	0.46	0.68	0.70
Adj. R-Squared	0.30	0.36	0.14	0.38	0.41	0.65	0.67
Long-Run Gas Price Elasticity	0.66	0.56	0.64	0.65	0.50	1.65	1.53
	(0.22)	(0.22)	(0.26)	(0.29)	(0.14)	(0.08)	(0.03)
Long-Run Oil Price Elasticity	0.56	0.68	0.58	0.56	0.44	-0.27	-0.27
	(0.24)	(0.25)	(0.32)	(0.22)	(0.23)	(0.03)	(0.02)
Estimation Method	2SLS	2SLS	2SLS	2SLS	OLS	2SLS	OLS
Variables in levels or differences?	Diffs.	Diffs.	Diffs.	Diffs.	Diffs.	Levels	Levels
Wells Included	All Gas	All Gas	Unconv. Gas	Conv. Gas	All Gas	All Gas	All Gas
First-stage F statistics							
Gas Revenues	7.50	9.79	7.68	2.81	na	3.31	na
Oil Revenues	4.92	3.75	7.19	2.11	na	13.84	na
p-value, Wu-Hausman test for endogeity	*0.009*	*0.017*	*0.022*	*0.000*	na	*0.000*	na
p-value, Sargan overidentification test	*0.480*	*0.318*	*0.334*	*0.732*	na	*0.119*	na

HAC standard errors in parentheses. Sample period is 2000-2015, quarterly, with the exception of (3) which is estimated over 2005-2015 because that is when the shale gas boom began in earnest. Instruments are Cooling Degree Days (CDD), Heating Degree Days (HDD), copper prices, and gas inventories. With the exception of gas inventories, contemporaneous and 1-3 lagged values are used as instruments. Contemporaneous gas inventories are not used, as these are likely endogenous to gas prices. All variables are in differences with the exception of (7) and (8). In (3) and (4), the computation of revenues is performed separately for unconventional and conventional wells to account for differences in productivity trends between these types of wells.

Sources: Authors' calculations based on data from Drillinginfo, EIA, and Bloomberg

$$h(t, \boldsymbol{X}_{i,j,t}, \boldsymbol{\theta}_j) = \frac{f(t, \boldsymbol{X}_{i,j,t}, \boldsymbol{\theta}_j)}{1 - F(t, \boldsymbol{X}_{i,j,t}, \boldsymbol{\theta}_j)}, \tag{2}$$

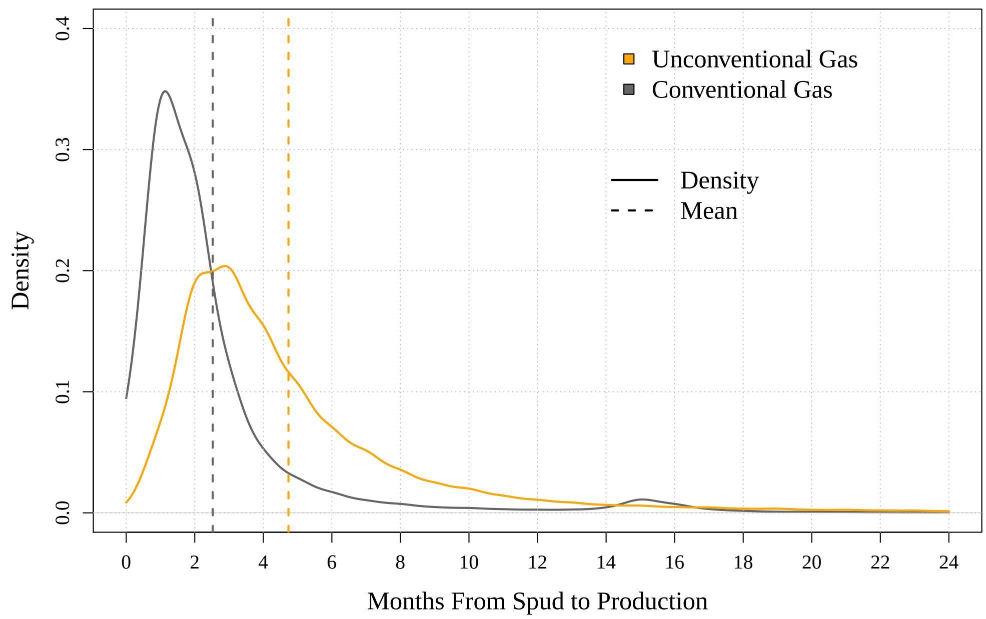

Figure 5: Non-parametric Densities of Time from Spud to Initial Production, by Well Type

Sources: Authors' calculations based on data from Drillinginfo and EIA

where $f(t, \boldsymbol{X}_{i,j,t}, \boldsymbol{\theta}_j)$ is the density function of the spud-to-production time, and $F(t, \boldsymbol{X}_{i,j,t}, \boldsymbol{\theta}_j)$ is the corresponding cumulative distribution function. $\boldsymbol{X}_{i,j,t}$ is a vector of explanatory variables, some of which may change over time (for example, gas and oil prices can and do change over time). Hence, the hazard function describes the probability that a well with characteristics $\boldsymbol{X}_{i,j,t}$ will begin production t months after it was spudded, given that it has not yet begun producing.

We estimate this model using maximum likelihood by assuming an underlying density $f(\cdot)$ to specify the form of the baseline hazard function. We focus on using the generalized gamma distribution, which is a very flexible distribution that is parameterized by two ancillary parameters determining the shape of the distribution.[28] We found that the gamma distribution results in an estimated distribution that closely resembles the non-parametric distributions shown in Figure 5 and also yields a significantly higher log-likelihood than other alternatives.[29]

A hazard model estimated with the gamma distribution is parameterized in an "accelerated failure time" (AFT) setup. In this setup, the explanatory variables can be interpreted as additively affecting the observation's logged expected "failure" time, which here is the time it takes for a spudded well to reach production. This implies that if an increase in gas prices encourages operators to work faster to speed up the time of production, this would be represented as a negative coefficient in the AFT model (i.e., reducing the time to production).

