Three Essays on the Economics of the Oil and Gas Industry

by

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ABSTRACT

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In this dissertation I explore the economics of the oil and gas industry, with a particular focus on onshore leasing, drilling, and production. Using theory, data, and a variety of natural experiments, I analyze the impact of ownership, policies, and markets on drilling and production outcomes.

In the first chapter I discuss the impact of heterogeneous mineral ownership on the oil and gas industry. I show how policies imposed by one owner can affect extraction both on that owner's land as well as on nearby land. Using a natural experiment in Wyoming, I find that low cost policies on state land increased drilling on state land while decreasing drilling on nearby federal land. I also find that state policies helped firms discover lower productivity wells both on state land and on nearby federal land.

In the second chapter, co-authored with Paul Brehm, I explore how efficiently markets correct for misallocation. We examine a setting where oil and gas leases were awarded to individuals who likely lacked the expertise and capital to efficiently extract oil and gas. In spite of this initial misallocation, we find that these leases were usually quickly sold to firms. As a result, these leases had similar drilling and

production outcomes to leases that were awarded to firms.

In the third chapter I examine a setting in Wyoming where alternating blocks of land were assigned either to government ownership or to private ownership. I describe how government and private land differed in environmental protection, lease lengths, lease sizes, and quality of management. I find that in spite of environmental protections on government land, government land was more likely to have experienced drilling. I show why longer leases, smaller parcels, or inefficient management of private land may have decreased drilling on private land. I also find that after an oil and gas firm took over management of the private land, drilling and production outcomes improved on private land relative to government land.

CHAPTER I

Federal Environmental Protection and the Distorted Search for Oil and Gas

1.1 Introduction

Environmental policy makers try to balance promoting economic activity with protecting the environment. However regulators may be limited in the extent to which they can implement environmental protections. Firms may respond strategically to this incomplete protection, leading to unintended consequences. This paper explores how oil and gas firms have responded to heterogeneous environmental protection policies, where some plots of land have more environmental protection than other plots.

In particular, I examine the role of environmental protection on U.S. Federal Government lands. The United States Federal Government owns more than one quarter of the land in the U.S. and imposes special environmental policies on this land. I show how such policies can affect the oil and gas production both on federal land and on nearby non-federal land. Using a novel natural experiment where federal and non-federal land were exogenously assigned, I show how spatial patterns of federal ownership induce firms to shift where they drill as they search for and produce oil and natural gas. I find that federal policies lead to local leakage, where firms move drilling and production from federal land to less regulated areas.

Federal land management and environmental regulations have become increasingly controversial. Representative Doug Lamborn of Colorado argued: "In recent years we have seen a boom in energy jobs and economic growth on state and private lands . . . I believe the only reason we haven't seen that same dynamic growth on federal lands is because of excess regulations" (Snow, 2013). The Western Energy Alliance has estimated that federal environmental protection measures are impeding the development of 58,480 jobs in Wyoming (SWCA Environmental Consultants, 2012). However, there is very little academic research examining the effect of these policies.

A major challenge in analyzing the impact of federal ownership is properly accounting for spillovers from one owner to another: The US has a complex patchwork of federally owned land, state government-owned land, and privately owned land. Each owner imposes different policies for oil and gas firms that affect the firm's willingness to drill on the owner's plot. Policies on one plot can have spillover effects on nearby plots. This is especially likely with oil and gas exploration, where drilling an exploratory well on one owner's plot is a substitute for drilling on another owner's plot. Shifted exploration patterns in turn affect later drilling and production outcomes. This paper models the exploration, drilling, and production process, showing how policies on one plot of land can have spillovers on nearby plots. I demonstrate how heterogeneous mineral ownership can lead to inefficient drilling and production outcomes.[1]

Even after accounting for spillovers, another challenge is the potential endogeneity of ownership patterns. I exploit a novel natural experiment resulting from the Land Ordinance of 1785 where land was exogenously assigned to either federal government or state government ownership, as shown in Figure 1.1. Most land was in federal

[1] Almost every other country in the world has mineral rights centrally owned and leased by a single government body. Canada is one exception, where a small fraction of land is in private or First Nations ownership.

ownership, with the state government owning small, isolated, and regularly-spaced plots. I refer to these state land plots as "16/36 sections" because every 16th and 36th square mile plot of land was to be transferred to state ownership. This resulted in variation in federal versus state ownership, as well as variation in how close a given plot of federal land is to state land. I leverage both of these sources of variation to identify evidence of direct effects and spillover effects of policy.

