Real Option Exercise: Empirical Evidence *

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Abstract

We study when and why firms exercise real options. Using detailed project-level investment data we find that variables commonly associated with standard real option theories, such as volatility, are linked with exercise behavior. However, we find that additional factors are as important in explaining real option exercise decisions. Using localized exogenous variation in peer project exercise decisions, we find that adjacent exercise activity from peers leads firms to exercise real options sooner. We find evidence that this result is consistent with information externalities being important for exercise behavior.

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Introduction

Every investment decision made by a firm is both a decision about which capital project to pursue as well as when to pursue it. The flexibility associated with the timing of investment decisions has value to the firm; this value is commonly referred to as real option value (Myers (1977)). Real options are a central component of models of the macro economy (Bernanke (1983)), and their exercise has received ample attention in the corporate finance theory literature (e.g., Dixit and Pindyck (1994), Kellogg (2014)). Moreover, existing corporate finance theories hypothesize the importance of peer exercise decisions and information revelation in determining exercise behavior.[1] However, despite the importance of real options, micro-level empirical evidence on exercise behavior remains limited.[2] In this study, we provide novel evidence on the real option exercise behavior of firms; and directly assess the role that peer effects and information externalities can have on exercise decisions.

Characterizing firms' exercise behavior of real options is empirically challenging. First, detailed data on the timing flexibility associated with capital projects is typically unavailable. Second, in order to fully characterize a firm's exercise behavior, one needs to obtain data on all projects that the firm is contemplating; that is, not only those it decides to undertake but also those it decides *not* to pursue. This level of visibility is often not available. Third, being able to observe the key inputs that might drive option exercise decisions is necessary in order to characterize exercise behavior; these would include expected project cash flows, costs, and volatility of project cash flows. Fourth, in a competitive setting where peer firms' exercise behavior can influence exercise decisions, one needs to be able to precisely measure the actions taken on every peer project in order to gauge their potential impact. Lastly, one needs to develop an empirical framework to appropriately identify the effect of peer behavior

[1] See Grenadier (1996), Grenadier (1999), Grenadier (2002), Novy-Marx (2007), Grenadier and Wang (2005), Grenadier and Malenko (2011), and Scharfstein and Stein (1990).

[2] Kellogg (2014) studies oil drilling activity and finds that oil price volatility affects investment decisions in a manner consistent with real options models. However, the study does not assess or quantify how actual behavior may deviate from theoretical predictions or assess the importance of information externalities across firms as it focuses on fields operated by a single firm. Moel and Tufano (2002) study mine opening and closing decisions relative to what real options theories would imply, however, their setting is also not conducive to assessing the importance of peer effects and information externalities.

and mitigate endogeneity concerns

This study focuses on a setting which allows us to make significant progress on each of these challenges. We analyze \$31.6 Billion in capital projects comprised of exercised and unexercised natural gas infill well investments in a major shale development in North America. First, the institutional structure of this setting allows us to have full visibility into the timing flexibility firms have in making drilling decisions. Second, due to the institutional structure of lease contract terms we are also able to observe both exercised and unexercised options at any given point in time. Third, because the key determinant of project cash flow is the price of natural gas, a commodity whose expected price and implied volatility is readily observable to the econometrician from financial derivatives, we have the inputs necessary to characterize investment behavior. Fourth, due to the regulatory environment of the shale field in our setting, we are able to observe and precisely measure neighboring activity from peers.[3] Lastly, we develop an empirical framework which uses novel quasi-exogenous variation in peer activity to mitigate inference challenges in identifying peer effects.

Our empirical design to assess the exercise behavior of firms is based on a duration analysis using a hazard model. The objective of using this empirical framework is to compute how different factors affect the probability of exercising an option at time t, conditional on the option having not been exercised up to time t. The data in our sample is conducive to this type of analysis because each option has a well defined starting point, we can clearly observe when an option is exercised, and we have detailed data on how covariates vary during and up to the time of exercise. This dynamical modeling is consistent with others that have modeled drilling decisions (Kellogg (2014)).

Using duration analysis we find three features of exercise behavior that are directionally consistent with standard real options theory. First, we find that a one standard deviation increase in natural gas price volatility decreases the likelihood of exercising an option by 25.1% relative to the baseline hazard rate. Second, we find that an increase in natural gas prices of \$1 increases the likelihood of exercise by 15%, due to the relative increase in project value

[3] This is a key distinction from Kellogg (2014) who focuses on single operated fields, where there is only one firm operating in each area.

(NPV) compared to the optimal exercise threshold. Third, we find no consistent directional effect of interest rates on exercise decisions.[4]

We also find that additional factors are important for exercise decisions. Specifically, the likelihood that a firm exercises its real option is strongly related to peer exercise behavior. We find that a one standard deviation increase in peer project exercise behavior is linked with a 33.7% increase in exercise likelihood. These magnitudes imply that peer behavior can be as economically important as baseline real option inputs, such as volatility, in determining exercise decisions. We show that our baseline peer effect result holds after mitigating endogeneity concerns linked with peer exercise decisions as well as across a series of robustness tests.

Corporate finance theory provides a rich set of extensions on baseline real option models highlighting the importance of peer behavior and information revelation for exercise decisions (e.g., Grenadier (1999), Grenadier and Wang (2007), Grenadier and Malenko (2011), Novy-Marx (2007)). Our empirical framework is well suited to assess these theories. In most other settings, even the task of defining the set of peers can be a challenge.[5] In our setting, geographical proximity of *real options* to one another provides a natural direct and relevant peer group. Specifically, we are able to precisely observe how firms respond to adjacent competitor project exercise decisions because our data is granular enough that we can observe the specific drilling units (real options) a firm has, as well as the adjacent drilling units operated by competitors. The grid pattern of drilling units in the state of Oklahoma is such that every six square mile township is divided in 36 sections and for each section in our sample, we have eight adjacent sections to it (see Figure 3). We can take advantage of the significant variation in neighboring activity to evaluate two possible channels through which peer exercise could affect exercise decisions.

First, as Grenadier (1996) highlights, firms may face a common pool problem, in which

[4] We provide intuition for these predictions on pages 11 and 12, which is based on the baseline predictions from Dixit and Pindyck (1994).

[5] In a broad cross-section of firms, defining peer sets, often through industry classification, can be challenging (see Hoberg and Phillips (2016)). Defining geographic proximity at the firm level represents another challenge; for instance, headquarter location (easily observable) might act as a poor proxy for where firm operations actually take place.

case they may decide to exercise early because the common pool of resources could be drained by neighboring competitors and hence unravel any option value to wait. However, this phenomenon is unlikely to explain exercise behavior because shale rock lies deep underground and traps hydrocarbons tightly. It is only under very intense pressure (hydraulic fracturing or "fracking") that the highly non-permeable rock releases hydrocarbons, with minimal impact on neighboring non-fracked shale rock. If shale gas were a significant common pool, one would likely see only a few wells being drilled to extract natural gas, which is in sharp contrast to the dense drilling that one actually observes in shale gas extraction (see Figure 3).

Second, we evaluate the role that competitor exercise behavior has in providing potentially important information externalities. As Grenadier (1999) points out, information revelation through real option exercise decisions is a key dimension through which real option exercise behavior differs from financial option exercise behavior.[6] However, micro-level empirical evidence attempting to quantify the potential importance of information revelation remains limited. We find direct evidence that information externalities linked with peer behavior is important. Specifically, we find that firms respond to peer activity only when the peer projects being exercised are exercised by a firm that is experienced in the shale field. Firms with the most experience in a field are higher up the learning curve in terms of how to extract natural gas, so the information revealed from their exercise is likely more valuable.

What is the nature of the information firms obtain from adjacent exercise activity? Adjacent exercise activity could inform a firm on how to better extract reserves from its own project. Specifically, adjacent exercised projects reveal detailed information on the "target" depths at which the formation was drilled, which helps firms target their own drilling prospects better. Further, public disclosures require information to be disclosed on the mix of fracking chemicals and techniques applied to drill and complete a well; this information can then be used by peer firms to determine which approach will allow them to extract natural gas most efficiently from their own reservoir.[7] Lastly, adjacent exercise activity by peer firms could also be a reflection of some private information about rock quality a firm has which

[6] A notable potential exception is the exercise of financial options by insiders or executives.

[7] See fracfocus.org for examples of the types of disclosures that are made public.

is not yet publicly known, so that seeing a peer firm exercise could cause a firm to update positively on the rock quality of a project. All of these reasons highlight how neighboring exercise activity can lead to economically important information externalities which can result in upward project NPV revision after peer exercise.

A central concern when evaluating the effect of peer decisions is endogeneity. For example, common characteristics (e.g., shared geology or technology) may be driving the exercise behavior of both the firm and its neighboring competitors. This common unobserved factor is a well-established source of endogeneity that leads to the reflection problem (Manski (1993)). To mitigate this endogeneity concern we develop novel quasi-exogenous variation in peer firm exercise activity.

Our primary identification strategy relies on the idea that beyond the Net Present Value (NPV) of a project, the relative rank of a given project in a firm's portfolio of capital projects may also matter for investment exercise decisions.[8] Therefore, two peer firms with adjacent projects of similar NPVs could undertake exercise decisions differently due to the relative rank of their project within each firm's portfolio of projects. For each real option in our sample, we construct the relative rank percentile of adjacent projects within the peer firms' portfolio of projects at each point in time. We use this variable to instrument for the exercise activity of adjacent projects. We find evidence, using both instrumented and reduced form versions of this measure of quasi-exogenous variation in peer exercise activity, that the adjacent exercise behavior of peer firms affects the exercise behavior of a firm.

The primary identification assumption of our empirical design is that the relative rank of the NPV of an adjacent real option in a peer firm's portfolio affects a firm's own exercise decision only through its effect on the likelihood that the peer firm will exercise that adjacent option, and not through another channel. While this assumption is not directly testable, we can provide several pieces of evidence that support it. First, if a common characteristic affected both the relative rank of a peer firm's real option as well as the exercise of a firm's own real option, then the exclusion restriction would be violated. In such circumstances, one

[8] It is well established that firms cannot pursue all positive NPV projects at the same time due to operational, labor, or capital constraints. Hence project ranking is a commonly used tool to select only the most profitable projects (see Berk and DeMarzo (2014) as an example).

might expect highly ranked projects by different firms would tend to cluster in the same area and we show that this is not the case. Specifically, we show that after controlling for local geography fixed effects, which essentially controls for the absolute (but not relative) NPV of a project, the relative rank of adjacent projects owned by peer firms is uncorrelated with the relative rank of a given project within a firm's own portfolio. Second, we show that our results hold when we limit our sample only to the real options with low relative rank within a firm's portfolio, while its peer firm's adjacent project's relative rank is high. Third, we find that firms only respond to peer exercise decisions on units that are directly adjacent to theirs, and do not respond to peer exercise decisions on projects elsewhere. Fourth, we find that firms only respond to exercise decisions on adjacent units from peer firms with substantial experience in extracting shale in the area of interest. Taken together, these tests make significant progress in addressing the primary endogeneity concerns in measuring responses to peer real option exercise decisions, and set a high bar for alternative explanations. Specifically, an alternative explanation would need to reconcile why the relative NPV rank of a given project in a peer firm portfolio would have a direct effect on a firm's exercise decision for a reason other than peer exercise activity, when that relative rank is uncorrelated with any metric that is linked with the absolute NPV of a project, ex ante.

As a final set of analysis, we estimate a firm's real option decision problem based on the granular data inputs available to us. Estimating the optimal stopping time based on the baseline real option models (e.g., Paddock et al. (1988), Dixit and Pindyck (1994)), we find that substantial unexplained variation in exercise activity remains, even if actual exercise behavior is correlated with the predictions from these theories. We show further that the predictions of the baseline models are closer to the actual behavior once we include an effect for information externalities due to peer exercise decisions.

By analyzing peer effects and social learning in the context of real option exercise behavior, our study contributes to two important strands of the literature. First, we contribute to the real option literature by empirically evaluating the importance of a broad set of theories which hypothesize that information revelation and externalities may be an important component of exercise decisions (Grenadier (1996), Grenadier (1999), Grenadier (2002), Novy-Marx (2007), Grenadier and Wang (2005) and Grenadier and Malenko (2011)). In particular, we show that firms seem to to exercise early relative to the predictions from standard real option models (e.g., Dixit and Pindyck (1994), and Kellogg (2014)). To understand why this may be the case, we focus on a setting where we can directly identify peer effects and the role of information externalities in option exercise behavior (Grenadier (1999)). Using a hazard model framework we show that information externalities from peer effects can have economic magnitudes equal to that of volatility in affecting exercise behavior. Second, our novel micro-level evidence of the effect of peer activity on option exercise helps us contribute to the vast literature on learning from peers. That literature documents that peer effects are important for a variety of corporate decisions, such as those on the investment policy (Foucault and Fresard (2014), Bustamante and Fresard (2017)), capital structure policy (Leary and Roberts (2014)), dividend policy (Greenan (2018)), and R&D policy such as the adoption of new technologies (Covert (2015)). While Covert (2015) also uses the context of the oil and gas industry to show that the technology used in investments made is affected by peers, we show that peer effects also have an important impact on the *timing* of investment decisions.

The paper proceeds as follows. In Section 1, we provide the institutional background on the natural gas industry. In Section 2, we provide an overview of standard real option theory and its predictions. In Section 3 we discuss our data, and in Section 4 we report our results and methodology. Section 5 we estimate the optimal stopping time of the real options of firms in our sample. Section 6 concludes.

1 Real Options in the Context of Shale Drilling

1.1 Project Overview: Natural Gas Shale Drilling

Our setting exploits the institutional features of natural gas shale development to study real option exercise behavior of firms. To extract shale natural gas, firms must first drill a well with a horizontal leg into the shale rock (typically more than a mile below the surface), then complete the well by hydraulically fracturing ("fracking") it. The process of drilling a well may take a few days to a few weeks, while fracking is done as a separate process after drilling, and takes another few days. Both drilling and fracking entail substantial upfront capital costs of $4.7 million per well on average in our sample. Once a well is completed, it produces natural gas, and declines over time. The critical features determining the profitability of the cash flows are natural gas prices and the volume extracted. Costs include lease operating costs and royalty costs, and typically comprise less than 40% of a well's revenues after the well is drilled. Cash flows are at their highest level at the beginning of a well's life, then decline over time as pressure from the well declines, and once a well starts producing there is little that a firm can do to cause the production to go up or down outside of a wells natural decline without risking damage to a well. Figure 1 plots the cash flows and capital expenditures associated with drilling a well (see Gilje and Taillard (2016) for more details).

1.2 Infill Drilling

One of the key features of our setting is the unique ability to observe the flexibility and maturity that firms have on their investment options. As in Kellogg (2014), we focus on "infill" drilling projects in order to have well defined maturity assumptions. An "infill" project corresponds to the decision to drill additional wells on a drilling unit (section) that a firm already operates. The first (or existing well) on a unit contractually holds the operatorship of the acreage as long as the first well produces; in this case the lease is said to be "held by production" or HBP. A firm has the option to drill additional wells at any point in the future so long as the initial well is still producing. This provides firms with options that have very long maturities as the life of the first well can range anywhere from 20 to 40 years. In all the natural gas shale developments that we study in Oklahoma, a single drilling unit (section) of 640 acres can support up to 8 shale wells (or roughly up to $38.6 million in capital expenditures). With almost 3,000 units representing more than $13Bn in potential capital commitments, the infill options in this study represent capital investments that are economically meaningful, with a significant degree of flexibility on when to exercise these options. Figure 2 plots a timeline of the infill drilling decision.

A key advantage of focusing on infill drilling is that, unlike most studies of investment decisions, we can observe both exercises *and* unexercised options. Indeed, drilling units with only one existing well effectively contain many unexercised options as no additional wells (infill wells) have been drilled in the unit yet. Our study focuses on the timing of the first infill well in a unit. It is important to note that a firm could delay the exercise of the second, third, and follow-up infill wells. However, we find that 88% of all infill wells are drilled concurrently to the first infill well. Further, even when there is a sequencing of infill drilling, it would not be clear how "independent" of each other these infill drilling decisions would be as firms would likely save on drilling costs through efficient "pad" drilling, whereby a rig is contracted and remains in place and drill sequentially all infill wells.

1.3 Measuring Peer Activity

The ability to analyze firm's investment responses to competitors' actions is a key novelty of our study. We focus on the development of major natural gas fields across multiple operators, a setting where information and other externalities may be more relevant. This is a key distinction from Kellogg (2014) who focuses on single operated fields, where there is only one firm drilling a field.

The regulatory and land environment in Oklahoma lends itself well to further our understanding of how firms might react to adjacent drilling activity. Specifically, every drilling unit in our setting conforms to Jeffersonian survey, and lies on a grid system with squares that are one mile by one mile. Every 6 by 6 group of squares (36 "units" in total) rolls up to a township survey (township level). This is attractive for several reasons. Every drilling unit, by construction, has eight well delineated adjacent units. We observe every natural gas well drilled in Oklahoma so we can observe the exact timing and nature of all adjacent activity throughout our sample period. Second, we will use the township survey information to control for potential geography or area specific effects in our econometric specifications. Figure 3 plots the shale drilling activity in a township. The lines represent the horizontal wellbores of shale wells. Sections in the grid are the drilling units, sections with one wellbore have not yet been infill drilled, while sections with multiple wellbores have been infill drilled.

1.4 Real Option Framework

The firm's option to infill drill corresponds to the choice it has to spend capital to further develop its proven natural gas reserves. As noted in the introduction, the timing flexibility related to the investment decision to drill a well on proved reserves can be viewed as an American call option (e.g., Paddock et al. (1988)). Infill drilling maps nicely into the real option framework: The capital needed to develop the reserves can be viewed as the strike price of the option. The value of the reserves after capital has been expended, that is, the producing proved developed reserves, corresponds to the underlying asset. The timing flexibility a firm has to infill drill can be viewed as the time to maturity. Because the first well on the section holds by production (HBP) the section as long as it is economically viable, the option to infill drill has a long maturity attached to it; at least 20 years on average. And as the decision to infill drill (exercise the option) can be made at any time over this period, it can be viewed as an American call option (e.g., Paddock et al. (1988)). The cash flow volatility of infill wells corresponds to the volatility of the underlying asset used in standard option pricing model. Firms in our setting all produce the same commodity, natural gas, and the market provides indicators of expected futures prices and volatility, both of which can be used as inputs for an option pricing model, along with other inputs described in more details in Section 4.

1.5 Optimal Exercise Time

It is well established that American call options on dividend paying underlying assets have an optimal exercise time that can occur prior to maturity. As Dixit and Pindyck (1994) point out dividends can be viewed as either explicit or implicit in the context of real options, and broadly speaking can be viewed as the benefit a firm obtains from exercising an option sooner rather than later. In our setting, a straightforward way of viewing the cost a firm incurs by waiting is that future cash flows get discounted by a firm's cost of capital. The longer a firm waits to exercise, the more discounting will be applied to the underlying cash flows generated by the well. Conversely, waiting (delay drilling) confers the ability to drill in future states of the world that exhibit higher natural gas prices.Therefore one can view early exercise as the result of a tradeoff between the value of early exercise from having to discount cash flows less relative to delaying the exercise in order to get better natural gas pricing in the future.[9]

All else equal, higher cash flow volatility tends to result in delayed investment, due to the increased prospects of higher cash flows, while a higher cost of capital tends to result in investment occurring sooner. The classic derivations of the optimal stopping time (see Appendix for a review) lead to a trigger rule, whereby a trigger value can be computed such that it is optimal to exercise the option when the value of the underlying asset (natural gas reserves) exceeds the trigger value from below for the first time. When natural gas prices rise, it is more likely that the value of the underlying asset will exceed the trigger value. Hence, commodity price increases will lead to earlier exercise of the real option all else equal.