We estimate the hazard models for each unconventional and conventional wells independently, with no cross-equation restrictions. This allows each well type to have its own distribution, in addition to its own estimated parameters. As in the drilling regressions in section III.B, the explanatory variables include (in logs): expected revenue from gas and oil production,[30] and cost controls of well depths and

[28]The density of the gamma distribution is given by,

$$f(t) = \begin{cases} \frac{\gamma^\gamma}{\sigma t \sqrt{\gamma}\Gamma(\gamma)} \exp(z\sqrt{\gamma} - u) & \text{if } \kappa \neq 0 \\ \frac{1}{\sigma t \sqrt{2\pi}} \exp(-z^2/2) & \text{if } \kappa = 0, \end{cases}$$

where $\gamma = |\kappa|^{-2}$, $z = \text{sign}(\kappa)(\ln(t) - \mu)/\sigma$, $u = \gamma \exp(|\kappa| z)$, $\Gamma(\cdot)$ is the gamma function, and we parameterize $\mu = \boldsymbol{X}'_{i,j,t}\boldsymbol{\theta}_j$. We estimate the ancillary parameters σ and κ from the data.

[29]We test the Weibull, exponential, Gompertz, Log-normal, and Log-logistic distributions. Several of these distributions are special cases of the gamma distribution (namely, the Weibull, exponential, and log-normal distributions). For those nested distributions we can test for whether the gamma distribution's better fit is statistically significant: we find it is in all cases. We also compared the results to a Cox proportional hazards model, which leaves the baseline hazard unspecified: the key estimates were generally in the same directions and of similar relative sizes.

[30]As before, the results are robust to simply using gas and oil prices, but we use the revenue variables as we believe they are more accurate depictions of firms' incentives. We do not use instrumental variables as the theoretical and empirical literature for implementing them in duration

lateral lengths. We also explore the possibility that spud-to-completion times are affected by drilling experience by including a cumulative count of unconventional gas wells drilled as another control.

The unit of observation is a well-month, which means we can use well-specific characteristics (lateral length and well depth) rather than the means across wells used in the drilling equations of the prior section. Nonetheless, even though we observe wells' realized production, we do not use it because firms do not know with certainty how productive a well will be until it actually starts producing. Hence, using the well's actual, *ex post* production as an explanatory variable would imply that the firm responds to unobservable information. Instead, we use the same method of calculating productivity and revenues used in the drilling equations.[31] In the terminology of hazard analysis, we consider a well to be "at risk" of being produced for 24 months following its spud month, at which point it exits our sample.[32]

III.C.2 Spud-to-Production Duration Estimation Results

Table 3 shows the estimates of the duration models. Our preferred estimates are again the simplest ones, shown in columns (1) and (4) for unconventional and conventional wells respectively. The first coefficient reported in column (1) is -0.172, indicating that a 10 percent increase in the gas price (or revenues more generally) is expected to reduce the time to production for an unconventional well by less than 2 percent. Across columns (1) through (3), unconventional wells have generally

models is very limited. We are aware of only one published paper, MacKenzie et al. (2014), that considers the implementation of instrumental variables in duration models; that study only applies to a Cox proportional hazard setup, as opposed to the accelerated failure time model that we use.

[31] Since we conduct the hazard analysis at the monthly level, average revenues are calculated on a monthly basis, rather than quarterly.

[32] We chose 24 months for the reasons described in section II.B

consistent price response coefficients between -0.06 and -0.17. The corresponding responses for conventional wells, found in columns (4) through (6), are somewhat more modest, with coefficients in the range of -0.08 to -0.10.[33]

Table 3: Spud-to-Production Duration Model Results

	(1)	(2)	(3)	(4)	(5)	(6)
Spud-to-Production Survival Time	**Unconventional Gas Wells**			**Conventional Gas Wells**		
Log(Gas Revenues)	-0.172	-0.113	-0.0576	-0.0754	-0.0974	-0.0889
	(0.0148)	(0.0143)	(0.0152)	(0.00821)	(0.00819)	(0.00831)
Log(Oil Revenues)	0.0275	-0.0209	-0.0498	0.0855	0.0786	0.0228
	(0.00340)	(0.00381)	(0.00500)	(0.00613)	(0.00593)	(0.0110)
Log(Vertical Depth)		-0.0217	-0.0297		0.226	0.222
		(0.0163)	(0.0162)		(0.00745)	(0.00746)
Log(Lateral Length)		0.187	0.18			
		(0.00472)	(0.00470)			
Log(Cum. Unconv. Gas Spud Count)			0.102			0.035
			(0.0112)			(0.00592)
Constant	2.856	1.371	0.235	0.992	-0.82	-0.791
	(0.160)	(0.214)	(0.235)	(0.0743)	(0.0948)	(0.0947)
Gamma Density Function Parameters						
σ	0.48	0.46	0.46	0.51	0.49	0.49
κ	-0.55	-0.60	-0.60	-0.66	-0.74	-0.74
Well-Months (N*T)	146,859	146,736	146,736	126,990	126,990	126,990
Wells (N)	25,725	25,701	25,701	36,055	36,055	36,055
Log-Likelihood	-19,025	-18,130	-18,087	-29,148	-28,555	-28,536
p-value on test of equal unconv./conv. gas elasticities	<0.0001	0.33	0.07			

Clustered standard errors in parentheses. Standard errors are clustered at the well level. Coefficients can be interpreted as elasticities of expected spud-to-completion time.