I write a simple model of search and learning that provides predictions for three types of land—state land, federal land close to state land, and federal land far from state land. I show that under higher federal costs, federal land close to state land will have less exploratory drilling relative to federal land far from state land because the firm shifts exploration to state land from nearby federal land. Lower costs on state land lead to higher drilling and production as well as a greater willingness to drill low productivity wells. I also show that proximity to state land has an ambiguous effect on drilling and production on federal land. Federal land that is closer to state land may have lower drilling and production because of long run effects of substitution to state land. However federal land that is close to state land may have higher drilling and production if there are positive information spillovers from state land.

To test whether federal costs are higher and to explore how proximity to state land affects federal land, I compile extensive data on drilling and production in Wyoming. I focus on a region in southwest Wyoming where the federal-state ownership pattern has particularly robust. The drilling data allow me to examine the rollout of oil and gas drilling over time and space. Production data allow me to compare individual well productivity on different plots of land. The long range of data allow me to compare outcomes before and after the 1970's, when the federal government instituted most of the environmental protections for federal land.

Using an intent-to-treat specification, I find that ownership patterns have a significant effect on drilling and production. State land has is 35% more likely to have exploratory drilling relative to federal land far from state land, and up to 54% more likely to have exploratory drilling relative to federal land that is close to state land. This suggests that state costs are lower and have displaced exploratory drilling from federal land to state land. I find evidence that there is long run leakage from federal land to state land as federal land close to state land has lower drilling and production. I also find evidence that lower costs on state land lead firms to drill on sites with lower expected productivity as the average state well is 34% less productive relative to an average well on federal land far from state land. I also find evidence that federal land next to state land benefits from higher drilling rates on state land because drilling on state land helps firms discover lower productivity but still profitable fields that extend to nearby federal land. Finally, I find that differences between state and federal land increased after the 1970's when new environmental policies were implemented for federal land.

I rule out alternate mechanisms that may explain these drilling and production patterns. I find no evidence that lower drilling on federal land is driven by the federal government withholding leases. Similarly, I also rule out the concern that differential well production outcomes are driven by common pools.

I discuss the policy implications of these findings. I develop a simple structural estimation that gives a back-of-the-envelope estimate of the costs of operating on federal and state land. Point estimates suggest that federal regulations add a cost of about $17 million (2010 dollars) per well. I also discuss the spatial extent of spillovers and the role of information spillovers in leakage.

This paper is the first to show how spatially heterogeneous ownership patterns have affected the search for oil and gas. This paper builds on insights from two different strands of the literature: One shows how firms search for oil and gas, updating beliefs about the payoff from future wells from discoveries on past wells (Levitt, 2011; Hendricks and Kovenock, 1989; Lin, 2013). The other shows that local ownership and policies affect outcomes in the oil and gas industry, though this literature does not account for spillovers (Balthrop and Schnier, 2012; Fitzgerald, 2010; Fitzgerald and Stocking, 2014). I use insights about search and spillovers from the first strand of literature and apply it to the heterogeneous ownership policy setting of the second. This paper also contributes to a small but growing literature about search and learning where agents use payoffs from one action to update beliefs about the payoffs from other actions (Crawford and Shum, 2005; Sullivan, 2010; James, 2012). I show how the econometrician can make inference about policies using revealed drilling and production outcomes without estimating a structural model.

In the next section, I discuss background information on the oil and gas industry, discuss the empirical strategy, and introduce the natural experiment. In section 1.3 I introduce the model of search. Section 1.4 introduces the data and the empirical specification, and section 1.5 contains the main empirical analysis. Section 1.6 tests whether alternative mechanisms are driving revealed drilling and production results. Section 1.7 discusses the policy implications of these findings, and section 1.8 concludes.

1.2 Background

In this preliminary section I discuss institutional details of federal environmental policy related to the oil and gas industry. I discuss why it is important to account for spatial ownership patterns, search, and spillovers in analyzing the effects of federal policy. I outline my empirical strategy, describing how I use a model coupled with a natural experiment where federal ownership was exogenously assigned. I discuss the historical origins of the natural experiment.

1.2.1 Federal Mineral Lands and Environmental Policy

The United States Federal Government owns and manages a significant fraction of land in the United States. Approximately 31% of land is in federal mineral ownership, meaning the federal government has the rights to extract oil, natural gas and subsurface minerals on those lands. This land is often actively leased to oil and gas firms, with leasing managed by the Bureau of Land Management (BLM).[2] Oil and gas firms operating on federal land must comply with federal leasing policies, including federal environmental protection measures.

US Federal lands became subject to increasing environmental protection starting in the 1970's. In 1970, the National Environmental Policy Act (NEPA) required the BLM to factor in environmental concerns in managing oil and gas operations. Soon after, the Endangered Species Act (ESA) of 1973 required that federal land policies must protect both endangered and vulnerable species, imposing stronger requirements on federal land than on other land. A number of other regulations have also been incorporated, including the Federal Land Policy and Management Act (1976), the Clean Air Act Amendment of 1977, and the National Historic Preservation Act (1966), as well as executive orders and internal BLM policies (Pendery, 2010). The BLM soon established rules and procedures such that oil and gas operations on federal land complied with these policies (Skillen, 2013). Typically these environmental policies specified particular actions that firms would need to take before a permit to drill was issued.