Natural gas prices and its volatility have clear predictions as to how they might affect exercise based on a standard options framework, with volatility being negatively correlated with exercise (more valuable to delay when volatility is high) and natural gas prices being positively correlated with likelihood of exercise. We also include information on nominal interest rates in our initial tests. Typically a decrease in interest rates decreases the discount rate and hence makes projects more valuable and hence more likely to be undertaken. However, in the context of real options, the effect of interest rates is more ambiguous because a decrease in interest rates makes waiting more appealing, as cash flows in the future are valued more today.[10]

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[9]As we will see in Section 5, in our context, a firm's cost of capital will correspond to the dividend rate on a stock.

[10]The effect depends somewhat on whether a movement in interest rates (r) will have a commensurate impact on the firm's cost of capital (δ). See Section 5.4 of Dixit and Pindyck (1994) for a more detailed discussion on the topic.

2 Data

2.1 Construction of Panel for Hazard Model

Our sample period begins in January 2005 and ends in December 2016. We construct a panel of all units (sections) in Oklahoma with one horizontal natural gas well in production. This first well confers the operator the option to infill drill the unit with additional wells as described above. The number of these outstanding available options gradually increases over the sample period as shown in Figure 4C. By the end of our sample in 2016, there is a total of 2,853 infill drilling options, 680 of which have been exercised (~24%). The number of firms (operators) corresponds to 159. Table 1 reports the summary statistics for the panel we use in the hazard model.

Our empirical analysis is based on the panel data of exercise decisions to infill drill on sections that are held by production with the existing well (first drilled) on the section. The unit of observation in this panel is at the section-month level, in total there are 162,905 section-months prior to exercise in our sample. To test some of the key predictions of the real option framework, we include the 18-month natural gas futures price from Bloomberg and 18 month implied volatility of natural gas prices as in Kellogg (2014). We also include the 5 year nominal risk free rate on U.S. Treasury bond to capture the impact of interest rate movements. All these variables are computed at the monthly frequency.

To proxy for the expected value of the reserves that will be unlocked by exercising the option to infill drill, we compute the present value of future cash flows generated by the infill well using the futures curve for pricing, and an expected production profile based off the unit's first horizontal well's production its its first year.[11] Lastly, we compute the expected drilling and completion costs for each well based on daily rig rates provided by based on regulatory disclosures of well costs filed with the Oklahoma Corporation commission. Although these variables are computed for every section every month, Table 1 only provides the summary

[11]There are many potential ways to model for expected production of a well. We settled on the simplest specification based on the 1st well in the section. Our results are robust to modeling different types of technological improvements over time. Using the simple approach, we find that using the 1st well's production explains (R-squared) 64% of the 2nd well's production in the section (the first infill well exercised).

values for these variables at the time of exercise.

The final set of variables relate to adjacent activity from the firm itself (own) and its peers (competitors). Recall that each section can have up to eight neighboring infill options exercised. We find that on average, over the entire sample period, there are 0.34 adjacent options exercised by its peers and 0.40 by itself. The medians are at zero reflecting the fact that many units do not have any infill wells during our sample period, the standard deviations do signal heterogeneity in neighboring activity. We exploit this heterogeneity in our main econometric specifications. To address potential endogeneity concerns, we also compute the ranking of each infill well based on the portfolio of options an operator has at any given point in time. This variable can only be computed on a subset of observations (103,451) and is defined as the relative rank of an infill option based on the quality of the first well drilled on a drilling unit at a given point in time (see Section 3 for details).

The key event that we use to determine whether an option is exercised is the "spud date" of the first infill well. This is the date when drilling capital expenditure is initiated and the drilling of a second well in the section begins and is directly observable from regulatory filings from the Oklahoma Corporation Commission. From this data we know precisely the date, time, firm, location (drilling unit) of the infill exercise decision. Figure 4A plots the number of options exercised over time, while Figure 4B plots the amount of time firms wait to exercise an option for the subset of options that are exercised. Because an option only becomes available to exercise after the first well has been drilled on a drilling unit, the number of options during the sample period is not the same across time. Figure 4C plots the number of options over time, as well as the number of options exercised at any given point in time.

3 Results

3.1 Exercise Behavior: Baseline Hazard Model

To assess the factors that might affect real option exercise behavior, we perform a duration analysis based on hazard functions. The objective of using a hazard function is that it allows us to compute the probability of exercising an option, within an interval, conditional on having not exercised the option up to the time of the interval. Specifically, the hazard function is defined as:

$$h(t) = \lim_{s \to 0} \frac{Pr(t \leq T < t + s | T \geq t)}{s}$$

We parametrize the hazard function using a commonly-used semi-parametric approach:

$$h(t) = h_0(t) \exp(\beta_1 NGPrice_t + \beta_2 NGVol_t + \beta_3 DrillingCosts_t + \beta_4 IntRate_t + \beta_5 FirstWellProd_i)$$

This parametrization corresponds to the well-established Cox Proportional Hazard Model, whereby the unit of observation is at the section-month level. We cluster standard errors at the township level in every specification and provide further robustness tests in terms of econometric specifications in the Appendix. A useful baseline when conducting hazard analysis is to plot the survival function; this allows us to observe the rate at which options are being exercised in the sample, we do this in Figure 5. The plot begins at 1 and then declines as time passes (in months) and options are exercised (and no longer survive). By the end of the time period available 23.8% of all options are exercised.

Having established a baseline we can then assess which covariates may cause a shift up or down in the curve in Figure 5, that is, what are the factors that might explain firms exercising options sooner or later. To do so, we begin our empirical analysis by replicating the reduced form hazard model found in Table 1 of Kellogg (2014). In terms of covariates, the two central ones are natural gas prices and volatility. Recall that standard option theory predicts that higher volatility will raise the option value, therefore, all else equal an increase in volatility would push firms to delay investment. By including volatility of natural gas as a covariate ($NGVol_t$), we can assess whether this theoretical relationship holds in the data.

In Table 2 we find higher volatility reduces the hazard rate (the rate at which options are exercised) and results in an upward shift in the curve plotted in Figure 5. Conversely, natural gas prices ($NGPrice_t$) tend to have a positive effect on the hazard rate, as an increase in the natural gas price increases the value (NPV) of the project and makes the option to delay less valuable. In economic terms, based on the Hazard Impact percentage in specification

(1) of Table 2, we find that a one standard deviation increase in natural gas price volatility decreases the likelihood of exercising an option by 13.7% (-2.57*5.35) relative to the baseline hazard rate. Alternatively, a one standard deviation increase in the price of natural gas increases the likelihood of exercise by 38.5% (15.79*2.44) relative to the baseline hazard rate. These results hold across the three specifications of Table 2 and are quantitatively similar to those found by Kellogg (2014). They suggest that firms' behavior is directionally consistent with these key predictors of option exercise activity.

Table 2 also highlights another central feature of real options models and investment, and that is the relation between interest rates and investment. As Dixit and Pindyck (1994) point out, a puzzle in the literature is why aggregate investment does not increase more when interest rates are reduced. Specifically, a reduction in interest rates should result in a reduction in a firm's cost of capital, potentially moving projects from being negative NPV to positive NPV, holding cash flows constant. However, as Dixit and Pindyck (1994) point out, a reduction in interest rates also makes waiting more appealing, as cash flows in the future are valued more today. The results in Table 2 are consistent with these countervailing incentives, and provide micro-level evidence that interest rates do not necessarily have a pulling forward effect on investment.

Lastly, we also control for both the estimated cost of the infill well and the quality of the first well that is drilled in specifications (2) and (3) of Table 2. The intuition behind this control is that the first well is an indicator of the quality of the geology in an area, and that the more it produces, the higher the NPV the additional infill projects will be, and the more likely the project will be exercised. As can be seen in Table 2, the higher the quality of the first well, the more likely a firm is to exercise the option. Specifically, a one standard deviation increase in the quality of the first well results in a 90.8% (68.82*1.32) increase in the likelihood of exercise. Controlling for time-varying drilling costs is important and we do so in specifications (2) and (3). Though not statistically significant, this result is directionally consistent with the dampening effect that an increase in drilling costs increase could have on the likelihood of exercising.

3.2 Peer Effects and Option Exercise

The baseline hazard results we report are directionally consistent with what real option theory would predict as to how the hazard function ought to shift in response to changes in key covariates. However, there is a broad set of theoretical papers that claim that informational spillovers from peer activity can be of first order importance in understanding real option exercise behavior. In this section, we assess whether adjacent competitor investment decisions (peer effects) on adjacent drilling units impact the propensity of firms to exercise their real options.

The mechanism underpinning this peer effect relates to the information content that is revealed by the exercise of infill drill options on the eight adjacent drilling units (see Figure 6). Specifically, the more infill wells being drilled nearby, the more information there is on the depths and porosity of the formation, which will in turn inform a firm on how to most efficiently extract natural gas from its own infill wells. Additionally, public disclosures require information to be disclosed on particular chemical mixes and techniques of hydraulic fracturing of "fracking" a well (see Covert (2015)). This reveals information on techniques that might work well for fracking a particular reservoir as well as those that might not work as well.[12] It is important to note that, even seeing a negative outcome in terms of production in an adjacent section, that is knowing which "fracking" techniques do not work, will allow a firm to learn how to better extract from its own section. Lastly, adjacent exercise activity by peer firms could also be a reflection of some private information about rock quality a peer firm has which is not yet publicly known; as such, observing adjacent exercise may lead a firm to update positively on the rock quality of a project. Grenadier (1999)'s develops a theoretical framework of real option exercise to assess the potential impact of information externalities from peer exercise activity. All of the reasons listed above justify why we could see positive information externalities from neighboring activity in our setting and thus validate the use of our setting to empirically assess Grenadier (1999)'s main prediction that peer exercise activity will lead firms to exercise early.

[12]See fracfocus.org for examples of the types of disclosures that are made public.

We test the effect of neighboring peer activity on the decision to exercise by calculating the number of adjacent drilling sections (as many as eight) that have infill options exercised at each point in time by other (peer) firms. We add this new variable to the previous set of covariates found in the baseline hazard specification, as well as a measure of the firm's own adjacent activity. Results are shown in Table 3. We find a strong positive relationship between likelihood of exercise and peer behavior. Specifically, a one standard deviation increase in adjacent peer infill exercise activity increases the likelihood that a firm will exercise its infill option by 32.7% (38.17*.86). The economic magnitude found here is greater in absolute terms to a one standard deviation change in volatility. This result is supportive of Grenadier (1999)'s main prediction that information externalities play an important role in the exercise decisions of firms.

3.3 Endogeneity: Peer Effects and Option Exercise

A potential concern with the interpretation of Table 3 is that the correlation between a firm's exercise behavior and its competitors' adjacent exercise activity cannot necessarily be attributed to a *reaction* to adjacent activity (Manski (1993)). For example, a common factor, such as shared technology or similar reserve quality, could affect both the adjacent competitors' decisions to exercise as well as a firm's own decision to exercise. To address this concern, we need to identify the exogenous component of adjacent exercise activity.

3.3.1 Defining the Instrument for Peer Activity

For the construction of our measure of exogenous variation of peer activity, we start from the observation that firms typically face operational, labor, or capital constraints and thus are unlikely to undertake all positive NPV projects at once. As such, they make decisions to invest not just based on the absolute NPV of a project, but also on the relative NPV or rank of a project in a firm's portfolio of capital projects. The measure we construct can best be illustrated with an example. Figure 7 shows the real options of three firms. Firm A has two separate drilling units, each of which is adjacent to drilling units owned by Firm B and Firm

C. Now assume that the NPV of Firm A's infill projects and the infill project adjacent to it, owned by peers, is \$1 million. However, let's also assume that Firm B has a portfolio of four additional real options with NPVs, if exercised today, of \$2 million, \$3 million, \$4 million, and \$5 million respectively. Alternatively Firm C has a portfolio of real options with an NPV, if exercised today, of \$0.90 million, \$0.50 million, \$0.30 million, and \$0.20 million. All firms have positive NPV projects, but for Firm B the project adjacent to Firm A is ranked fifth among its portfolio of projects, while for Firm C it is ranked first. Now assuming that these firms face some operational, labor, or capital constraints, and firms can only undertake one project at a given point in time.[13] Based on the rankings of these projects, we would expect Firm B will not exercise its project next to Firm A, while Firm C will, even though the projects have the same absolute NPV. When Firm C exercises, Firm A benefits from the information on how to complete the well, and information on the depths of the zone to target, while it has no new information for its project next to Firm B. Therefore Firm A benefits from an information externality not due to any shared or common characteristic of the specific real option in question, but due to the ranking within the existing portfolio of the other real options that Firm C has. The identification assumption is that the rankings of the projects in firm B and Firm C's portfolios is exogenous relative to the investment opportunities that Firm A has. We offer several tests in the next section to document that the investment opportunities of a given firm's option are unrelated to the relative ranking of peer options owned by other firms.

In Table 4 Panel A, we empirically test whether rank ordering matters in option exercise decisions. The variable we construct is the relative percentile of each infill project in a firm's portfolio. Our rank ordering is based on the production of the first horizontal well on a drilling unit. For every month in the sample, for every firm, we rank the total number of natural gas infill real options the firm has across the entire state of Oklahoma as of that point in time, and then map that rank ordering to percentiles.[14] So, for example, if a firm has 20

[13]Our analysis assumes all projects have the same investment cost at a given point in time, a reasonable assumption in our sample as Gilje and Taillard (2016) provide evidence that investment cost does not vary significantly across firms in a given region for shale gas development.

[14]While we recognize that some of our sample firms have drilling options outside of the state of Oklahoma,

real options in its portfolio, the number one well would be in the 95th percentile (1-1/20). As can be seen in Table 4, Panel A, the higher the percentile rank in a firm's portfolio, the more likely it is that the project is exercised. Specifically based on specification (2) in Table 4 Panel A, for a one standard deviation increase in percentile, a firm is 19.2% (65.84*.29) more likely to exercise an option. Interestingly, this relative rank appears to be as economically important as the effect of volatility..

3.3.2 Instrumental variable approach

Table 5 Panel A reports both the first stage and second stage estimations, whereby the Adjacent Peer Exercise Activity, defined as the number of infill options exercised by peers adjacent to the drilling unit i at month t is the variable that is instrumented.[15] The instrument we construct is the average relative percentile of all adjacent drilling units owned by peer firms as of month t based on the relative rank of each adjacent infill project in a peer's portfolio of projects. This figure will fluctuate over time, for example, if a peer firm adds real options with really good first wells elsewhere, then the relative percentile will go down. If it adds real options with relatively poor first wells elsewhere, then the relative percentile will improve. The first stage regression is given by:

$$\begin{aligned} NumberOfAdjacentExercisedOptionsPeer_{i,t} = \\ &\beta_1 AvgRelativeRankPercAdjacentPeerProjects_{i,t} \\ &+ Controls + FE + \varepsilon_{i,t} \end{aligned}$$

The second stage is given by the Cox proportional hazard model whereby the covariates are comprised of our instrumented variable for neighboring peer activity from the first stage,

our discussions with industry experts suggest that drilling decisions are made at the play/regional level and as such the portfolio ranking within Oklahoma seems appropriate. The results shown in Table 4 confirm the strong effect that our ranking variable has on the probability of drilling an infill well.

[15]Table 5 has fewer observations than Table 4 because we can only use our instrument once some adjacent peer infill options exist: if a firm's real option to infill has no adjacent infill options then there is no relative rank from an adjacent peer that can be used to construct the instrument.

as well as a series of additional control variables. We correct for the estimation error in the first stage in our Cox two-stage IV model by bootstrapping the standard errors (MacKinnon (2002)). The appropriateness of this approach has been supported in recent literature (see Tchetgen et al. (2015)).[16]

As can be seen across the different first stage specifications at the bottom of Table 5 Panel A, the relative rank of a real option in a firm's portfolio has high predictive power for the adjacent peer exercise activity.[17] In our second stage estimations, we control directly for the absolute NPV of adjacent peer infill projects by including the average production from the first (pre-infill) well of adjacent infill peer options as a control. The underlying assumption of this instrument is that the only dimension through which it affects our key dependent variable of interest, the exercise decision of a firm, is through the exercise behavior of peers. We provide a number of tests supporting this assumption in Section 3.3.4. Overall the results from Table 5 suggest that the economic interpretation from Table 3 still holds when we use an exogenous source of variation in adjacent activity driven by the relative rank of projects in peer portfolios. For ease of economic interpretation for our key variable of interest, the instrumented neighboring activity from peers, we report the coefficient on the standardized instrument variable in the second stage. As such, a one standard deviation increase in our instrument leads to an 81.3% increase in the likelihood of exercising the option to infill drill.

3.3.3 Robustness Tests

We first report the reduced form results in Table 5 Panel B for robustness. This regression is still subject to the exclusion restriction, which in our case means that the relative ranks of adjacent projects only affect a firm's decision to exercise via the relative rank's effect on adjacent peer project exercise decisions. By not instrumenting we lose the economic interpretation of the coefficient on the number of adjacent peer exercised options, but maintain

[16]We document the robustness of our main two-stage models by estimating both IV Probit and IV OLS models on our data and obtain similar results to our main Cox model tests..

[17]We report specifications with different fixed effects and find similar results throughout. We acknowledge that introducing fixed effects could introduce bias in non-linear models, we report these specifications in the event that there is a fixed effect in the data generating process to assess the overall robustness of our results.

the overall intuition of the result reported in Table 5 Panel A: firms' exercise decisions are affected when a project has plausibly exogenous exposure to a variable that affects adjacent exercise behavior (relative rank percentile of adjacent peer projects (β_6)).

We retain the Cox model as the primary specification in the paper because we are studying the motivation behind the decision to exercise real options, and this decision is dynamic by nature: firms have to decide in each period whether to exercise or not, conditional on not having exercised until then. A natural econometric specification for this is the duration model (as in Kellogg (2014)). The hazard function allows us to approximate the probability of exercising the option, conditional on having not exercised until then. This modeling has been used in other contexts in corporate finance (e.g., Leary and Roberts (2014)) and has several advantages. One of the main advantages in the context of our study being that the hazard function can easily be made to depend on time-varying variables and have a natural interpretation.

The linear probability model and probit specifications both face several drawbacks. First, even though the decision to exercise is binary, a linear specification implicitly assumes that the outcome variable can be non-binary and even negative. This is one drawback of using the linear probability model. Second, both the linear and probit models are not well suited to capture the dynamic nature of the decision to exercise. Even for probit (or logit) models that accommodate for the binary nature of the left-hand side variable, these modeling approaches aim to explain the proportion of exercised options across the entire sample at any given point in time, which is slightly different from what the hazard models capture in terms of the variables that influence the probability of exercise at time t, conditional on not having been exercised up to that time. Third, the censoring of the data is another impediment to implementing traditional methods such as linear probability models or probit regressions. In our setting, the censoring bias is caused by the fact that we only observe the data until the end of the sample (right censoring); for firms that do not exercise prior to the end of the sample period, we only know that they did not exercise their option until that point in time. Although the linear and probit specifications do not have a natural way of handling this right censoring issue, the maximum likelihood estimations (MLE) of Cox hazard models are well suited to handle this specific type of right censoring (see 20.3.2 of Wooldridge (2002)).

That being said, estimating models using the IV-regression and IV-probit frameworks is informative in assessing the robustness of our estimates to choice of estimation model. In another set of robustness tests, we perform two other specifications for the IV approach based on a probit and regression-based second stage for which the statistical properties are somewhat more established. Namely, in Appendix Table 1, we run an IV-probit specification where the second stage is a probit modeling of the exercise decision instead of a duration model. The coefficient on the instrumented adjacent drilling activity of peers is positive and significant. Appendix Table 2 provide the results for the IV-regression specification. Again, we find a positive and significant loading on the instrumented adjacent peer activity variable. Appendix Table 3 and 4 further confirms the results found in the context of an IV-probit and IV-regression specification with double clustering (township and year fixed effects) of standard errors.