Sources: Authors' calculations based on data from Drillinginfo, EIA, and Bloomberg

Increases in oil revenues seem to slightly discourage conventional natural gas efforts, potentially representing a substitution effect, while having more muted and ambiguous effects on unconventional effort. The coefficient on lateral lengths sensibly indicates that unconventional wells with longer laterals take longer to reach production, consistent with longer drilling and completion periods. Well depth plays an analogous role for conventional wells: deeper wells take longer to reach production.

The "learning" proxy variable (unconventional spud counts) has a counter-intuitive sign in the unconventional equation in column (3). However, this variable grows

[33] These results are robust to including lagged oil and gas revenues. The coefficients on the lagged values were small and generally insignificant. The sum of the contemporaneous and lagged coefficients were very similar to the coefficients reported in Table 3.

roughly linearly in time, and it therefore acts similarly to a time trend, and is therefore ambiguous to interpret. It is indicative that spud-to-production times have not obviously fallen with experience. Indeed, the average spud-to-production time for unconventional wells during 2005-2009 was 4.1 months, compared to 5.2 months for 2010-2015. This positive coefficient on the cumulative spud counts cannot entirely be explained by longer lateral lengths, because this variable is included in equation (3). Regardless, these controls do not substantially affect the qualitative conclusions regarding the price responsiveness of spud-to-production times.

The shape of the gamma distribution of spud-to-production time is also estimated in the model, separately for each well type. The resulting shapes are plotted in Figure 6 at covariate means, along with the same non-parametric, kernel density estimate of the underlying distribution shown in Figure 5. The fitted gamma distributions strongly resemble the non-parametrically estimated densities, suggesting that the gamma distribution fits the true baseline hazard distribution well and is not driving the coefficient estimates. The estimated shape also demonstrates that monotonic functional forms (exponential, Gompertz, Weibull) would be inappropriate. While the gas price response coefficients are precisely estimated and their signs are consistent with economic expectations, they are small. For example, in order to achieve a 10 percent reduction in spud-to-production time for conventional wells, gas prices would have to nearly triple. For the more-responsive unconventional wells, gas prices would have to nearly double.[34]

This lack of strong price response is illustrated in Figure 7. That figure plots the parameterized gamma distributions for each well type under alternative natural

[34]These required price changes represent the change in gas prices needed to shift the fitted distribution, computed at covariate means, such that the mean of the distribution decreases by 10 percent.

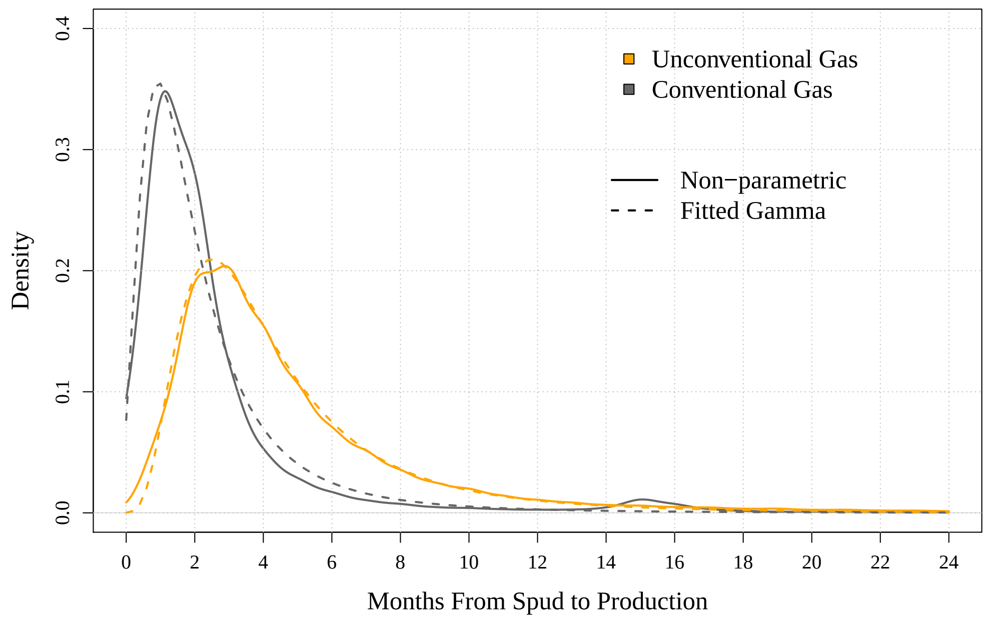

Figure 6: Estimated Spud-to-Production Time Distribution, by Well Type

Sources: Authors' calculations based on data from Drillinginfo, EIA, and Bloomberg

gas price assumptions of \$3.00 and \$6.00 per million Btu.[35] The effects are not large. Despite an assumed doubling of natural gas prices, the effect on the spud-to-production time distribution is modest.

These results suggest that once drilling has commenced, gas prices do not strongly influence the decision about whether and how fast to begin producing a well. This is sensible, since once drilling has begun, much of the well development costs have been sunk. There also may be limited opportunities for speeding up the completion

[35]This figure assumes 2015 average productivity values and a \$50 per barrel oil price.

process beyond a certain point.[36] With low additional marginal costs of production, operators typically have strong incentives to begin production as soon as possible.