Anecdotally, firms report that these environmental requirements are costly. In Congressional testimony, Bob Nance included costly regulation as a significant barrier prohibiting oil and gas firms from operating on federal land (Nance, 1997). This

[2] The federal government also owns 28% of surface ownership in the United States. The BLM manages oil and gas leasing for BLM land, Forest Service land, and areas where the federal government owns mineral rights but private individuals own surface rights. Figures are calculated from table 3 of U.S. Department of the Interior, Bureau of Land Management (2012). These numbers do not include ownership of offshore mineral rights.

is confirmed with conversations I had with various industry representatives. One industry representative in Wyoming I spoke with said that federal government lands are the most costly to operate on, followed by private land, with state-owned land the easiest to operate on. In another conversation, another industry representative said that environmental compliance costs are a major reason why federal land is costlier to operate on. These higher environmental protections on federal land presumably impose a higher fixed cost on the firm that it must pay before drilling.

While higher compliance costs are an important reason, there may be other reasons why federal land has limited operations (Nance, 1997; Krupnick et al., 2014; SWCA Environmental Consultants, 2012). One reason is costly delays in acquiring permits. To address this, in the appendix part 1.11.2 I include a simple model of delays to show that theoretical predictions about drilling and production are similar. I show that empirical predictions about drilling and production from delays on federal land are similar to higher fixed costs on federal land. Another reason for less drilling is that federal land is being withheld from firms. I provide some evidence in section 1.6.1 that at least within the subset of Wyoming I examine, land withholding seems to be very limited.

1.2.2 Accounting for Ownership Patterns and Spillovers

While federal policy affects drilling on federal land, it may also affect drilling on nearby land. Spillovers of federal policy onto nearby land are likely because land ownership is spatially fractured, with adjacent private and state-owned land. This can be seen in Figure 1.2, which shows the fraction of federal ownership for a sample of oil and gas fields in the Western United States where the Energy Information Administration has provided data on federal ownership. I find that 68% of these fields are in partial but not complete federal ownership. This demonstrates that heterogeneous ownership and federal policy spillovers are likely to be important throughout much of the Western United States.

Spillover effects of policies from one plot to another are likely to be important because of how firms search for and learn about oil and gas. A firm usually is interested in a moderately large area for oil and gas exploration. Higher costs on one plot affect willingness to drill on that plot, and may lead a firm to substitute to a different plot. Because firms update beliefs about the geology of the region from past drilling, such substitution means that costs on one plot can have long run effects on drilling and production outcomes on nearby plots.

1.2.3 The Natural Experiment

To identify how federal policy affects search, drilling, and production, I exploit a natural experiment that created exogenous variation in ownership.

Generally, analyzing the effect of federal land ownership is extremely difficult because federal land is not exogenously assigned. Land owned by the federal government tends to be more remote, more mountainous, and less agriculturally productive. These factors affect oil and gas profits directly, such that a comparison of outcomes on federal and non-federal land cannot identify how federal policy affects the oil and gas industry. Therefore it is important to use some kind of experiment where federal ownership status is not correlated with other factors that may affect oil and gas profits.

The United States Federal Government created such an experiment with the Land Ordinance of 1785. This policy specified rules for dividing land in newly acquired US territories, designating that certain exogenously-located plots of land would be transferred from the Federal Government to the governments of newly formed states. State governments then could use these lands to generate revenue through activities like oil and gas leasing.[3] In regions like southwest Wyoming that were too arid for

[3] Initially, such lands were usually designated to be sites for schools. However in later years, the sites instead were leased to generate revenue used to fund schools (Souder and Fairfax, 1996).

agriculture, the federal government retained ownership of the remaining land, leading to a persistent pattern of federal and state ownership.

The Land Ordinance of 1785 and later amendments specified survey rules and state land assignment leading to an unusual pattern of federal and state ownership: Land was to surveyed into six mile by six mile squares called townships, and further subdivided into 36 square-mile plots called sections. Sections were numbered from 1 to 36 in a predetermined pattern, as shown in figure 1.1. The law specified that certain numbered sections would be transferred to state ownership at the time of statehood—in Wyoming, sections 16 and 36 were transferred to the State of Wyoming.[4] Figure 1.1 shows the resulting pattern of federal and state ownership—most land is in federal ownership, but there are small, regularly-spaced "islands" of state land.