Throughout all our main specifications, we have clustered the standard errors at the township level. In Appendix Table 5 and 6, we re-run Table 5 Panel A and B, but this time allowing for clustering at the township and year level (double clustering). Our results remain robust to the double clustering approach. Lastly, in Appendix Table 7 we re-run Table 5 Panel A and B with the additional control variable that captures the number of adjacent sections that see a first well (not an infill option) being drilled on it. The idea is that there could also be an additional signaling effect from peers that drill a first well on a section. And although the coefficient on this variable (β_{10})) is positive and significant as predicted, the activity on infill real options in neighboring sections still comes out significant in both the reduced form (column (1)) and instrumented approach (column (2)). Overall, the results of this robustness section shows that our main IV Cox results are also found in specifications that use a reduced form (single stage) Cox estimation, a two-stage Probit and a two-stage IV regression modeling, with single and double clustering. We thus conclude that regardless of the econometric specifications are results are robust, and that exogenous neighboring real option exercise activity from peers leads to a greater likelihood of early exercise of real options.

3.3.4 Internal Validity

In this subsection, we undertake several falsification tests to assess the validity of the instrument we outline above. While the exclusion restriction cannot be tested directly, we can assess the plausibility of some potential explanations which would invalidate our instrument.

One potential explanation which might be problematic for our instrument would be if all firms had similar locations for their high percentile wells. For example, if all firms had their 90th percentile wells in one township, and their 80th percentile wells in another, such clustering would render inference problematic. Although our main tests include specifications with township fixed effects and township level clustering, which would control for an overall township effect; if there is clustering within townships of high percentile groups in some areas and low percentile groups in other areas it would be problematic as one could argue the instrument might proxy for the absolute value of the NPV of a project and not just the relative NPV of a project. We also control directly for production from adjacent peer wells, which should alleviate this concern to some extent. Nonetheless, we can also directly assess the impact of this possibility when we regress the relative rank of a real option in a firm's portfolio on the relative rank of the real options owned by peers that are adjacent to it at a given point in time, as in the below regression.

$$\begin{aligned} RelativeRankPercOwnProject_{i,t} &= \\ &\beta_1 AvgRelativeRankPercAdjacentPeerProjects_{i,t} \\ &+TownshipFE + \varepsilon_{i,t} \end{aligned}$$

The unit of observation is at the drilling unit i, month t level, and we estimate the OLS regression in Table 6. As can be seen the coefficient is neither statistically nor economically significant, suggesting that once township fixed effects are controlled for (as they are in our main regressions in Table 5), there is no correlation between the percentile rank of a given real option and the average percentile ranks from adjacent peer firms' surrounding real options. This test provides evidence against the idea that all firms have their 90th percentile wells clustered together somewhere, and their 80th percentile wells clustered somewhere else in a way that would confound our tests.

Conceptually, this makes sense as prior to any wells being drilled firms go out and lease drilling acreage when not much information is known about the natural gas resource. Firms thus end up with different portfolios which can be quite dispersed in terms of their potential (see Figure 8); this is the variation that is being exploited with our instrument.

An alternative way to test whether the clustering of relative project quality is driving our results is to look at situations where a real option is ranked low in a given firm's relative percentile rank (below median) while the adjacent real options are ranked highly based on peer relative rank (above median). We report results on this subsample of real options with highly dispersed relative rankings in specifications (1) and (2) of Table 7, and as can be seen from the table, our main result holds.[18] Overall we find magnitudes higher in these tests than our baseline regressions, which is consistent with the idea that information externalities become more important when relative ranks are more dispersed.

Another potential concern with our identification is whether a firm exercises its real option because of the action of a competitor (adjacent exercise) or a characteristic of an adjacent competitor as described in Manski (1993).[19] For example, one might imagine that a competitor exercising their option on an adjacent drilling unit might also be pursuing significant drilling activity (exercising other real options) elsewhere in the play, which might signal, for instance, an overall improvement in extraction technology going forward. In this case, a firm and its competitor are both deciding to exercise options that are adjacent to each other, but it is not because the firm is responding to information externalities from the competitor's actions taken on the neighboring drilling unit, but rather, due to the general activity of the competitor taking place both nearby and elsewhere.

To assess empirically whether our main coefficient of interest for peer effects is affected by such characteristics, we look at competitors with adjacent drilling units and test whether their drilling activity *outside* of the township also bears an influence on a firm's decision to

[18]Township fixed effects for this model are not well identified due to the dramatically reduced sample size, much of the sample is absorbed by township fixed effects.

[19]Leary and Roberts (2014) articulate this issue in detail as it relates to their capital structure analysis.

exercise. We include this measure as an additional explanatory variable ("Play" activity) in our hazard regression in Table 8. We find that our main coefficient of interest for peer exercise activity is unaffected by the inclusion of this control variable. Furthermore, we also find no consistent direction in the effect of the "Play" activity variable across model specifications.Overall, this evidence supports the view that firms are influenced by peers' activity when it occurs on the drilling units directly adjacent to them, consistent with the information channel hypothesized.

3.4 The Information Content of Adjacent Exercise Activity

After having established that firms react to neighboring exercise activity when making their own exercise decisions, we set out to investigate the possible channels behind this result. To do so, we re-estimate the hazard model from Table 3 with adjacent exercise activity as an explanatory variable, but this time, we decompose the adjacent exercise activity by competitor type. In particular, we define experienced and inexperienced competitors as those with above (respectively below) median drilling activity in the shale play at the time of exercise.

In an information transmission framework where agents do not have perfect information on the value of their drilling prospects, operators will look for informational cues from more experienced operators about the drilling opportunities in and around their own prospects (e.g., Grenadier (1999)). Moreover, the type of information disclosed via well completion and fracking reports is likely more useful when the firms that do so are experienced and higher up the learning curve in a given resource development. Under this hypothesis, we would expect firms to react strongly to adjacent exercise behavior from experienced operators.

In Table 9, we show the results of our empirical decomposition of neighboring activity. We standardize both of our inexperienced and experienced adjacent activity variables so that we can more readily make a direct comparison between the two coefficients. Specifically we normalize these variables to have a mean of zero and a standard deviation of one. We find that firms exhibit a strong reaction to the adjacent exercise activity of experienced competitors. The economic magnitudes are similar to Table 3 results. These results are supportive of Grenadier (1999), whereby operators make specific inferences from their competitors' exercise of real options. In particular, their exercise behavior is influenced by the exercise activity of experienced operators, and thus experienced operators seem to be creating positive informational spillovers when exercising their real options.

4 Real Option Modeling

Our data provides us with the unique ability to compute the inputs a firm would have if it were to follow real option decision rules following the classic baseline models of Dixit and Pindyck (1994). Having established empirical relationships, we focus our attention in this section on how the exercise behavior observed in the data maps into the classic real option framework. We do so in two steps, first we compute the real option problem using the basic framework from Dixit and Pindyck (1994), then we adjust the framework assuming that firms benefit from some positive information externality and compare both to observed exercise behavior. In Appendix, we provide results that extend those of this section by calibrating the dynamic discrete choice model of Rust (1987), which was first applied to the oil and gas industry in Kellogg (2014). All conclusions remain unchanged.

4.1 Real Option Pricing and Optimal Exercise Time

As mentioned earlier, the option to expend capital in order to develop shale reserves (infill drilling) correspond to a real option. Firms can decide when to exercise these real options and a large body of work has been developed to establish both the pricing of these real options as well as their optimal exercise (stopping) time. Without claiming any novelty, we provide the details of the classic derivations of these formulas in Appendix and provide the resulting standard pricing formula as well as the optimal "trigger" rule below.

It can be shown under rather general assumptions, that the value of an option $F(V)$ is given by the following closed-form solution:

$$F(V) = AV^{\beta_1}$$

where

$$\beta_1 = \frac{1}{2} - \frac{(r-\delta)}{\sigma_P^2} - \sqrt{\left[\frac{(r-\delta)}{\sigma_P^2} - \frac{1}{2}\right]^2 + \frac{2r}{\sigma_P^2}}$$

and

$$A = \frac{(\beta_1 - 1)^{\beta_1 - 1}}{(\beta_1)^{\beta_1} I^{\beta_1 - 1}}$$

Whereby r is the risk free rate, δ is the dividend rate of the project and σ_P is the volatility of the underlying project value. Furthermore, it can also be shown that there is an optimal stopping time given by a trigger rule. Specifically, there exists V^*, a trigger value, such that for when the underlying asset crosses V^* from below for the first time, it is optimal to exercise.[20] Defining I as the drilling costs of the well, the trigger value is given by:

$$V^* = \frac{\beta_1}{\beta_1 - 1} I$$

4.2 Construction of Real Option Input Variables

An attractive feature of our setting is that we are able to obtain all of the inputs needed to compute the real option decision model for firms within the standard real option framework. The critical components of this data include data on drilling costs, cash flows, natural gas prices, and natural gas implied volatility.

To obtain the cost of each well we collect data from the Oklahoma Corporation Commission pooling regulatory documents. This data is disclosed by all firms who initiate the drilling of the first well in a drilling unit, and is used by other firms with ownership stakes in the drilling unit who are deciding whether to participate in the well or not. Drilling costs fluctuate due to the supply and demand for drilling and completion services, and vary little across operators and geography within a shale basin at any given point in time (Gilje and

[20]Certain conditions need to be met for this trigger value to exist and be unique (see Kellogg (2014)).

Taillard (2016)), but they do vary substantially over time. We have detailed data on 996 wells to estimate the costs of the infill wells in our sample.

Cash flows from wells are based on production, prices, lease operating costs, and royalty costs. We obtain detailed production data at a monthly frequency on every well in our sample from IHS energy. This data is based on reports that firms make to state regulatory bodies on production. We also use this detailed month level data to derive the depletion rate, ω, a key parameter in standard real option models. Natural gas prices and the implied volatility of natural gas are obtained from Bloomberg data on natural gas price futures contracts. As in our main hazard model specifications, we use the 18 month futures price of natural gas and 18 month implied volatility of natural gas as estimates of the overall gas prices and implied volatility of natural gas over the life of a well (consistent with Kellogg (2014)). Lease operating costs are based on estimates obtained from 10-Ks. Royalty estimates are based on royalty percentages obtained from DrillingInfo on 71,120 oil and gas leases signed in Oklahoma, the sensitivities we report encompass a range that is covered by 89.6% of the royalty terms in the sample.

Taken together, the institutional environment in Oklahoma allows us to calculate each of the key inputs that are needed to compute the "trigger value" and exercise decisions predicted by standard real option models such as those of Paddock et al. (1988).

4.3 Calculation of Real Option Exercise Thresholds

For every drilling unit, we need to determine first the expected value of the developed reserves that can be tapped by the new infill well (V), the optimal exercise threshold (V^*), and the value of the undeveloped reserves, i.e. the value of the option $F(V)$. We rely on the closed-form formulas derived from option theory in Section 5.1 and in the Appendix.

To obtain the expected value of the well's developed reserves (V), we rely on a set of commonly used assumptions. First, we make the simplifying assumption that the 18 month future price of natural gas (P) can be used to compute the value of the stream of cash flow over the entire life of the well and that firms' discount their cash flows at the discount rate

μ. Second, the net profit per mcf is obtained by taking into account the operational cost (ϕ), the royalty rate (ρ), the accounting depreciation rate (θ) and the corporate tax rate (τ). Then, we define the net per-mcf profit as: $\Pi = P[(1-\phi-\rho)-\tau(1-\phi-\rho-\theta)]$. Finally, we assume that the well's reserves are being depleted at the exponential rate, ω, which enable us to model the value for one mcf of developed reserves as $V_0 = E_0 \int_0^{\infty} \omega \Pi e^{-(\omega+\mu)t} d_t = \frac{\omega\Pi}{\mu+\omega}$.

4.3.1 Estimates of the Model Parameters

In the baseline scenario, we set the discount rate at 10%, in line with the SEC guidelines in valuing reserves and recent empirical work estimates.[21] Then, we estimated the reserves' depletion rate, ω. From the exponential depletion rate formula of the reserves, we have that the monthly production at a given point in time t is equal to $Prod_t = \omega R_0 e^{-\omega t}$, where R_0 is the initial available reserves. Since we only observe the monthly production, but not the initial available reserves, we compute the ratio of monthly production such that $\frac{Prod_t}{Prod_{t-1}} = e^{-\omega}$. As such, for each well we empirically estimated ω from the ratio of monthly productions. In our sample, the average well has an annual depletion rate of 27%. In a subsequent section, we run a set of sensitivity analysis varying the ω parameters from 25% to 29%, roughly representing the 90^{th} confidence interval of the depletion rate distribution. For the royalty rate, we obtain the lease data from all the wells in the play, and the median royalty rate is equal to 18.75%.[22] Finally, we set the depreciation rate to 40% and the effective tax rate at 0%.[23]

4.3.2 Developed Reserves Value Calculation

To obtain the expected value of the total reserves accessible by the infill well ($B_0 * V_0$), we need to compute the expected amount of natural gas produced by the infill well. We compute the expected total reserves of the infill well in three steps. First, using realized

[21]See Kellogg (2014). In the sensitivity section, we run the calculation using discounting rate ranging from 7.5% to 12.5% on an annual basis.

[22]In our sample, the average royalty rate is 18.89%, but the industry standard is 18.75%, and 81% of the well's lease set a royalty rate of 18.75%.

[23]During the covered period, natural gas exploration firms benefited from multiple generous deduction and tax credit. It enabled them to virtually pay no cash taxes.

data from past infill wells drilled in the same play, we regress the first year of production of the second well on the first year of production of the first well for each section. Second, we use the estimated regression coefficient to obtain a *prediction* of the infill well's first year of production ($Production_{t=1}$) for all the wells that we include in our experiment. Finally, we obtain the expected total reserves tapped by the infill well by computing $B_0 = \frac{Production_{t=1}}{\omega}$. The expected value of the initial reserves corresponds to $B_0 * V_0$.

4.3.3 Optimal Threshold Calculation

To obtain the optimal threshold value of each wells, we need an estimate of the well drilling cost (I). To allow for time varying drilling costs, we obtained well level drilling cost and estimated the expected drilling cost for every month of our sample. We then compute the optimal threshold value (V^*) using the results derived in the previous sections.

4.4 Exercise Behavior: Actual vs. Predicted

In this subsection we calculate the real option decision rules that firms would have if they strictly followed the behavior predicted by real option theory and compare this predicted exercise behavior with their actual exercise behavior described earlier in the paper. Over the period of interest, there were a total of 2,853 potential infill well real options available. Of these infill well options, 680 are exercised. The objective of this section is to assess whether at the time of exercise, the project values (V) were above their trigger value (V^*) implied by the standard real option model of Dixit and Pindyck (1994), as outlined above.

We find that in our base case firms forgo an average of \$0.63 million or 52% of the option value. However, this value does not incorporate any updating from peer exercise behavior. In the baseline framework we find that while the projects are positive NPV at the time of exercise, as shown in Figure 9, the value of the option at exercise is much higher, standing at \$1.84 million on average. Figure 10 Panel A plots the distribution of foregone option value at exercise time. The histogram clearly shows that the majority of the wells are exercised when V minus V^* is negative, reflecting the fact that most exercise decisions result in foregone option value by exercising too early when the model expectations for V are based only on the performance of the first well.

Although we have actual project-level data to estimate inputs for our model parameters, it is prudent to assess how sensitive the project values and trigger values are to changes in model parameters. In Table 10 we report sensitivities across every major parameter in the model: depletion rate, operational costs, discount rate, taxes, and royalties. We find that in the case where the wedge between project value and option value is the smallest, 5.2% of the option value is still lost by early exercise. In each case, the average of the forgone option value in our sample is statistically different from zero.

To assess whether the "foregone" option value computed above could be due to not including the benefit of information externalities in our real option framework, we adjust our framework to include information externalities from adjacent peer exercise behavior. Specifically, to assess how the trigger value (V^*) could change relative to the project value (V), we compute an updated reserve estimate based on both the first well's production on a drilling unit and the adjacent peer exercise behavior assuming it would lead to a 10% increase in expected reserves, and plot the new distribution of foregone values in Figure 10 Panel B. The figure highlights that the relative gap between V^* and V is reduced once V is revised using adjacent exercise behavior. This final result is consistent with our earlier findings supporting the information channel linked to peer firm exercise activity in explaining early exercise (Grenadier (1999)).

5 Conclusion

In this paper we exploit detailed data on a large set of real options to empirically characterize the option exercise strategies employed by firms. We find that peer exercise behavior via an information revelation channel is as important in explaining exercise activity as standard real option inputs such as volatility. To date, the empirical real options literature has been limited, largely by data constraints. Our paper provides important micro-level evidence on both how real options are exercised, and which channels are important in explaining exercise behavior. Our results provide novel empirical support for the importance of information revelation from competitor exercise behavior in explaining how firms exercise real options.

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Appendix

To confirm the robustness of the results presented in Section 4, we calibrated a dynamic discrete choice model (see Rust (1987)), in the spirit of Kellogg (2014).[24] In particular, the model presented in this section incorporates time-varying volatility and time-varying prices. To properly map our institutional setting into Kellogg's model, we had to recalibrate the entire model.

First, we calibrated the nominal discount rate to follow the industry standard of 10%. In our sample, the average dayrate drilling cost is $49,638.98 and the average natural gas future price is $5.80. Additionally, the gas futures price ranges between $2.56 to $12.07 and the dayrate price ranges $25,850 to $74,671. For the gas futures price and the dayrate we directly follow Kellogg (2014)'s methodology. We calibrated the gas futures price process such that the expected drift of the oil futures price $\mu(P_t, \sigma_t^2)$ is obtained by the OLS regression: $E[ln(P_{t+1}] - ln(P_t) + \frac{\sigma_t^2}{2} = \kappa_{p0} + \kappa_{p1} P_t + \kappa_{p2} \sigma_t^2$. We estimate that $\kappa_{p0} = 0.01526$, $\kappa_{p1} = -0.00016$ and $\kappa_{p2} = 0.343$. Similarly, to calibrate the dayrate process, we estimate the scaling dayrate-to-oil futures price parameter (α) and the correlation parameter (ρ) such that $\alpha = 2.2500$ and $\rho = 0.04816$. Our scaling parameter is drastically higher than the one used in Kellogg (2014). The difference is driven by two factors. First, our sample is comprised of horizontal wells, as opposed to vertical wells. The horizontal well technology is much more expensive. Second, Kellogg's focuses on oil wells as opposed to natural gas wells. So his work refers to oil futures price which are substantially greater than the natural gas futures price we use. Thus, because the standard deviation is not a normalized measure of dispersion, when we constructed the scaling measure, it is normal to obtain substantially greater magnitude for α. Also, the correlation coefficient we obtain is an order of magnitude smaller than the one presented in Kellogg paper. This can be explained by the different periods covered by both our studies. Finally, for the volatility process calibration, we followed the mean reverting calibration methodology and we estimated that the volatility of the volatility process to be $\gamma = 0.08852$.

[24]Ryan Kellogg's original matlab code is publicly available on the American Economic Review web site. For technical details on the model properties, see Kellogg (2014).

Just as in the standard real options model from Dixit and Pindyck (1994), the dynamic discrete choice model of Kellogg (2014) yields optimal exercise thresholds for different combinations of expected well production and natural gas prices, as a function of the volatility of the underlying commodity. We proceed to replicate Figure 6 of Kellogg (2014) in the context of our study, whereby we estimate the optimal exercise threshold curve under two extreme scenarios of uncertainty: the lower and higher uncertainty bounds measured in our sample (19% and 39%). To compare the results obtained using the Dixit Pyndick model from those obtained by the Rust model, we generate the optimal exercise thresholds under the Dixit and Pindyck (1994) model for those two scenarios also. We then evaluate the fraction of firms that would have exercised too early according to both models and across the two extreme cases in terms of uncertainty (see figures 11 and 12).

For both models, we find that most options (infill wells) are exercised when they are to the left or below the exercise threshold curves; that is, firms tend to exercise earlier than the optimal thresholds would suggest under both models, even in the case where uncertainty is the lowest. Hence even when the option to delay value has the lowest value, firms seem to forgo the benefits of the option to delay drilling. To provide further evidence that our results are not driven by the specific type of projects studied or the sample period, we repeated the same exercise with the data used inKellogg (2014). Strikingly, we obtain results of similar magnitude. Taken together, these results suggest that firms appear to exercise earlier than what would be deemed optimal by two of the most well-established real options models in the literature. We leave to future research the theoretical modeling of incorporating peer activity to the computations of optimal exercise thresholds.