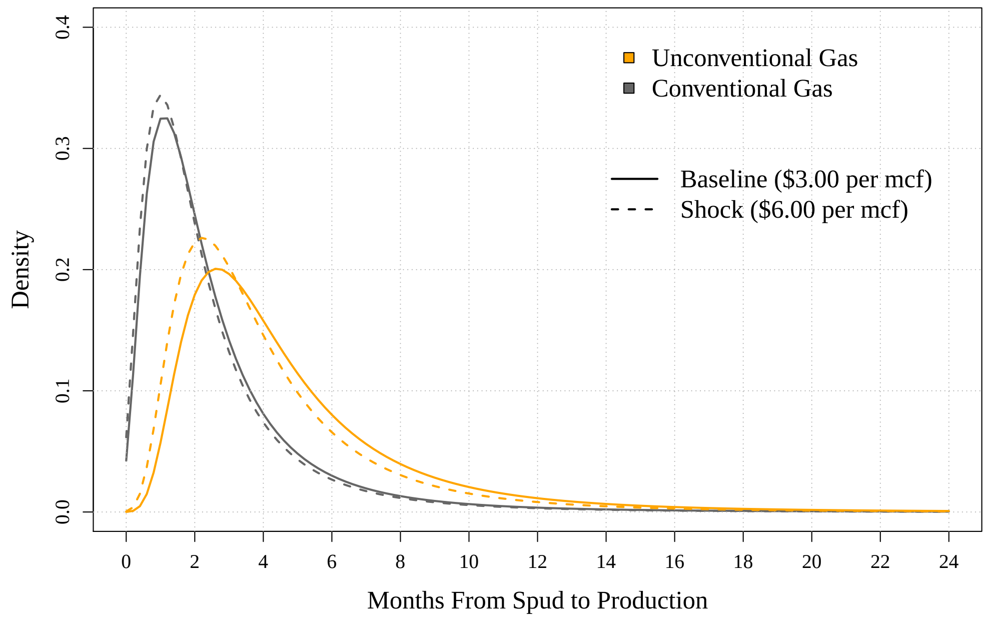

Figure 7: Illustration of Gas Price Effect on Spud-to-Production Time, by Well Type

Sources: Authors' calculations based on data from Drillinginfo, EIA, and Bloomberg

III.D Stage 3: Production Profile over Time

III.D.1 Production Profile Estimation Method

The final stage of the gas production process is the flow of gas from wells once they begin producing, and how that flow evolves over time. In this section, we estimate the time profile of well-level gas production and its relationship with prices.

[36] Although there is always the option to slow down or stop the completion process in the face of low prices, this may not save costs if service contracts are already in place.

Once a well begins producing, it often produces gas and oil for many years, with the production profile being determined principally by reservoir pressure. Because the variable cost of production from an existing well is very low, an operator would typically want to produce oil and gas at a well's capacity. For this reason, we would not expect gas and oil prices to have a significant effect on production from existing wells by a competitive firm. Instead, a well's flow rate is largely determined by the amount of pressure left in the reservoir to force the resource to the surface. The flow rate is therefore generally out of the operator's control.[37] These arguments are analyzed at an aggregate level for oil in Anderson, Kellogg and Salant (2014), and we find similar results for gas at the well level.

Even if production from existing wells is not price responsive itself, understanding the time profile of production is nonetheless still important to understanding aggregate supply responsiveness. This is because these profiles determine the relationship between drilling effort and realized production over time, and production profiles are quite different for unconventional versus conventional wells.

As described further in the next section, our estimates show a lack of price response of output from existing gas wells using a detailed panel dataset describing monthly gas production for each well's productive life. Specifically, we run fixed-effects regressions of the form:

$$\ln(q_{i,gas,j,t}) = \chi_i + \eta_{gas,j} \ln(p_{gas,t}) + \eta_{oil,j} \ln(p_{oil,t}) + g_j(Age_{i,t}) + \varepsilon_{i,j,t}, \quad (3)$$

[37] There are some exceptions. Firms can extract more hydrocarbons through investments in enhanced recovery methods like pumps (for oil) and various injection methods. For unconventional reserves, firms have the added option to re-fracture the well, which can create new fissures that release more hydrocarbons to the surface.

where i indexes the well and t indexes the calendar time in months. $q_{i,gas,j,t}$ is the gas production from well i of type j in month t. χ_i is a well-level fixed effect, which can roughly be interpreted as initial (log) production for well i. $p_{gas,t}$ and $p_{oil,t}$ are prompt-month gas and oil prices. The parameters of interest are $\eta_{gas,j}$ describing the contemporaneous price elasticity of gas production from a well (of type j) that has already been drilled. We use spot (i.e., prompt-month) oil and natural gas prices because of the immediate nature of the potential price response from existing wells.[38] Given the well-level fixed effects, our identification of the price response comes from changes in prices during the life of a well. The discussion above and prior evidence suggests that this parameter would be estimated as being close to zero. Regardless, the different production profiles of wells can still be consequential for the overall supply responsiveness to prices because this stage is conditioned on the earlier drilling decision, which we found above is responsive to price.

$Age_{i,t}$ is the age of well i at time t (i.e., the number of months since it began production). $g_j(Age_{i,t})$ is a function of the age of a well of type j, and we allow for flexible production profiles by approximating this function using polynomials of varying degrees as well as a cubic spline.[39] We conduct specification tests to select among these alternative flexible functional forms. We drop the first month of production, as wells are often only operating for a fraction of this month, instead beginning with the first full month of production. The age function is indexed by j to allow the average production profile to vary based on well type (i.e., unconventional versus conventional). Standard errors are clustered at the well level.

[38]Using lagged prices does not substantially affect the results.

[39]The cubic spline uses knots at every 12-month interval after initial production.