This policy led led to variation in ownership and proximity to state land that is uncorrelated with geology. As section numbers were assigned exogenously, this assures that state versus federal land assignment is uncorrelated with geology. Similarly, the natural experiment led to some sections of federal land lying closer to state land than other sections. For example, figure 1.1 shows section 13 lies far from state land while section 15 lies close. This proximity is also exogenous—federal sections that are close to state land are not expected to have different geology than federal sections that are far from state land. This variation can be used to identify spillovers as federal land close to state land is more affected by state costs than federal land far from state land.

[4]Initially the Land Ordinance of 1785 specified that section 16 would be transferred to state governments. Later when Wyoming became a state, both sections 16 and 36 were transferred. Some other states received either 3 or 4 sections depending on the date of statehood. See Souder and Fairfax (1996) for more details.

1.3 Modeling the search for oil and gas

I propose a simple model to show how spatial patterns of environmental protection affect drilling and production outcomes. I derive predictions for state land, federal land close to state land, and federal land far from state land. The model demonstrates how firms search for and learn about underlying oil and gas fields through successive drilling. The model provides testable predictions about how higher costs on federal land will affect drilling and production.

The model is conceptually simple. The firm solves a dynamic well placement problem, deciding in each period where to drill. The firm is initially uncertain about the oil and gas reserves in the region. The firm learns about geology through drilling wells and observing reserves, updating its beliefs about oil and gas reserves on nearby plots. The spatial profile of costs affect where the firm drills the initial exploratory well, and both costs and initial drilling affect later drilling and production outcomes.

1.3.1 A simple two plot model

To keep the model tractable, I focus on a simple setting with only two plots. I focus on two cases. In one case, one plot is in state ownership and the other plot is in federal ownership. This maps to the natural experiment, providing intuition for state land and federal land that is close to state land. I refer to this as the federal-state case. The other case is where both plots are in federal ownership, mapping to the case for federal land that is far from state land. I refer to this as the federal-federal case. All proofs are in the Appendix.

1.3.1.1 Model set up

I assume that there is a single firm that is choosing where and when to drill. The firm can drill up to one well on each plot. There are two time periods and the firm can drill in either $t = 1$ or $t = 2$. For simplicity, I assume no discounting.

Each plot has a fixed cost $C \in \{C_S, C_F\}$ that the firm must pay in order to satisfy environmental requirements and to drill. Because anecdotally, federal land is costlier to operate on, I assume that $C_F > C_S$.

Drilling on plot 1 allows the firm to extract reserves R_1 from plot 1; drilling on plot 2 allows the firm to extract reserves R_2 from plot 2. For simplicity, I assume that the firm immediately extracts any expected reserves at the time of drilling. There is no common pool—extracting from one plot does not deplete reserves on the other other plot. The value of reserves is normalized to 1.

Drilling also helps the firm learn about the geology of the region. The firm is initially uncertain about the true value of R_1 and R_2 but has an initial signal μ of expected value: $E(R_1) = E(R_2) = \mu$. The signal μ is drawn from a distribution with cdf $G(\cdot)$. The joint distribution of reserves $F(R_1, R_2|\mu)$ is symmetric, i.e., $F(R_1, R_2|\mu) = F(R_2, R_1|\mu)\ \forall R_1, R_2$. Drilling a well on plot i leads the firm to discover the true value R_i and update beliefs about the reserves on plot j with the conditional distribution $F_j(R_j|R_i, \mu)$.

I assume that higher signals μ and higher discovered reserves on one plot decrease the probability of low reserves on the other plot:

$$\frac{\partial F_i(R_i|\mu, R_{-i} = r)}{\partial \mu} < 0,\ \frac{\partial F_i(R_i|\mu, R_{-i} = r)}{\partial r} < 0\ ,\ \forall R_i, r, \mu \tag{1.1}$$

1.3.1.2 The Firm's Choices

In this setting, the firm has three choices:

1. The firm can drill an exploratory well on plot 1 first and then decide whether to drill plot 2, with expected profits:

$$\pi_1(\mu, C_1, C_2) \equiv \mu - C_1 + E_{R_1}[\max\{E_{R_2|R_1}(R_2|R_1) - C_2, 0\}] \tag{1.2}$$

2. The firm can drill an exploratory well on plot 2 and then decide whether to drill plot 1 with expected profits:

$$\pi_2(\mu, C_1, C_2) \equiv \mu - C_2 + E_{R_2}[\max\{E_{R_1|R_2}(R_1|R_2) - C_1, 0\}] \tag{1.3}$$

3. Finally, the firm may choose to not drill, yielding zero profits ($\pi_0 = 0$).[5]

1.3.1.3 Exploratory drilling

- **Proposition 1:** The probability that a site has an exploratory well will be highest on state land, next highest on federal land *far* from state land, and lowest on federal land *close* to state land

In the case where plot 1 is state land and plot 2 is federal land, $\pi_1 > \pi_2$, so the firm will drill the initial exploratory well on state land and never drills exploratory wells on federal land. In addition, exploration rates are higher on state land because with lower costs, the firm is willing to drill with a lower signal μ. In contrast, the federal-federal case has medium exploratory drilling because the firm randomizes which plot it drills the exploratory well on conditional on the signal μ being high enough.