Real Option Pricing

One of the key methods developed for option pricing models is through the use of replicating portfolios. The argument for this approach is straightforward: If one can construct a portfolio that replicates the payoff of the option at all times then, by arbitrage, the portfolio and the option should have the same value.[25] Similar to constructing a replicating portfolio using stocks, one can contemplate constructing a replicating portfolio on the underlying real asset. The value of the underlying in this real option setting corresponds to the value of natural gas reserves after they have been developed. As such, the replicating asset is a proved developed section that is producing, which corresponds to a leased section with wells already drilled and producing. In particular, the replicating asset requires no further incremental capital to extract the commodity. The total return on these assets can be decomposed into two components: (1) profits from production of γ unit (net of the corresponding depletion) and the (2) capital gain on holding the remaining reserves. It can easily be shown that, as long as the value of an extracted resource is worth more than the value gain of the resource left in the ground, the expected return on the producing reserves is greater than the expected return on the non-producing reserves.[26]

If all assets are in equilibrium, then the expected return of the producing proved reserve μ_P should be commensurate to its risk. From the argument in the previous paragraph, the expected return on the non-producing proved reserves μ should be lower than μ_P. McDonald and Siegel (1984) show that the replication strategy with an asset earning below equilibrium returns is inefficient and cannot be used to price the option. Thus, in equilibrium, the only efficient replicating strategy is to use the asset that earns the equilibrium return, in this case, the *producing* proved reserve.

Following Paddock et al. (1988), let V_t be the value per unit (thousand cubic feet (mcf)) of *producing* developed reserves; B_t be the number of units (mcf) in the developed reserves; Π_t is the after-tax price per unit of resource sold, and $R_t d_t$ capture the instantaneous change in wealth (payoff) to the owner on the developed reserves. Further, let us assume that the production of the developed reserve lead to an exponential decline of the reserves at rate ω,

[25]In our case, the firm's output is a traded commodity. We can calibrate the parameters of the stochastic process from natural gas futures market data (see Section 5 for the calibration exercise).

[26]This assertion will hold true as long as the storage costs above ground are smaller than the time and money it takes to extract the natural resource from the ground.

i.e. $dB_t = -\omega B_t dt$, then:

$$\begin{aligned} R_t d_t &= \underbrace{\omega B_t \Pi_t dt}_{(1)} + \underbrace{d\left(B_t V_t\right)}_{(2)} \\ &= \omega B_t \Pi_t dt + B_t dV_t + dB_t V_t \\ &= \omega B_t \Pi_t dt + B_t dV_t - \omega B_t V_t dt \end{aligned}$$

The instantaneous payoff to the owner of the producing developed reserves can be decomposed in: (1) the profit earned on the mcf extracted over dt, and (2) the change in value of the reserves that remain in the ground.

Assuming further that the returns per unit on the producing proved reserves follow a Brownian motion $\left(\frac{R_t}{B_t V_t} dt = \mu_P dt + \sigma_P dz\right)$, whereby the drift μ_P corresponds to having the producing proved reserves earn a competitive market return, then, by combining the two equations above, one can show that the dynamics of V_t are given by:

$$dV_t = \left(\mu_P - \delta\right) V_t dt + \sigma_P V_t dz$$

where $\delta = \omega\left(\Pi_t - V_t\right)/V_t$. As long as the price per unit sold exceeds the value of the resource left in the ground, then δ is positive and the return on the non-producing asset is less than μ_P. δ represents the opportunity cost of not exercising the option.

From here, we can develop what should be the value for the *non-producing* proved reserves $F\left(V_t\right)$. The non-producing proved reserves can be viewed as an option to acquire producing proved reserves by expending the development (drilling and completion) costs (I). Hence the value of the non-producing proved reserves is given by the value of the option to develop the proved reserves. Following the well-established contingency claim approach, one can show that the dynamics of $F\left(V_t\right)$ need to satisfy:

$$\frac{1}{2}\sigma_P^2 V_t^2 \frac{d^2 F\left(V_t\right)}{dV^2} + \left(r - \delta\right) V \frac{dF\left(V_t\right)}{dV} - rF\left(V_t\right) = \frac{dF\left(V_t\right)}{dt}$$

where r is the return on the riskless asset.

Given the long time to maturity of the option to develop (infill drill) units with existing production, one can approximate the time to maturity to be infinite, in which case the partial differential equation (PDE) simplifies to:[27]

$$\frac{1}{2}\sigma_P^2 V_t^2 \frac{d^2 F\left(V_t\right)}{dV^2} + (r-\delta) V \frac{dF\left(V_t\right)}{dV} - rF\left(V_t\right) = 0$$

which corresponds to the well established PDE of an American call option on the underlying asset V_t paying a "dividend" equal to δ. This PDE has an analytical solution, given the following boundary conditions:

$$F(0) = 0$$

$$F\left(V^*\right) = V^* - I$$

$$\frac{dF\left(V^*\right)}{dV} = 1$$

where $V^*$is the optimal trigger value (see next subsection). The second condition can be restated as $I = V^* - F\left(V^*\right)$, that is when you invest, you get the underlying but you lose the value of the option. Equivalently, we can rewrite the condition as $V^* = I + F\left(V^*\right)$, you only invest when the value of the project equals its direct cost plus its opportunity cost. The last condition is the so-called "smooth-pasting" condition.

The solution to this PDE is given by:

$$F(V) = AV^{\beta_1}$$

where

$$\beta_1 = \frac{1}{2} - \frac{(r-\delta)}{\sigma_P^2} - \sqrt{\left[\frac{(r-\delta)}{\sigma_P^2} - \frac{1}{2}\right]^2 + \frac{2r}{\sigma_P^2}}$$

and

$$A = \frac{\left(\beta_1 - 1\right)^{\beta_1 - 1}}{\left(\beta_1\right)^{\beta_1} I^{\beta_1 - 1}}$$

[27] Smith (2016) provides a deeper discussion on the nature of the time-to-maturity conferred by the HBP provision.

Optimal Stopping Time

The optimal time to exercise a real option is similar to the optimal time to exercise an American stock option. It can be shown that the optimal stopping time is given by a trigger rule under very general assumptions. Specifically, there exists V^*, a trigger value, such that for when the underlying asset crosses V^* from below for the first time, it is optimal to exercise.[28] The trigger value is given by:

$$V^* = \frac{\beta_1}{\beta_1 - 1} I$$

where $\beta_1$was defined in the previous section as:

$$\beta_1 = \frac{1}{2} - \frac{(r-\delta)}{\sigma_P^2} - \sqrt{\left[\frac{(r-\delta)}{\sigma_P^2} - \frac{1}{2}\right]^2 + \frac{2r}{\sigma_P^2}}$$

. When exercising at the optimal threshold, the firm gets $V^* - I$ where I is the infill drilling capital expenditure.

In the NPV framework, the NPV rule would state that one should drill as soon as $V = I$ or equivalently $\frac{V}{I} = 1$. Given that $\beta_1 > 1$, $V^* > I$, or equivalently $\frac{V}{I} > 1$, i.e. there is a wedge between the NPV rule and the optimal exercise rule. Given the option value to delay, the value of the underlying asset needs to exceed the investment cost (and in some cases by a large margin) before it becomes optimal to exercise. Also, recall that at the optimum, $F(V^*) = V^* - I = NPV$, and thus we should find that the option value equals the NPV of the project at the time of exercise, as long as firms drill at the optimal time.

Dixit and Pindyck (1994) show that δ, the implicit dividend a firm generates from a project, equals a firms risk adjusted cost of capital (μ) minus the expected appreciation of the project (α), $\delta = \mu - \alpha$. This makes sense because the effect of discounting can be offset by the expected appreciation of the asset. For the purpose of our study we assume that expected appreciation of the asset (its drift) is close to 0. If natural gas prices were expected to increase (contango) or if costs were to decrease one might expect some drift. However,

[28]Certain conditions need to be met for this trigger value to exist and be unique (see Kellogg (2014)).

because the natural gas futures curve is relatively flat, we take as a starting assumption that $\alpha = 0$. In this case δ simplifies to a firm's cost of capital. From the definition of V^*, one can see that the higher the cost of capital, the smaller the wedge between the NPV rule and the optimal trigger rule. We explore a wide range for δ in Section 4.

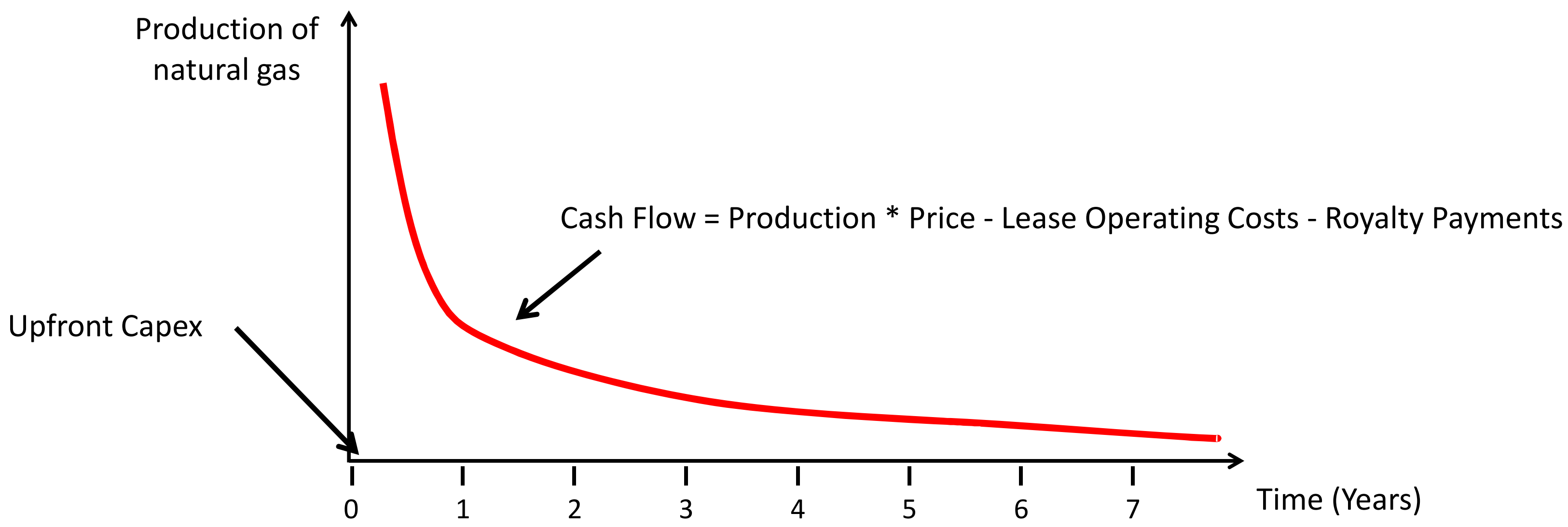


Figure 1: Project Timeline

This figure plots a typical production curve over time for a natural gas well, once production begins. It is based on similar figures found in Lake, Martin, Ramsey, and Titman (2012) as well as company investor presentations.

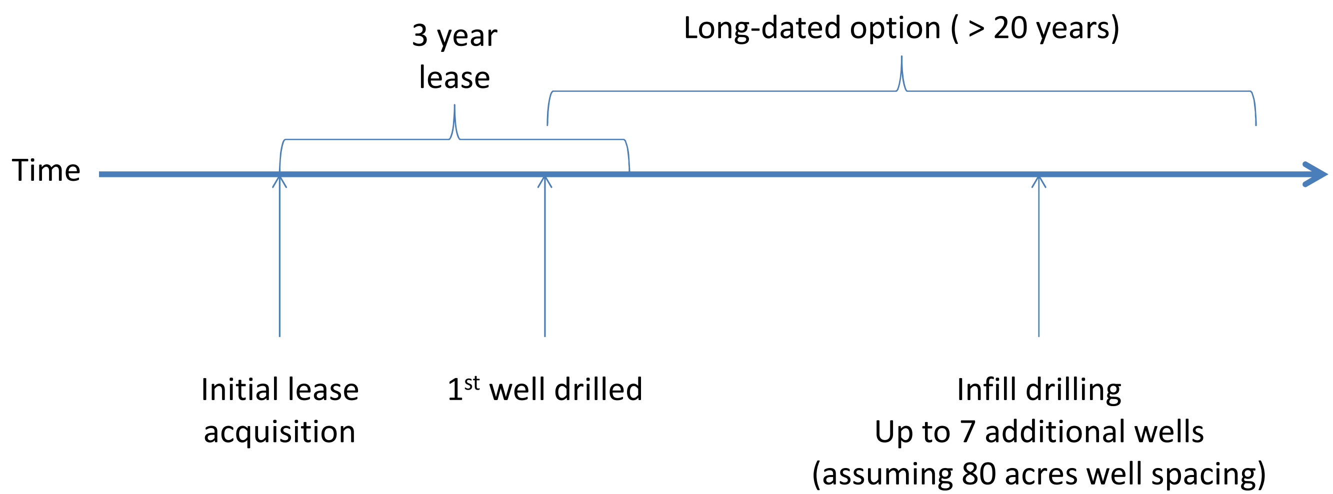


Figure 2: Infill Drilling Option Exercise Timeline
This figure plots the timeline associate with the option to infill drill.

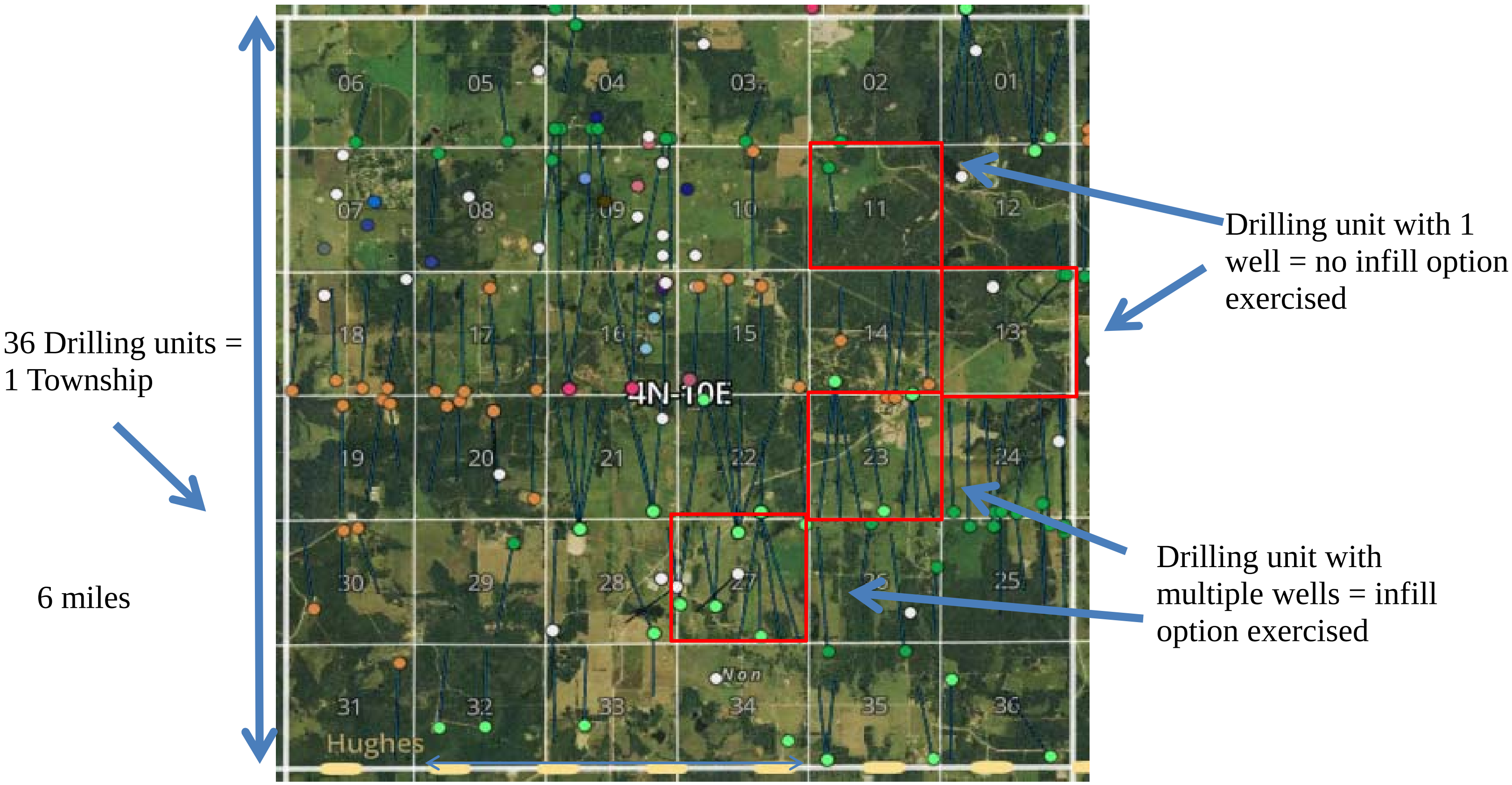


Figure 3: Map of Real Option Exercise Activity

This figure provides a map of drilling activity in one township in the Arkoma Woodford shale. The area covers approximately 36 individual drilling units. The blue lines are the horizontal well-bores of the wells in the drilling units and the multiple horizontal lines in a drilling unit correspond to the real option to "infill" drill having been exercised. In some instances the wellhead (top of the well) may be in a different drilling unit than the horizontal wellbore, in this instance, the well will only drain the reservoir in the drilling unit with the horizontal wellbore. The colors of the wellhead correspond to different companies.

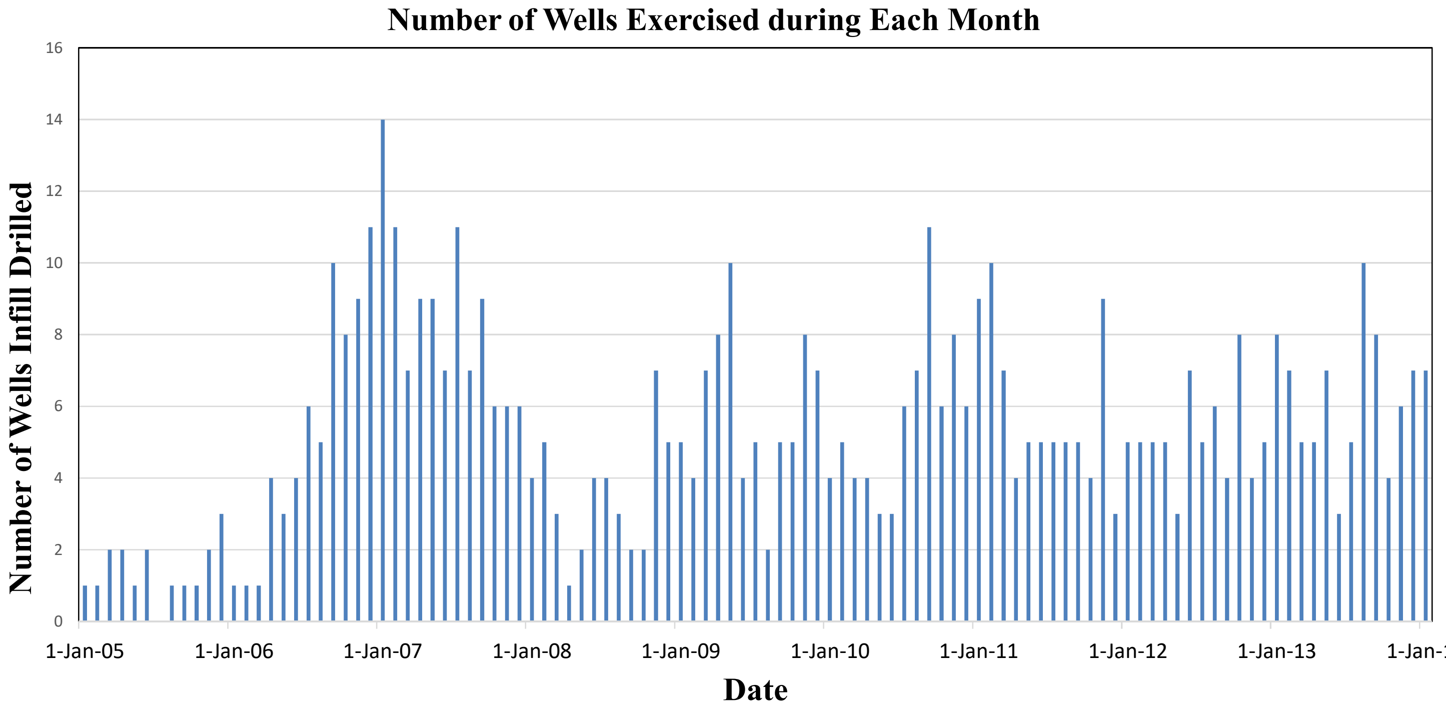


Figure 4A: Number of Infill Well Exercised Over Time
This figure plots the infill drilling activity, measured by the number of infill wells drilled in a given month, for the time period 2005 through 2016.