III.D.2 Production Profile Estimation Results

Table 4 contains the results for the fixed effects regressions for unconventional and conventional gas wells. Consistent with the above discussion, we find very small coefficients on natural gas prices, suggesting that gas production from existing wells is not price responsive. The elasticity point estimates are small, typically ranging between +0.09 and -0.04 (with one exception in column (5), discussed below), all very close to zero and often of a theoretically implausible sign. The same is true for oil price coefficients, which are generally very close to zero and occasionally insignificant despite small standard errors.[40]

The substantial size of our dataset (over 5 million well-month observations for conventional and unconventional wells combined) generates very small standard errors. As a result, even many of these very small estimates (e.g., smaller than 0.02 in magnitude) are nevertheless significant at the 1 percent level. These negligible elasticity estimates are generally robust to variations in the functional form describing the decline path. Polynomials of orders one through four and cubic splines produce similar results. The linear-in-age specification in column (1) is probably insufficiently flexible because production is commonly observed to decline slower-than-exponentially (as captured by a positive "b" parameter in the Arps equation), and a linear specification effectively assumes an exponential decline. We find support for slower-than-exponential declines in the significant positive coefficient on the well-age-squared terms in columns (2) through (4). We also include a specification using $\log(Age_{i,t})$, following Patzek, Male and Marder (2013) who argue for

[40]Excluding oil prices from the specification completely (not shown) also has little effect on the results, except in column (1), where it shrinks the gas price coefficients even closer towards zero.

Table 4: Well Production Profile Fixed Effects Regressions

Dep. Var.: Log(Gas Production)	(1)	(2)	(3)	(4)	(5)	(6)
Unconventional Wells						
Log(Gas Price)	0.09	-0.01	-0.04	-0.03	0.08	-0.04
	(0.009)	(0.009)	(0.008)	(0.008)	(0.009)	(0.008)
Log(Oil Price)	-0.07	0.04	0.01	0.01	0.03	0.01
	(0.006)	(0.006)	(0.006)	(0.006)	(0.006)	(0.006)
Well Age (months)	-0.021	-0.044	-0.067	-0.086		
	(0.000131)	(0.000276)	(0.000476)	(0.000749)		
Well Age^2 (months)		0.00023	0.00076	0.00153		
		(0.000003)	(0.00001)	(0.000028)		
Well Age^3 (months)			-0.0000032	-0.0000136		
			(0.0000001)	(0.0000004)		
Well Age^4 (months)				0.00000004		
				(0.000000002)		
Log(Well Age)					-0.679	
					(0.00302)	
Conventional Wells						
Log(Gas Price)	0.09	-0.01	0.03	0.03	0.23	0.04
	(0.006)	(0.005)	(0.005)	(0.005)	(0.005)	(0.005)
Log(Oil Price)	-0.19	0.01	0.01	0.02	-0.05	0.01
	(0.005)	(0.005)	(0.005)	(0.005)	(0.005)	(0.005)
Well Age (months)	-0.017	-0.035	-0.052	-0.069		
	(0.000077)	(0.000168)	(0.000282)	(0.000433)		
Well Age^2 (months)		0.00011	0.00039	0.00085		
		(0.000001)	(0.000004)	(0.000011)		
Well Age^3 (months)			-0.0000011	-0.0000054		
			(0.00000002)	(0.0000001)		
Well Age^4 (months)				0.00000001		
				(0.0000000003)		
Log(Well Age)					-0.763	
					(0.00241)	
N (Well-Months)	5,331,586	5,331,586	5,331,586	5,331,586	5,331,586	5,331,586
Number of Wells	62,568	62,568	62,568	62,568	62,568	62,568
Well Fixed Effects	✓	✓	✓	✓	✓	✓
Cubic Spline						✓
R-Squared (Full Model)	0.744	0.759	0.762	0.763	0.762	0.764
R-Squared (Excluding Fixed Effects)	0.352	0.388	0.397	0.400	0.396	0.401

Clustered standard errors in parentheses. The first month of each well's production is dropped, as wells are typically operational for only a fraction of its first month.

Sources: Authors' calculations based on data from Drillinginfo, EIA, and Bloomberg such a specification for unconventional gas wells in the Barnett shale formation, a subset of our data.[41]

In general, we do not find a positive price response of gas production from existing wells. To our knowledge, this is the only published study that finds empirical evidence for this proposition using well-level data. Because the negligible observed price response from existing wells comports with both structural economic factors and empirical evidence, we proceed to model production from existing wells as completely unresponsive to price. This assumption also allows us to model well production profiles non-parametrically in our combined model in Section III.E.

To represent the production profile from unconventional and conventional wells, we use the mean monthly production in our dataset by well age. For example, to estimate the production from an average unconventional well in its 7th month of production, we calculate the average production from every unconventional well in our dataset during its 7th month.[42] The results of this procedure are illustrated in Figure 8. The solid lines in that figure represent the mean production profile of unconventional (orange) and conventional (gray) wells. The dashed lines represent the median production profiles.

[41] Patzek, Male and Marder (2013) specifically argue that the coefficient on $\log(Age_{i,t})$ should be approximately -0.50 for unconventional gas wells, but we find a somewhat larger coefficient of -0.68. If we include each wells' first, partial month of production, we find an estimated coefficient of -0.52, very close to -0.50. However, including the first, partial month is inappropriate when fitting parametric decline curves, as an inspection of Figure 8 suggests. Regardless, our finding of no meaningful price response is generally robust to including wells' first, partial months. The only specification with an economically meaningful gas price response estimate is the one using $\log(Age_{i,t})$ for conventional reservoirs, which is likely inappropriate because Patzek, Male and Marder (2013) only advise using that functional form for unconventional Barnett wells, not conventional ones.

[42] For each well that has ceased production before the end of our sample period, we impute zero production in each month after its last month of production when calculating this average.