Here the predictions are especially sharp because as the two plots of land are perfect substitutes, a firm will never drill an exploratory well on federal land if it can drill on state land. In a more nuanced model, expected reserves may be higher on the federal plot such that the firm still sometimes drills an exploratory well on federal land in spite of the higher cost.

[5] We can ignore other cases, such as where the firm drills both plots in the same time period, or cases where the firm waits until period 2 before drilling. All of these possibilities are dominated by $\max\{\pi_1, \pi_2\}$.

1.3.1.4 Any drilling

- **Proposition 2:** The probability that a site ever has drilling will be higher on state land than on federal land. It is ambiguous whether overall drilling will be higher on federal land close to or far from state land.

Ownership also affects the probability that drilling ever happens. A firm will only ever drill the second plot of land if after drilling the first plot, the firm believes expected reserves are higher than the fixed costs. Not all exploratory wells lead to a second well. Therefore state land will be more likely to ever have drilling relative to nearby federal land.

State land will also be more likely to ever have drilling relative to federal land in the federal-federal case. State land does not require as high of a μ to drill. Furthermore, conditional on μ being large enough for exploratory drilling, a given plot of federal land in the federal-federal case has less then a 100% probability of being drilled, because the firm may place the exploratory well on the other plot.

It is ambiguous whether federal land close to state land is more likely to ever have drilling relative to federal land far from state land. The probability of ever drilling on federal land in the state-federal case is:

$$\int\limits_{\mu^*(S,F)}^{\infty} [1 - F_1(R_1^*(\mu, C_F))]\partial G(\mu) \tag{1.4}$$

While the probability of ever drilling on federal land in the federal-federal case is:

$$0.5 \cdot \int\limits_{\mu^*(F,F)}^{\infty} \partial G(\mu) + 0.5 \cdot \int\limits_{\mu^*(F,F)}^{\infty} [1 - F_1(R_E^*(\mu, C_F))]\partial G(\mu) \tag{1.5}$$

where $\mu^*(S, F) < \mu^*(F, F)$ gives the minimum μ required to justify drilling in the state-federal and federal-federal cases respectively, and R_E^* is the minimum reserves that need to be discovered on the initial exploratory well to justify drilling the second plot.

In comparing expressions 1.4 and 1.5, it is possible that federal land next to state land may have less overall drilling because it will never be the site of the exploratory well. But it may also have more overall drilling because as $\mu^*(S, F) < \mu^*(F, F)$, there is more likely to be exploratory drilling in the region in the state-federal case: If the probability that exploratory drilling happens increases significantly with state land ($G(\mu^*(F, F)) - G(\mu^*(S, F))$ is large) and the probability of drilling a second well is large, federal land close to state land may have more drilling than federal land far from state land.

1.3.1.5 Well level production

- **Proposition 3:** Wells on state land will have lower expected production relative to wells on federal land. It is ambiguous whether expected production will be higher for wells on federal land close to state land or for wells on federal land far from state land.

Costs affect production. Because the state-federal case has lower expected costs (and a lower μ^*), the firm is willing to drill exploratory wells in places with lower expected productivity. This will translate to lower expected well production for exploratory wells in the state-federal cases relative to exploratory wells in the federal-federal case. By lowering costs, the firm develops low productivity wells that would not have been drilled under higher costs.

Second, order of drilling affects production. For the first well drilled, the firm must believe that expected reserves plus the value of learning about the second plot are larger than the fixed costs. But for the second well drilled, there is no additional value in learning, and expected reserves need only cover costs. Firms will be willing to accept lower production for an exploratory well relative to a second well.

The cdf of production on an exploratory well is:

$$p(R_1 < r) = \frac{\int_{\mu^*}^{\infty} F(r|\mu)\partial G(\mu)}{\int_{\mu^*}^{\infty} \partial G(\mu)} \tag{1.6}$$

The cdf of production on a second well drilled is:

$$p(R_2 < r) = \frac{\int_{\mu^*}^{\infty} \int_{R_E^*(C_F,\mu)}^{\infty} F(r|R_E,\mu)\partial F(R_E|\mu)\partial G(\mu)}{\int_{\mu^*}^{\infty} \int_{R_E^*(C_F,\mu)}^{\infty} \partial F(R_E|\mu)\partial G(\mu)} \tag{1.7}$$

For any value of r, the expression in equation 1.6 is greater than the expression in equation 1.7.