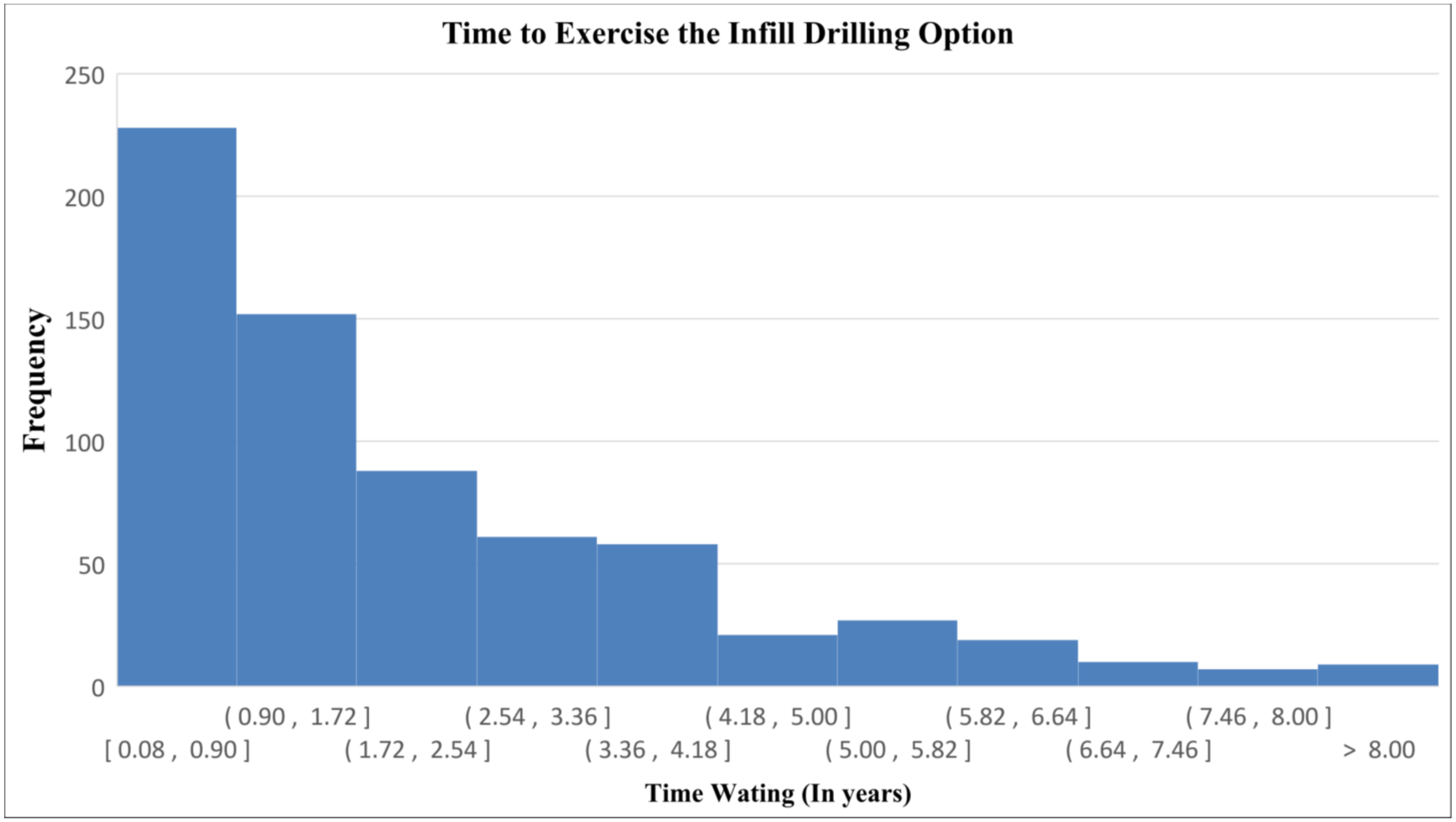


Figure 4B: Time to Exercise the infill Drilling Option

This figure plotes the frequency distribution of the time that firms wait before exercising the infill drilling option, for the time period 2005 through 2016.

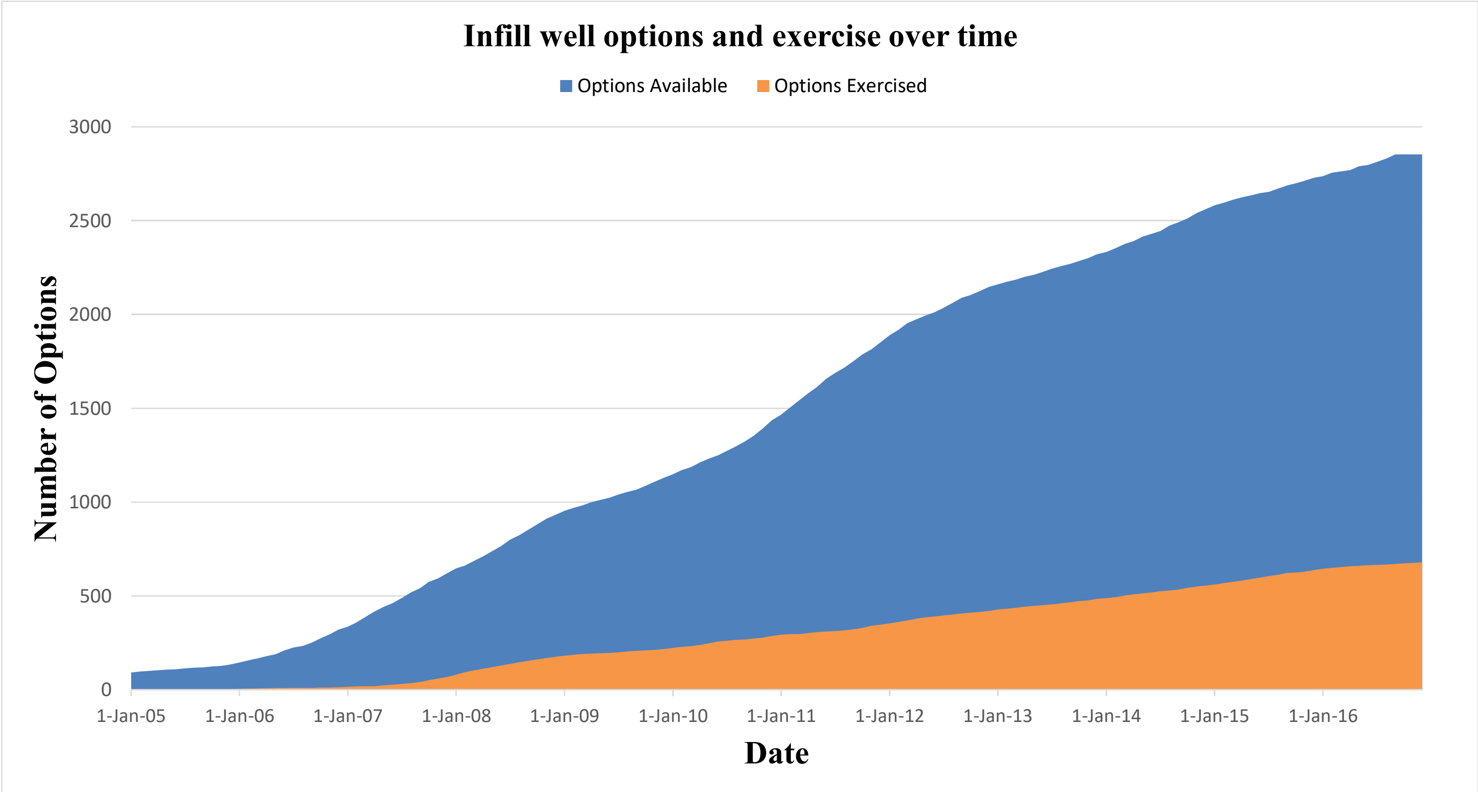


Figure 4C: Infill well options and exercise over time.
This figure plots the number of infill drilling option available and the number of option that have been exercised, measured by the number of infill wells drilled, for the time period 2005 through 2016.

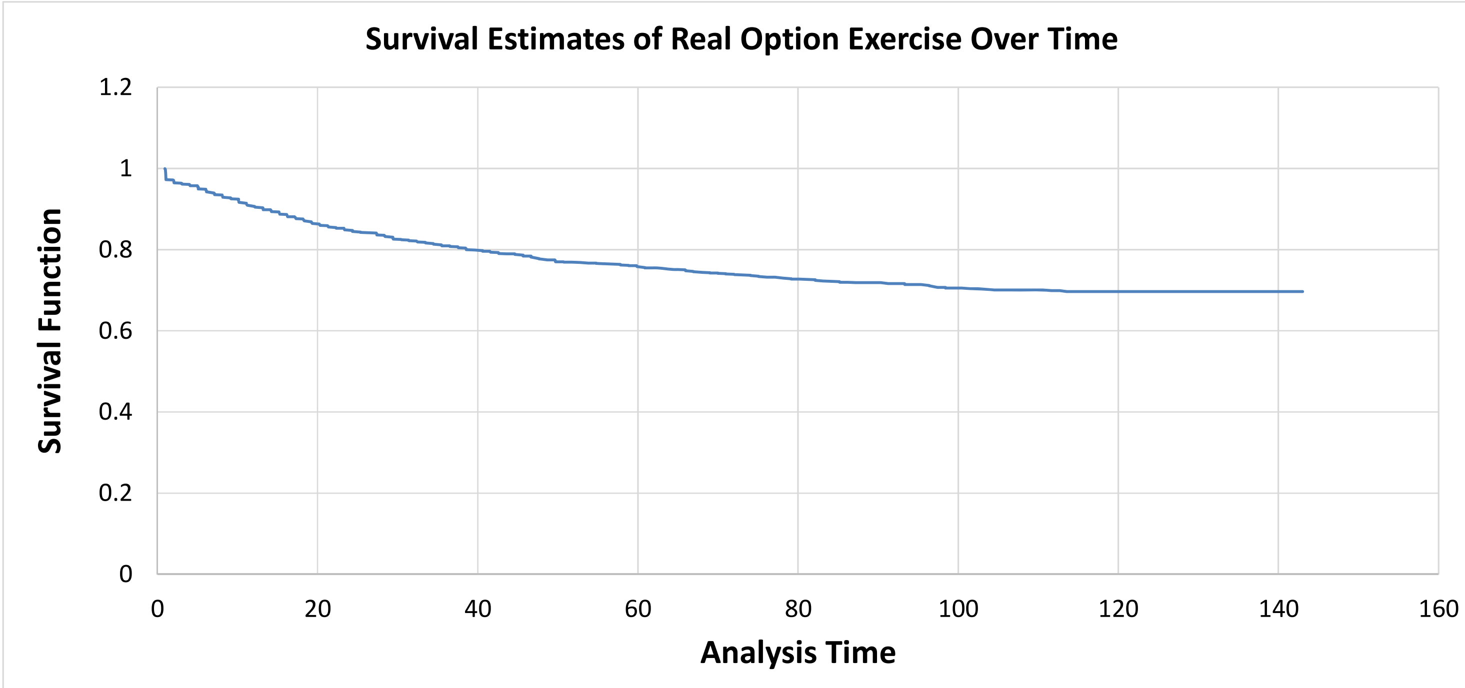


Figure 5: Survival Estimates for the full sample
This figure plots the survival function, measured by the amount of time it takes for the infill drilling option to be exercised, for the option available over the time period 2005 through 2016.

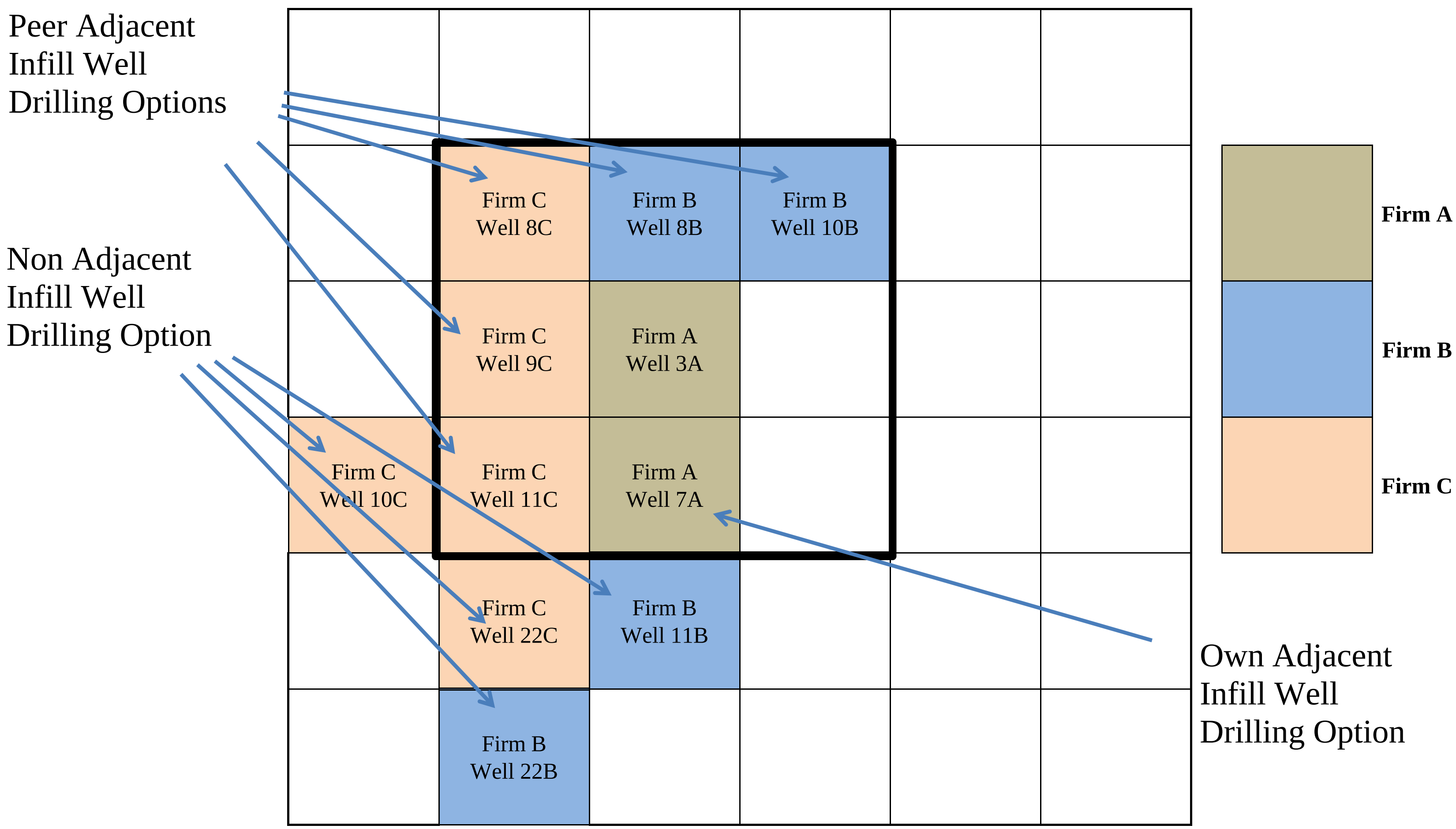
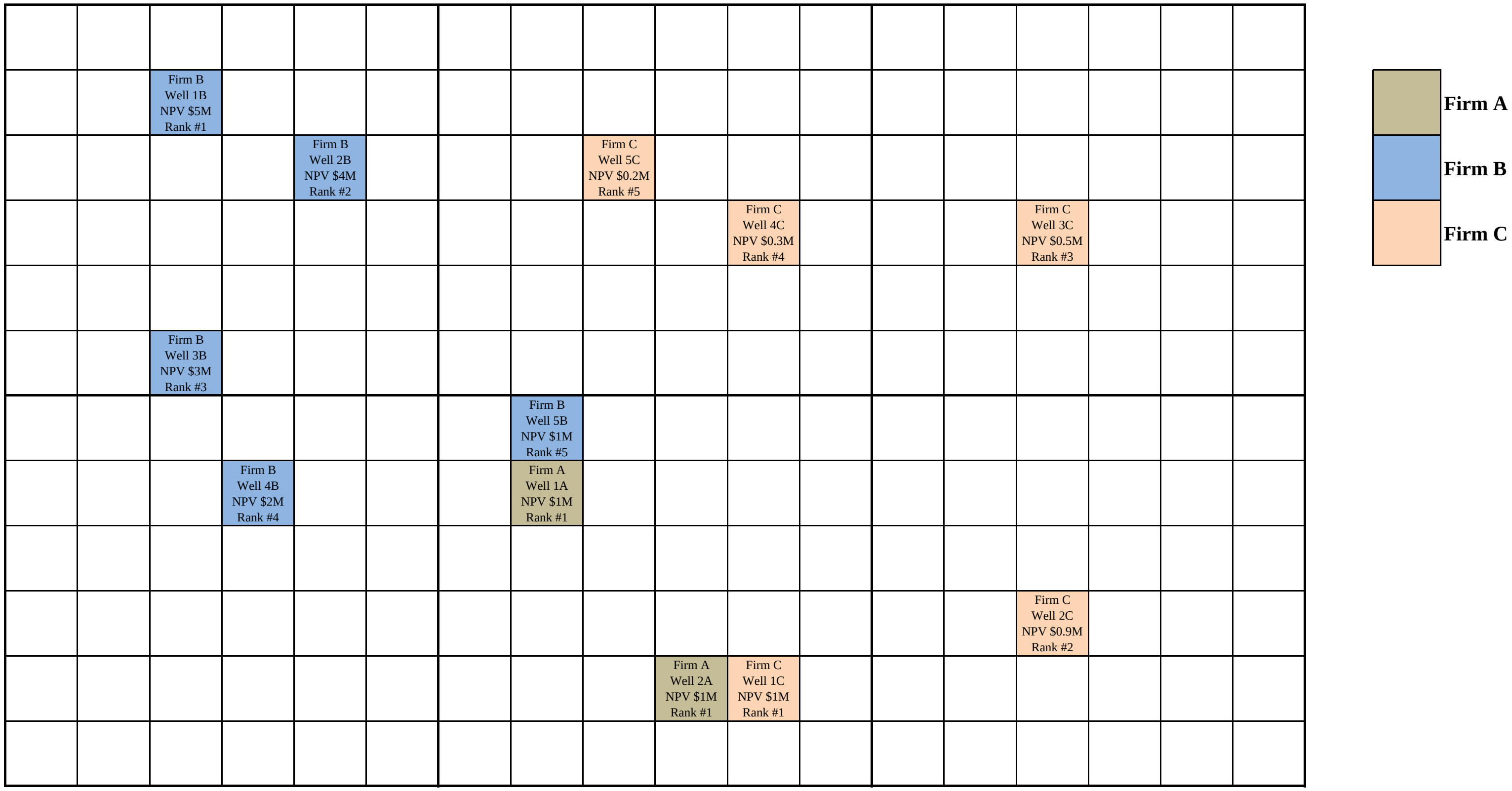


Figure 6: Peer Project Definition

This figure provides an illustrative example of the definition that is used for adjacent peer exercise activity. Specifically, the figure plots a 6 x 6 township which has 36 one mile by one mile drilling tracts. Due to institutional features of the land survey in our empirical setting, all infill drilling options conform to the above grid layout, and each infill drilling option is linked to a one mile by one mile drilling tract. We compute adjacent activity as the number of adjacent infill options that have been drilled by firms on the 8 adjacent drilling tracts, we further subdivide this activity by whether peer firms or a firm itself has exercised. For example, for the infill option on well 3A, if Firm C exercised option 8C and 9C and no other options were exercised, the number of adjacent peer options exercised would be 2. If Firm A exercised option 7A, then its own adjacent options exercised would increase to 1, while peer adjacent exercise would remain at 2.