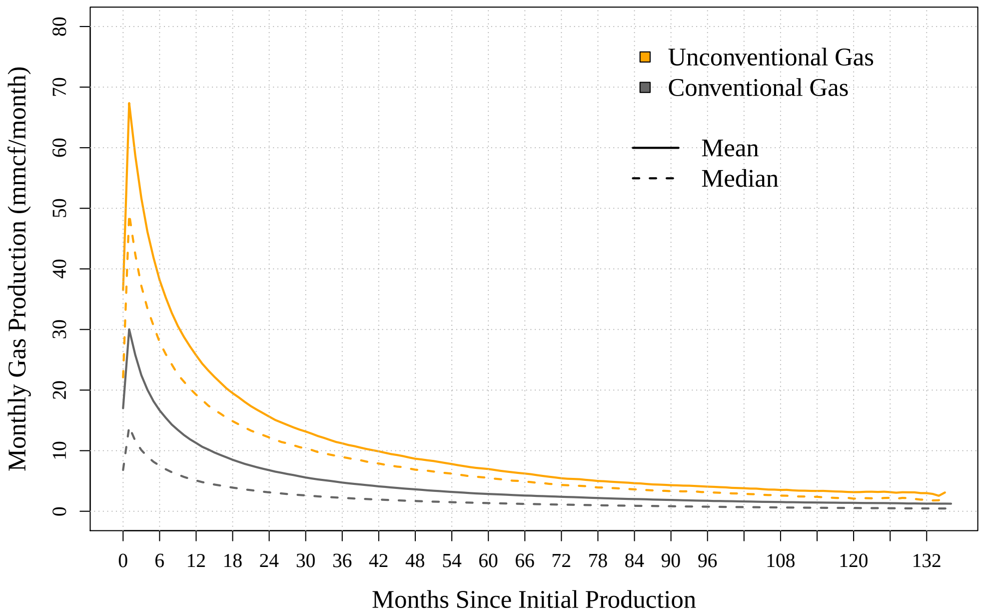

Figure 8: Mean and Median Profile of Monthly Gas Production from Gas Wells

Sources: Authors' calculations based on data from Drillinginfo and EIA

These production profiles reflect the well characteristics presented in Table 1. The mean and median unconventional production profiles strongly resemble each other, suggesting that unconventional gas production profiles are generally not very skewed in productivity. In contrast, the median conventional well produces much less than the mean, indicating a right-skewed distribution with some highly-productive "jackpot" reservoirs and many relatively "dry holes." These facts align with discussions of decline paths in industry and popular press.

However, as mentioned previously, in percentage terms, the decline curves are not very different between unconventional and conventional wells in our data. Figure 9 shows these decline curves scaled as a percent of initial production, and all

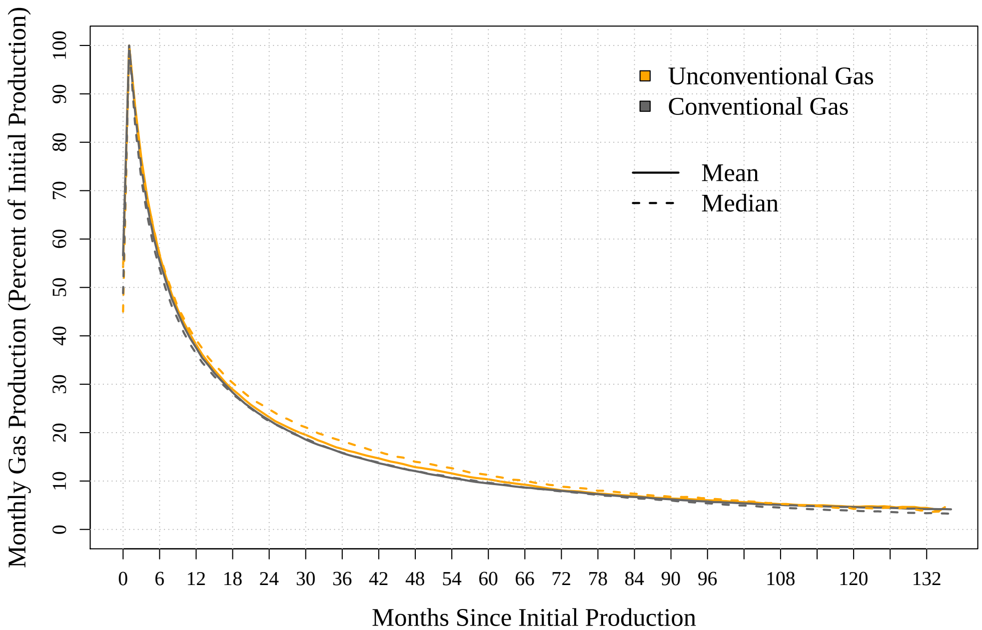

Figure 9: Mean and Median Profiles of Monthly Gas Production from Gas Wells, as a Percent of Initial Production

Sources: Authors' calculations based on data from Drillinginfo and EIA

four curves appear nearly identical, suggesting that the main difference between unconventional and conventional gas wells in Texas are in the magnitude, rather than shape, of the production profile.

III.E Integrating Natural Gas Supply Stages to Measure Overall Price Responsiveness

III.E.1 Integrated Model of Well Drilling, Production, and Decline over Time

In this section, we combine the analysis of the three gas supply stages from the preceding sections into a single integrated simulation model. The purpose of this integrated model is to understand the overall price-responsiveness of natural gas supply, how it evolves over time, and how it differs between unconventional and conventional resources. The three separate stages of the natural gas production process are the spud decision, the time from spudding to the first production of a well, and the production profile of a gas well over time. We link these stages together by simulating the effects of an unexpected, permanent 10 percent shock to natural gas prices (from $3.00 to $3.30 per million Btu). We then illustrate the effect of this shock on drilling activity and natural gas production over time in a manner readily understandable in percentage and elasticity terms.