As a result, wells on state land will have lower production relative to wells on nearby federal land because they are more likely to be exploratory. Similarly, wells on state land will have lower production relative to wells in the federal-federal case both because state land wells are more likely to be exploratory as well as because state land has a lower μ^*.

It is ambiguous whether federal wells in the federal-federal case will have higher or lower expected production relative to federal wells in the state-federal case. If secondary wells have much higher expected production than exploratory wells, then federal wells in the federal-federal case will have lower expected production because they are more likely to be exploratory. But if a lower μ^* in the state-federal case leads to new low-productivity wells on federal land, wells on federal land can have lower production than wells drilled in the federal-federal case. In this case, low costs on state land help the firm discover low productivity but still profitable fields that extend to nearby federal land.

1.3.1.6 Production per square mile

- **Proposition 4:** Expected production will be higher on state land rather than federal land. It is ambiguous whether federal land close to or far from state land will have higher expected production.

Because production requires drilling, places with higher probability of drilling will have higher expected production. State land will have higher expected production relative to federal land—both relative to nearby federal land as well as further away federal land.

However it is not possible to predict whether federal land in the state-federal case or federal land in the federal-federal case will have higher production. This is because it is ambiguous whether proximity to state land will increase the probability of drilling and whether proximity to state land leads to higher expected well production.

1.3.2 Summary of Predictions and Mechanisms

The following list summarizes the propositions of the model, comparing state land (S), federal land close to state land (FC), and federal land far from state land (FF):

1. Probability of exploratory drilling: $S > FC$, $S > FF$, $FF > FC$
2. Probability of any drilling: $S > FC$, $S > FF$, FF (?) FC
3. Expected well production: $S < FC$, $S < FF$, FF (?) FC
4. Expected production per square mile: $S > FC$, $S > FF$, FF (?) FC

The model demonstrates how changing costs affect drilling through three mechanisms: A direct cost effect, a substitution effect, and a "signal threshold "effect.

- The **direct cost effect** is the fact that lowering costs on a plot increase willingness to drill. This leads to more drilling and lower expected production conditional on drilling
- The **substitution effect** is that having a low cost plot in a region shifts exploratory drilling from the high cost plots to the low cost plot. Shifting order

of drilling also affects production, because exploratory wells tend to have lower production than secondary wells

- The **signal threshold effect** is the effect that overall profile of costs in the region have on the minimum signal required for drilling an exploratory well. The minimum expected reserve signal μ^* does not need to be as high in the state-federal case to justify exploratory drilling as it does in the federal-federal case. As drilling on places with lower signals leads to lower productivity wells, average well productivity will be lower on state land relative to the federal-federal case. This can potentially also lead to low productivity wells drilled on nearby federal land.

The model provides predictions and intuition that can be taken to the data. The model provides strong predictions about relative outcomes on federal versus state land if the costs of operating on federal land are higher. I compare outcomes on state and federal land to test whether the cost of operating on federal land is higher. The model is ambiguous about how proximity to state land affects drilling and production on federal land. In the empirical work, I test how proximity to state land affects outcomes on federal land and use the model to provide intuition on how to interpret the results.

While some modeling assumptions are strong for analytic tractability, it is fairly intuitive that the predictions will extend even when some assumptions are relaxed. For example, the model assumes that the firm has the same signal for both plots—which results in the stark prediction that there will be no exploratory drilling on federal land close to state land. If signals for each plot differ, we can have cases where a firm drills an exploratory well on federal land rather than on nearby state land because the signal on federal land was significantly higher. However, even in this more general case, lower costs on state land will still lead to more exploratory drilling, overall drilling, and production on state land.

In the appendix, I extend the model to a variety of other settings. One case is the case of delays, where federal policy is sometimes considered to be costly not because the environmental requirements are costlier to meet, but rather in that there are longer delays in processing approvals (Krupnick et al., 2014). I show a similar model in the appendix with delays and show how this leads to similar predictions about revealed drilling and production. Another concern is that there may be multiple firms who are operating on adjoining plots, as in Hendricks and Kovenock (1989). In the appendix I write a simple two-firm two-plot model and show that it also leads to similar predictions.

1.4 Empirical Specification, Data, and Setting

In this section I describe how I take the model to the natural experiment, and describe the main empirical specification and inference. I also discuss the data and setting in Wyoming, showing why this setting is ideal for testing how federal ownership patterns affect drilling and production.