Firm B Infill Real Option Portfolio

Well	Rank	NPV ($M)	Percentile
1B	1	5.0	0.80
2B	2	4.0	0.60
3B	3	3.0	0.40
4B	4	2.0	0.20
5B	5	1.0	0.00

Firm C Infill Real Option Portfolio

Well	Rank	NPV	Percentile
1C	1	1.0	0.80
2C	2	0.9	0.60
3C	3	0.5	0.40
4C	4	0.3	0.20
5C	5	0.2	0.00

Firm A Adjacent Peer Project Percentile Ranks

Well	Adjacent Well	Peer Rank	Peer Rank %	Peer NPV
1A	5B	5	0.00	1.0
2A	1C	1	0.80	1.0

Figure 7: Identification Strategy

This figure provides an illustrative example of the variation we are using for our primary identification strategy. The figure plots different infill well options owned by Firm A, Firm B, and Firm C, along with NPVs and the relative rank of the options in a firm's capital project portfolio. Firm A has two different infill options, one of which is adjacent to Firm B and one of which is adjacent to Firm C. As the example shows, the NPV of Firm A's options and the options adjacent to it are $1 million. However, for infill option 1A the adjacent option owned by firm B (5B) is the fifth ranked option in Firm B's portfolio. Alternatively for infill option 2A, the adjacent option owned by firm C (1C) is the top project in Firm C's portfolio. Our instrument relies on the idea that because option 2A is adjacent to a peer project that is in the 80th percentile of that peer's portfolio (1C) and not the 0th percentile (5B), that 1C is more likely to be exercised, even though the absolute NPVs 1C and 5B are similar.

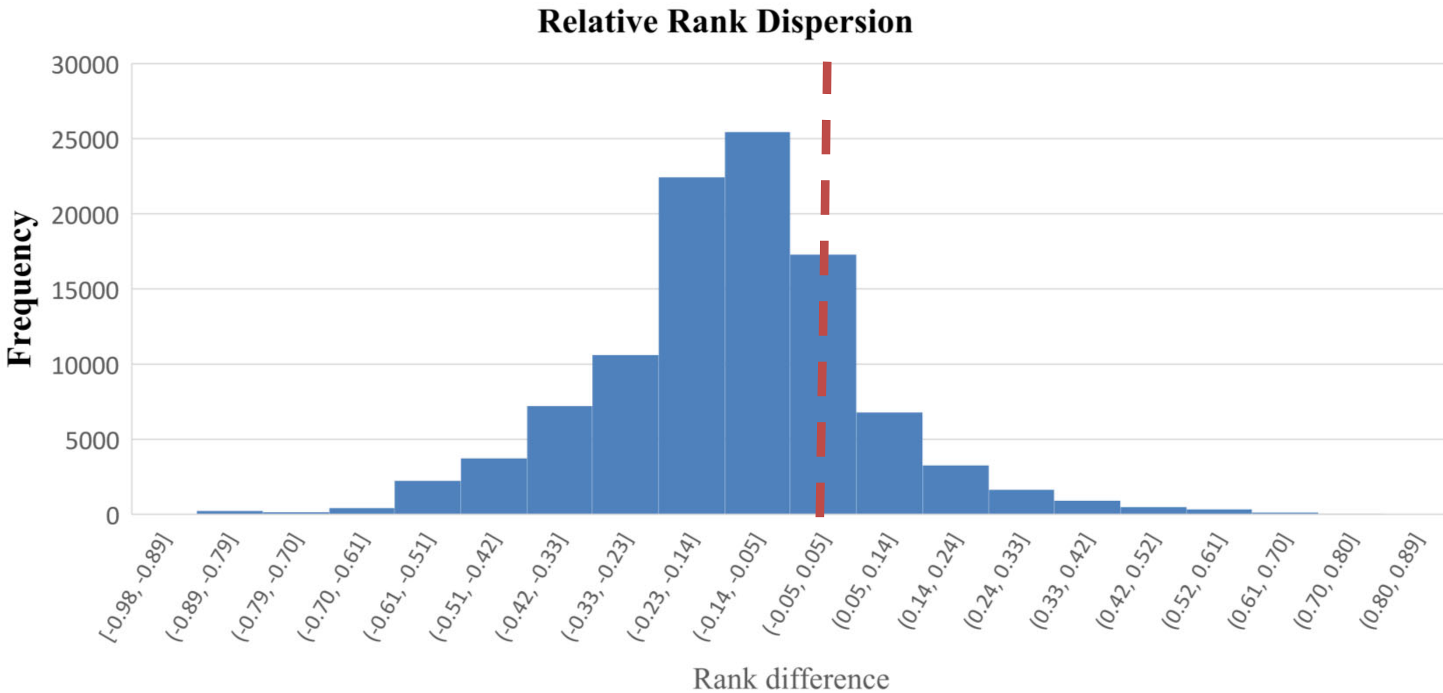


Figure 8: Relative Rank Dispersion

This figure plots the distribution of the difference in the relative rank percentile of the NPV of infill options in a given firm's portfolio versus the relative rank percentile's of the NPV of infill options that are adjacent to the project, but owned by peer firms. Positive numbers mean that the peer relative rank percentile is higher, while negative numbers mean that the peer relative rank percentile is lower. The rank of an infill option's NPV is based on the quality of the initial test well that is drilled to hold the acreage by production (HBP) for the infill option. At every time period all initial wells in a firm's project portfolio are ranked and percentiles are computed.

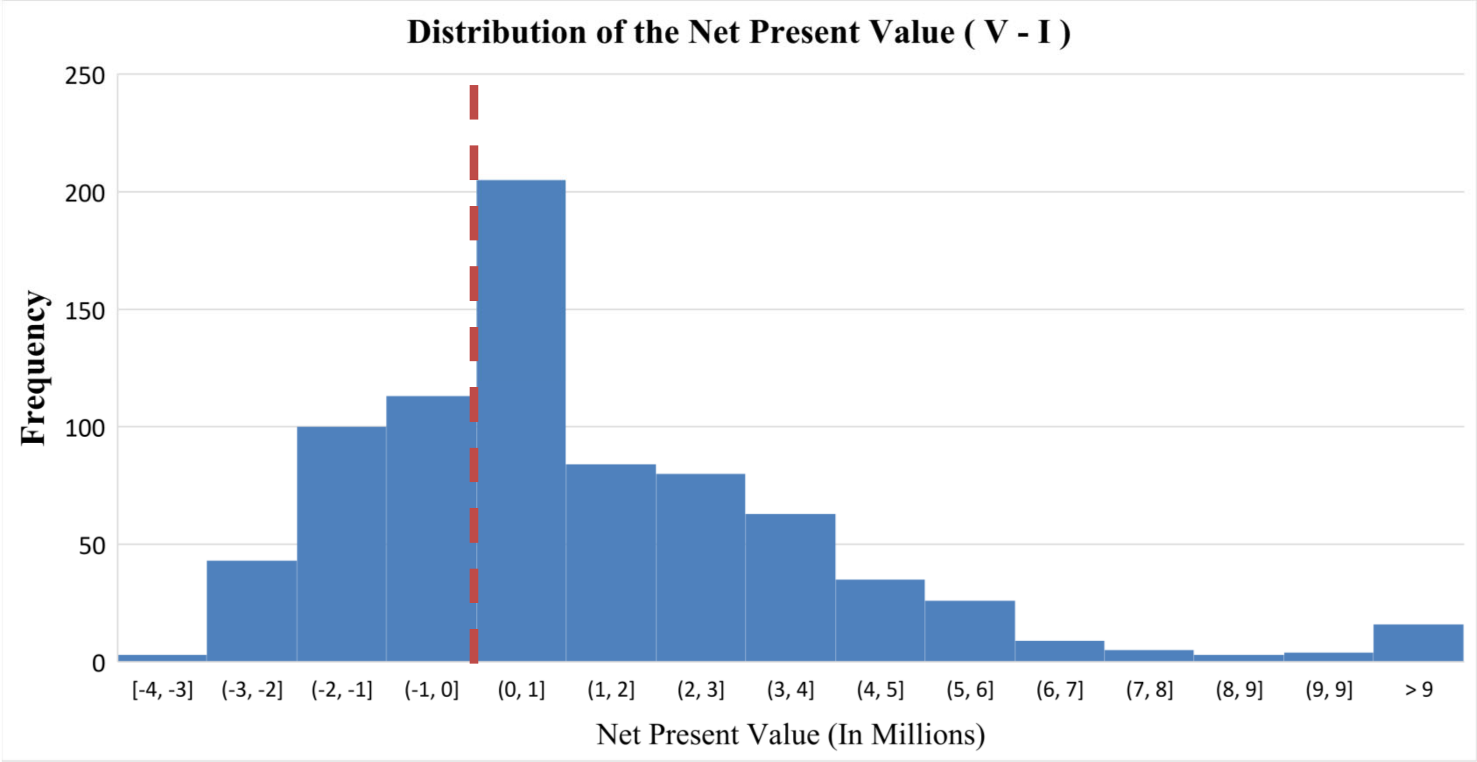


Figure 9: Distribution of the Net Present value (V-I)

This figure plots the distribution of the net present value (V-I) under the base case scenario, such that we set the depletion rate (ω) at 27%, the accounting depreciation rate (Θ) at 40%, the operational cost (φ) at 20%, the royalty rate (ρ) at 18.75%, the tax rate (τ) at 0% and the discount rate (μ) at 10%.

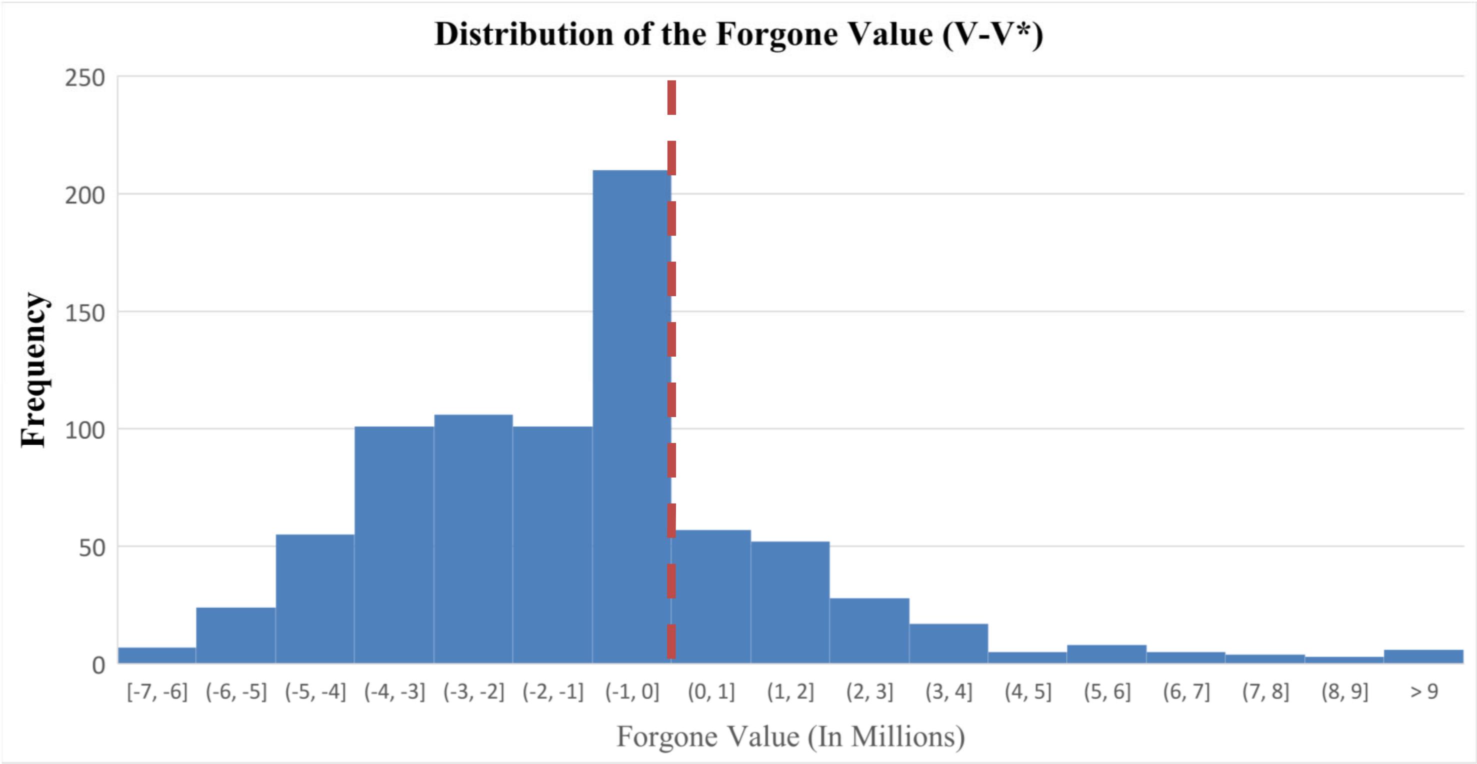


Figure 10A: Distribution of the Forgone Value (V-V*)

This figure plots the distribution of the forgone value (V-V*) under the base case scenario, such that we set the depletion rate (ω) at 27%, the accounting depreciation rate (ϴ) at 40%, the operational cost (ϕ) at 20%, the royalty rate (ρ) at 18.75%, the tax rate (τ) at 0% and the discount rate (μ) at 10%.

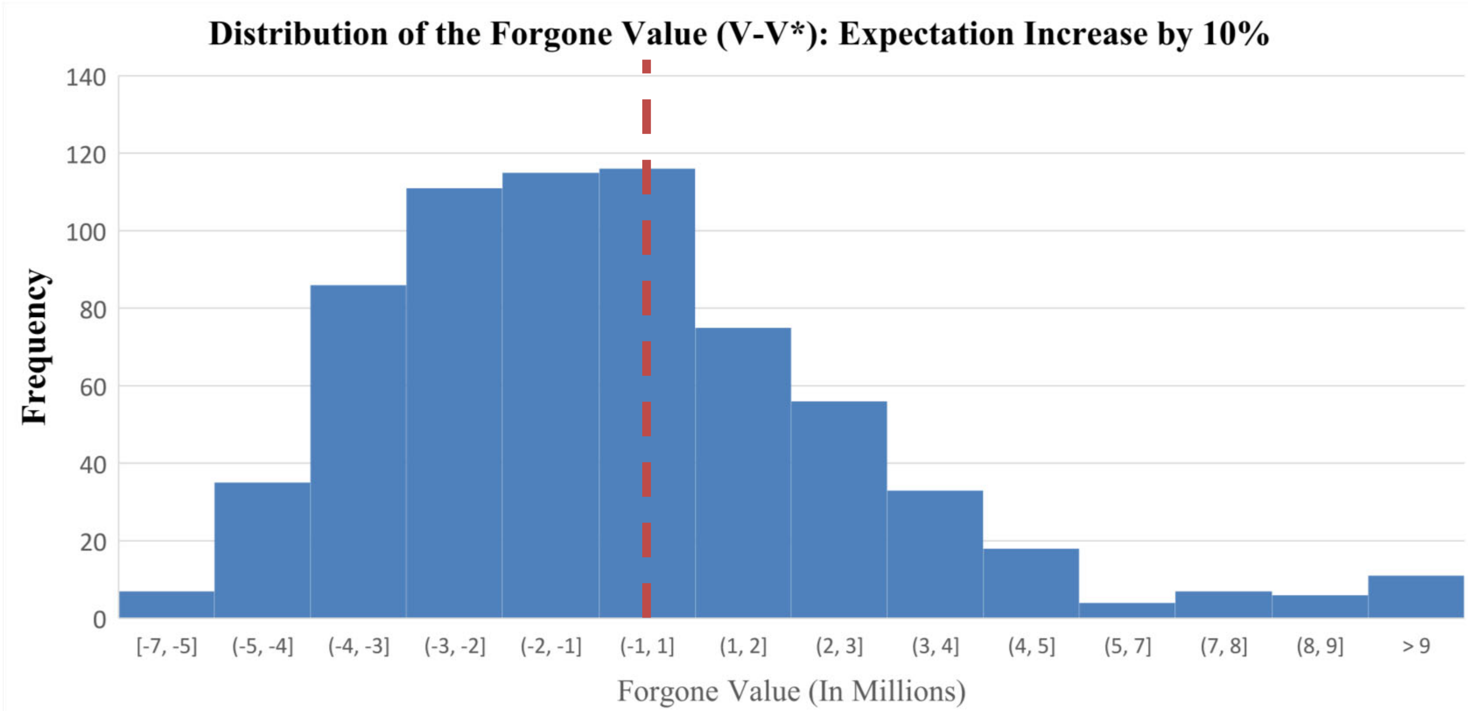


Figure 10B: Distribution of the Forgone Value, V-V*, if adjacent activity signals lead to an expected reserve increase of 10%

This figure plots the distribution of the forgone value (V-V*) under the base case scenario, such that we set the depletion rate (ω) at 27%, the accounting depreciation rate (ϴ) at 40%, the operational cost (ϕ) at 20%, the royalty rate (ρ) at 18.75%, the tax rate (τ) at 0% and the discount rate (μ) at 10%. The mean of the distribution is $-273,986.