This shock increases the number of spuds of each well type in every period, based on the elasticities presented in Table 2. The additional spudded wells take time to reach production, according to the estimated distributions associated with the hazard estimation results in Table 3 (illustrated in Figures 6 and 7). We then use the mean production profile shapes presented in Figure 8 to simulate the amount of production from wells of each type. We scale up the unconventional profile by a factor of approximately 1.2 to reflect the higher initial productivity levels of about 80,000 mcf per month in recent years (2010 to 2014), relative to average levels of about 67,000 over the entire 2005 to 2015 period.[43] The result is a time series of changes in production by well type. Given this, it is straightforward to calculate a time-varying supply elasticity by dividing the change in production (as a percentage) by the assumed price shock (10 percent in this simulation).

[43]We exclude 2015 when computing recent productivity (of 80,000 mcf) out of concern that the large jump in productivity during that year reflects not permanent innovation but instead a temporary re-focusing of efforts on "sweet spots" during a time of low oil & gas prices, which can be seen in Figure 4.

We begin by noting that, given the number of wells drilled, the number of wells beginning production at month t is the accumulation of wells that were spudded in recent months. We can write this relationship precisely using the spud-to-production distributions in Table 3 (seen in equation (2) and illustrated in Figures 6 and 7). Denoting the discrete analogues of these distributions as $f_{j,l}$ for a well type j beginning production l months after spudding, we can write the number of wells beginning production at month t, denoted $x_{j,t}$, as a function of $f_{j,l}$ and the number of wells spudded in each of preceding 24 months, denoted $w_{j,t}$, as follows:

$$x_{j,t} = \sum_{l=0}^{24} w_{j,t-l} f_{j,l}. \tag{4}$$

Equation (4) thus combines supply stages 1 and 2: well drilling and commencement of production. Next, by combining this with stage 3—well-level production profiles—we can calculate the total gas production over time. As in the production profile analysis (see equation (3)), we use $q_{gas,j,\tau}$ to denote gas production of a well of type j in its τ^{th} month of operation. Denoting the productive life of a well of type j as T_j, we can write total gas production at time t from all wells of type j as:

$$Q_{gas,j,t} = \sum_{\tau=0}^{T_j-1} x_{j,(t-\tau)} q_{gas,j,\tau}. \tag{5}$$

Using equations (4) and (5) and the results from the drilling, completion, and production models (sections III.B, III.C, and III.D), we can simulate the effect of a change in prices on spuds ($w_{j,t}$), wells entering production over time ($x_{j,t}$), and aggregate gas supply over time ($Q_{gas,j,t}$).

Note that it takes a significant period of time to reach a steady state in gas production after a price shock because today's production depends on events that happened as long at T_j periods ago. For example, if a typical well produces for 10 years, then today's production level depends to some degree on drilling 10 years ago. This inertia is endemic to oil and gas supply dynamics, and it underpins much of the cyclicality in these markets. However, since old wells produce little, the effect of a price change is front-loaded. A key issue of interest for this paper is whether unconventional resources and technologies may reduce the volatility inherent in this industry characterized by large fixed investments and low variable production costs.

In our simulation's baseline, we assume constant prices, implying that the quantity of drilling $w_{j,t}$ does not vary over time, denoted w_j^{base}. Given this and equation (4), the number of wells entering production each month in the baseline equilibrium (i.e., without a price shock) is also constant:

$$x_j^{base} = w_j^{base} \sum_{l=0}^{24} f_{j,l} = w_j^{base}, \tag{6}$$

where the latter equality follows because the density of spud-to-production time must sum to one: $\sum_{l=0}^{24} f_{j,l} = 1$.[44] This and equation (5), in turn, imply that baseline gas production is also in steady state in the baseline:

$$Q_{gas,j}^{base} = x_j^{base} \sum_{\tau=0}^{T_j-1} q_{gas,j,\tau}. \tag{7}$$

[44]In reality, not all spuded wells go on to produce. However, for simplicity we are ignoring this complication. An exploration of Drillinginfo's permit dataset found only a small fraction of the wells in our dataset for which we could identify as unconventional or conventional that were drilled but never reached production. For this reason, we ignore such wells. However, including them would simply multiplicatively scale down the price responsiveness for both well types slightly.

Using equations (4) through (7), we compute the number of wells beginning production and quantities of gas produced over time, by well type, under a baseline price scenario of \$3.00 per million Btu and a scenario with a permanent 10 percent increase to \$3.30 per million Btu.

III.E.2 Overall Unconventional vs. Conventional Gas Supply Responsiveness

For this analysis of the supply impact of a 10 percent gas price increase, we use our preferred estimates for spud elasticities from columns (1) of Tables 2 and 3. The production profiles are represented by the mean production over time for each well type, shown by the solid lines in Figure 8, with the unconventional profile scaled up to reflect productivity increases, as described above.

We must also specify how many wells of each type are drilled in the baseline. To capture the relative supply elasticities, we run the simulation separately for unconventional and conventional wells, each time assuming the same spud baseline of 72 wells for each type: $w_{conv}^{base} = 72$ or $w_{unconv}^{base} = 72$.[45] From these baselines, we simulate the time series of the number of new wells entering production and aggregate gas production for each type of well.

We then convert the change in wells beginning production and gas produced to percentage changes. To compare the results for unconventional and conventional wells on an equal footing, when computing the percentage changes in gas production, we divide by the same denominator in each case: the amount of gas consistent

[45] 72 is the average number of monthly unconventional gas spuds in our data during our final sample year, January 2015 - September 2015. The breakdown was 61 unconventional spuds and 11 conventional spuds. We use the same baseline for unconventional and conventional spuds in order to conduct the thought experiments, "what would the price responsiveness look like if all gas drilling were conventional (unconventional)?" Using a different baseline for the two well types would bias the comparison towards the one with the larger baseline.

with the types of wells actually drilled in our data, on average, in 2015.[46] This equal denominator allows one to observe that, even if more conventional wells existed in 2015 than actually did (72 instead of 11), their much lower productivity means that they would still contribute relatively little to the overall gas supply response.