1.4.1 Empirical Specification and Inference

My empirical specification explores how drilling and production outcomes vary as a function of whether land was assigned to be in state ownership (section 16 or 36) as well as whether land was close to or far from state-assigned land (proximity to the closest 16 or 36). Using the square mile section as the unit of observation, I use the regression specification:[6]

$$Y_i = \alpha + \beta \cdot 1_i(16/36) + \sum_{d \in \{1, \sqrt{2}, 2, \sqrt{5}\}} \beta_d \cdot 1_i(\text{closest } 16/36 \approx \text{d miles away}) \ + \ \varepsilon_i \quad (1.8)$$

[6] I use the square mile section as the unit of observation because the policy rule specified ownership at the section level and because sections have well-defined exogenous boundaries.

Here, proximity d to the closest 16 or 36 section is measured as the distance between the section centroid and the centroid of the closest 16 or 36 section, as shown in figure 1.1. Because of the grid structure, sections may be 1, $\sqrt{2}$, 2, $\sqrt{5}$, or 3 miles from the closest 16 or 36 section. Here, 3 miles away is the omitted category. The dependent variable Y_i is the outcome of interest such as exploratory drilling or production.

Because outcomes on one section are correlated to outcomes on nearby sections, proper inference requires accounting for spatial correlation. I use Conley (1999) standard errors and assume that ε_i and ε_j may be correlated if section i and section j are within 20 miles of each other.[7] For most specifications, I use a uniform weight (as recommended by Conley (2008)), but use a Bartlett weight when the estimated variance-covariance matrix is not positive-definite (Newey and West, 1987).[8] I find that when both methods give positive-definite variance-covariance matrices, the standard errors are similar.

1.4.2 Setting

To test model predictions, I use data from the Greater Green River Basin (GGR) of Wyoming—a geological region in Southwest Wyoming. A map of the Greater Green River basin is in Figure 1.4. I focus on the GGR for a variety of reasons:

[7]Using data I describe in subsubsection 1.4.2.3, I find that whether a section has ever had a productive well drilled predicts whether a nearby section has ever had a productive well drilled only if the sections are within 20 miles of each other (see figure 1.3).

[8]In inference, $\text{var}(\widehat{\beta}) = (\mathbf{x}'\mathbf{x})^{-1}\mathbf{x}'\Sigma\mathbf{x}(\mathbf{x}'\mathbf{x})^{-1}$. Because the true Σ is not observable, we approximate $\Sigma \approx \dfrac{N}{N-k} \cdot \widehat{\Sigma}$. Here N is the number of observations and k is the number of parameters. The estimate of $\widehat{\Sigma}$ can be done with either a uniform or a Bartlett weight. With a uniform weight, each element $\widehat{\sigma_{ij}}$ of $\widehat{\Sigma}$ is $\widehat{\varepsilon_i}\widehat{\varepsilon_j}$ if the distance between i and j is less than 20 miles, and zero otherwise. With Bartlett weights, σ_{ij} is $1(d_{ij} \leq 20) \cdot \dfrac{20 - d(i,j)}{20} \cdot \widehat{\varepsilon_i}\widehat{\varepsilon_j}$, where $d(i,j)$ is the distance in miles between sections i and j.

1.4.2.1 Oil and gas productivity

One reason to focus on the GGR is that it is a very productive natural gas region, with significant oil reserves as well. The GGR has 12 of the 100 largest natural gas fields in the US, and 2 of the 100 largest oil fields (Energy Information Agency, 2010). This productivity is reflected in my data: I find 22% of square-mile sections have had drilling by 2010, 10% have had exploratory (or "wildcat ") wells, and that 14% of sections have had a productive oil or gas well (Table 1.1). There has been extensive drilling in the area—98% of sections lie within 6 miles of a well. This extensive drilling means that there are relatively few fields that have been discovered recently, with most fields discovered between 1955 and 1995 (Figure 1.5).

1.4.2.2 Lack of common pools

Another reason to focus on the GGR is that there is little evidence of common pools. If common pools exist, production from one well can be affected by drilling and production of nearby wells—meaning that observed production is not a good proxy for geological productivity. However common pools are unlikely in this setting. Many of the oil and gas wells in the region are in relatively impermeable geological areas, meaning that oil and gas cannot flow long distances underground (Nelson et al., 2009). Furthermore, Wyoming policy restricts how closely wells can be drilled to each other.[9] As a result, it is unlikely that one well can significantly affect production on nearby wells. While firm data is limited, Figure 1.6 shows that more than half of fields have only one operating firm, and less than 10% have more than 3 operating firms, which further decreases the possibility of common pools distorting production. I discuss this issue more in subsection 1.6.2, where I test whether decline curves are consistent with common pools.

[9] In fact, well spacing rules have existed in nearly if not all states with oil and gas drilling since 1935, when a coalition of states formed the Interstate Oil Compact Commission. This was a response early oil field drilling where wells were located quite close to each other which led to significant waste

1.4.2.3 Data Quality

A third reason to study Wyoming is that Wyoming has fairly detailed oil and gas data spanning a long time period. Drilling data date back to 1900. Federal and state leases date back to the 1800's. Production data date back only to 1978, but are particularly useful because Wyoming tracks production at the well level rather than the lease level.[10] I also compile detailed GIS data on state, federal, and private mineral ownership, as well as a number of other geographic features.