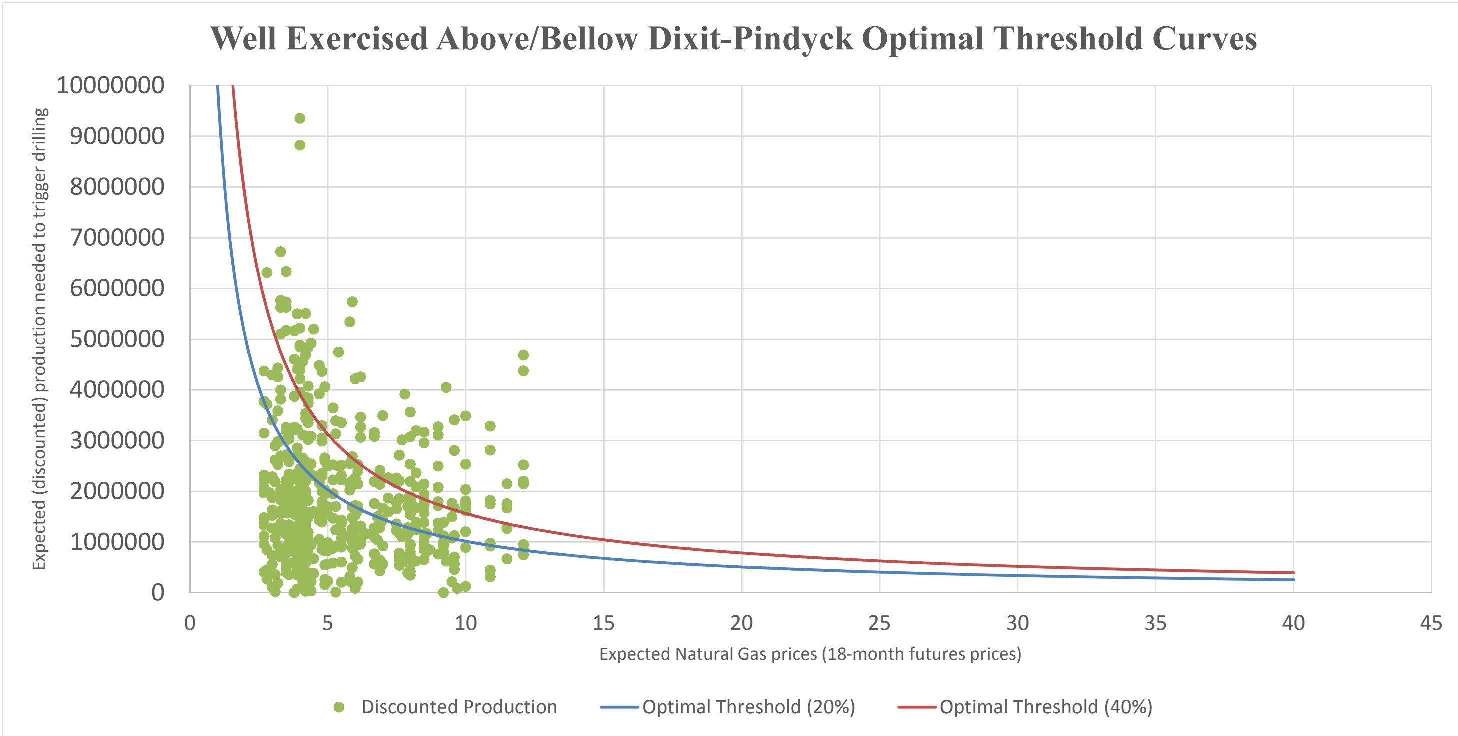


Figure 11: Distribution of the realized Discounted Production of the Wells

This figure provides a comparison between the distribution of the realized discounted production of our sample wells with the Dixit-Pindyck optimal exercise threshold curves at the two most extreme volatility value measured in our sample, 20% (minimum) and 40% (maximum). The x-axis shows natural gas 18-months futures prices at time of exercise. The y-axis shows expected discounted well production (mcf).

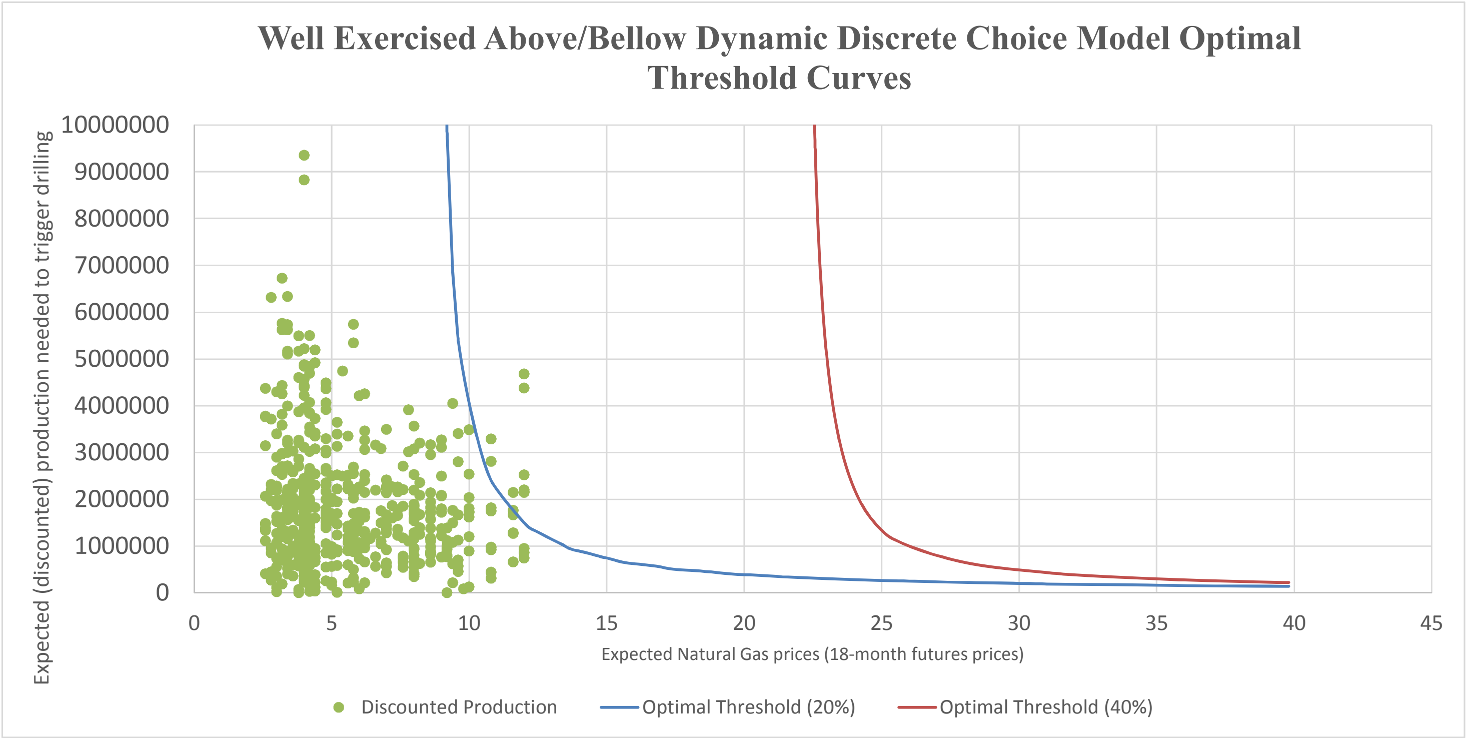


Figure 12: Distribution of the realized Discounted Production of the Wells

This figure provides a comparison between the distribution of the realized discounted production of our sample wells and the Rust dynamic discrete choice model optimal exercise threshold lines (see Figure 6 in Kellogg (2014)) at the two most extreme volatility value measured in our sample, 20% (lowest) and 40% (highest). The x-axis shows natural gas 18-months futures prices at time of exercise. The y-axis shows expected discounted well production (mcf).

Table 1: Summary Statistics

This table contains summary statistics for the data in our study. Panel A presents an overview of the sample of options on infill drilling opportunities that firms have, including summary statistics on well costs and cash flows at the time of exercise. Panel B presents summary statistics on the panel data we estimate our hazard models on. The unit of observation in this panel is at the infill option-month level, that is, there is an observation for every available option to be exercised every month by all firms. The baseline variables are all variables used in the hazard model to assess whether exercise is directionally correlated with factors standard real option theories suggest are important. The peer effect variables are all variables used to assess whether competitor peer affects in adjacent drilling units alter option exercise decisions.

Panel A: Well Data Summary Statsitcs

Time Period	2005-2016			
Number of Total Options	2853			
Number of Exercised Options at End of Sample	680			
Number of Firms	159			
Well Statistics at Exercise	N	Mean	Median	Std Dev
Well Costs	680	$ 4,728,552.0	$ 4,685,432.0	$ 775,753.1
Present Value of Well Cash Flow	680	$ 5,708,996.8	$ 5,255,193.3	$ 2,862,803.0

Panel B: Panel Data Summary Statistcs

Baseline Variables	N	Mean	Median	Std Dev
Natural Gas Price	146	5.80	5.03	2.44
Implied Volatility of Natural Gas	138	28.79	27.92	5.35
Interest Rates	146	2.33	1.78	1.33
Log(First Well Production)	680	13.10	13.27	1.32
Peer Effect Variables	*N*	Mean	Median	Std Dev
Adjacent Competitor Options Exercised	162905	0.34	0.00	0.86
Adjacent Own Firm Options Exercised	162905	0.40	0.00	0.88
Relative rank percentile (own infill option)	103451	0.46	0.45	0.29
Relative rank percentile (adjacent peer infill options)	103451	0.57	0.58	0.29

Table 2: Baseline Determinants of Real Option Exercise

This table reports coefficient estimates from a Cox hazard model of real option exercise. The time period of the sample is from 2005 to 2016. The unit of observation in the underlying panel is at the infill drill option i month t level. The spell in the hazard model is defind as the time period from which an infill option becomes available (first well drilled) to when the infill option (two or more wells) are drilled. The implied volatility of natural gas is the implied volatility based on option prices 18 months in the future, and the natural gas price is the price of the natural gas futures contract 18 months out into the future. The five year risk free rate is the 5 year nominal risk free rate on U.S. Treasury bonds. The log of drilling costs is a time-varying estimate of drilling costs for an infill well (analogous to the strike price of the real option). The log first well production variable is fixed for a given option, and is the logarithm of the first year of production of the first well on the drilling unit, which corresponds to production prior to the exercise of the infill option. The hazard impact percentage (HI), which is the percentage change in the hazard rate per unit change of the covariate is reported next to the coeffiecient. z-statistics are reported in brackets below the coefficients. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Hazard model for infill option exercise					
	(1)		(2)		(3)	
	Estimates	HI (%)	Estimates	HI (%)	Estimates	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.026*	-2.57	-0.029**	-2.85	-0.0265*	-2.62
	[-1.93]		[-2.12]		[-1.89]	
(β_2) Natural gas price ($/mcf)$_t$	0.1466***	15.79	0.192***	21.16	0.1743***	19.04
	[3.38]		[3.76]		[3.51]	
(β_3) Log drilling cost$_t$			0.2019	22.38	-0.0086	-0.85
			[0.71]		[-0.03]	
(β4) 5 years risk free interest rate$_t$			0.0632	6.52	0.0036	0.36
			[0.71]		[0.04]	
(β5) Log first well production$_i$			0.5237***	68.82	0.367***	44.34
			[7.20]		[3.48]	
Township FE	No		No		Yes	
N	162,905		162,905		162,905	

Table 3: Peer Effects and Real Option Exercise

This table reports coefficient estimates from a Cox hazard model of real option exercise. The time period of the sample is from 2005 to 2016. The unit of observation in the underlying panel is at the "infill drill option" i, month t level. The number of adjacent exercised option (competitor) for an unexercised option i at time t is the number of the adjacent 8 drilling units owned by competitors in which the "infill drill option" has been exercised by time t. The number of "own" adjacent options exercised for an unexercised option i at time t is the number of the adjacent 8 drilling units owned by the firm itself in which the "infill drill option" has been exercised. The hazard impact percentage (HI), which is the percentage change in the hazard rate per unit change of the covariate is reported next to the coefficient. z-statistics are reported in brackets below the coefficients. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Hazard model for infill option exercise					
	(1)		(2)		(3)	
	Estimates	HI (%)	Estimates	HI (%)	Estimates	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0328**	-3.23	-0.0337***	-3.31	-0.0282**	-2.79
	[-2.47]		[-2.58]		[-2.22]	
(β_2) Natural gas price ($/mcf)$_t$	0.1378***	14.77	0.1412***	15.17	0.1839***	20.19
	[3.68]		[2.98]		[4.10]	
(β_3) Log drilling cost$_t$			-0.0079	-0.79	0.0667	6.90
			[-0.03]		[0.24]	
(β_4) 5 years risk free interest rate$_t$			0.1382	14.82	0.0749	7.77
			[1.50]		[0.78]	
(β_5) Log first well production$_i$			0.4153***	51.48	0.3302***	39.13
			[5.74]		[3.08]	
(β6) Number of adjacent exercised options (own)$_{i,t}$	0.546***	72.63	0.5263***	69.26	0.3781***	45.95
	[15.22]		[14.24]		[8.83]	
(β7) Number of adjacent exercised options (peer)$_{i,t}$	0.3233***	38.17	0.2821***	32.59	0.1038*	10.94
	[8.75]		[7.58]		[1.96]	
Township FE	No		No		Yes	
N	162,905		162,905		162,905	

Table 4: Project Relative Rank Percentile and Option Exercise

This table reports the effect of the relative project rank percentile within the portfolio of a firm's infill drilling options on the decision to exercise the real option to infill drill. The time period of the sample is from 2005 to 2016. The unit of observation in the underlying panel is at the "infill drill option" i , month t level. The relative project rank percentiles are based on the quality of the project, as measured by the production from the first well on a drilling tract within a firm's portfolio. The percentile is computed as the rank of the project divided by the total number of infill options a firm has, higher percentile projects can be viewed as having a higher relative NPV rank within a firm's portfolio. The hazard impact percentage (HI), which is the percentage change in the hazard rate per unit change of the covariate is reported next to the coefficient. z -statistics are reported in brackets below the coefficients. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Hazard model for infill option exercise					
	(1)		(2)		(3)	
	Estimate	HI (%)	Estimate	HI (%)	Estimate	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0252*	-2.49	-0.028**	-2.76	-0.0245*	-2.42
	[-1.92]		[-2.07]		[-1.77]	
(β_2) Natural Gas price ($/mcf)$_t$	0.1751***	19.14	0.1692***	18.44	0.1631***	17.71
	[4.21]		[3.28]		[3.38]	
(β_3) Log drilling cost$_t$			0.1772	19.39	-0.0141	-1.40
			[0.62]		[-0.05]	
(β_4) 5 years risk free interest rate$_t$			0.0533	5.47	-0.0093	-0.93
			[0.60]		[-0.10]	
(β_5) Log first well production$_i$			0.1273	13.57	-0.0974	-9.28
			[1.29]		[-1.44]	
(β_6) Relative rank percentile (own project)$_{i,t}$	0.6147***	84.91	0.5059***	65.84	0.6014***	82.47
	[10.24]		[4.70]		[5.69]	
Township FE	No		No		Yes	
N	162,905		162,905		162,905	

Table 5: Real Option Exercise and Exogenous Peer Effects

This table reports the effects of peer real option exercise decisions based on the exogenous measure of peer exercise activity from an instrument. The time period of the sample is from 2005 to 2016. The unit of observation in the underlying panel is at the "infill drill option" *i*, month *t* level. The results in Panel A report coefficient estimates of a hazard model which uses the average adjacent peer project relative rank percentile to instrument for the number of adjacent peer infill options which have been exercised. The bottom of Panel A reports the first stage regression of the two-stage estimation approach, where controls are not shown to save space. Panel B reports the direct effect of our instrument in the Cox hazard model. The hazard impact percentage (HI), which is the percentage change in the hazard rate per unit change of the covariate is reported next to the coefficient. *z*-statistics are reported in brackets below the coefficients. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

Table 5: Panel A

	Hazard model					
	Instrumented - Number of adjacent exercised options (peer)					
	(1)		(2)		(3)	
	Estimate	HI (%)	Estimate	HI (%)	Estimate	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0245	-2.42	-0.0281	-2.77	-0.0166	-1.64
	[-1.45]		[-1.62]		[-0.98]	
(β_2) Natural gas price (\$/mcf)$_t$	0.2062***	22.90	0.1546***	16.72	0.2801***	32.33
	[2.86]		[2.62]		[2.70]	
(β_3) Log drilling cost$_t$	0.0494	5.06	-0.0319	-3.14	0.4462	56.24
	[0.17]		[-0.10]		[1.07]	
(β_4) 5 year risk free interest rate$_t$	0.1325	14.17	0.1564	16.93	0.2168	24.21
	[1.07]		[1.50]		[1.29]	
(β_5) Log first well production$_i$	0.2432***	27.54	-0.0064	-0.64	-0.0565	-5.50
	[2.61]		[-0.07]		[-0.68]	
(β_6) Instrumented - Number of adjacent exercised options (peer)$_{i,t}$	0.595***	81.31	0.5825***	79.06	0.6623**	93.93
	[2.72]		[2.82]		[2.16]	
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	-0.0671	-6.49	-0.0746**	-7.18	-0.0236	-2.33
	[-1.63]		[-2.15]		[-0.75]	
(β_8) Number of adjacent exercised options (own)$_{i,t}$			0.3731***	45.22	0.7649***	114.88
			[3.35]		[4.25]	
(β_9) Relative rank percentile (own project)$_{i,t}$			0.311**	36.48	0.2563	29.21
			[2.05]		[1.63]	
Township FE	No		No		Yes	
N	103,451		103,451		103,451	

	First Stage Regression		
First Stage Coefficients	Dependent Variable = Number of adjacent exercised options (peer)$_{i,t}$		
(β_1) Average relative rank percentile (adjacent peer projects)$_{i,t}$	0.1306***	0.121***	0.1117***
	[3.28]	[3.14]	[2.93]
Township FE	No	No	Yes
Included Instruments/Controls	Yes	Yes	Yes

Table 5: Panel B

	Hazard model					
	Reduced form - Relative rank percentile (adjacent peer projects)					
	(1)		(2)		(3)	
	Estimate	HI (%)	Estimate	HI (%)	Estimate	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0242	-2.39	-0.028*	-2.76	-0.0211	-2.09
	[-1.55]		[-1.84]		[-1.43]	
(β_2) Natural gas price ($/mcf)$_t$	0.1838***	20.18	0.1301***	13.90	0.1588***	17.21
	[3.64]		[2.71]		[3.12]	
(β_3) Log drilling cost$_t$	0.1768	19.34	0.0805	8.39	0.2025	22.45
	[0.55]		[0.26]		[0.55]	
(β_4) 5 year risk free interest rate$_t$	0.0704	7.30	0.1022	10.76	0.0441	4.51
	[0.75]		[1.11]		[0.45]	
(β_5) Log first well production$_i$	0.295***	34.31	0.0045	0.45	-0.0446	-4.36
	[3.40]		[0.06]		[-0.60]	
(β_6) Relative rank percentile (adjacent peer projects)$_{i,t}$	0.3043***	35.57	0.2676***	30.69	0.2417***	27.34
	[3.31]		[3.65]		[2.90]	
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	0.0567***	5.84	0.0365**	3.72	0.0566***	5.82
	[3.46]		[2.31]		[3.06]	
(β_8) Number of adjacent exercised options (own)$_{i,t}$			0.5002***	64.90	0.3985***	48.96
			[11.01]		[7.67]	
(β_9) Relative rank percentile (own project)$_{i,t}$			0.4146***	51.37	0.4256***	53.05
			[3.86]		[3.67]	
Township FE	No		No		Yes	
N	103,451		103,451		103,451	

Table 6: Internal Validity - Correlation of Project Relative Rank Percentiles

This table reports the coefficient estimates of an ordinary least squares (OLS) regression of the relative rank percentile of a firm's own project on the relative rank percentiles of adjacent infill options owned by peer firms. The unit of observation in the underlying panel is at the "infill drill option" *i* , month *t* level. *t* -statistics are reported in brackets below the coefficients. Standard errors are clustered by township. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Dependent variable = Relative rank percentile (own project)
	(1)
(β_1) Relative rank percentile (adjacent peer projects)$_{i,t}$	-0.0359
	[-1.11]
Township FE	Yes
N	103,451

Table 7: Internal Validity - Subsample Analysis

This table reports coefficient estimates from a Cox hazard model of real option exercise on a specific subsample to test instrument validity. The time period of the samples are from 2005 to 2016. The unit of observation in the underlying panel is at the "infill drill option" *i*, month *t* level. Specifications (1) and (2) report exercise behavior for the subsample of real options where a project's relative rank percentile within a given firm's portfolio is below median for that firm, but adjacent projects owned by peer's have project relative rank percentiles in peer project portfolios that are above median. The hazard impact percentage (HI), which is the percentage change in the hazard rate per unit change of the covariate is reported next to the coefficient. *z*-statistics are reported in brackets below the coefficients. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Hazard model			
	Low own project rank vs. High adjacent peer project rank			
	Reduced Form Peer Effects		Instrumented Peer Effects	
	(1)		(2)	
	Estimates	HI (%)	Estimates	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0107	-1.06	-0.0157	-1.56
	[-0.38]		[-0.51]	
(β_2) Natural gas price (\$/mcf)$_t$	0.0584	6.02	0.1579	17.11
	[0.66]		[1.41]	
(β_3) Log drilling cost$_t$	-0.0701	-6.77	-0.0328	-3.23
	[-0.15]		[-0.06]	
(β_4) 5 year risk free interest rate$_t$	0.1505	16.25	0.1107	11.71
	[1.01]		[0.63]	
(β_5) Log first well production$_i$	0.0241	2.44	0.0308	3.12
	[0.27]		[0.22]	
(β_6) Relative rank percentile (adjacent peer projects)$_{i,t}$	0.4345***	54.42		
	[3.46]			
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	0.0793***	8.26	-0.0936	-8.93
	[3.02]		[-1.48]	
(β_8) Number of adjacent exercised options (own)$_{i,t}$	0.399***	49.03	0.0166	1.67
	[5.27]		[0.06]	
(β_9) Relative rank percentile (own project)$_{i,t}$	0.1793	19.64	-0.2562	-22.60
	[0.83]		[-0.60]	
(β_{10}) Instrumented - Number of adjacent exercised options (peer)$_{i,t}$			1.1038***	201.57
			[2.66]	
Township FE	No		No	
N	43,686		43,686	

Table 8: Actions vs. Characteristics

This table reports coefficient estimates from a Cox hazard model of real option exercise. The time period of the sample is from 2005 to 2016. The unit of observation in the underlying panel is at the "infill drill option" *i*, month *t* level. The spell in the hazard model is defined as the time period from which an infill option becomes available (first well drilled) to when the infill option (two or more wells) are drilled. The variable "Play activity" is computed in two steps. First, we compute the drilling activity intensity across the entire shale field for each adjacent competitor at a given point in time *t*, while excluding the wells they drilled in the township of infill option *i*. Then, for each infill drill option in our sample, we define the variable "Play activity" as the sum the adjacent competitor activity at each point in time. The hazard impact percentage (HI), which is the percentage change in the hazard rate per unit change of the covariate is reported next to the coeffiecient. *z*-statistics are reported in brackets below the coefficients. * indicates significance at the 10% level, ** at the 5% level, and *** at the 1% level.