The simulation results are shown in Figure 10. The left panel shows the change in number of wells beginning production each month for unconventional and conventional wells as a percentage of the baseline number of wells. The price shock at period zero leads to new drilling effort which gradually bears fruit over the course of the subsequent 24 months and beyond. After 24 months, the wells reach a new "steady state," with the same number of wells beginning production in every month.

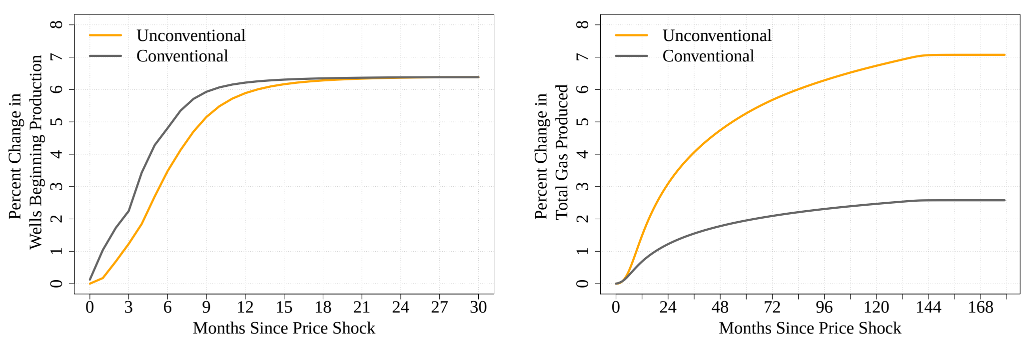

Figure 10: Change in Wells Beginning Production and Natural Gas Produced, Following a 10 Percent Price Shock

Sources: Authors' calculations based on data from Drillinginfo and EIA

The right panel combines the results of the left panel with production decline paths and traces out the effect of the price shock on incremental natural gas supply,

[46]The baseline gas production corresponds to the production from 61 unconventional gas wells and 11 conventional gas wells, computed in steady state using the average production profiles used in this simulation and depicted in Figure 8. The amount is simply the cumulative total production across the average well's lifetime, by well type, multiplied by the baseline number of spuds (61 and 11 for unconventional and conventional respectively).

which shows a similar gradual adjustment. Each incremental well in the left panel produces for many years; as a result, the rising drilling effort builds on itself, until we reach a new steady state after more than a decade. Before reaching the steady state, some portion of the production is from "legacy" wells drilled before the price shock. In other words, an immediate 7 percent increase in drilling effort increases total gas production by less than 7 percent because of the lack of response from legacy wells, at least until those wells eventually cease production and a new steady state is reached. Only once the increased drilling effort has propagated throughout the system does it fully affect the level of gas produced.

The primary finding is that unconventional gas supply is in fact much more responsive to price changes than is conventional gas supply once one takes an integrated view of the entire production process. The time and shape of the path to reach the steady state depends on both the shape of the spud-to-production distributions and the production profiles. The more front-loaded the distribution and production profile are, the faster the drilling effort translates into increased production.

Note that these effects are partly, but not completely, offsetting for unconventional wells. On one hand, unconventional wells are more productive than conventional wells (see Figure 8). This supports the notion that unconventional gas production should respond more to a price change than conventional wells would. On the other hand, unconventional wells generally take longer to reach production (see Figure 6), which somewhat moderates the short-term effects of increased drilling effort on gas production. Note that the superior productivity of unconventional wells more than offsets their longer drilling and completion times after just a few months. On net, for the first three months of the simulation, unconventional gas actually responds less than conventional gas as wells take longer to bring online. But unconventional production quickly surpasses conventional production after three months, once the much-more productive wells come online. By the 11^{th} month of the simulation, the unconventional gas supply response is more than twice as large as the conventional response.

The right-hand panel of Figure 10 illustrates that, in the long run, the gas supply response from unconventional wells is about 2.7 times ($\approx \frac{7.1 \text{ percent}}{2.6 \text{ percent}}$) larger than that of conventional wells. This is entirely due to the fact that unconventional wells are about 2.7 times as productive as conventional wells, with initial production of approximately 80,000 mcf per month compared to 30,000 mcf per month.

IV Conclusion

We empirically analyze drilling and production from approximately 62,000 gas wells in Texas from 2000 to 2015 to examine whether unconventional gas supply is in fact more responsive to price changes than conventional sources, as has been widely conjectured. We consider separate stages of the natural gas extraction process: drilling investment, time to completion and initial production, and the profile of output over time. We find that neither production from existing wells nor completion times respond strongly to price changes. Rather, the important margin for supply response is drilling investment. We estimate a drilling elasticity with respect to gas prices of approximately 0.7, finding no evidence that this elasticity is different for unconventional versus conventional gas wells.

We also find other relevant differences between conventional and unconventional wells. While unconventional wells tend to take longer to reach production, they produce much more gas per well than conventional wells and have much lower percent variation in production, consistent with the notion of a manufacturing process. The faster flow rate per well turns out to be the primary margin by which aggregate supply from unconventional gas production is more price-responsive than conventional reservoirs. In particular, we find an approximately 2.7-fold greater responsiveness of unconventional gas supply to price changes compared to conventional gas, due entirely to greater well productivity. This distinction is critical in an industry where drilling rigs are a major cost factor and the total number of operating rigs is slow to change. Among other important results, this research demonstrates why simply counting wells drilled or rigs operating is no longer sufficient to gauge changes in gas supply, without also measuring heterogeneity in well productivity.

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