	Hazard model							
	Reduced Form Peer Effects				Instrumented Peer Effects			
	(1)		(2)		(3)		(4)	
	Estimates	HI (%)	Estimates	HI (%)	Estimates	HI (%)	Estimates	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0272*	-2.69	-0.0203	-2.01	-0.0289*	-2.85	-0.0168	-1.67
	[-1.80]		[-1.38]		[-1.67]		[-0.93]	
(β_2) Natural gas price ($/mcf)$_t$	0.1205**	12.81	0.1548***	16.75	0.1665***	18.12	0.2767***	31.88
	[2.54]		[3.08]		[2.81]		[2.96]	
(β_3) Log drilling cost$_t$	0.0536	5.51	0.2035	22.57	0.0145	1.46	0.4603	58.45
	[0.17]		[0.55]		[0.04]		[1.30]	
(β_4) 5 year risk free interest rate$_t$	0.1052	11.09	0.0501	5.13	0.1471	15.85	0.2193	24.52
	[1.13]		[0.51]		[1.39]		[1.08]	
(β_5) Log first well production$_i$	0.0048	0.48	-0.0413	-4.05	-0.0033	-0.33	-0.0564	-5.49
	[0.06]		[-0.55]		[-0.04]		[-0.56]	
(β_6) Relative rank percentile (adjacent peer projects)$_{i,t}$	0.2689***	30.85	0.2448***	27.74				
	[3.65]		[2.94]					
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	0.0307**	3.12	0.0535***	5.50	-0.0665**	-6.43	-0.0200	-1.98
	[1.96]		[2.91]		[-2.17]		[-0.57]	
(β_8) Number of adjacent exercised options (own)$_{i,t}$	0.5106***	66.62	0.4066***	50.18	0.355***	42.62	0.7553***	112.83
	[11.11]		[7.93]		[3.01]		[4.07]	
(β_9) Relative rank percentile (own project)$_{i,t}$	0.4107***	50.79	0.4207***	52.30	0.3062**	35.82	0.2527	28.75
	[3.84]		[3.63]		[2.02]		[1.26]	
(β_{10}) Play activity (peer)$_{i,t}$	0.0916***	9.60	0.0575**	5.92	-0.2544**	-22.46	-0.1165	-11.00
	[4.24]		[2.26]		[-1.96]		[-1.00]	
(β_{11}) Instrumented - Number of adjacent exercised options (peer)$_{i,t}$					0.7351***	108.58	0.6926*	99.89
					[2.79]		[1.76]	
Township FE	No		Yes		No		Yes	
N	103,451		103,451		103,451		103,451	

Table 10: Sensitivity of Option Value to Parameters

This table reports sensitivity of the values generated by a standard real options model (Paddock et al. (1988)) to different assumptions on model parameters. Depletion rate is the rate at which a well depletes its reserves, a rate of 27 can be interpreted as a wells production declining at a rate of 27% a year. Operational Cost is the percentage of cash flows going towards lease operating expenses, a rate of 20 can be interpreted as 20% of cash flows going to pay for ongoing costs. The discount rate is the firm's cost of capital, and the tax rate is the rate used to compute after tax cash flow.

Depletion Rate Sensitivity	Mean	Pr(Mean = 0)	Median	Pr(Median = 0)
Net Present Value (NPV at Exercise)				
Depletion Rate (ω = 25)	$1,614,417	0.05	$1,084,480	0.00
Depletion Rate (ω = 27)	$1,216,441	0.00	$700,523	0.00
Depletion Rate (ω = 29)	$1,002,391	0.00	$517,302	0.00
Forgone Value (Option Value at Exercise - NPV at Exercise)				
Depletion Rate (ω = 25)	$228,173	0.00	$710,023	0.00
Depletion Rate (ω = 27)	$627,575	0.00	$1,063,742	0.00
Depletion Rate (ω = 29)	$842,392	0.00	$1,232,361	0.00
Operational Cost Sensitivity	Mean	Pr(Mean = 0)	Median	Pr(Median = 0)
Net Present Value (NPV at Exercise)				
Operational Cost (ϕ = 15)	$1,751,721	0.44	$1,228,408	0.00
Operational Cost (ϕ = 20)	$1,216,441	0.00	$700,523	0.00
Operational Cost (ϕ = 25)	$834,099	0.00	$363,171	0.00
Forgone Value (Option Value at Exercise - NPV at Exercise)				
Operational Cost (ϕ = 15)	$90,378	0.00	$600,760	0.00
Operational Cost (ϕ = 20)	$627,575	0.00	$1,063,742	0.00
Operational Cost (ϕ = 25)	$1,011,287	0.00	$1,401,705	0.00
Discount Rate Sensitivity	Mean	Pr(Mean = 0)	Median	Pr(Median = 0)
Net Present Value (NPV at Exercise)				
Discount Rate (μ = 7.5%)	$1,700,225	0.00	$1,174,428	0.00
Discount Rate (μ = 10%)	$1,216,441	0.00	$700,523	0.00
Discount Rate (μ = 12.5%)	$934,084	0.00	$454,473	0.00
Forgone Value (Option Value at Exercise - NPV at Exercise)				
Discount Rate (μ = 7.5%)	$676,671	0.00	$1,155,076	0.00
Discount Rate (μ = 10%)	$627,575	0.00	$1,063,742	0.00
Discount Rate (μ = 12.5%)	$567,374	0.00	$1,023,884	0.00
Tax Rate Sensitivity	Mean	Pr(Mean = 0)	Median	Pr(Median = 0)
Net Present Value (NPV at Exercise)				
Tax Rate (τ = 0 %)	$1,216,441	0.00	$700,523	0.00
Tax Rate (τ = 15 %)	$1,076,249	0.00	$584,322	0.00
Tax Rate (τ = 30 %)	$859,588	0.00	$388,711	0.00
Forgone Value (Option Value at Exercise - NPV at Exercise)				
Tax Rate (τ = 0 %)	$627,575	0.00	$1,063,742	0.00
Tax Rate (τ = 15 %)	$768,269	0.00	$1,169,831	0.00
Tax Rate (τ = 30 %)	$985,706	0.00	$1,381,667	0.00
Royalty Rate Sensitivity	Mean	Pr(Mean = 0)	Median	Pr(Median = 0)
Net Present Value (NPV at Exercise)				
Royalty Rate (ρ = 13.75%)	$1,292,910	0.00	$767,158	0.00
Royalty Rate (ρ = 18.75%)	$1,216,441	0.00	$700,523	0.00
Royalty Rate (ρ = 23.75%)	$502,735	0.00	$30,277	0.01
Forgone Value (Option Value at Exercise - NPV at Exercise)				
Royalty Rate (ρ = 13.75%)	$550,833	0.00	$1,001,073	0.00
Royalty Rate (ρ = 18.75%)	$627,575	0.00	$1,063,742	0.00
Royalty Rate (ρ = 23.75%)	$1,343,838	0.00	$1,685,949	0.00

Appendix Table 1: Real Option Exercise and Exogenous Peer Effects - IV Probit Model, Cluster by Township

Table 5: Panel A

	IV Probit model Instrumented - Number of adjacent exercised options (peer)		
	(1)	(2)	(3)
	Estimate	Estimate	Estimate
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0088*	-0.0097*	-0.0046
	[-1.79]	[-1.94]	[-0.76]
(β_2) Natural gas price (\$/mcf)$_t$	0.0241	0.0093	0.0867***
	[1.05]	[0.42]	[3.51]
(β_3) Log drilling cost$_t$	-0.0373	-0.0592	0.1389
	[-0.35]	[-0.57]	[1.13]
(β_4) 5 year risk free interest rate$_t$	0.0581*	0.07*	0.0958**
	[1.65]	[1.92]	[1.97]
(β_5) Log first well production$_i$	0.0436	-0.0103	-0.0099
	[1.34]	[-0.48]	[-0.39]
(β_6) Instrumented - Number of adjacent exercised options (peer)$_{i,t}$	0.5688***	0.5697***	0.5476***
	[4.14]	[4.22]	[2.69]
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	-0.014*	-0.0182***	-0.0154
	[-1.86]	[-2.68]	[-1.25]
(β_8) Number of adjacent exercised options (own)$_{i,t}$		0.15***	0.2567***
		[3.91]	[7.95]
(β_9) Relative rank percentile (own project)$_{i,t}$		0.0707	0.0686
		[1.39]	[1.01]
Township FE	No	No	Yes
N	92,306	92,306	62,084

Appendix Table 2: Real Option Exercise and Exogenous Peer Effects - IV Regression Model, Cluster by Township

Table 5: Panel A

	IV regression model		
	Instrumented - Number of adjacent exercised options (peer)		
	(1)	(2)	(3)
	Estimate	Estimate	Estimate
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0001	-0.0001*	-0.0001
	[-1.63]	[-1.70]	[-1.04]
(β_2) Natural gas price (\$/mcf)$_t$	0.0009**	0.0008*	0.0017***
	[2.04]	[1.85]	[3.04]
(β_3) Log drilling cost$_t$	-0.0007	-0.0008	0.0013
	[-0.44]	[-0.49]	[0.86]
(β_4) 5 year risk free interest rate$_t$	0.0006	0.0007	0.0007
	[0.92]	[1.03]	[0.98]
(β_5) Log first well production$_i$	0.0003	-0.0002	-0.0002
	[1.54]	[-1.13]	[-0.79]
(β_6) Instrumented - Number of adjacent exercised options (peer)$_{i,t}$	0.0071***	0.0046**	0.0052*
	[2.97]	[2.10]	[1.65]
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	-0.0001	-0.0001	0.0000
	[-0.75]	[-0.71]	[0.17]
(β_8) Number of adjacent exercised options (own)$_{i,t}$		0.0032***	0.0039***
		[4.89]	[4.04]
(β_9) Relative rank percentile (own project)$_{i,t}$		0.0018***	0.0019***
		[3.13]	[2.71]
Township FE	No	No	Yes
N	103,451	103,451	103,451

Appendix Table 3: Real Option Exercise and Exogenous Peer Effects - IV Probit Model (Cluster by Township and by Year)

Table 5: Panel A

	IV Probit model		
	Instrumented - Number of adjacent exercised options (peer)		
	(1)	(2)	(3)
	Estimate	Estimate	Estimate
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0088*	-0.0097**	-0.0046
	[-1.80]	[-2.05]	[-0.51]
(β_2) Natural gas price ($/mcf)$_t$	0.0241	0.0093	0.0867***
	[1.04]	[0.38]	[3.19]
(β_3) Log drilling cost$_t$	-0.0373	-0.0592	0.1389
	[-0.29]	[-0.44]	[1.16]
(β_4) 5 year risk free interest rate$_t$	0.0581*	0.07*	0.0958**
	[1.68]	[1.91]	[2.30]
(β_5) Log first well production$_i$	0.0436	-0.0103	-0.0099
	[1.61]	[-0.47]	[-0.44]
(β_6) Instrumented - Number of adjacent exercised options (peer)$_{i,t}$	0.5688***	0.5697***	0.5476***
	[4.88]	[4.66]	[2.79]
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	-0.014*	-0.0182***	-0.0154
	[-1.90]	[-2.64]	[-1.15]
(β_8) Number of adjacent exercised options (own)$_{i,t}$		0.15***	0.2567***
		[3.95]	[7.55]
(β_9) Relative rank percentile (own project)$_{i,t}$		0.0707	0.0686
		[1.31]	[0.97]
Township FE	No	No	Yes
N	92,306	92,306	62,084

Appendix Table 4: Real Option Exercise and Exogenous Peer Effects - IV Regression Model (Cluster by Township and by Year)

Table 5: Panel A

	IV regression model Instrumented - Number of adjacent exercised options (peer)		
	(1)	(2)	(3)
	Estimate	Estimate	Estimate
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0001	-0.0001	-0.0001
	[-1.38]	[-1.38]	[-0.74]
(β_2) Natural gas price ($/mcf)$_t$	0.0009	0.0008	0.0017***
	[1.49]	[1.32]	[4.19]
(β_3) Log drilling cost$_t$	-0.0007	-0.0008	0.0013
	[-0.32]	[-0.34]	[0.77]
(β_4) 5 year risk free interest rate$_t$	0.0006	0.0007	0.0007
	[0.88]	[0.98]	[1.01]
(β_5) Log first well production$_i$	0.0003*	-0.0002	-0.0002
	[1.71]	[-1.09]	[-0.90]
(β_6) Instrumented - Number of adjacent exercised options (peer)$_{i,t}$	0.0071***	0.0046***	0.0052**
	[3.49]	[2.82]	[1.96]
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	-0.0001	-0.0001	0.0000
	[-0.84]	[-0.79]	[0.16]
(β_8) Number of adjacent exercised options (own)$_{i,t}$		0.0032***	0.0039***
		[3.65]	[3.74]
(β_9) Relative rank percentile (own project)$_{i,t}$		0.0018**	0.0019**
		[2.39]	[2.15]
Township FE	No	No	Yes
N	103,451	103,451	103,451

Appendix Table 5: Real Option Exercise and Exogenous Peer Effects - IV Cox Model (Cluster by Township and by Year)

Table 5: Panel A

	Hazard model					
	Instrumented - Number of adjacent exercised options (peer)					
	(1)		(2)		(3)	
	Estimate	HI (%)	Estimate	HI (%)	Estimate	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0245	-2.42	-0.0281	-2.77	-0.0166	-1.64
	[-1.39]		[-1.55]		[-0.61]	
(β_2) Natural gas price (\$/mcf)$_t$	0.2062**	22.90	0.1546	16.72	0.2801**	32.33
	[2.23]		[1.63]		[2.45]	
(β_3) Log drilling cost$_t$	0.0494	5.06	-0.0319	-3.14	0.4462	56.24
	[0.15]		[-0.08]		[0.96]	
(β_4) 5 year risk free interest rate$_t$	0.1325	14.17	0.1564	16.93	0.2168	24.21
	[1.11]		[1.19]		[1.15]	
(β_5) Log first well production$_i$	0.2432***	27.54	-0.0064	-0.64	-0.0565**	-5.50
	[3.10]		[-0.08]		[-2.44]	
(β_6) Instrumented - Number of adjacent exercised options (peer)$_{i,t}$	0.595***	81.31	0.5825***	79.06	0.6623***	93.93
	[3.65]		[3.11]		[2.79]	
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	-0.0671*	-6.49	-0.0746**	-7.18	-0.0236	-2.33
	[-1.82]		[-2.00]		[-0.96]	
(β_8) Number of adjacent exercised options (own)$_{i,t}$			0.3731***	45.22	0.7649***	114.88
			[3.41]		[5.03]	
(β_9) Relative rank percentile (own project)$_{i,t}$			0.311**	36.48	0.2563*	29.21
			[2.04]		[1.68]	
Township FE	No		No		Yes	
N	103,451		103,451		103,451	

Appendix Table 6: (Table 5 Panel B) - Reduced Form (Cluster by Township and by Year)

	Hazard model					
	Reduced form - Relative rank percentile (adjacent peer projects)					
	(1)		(2)		(3)	
	Estimate	HI (%)	Estimate	HI (%)	Estimate	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0242	-2.39	-0.028*	-2.76	-0.0211	-2.09
	[-1.33]		[-1.67]		[-1.09]	
(β_2) Natural gas price ($/mcf)$_t$	0.1838***	20.18	0.1301**	13.90	0.1588***	17.21
	[3.95]		[2.54]		[4.11]	
(β_3) Log drilling cost$_t$	0.1768	19.34	0.0805	8.39	0.2025	22.45
	[0.50]		[0.22]		[0.58]	
(β_4) 5 year risk free interest rate$_t$	0.0704	7.30	0.1022	10.76	0.0441	4.51
	[1.02]		[1.34]		[0.44]	
(β_5) Log first well production$_i$	0.295***	34.31	0.0045	0.45	-0.0446	-4.36
	[3.45]		[0.05]		[-0.81]	
(β_6) Relative rank percentile (adjacent peer projects)$_{i,t}$	0.3043***	35.57	0.2676***	30.69	0.2417***	27.34
	[4.38]		[4.42]		[2.96]	
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	0.0567***	5.84	0.0365**	3.72	0.0566***	5.82
	[3.51]		[2.24]		[3.13]	
(β_8) Number of adjacent exercised options (own)$_{i,t}$			0.5002***	64.90	0.3985***	48.96
			[11.93]		[7.60]	
(β_9) Relative rank percentile (own project)$_{i,t}$			0.4146***	51.37	0.4256***	53.05
			[3.55]		[3.77]	
Township FE	No		No		Yes	
N	103,451		103,451		103,451	

Appendix Table 7: Effect of Adjacent First Wells

	Reduced Form Peer Effects (1)		Instrumented Peer Effects (2)	
	Estimate	HI (%)	Estimate	HI (%)
(β_1) Implied volatility of natural gas (percent)$_t$	-0.0200	-1.98	-0.0179	-1.77
	[-1.34]		[-1.09]	
(β_2) Natural gas price ($/mcf)$_t$	0.1621***	17.60	0.249**	28.27
	[3.28]		[2.41]	
(β_3) Log drilling cost$_t$	0.1969	21.76	0.4256	53.05
	[0.54]		[1.00]	
(β_4) 5 year risk free interest rate$_t$	0.0782	8.13	0.1981	21.90
	[0.78]		[1.20]	
(β_5) Log first well production$_i$	-0.0436	-4.27	-0.0520	-5.07
	[-0.61]		[-0.65]	
(β_6) Relative rank percentile (adjacent peer projects)$_{i,t}$	0.2633***	30.12		
	[3.18]			
(β_7) Average log first well production adjacent options (peer)$_{i,t}$	0.0270	2.74	0.0261	2.64
	[1.44]		[1.40]	
(β_8) Number of adjacent exercised options (own)$_{i,t}$	0.4724***	60.39	0.5556***	74.30
	[9.52]		[6.22]	
(β_9) Relative rank percentile (own project)$_{i,t}$	0.4157***	51.55	0.2627*	30.04
	[3.73]		[1.83]	
(β_{10}) Number of adjacent first wells drilled (peer)$_{i,t}$	0.312***	36.61	-0.7108*	-50.88
	[5.82]		[-1.66]	
(β_{11}) Instrumented - Number of adjacent exercised options (peer)$_{i,t}$			1.1168**	205.50
			[2.29]	
Township FE	Yes		Yes	
N	103,451		103,451	