1.4.2.4 Robustness of ownership pattern

A fourth reason to focus on the Greater Green River basin is that the original federal-state ownership pattern has remained relatively robust. As this part of Wyoming is arid, there has been little private demand for the land. There have also been few transfers between federal and state land. I exclude the part of the GGR within 20.5 miles of the transcontinental railroad because much of this land was transferred to the Union Pacific Railroad (Kunce et al., 2002). I also exclude sections that are on the border with Utah and that are more than 3.2 miles away from the closest 16/36 section in Wyoming. This leaves a sample of 12,549 sections, with 696 sections that are numbered either 16 or 36.

Within this sample, whether a section is 16 or 36 is a strong predictor of current mineral ownership. Figure 1.7 is a map of ownership within a subset of the GGR that shows that the ownership pattern is fairly strong. To quantify the strength of the ownership pattern, I construct a measure of the fraction of the section that is in state or federal mineral ownership. In Table 1.3 I regress this measure on location and distance indicators. I find that a non-16/36 section is only about 2% state mineral lands on average, while a 16/36 section is on average 80% in state ownership. In

[10]Some other states, like Texas, only require reporting production at the lease level which complicates analysis because leases vary significantly in area and number of wells.

contrast, a non-16/36 section tends to be 90% in federal ownership, while a 16/36 section is on average only 18% in federal ownership. This is driven largely by sections either being almost completely in state or almost completely in federal ownership.

Crucially, these regressions also show that ownership does not change as a function of distance away from state land. In the second-to-last row of Table 1.3, the F test fails to reject the hypothesis that coefficients on 1 mile, $\sqrt{2}$ miles, 2 miles, and $\sqrt{5}$ miles are not all equal to zero.

1.4.2.5 Testing the exclusion restriction

Finally, the GGR is a useful place to study because there is little evidence that above-ground factors are correlated with ownership patterns. I find that for the most part, both physical and socio-economic characteristics are uncorrelated with ownership and distance to state land. Using the regression specification from equation 1.8, Table 1.4 shows that with the exception of wetlands, physical characteristics strongly correlated with 16/36 sections and proximity to 16/36 sections. I do however find that state land and land close to state land is somewhat less likely to have wetlands relative to federal land far from state land. Similarly, Table 1.5 examines social and economic outcomes like settlements and fences and finds very little evidence that such outcomes have been correlated with 16/36 sections and proximity to 16/36 sections.[11] If such economic activity was correlated with ownership patterns, it would not be possible to determine whether oil and gas outcomes were driven by federal and state policy or by variation in economic activity.

1.4.2.6 Does this setting have external validity?

One concern with this analysis is that it examines compares drilling outcomes on Wyoming state government land with US federal land—a sample that may lack

[11] These regressions do not include information on roads because in many cases roads were built by oil and gas firms as part of their exploration process.

external validity. In addition, this setting does not include privately owned mineral lands, which make of the majority of mineral lands in the United States. However in all states the ease of operating on private land is likely very similar to that of state land as the same state regulatory agency manages permitting and other regulation both on private and state-owned land. The major differences between private and state land in this setting seem to be that state land has a public auction to allocate oil and gas leases, whereas private leases are secured through costly search and bilateral negotiation. Because of this firms report that state-owned land is somewhat easier to operate on in comparison to private land. Another possible difference is in the terms of leases. While some information on private leases is available, there are no comprehensive data on lease terms.[12]

Another concern is that policies on state land in Wyoming might be very different from policies in other states (Krupnick et al., 2014). If this is so, state policies in Wyoming might be considered to be relatively low cost for firms relative to policies in other states, as Wyoming politics tend to lean to the right with less environmental protection. While an analysis of multiple states is beyond the scope of this paper, I discuss in the conclusion some evidence from nearby western States.

1.5 Empirical Results

1.5.1 Exploratory wells

First, I examine exploratory wells. Firms report whether a well is part of a known producing field or if the well is a "wildcat "well—one drilled in an area prior to there being any known oil or gas field. I regress an indicator for whether wildcat wells have ever been drilled on 16/36 sections and proximity to 16/36 sections using the

[12]Lease records, including information on royalty rates and lease expiration dates, are recorded in county records. However these records do not typically include information on the bonus payment paid by firms to mineral rights owners at the time the lease is signed.

specification of equation 1.8. Results are in columns 1 and 2 of Table 1.6. As predicted by theory, 16/36 sections are more likely to have exploratory drilling—14.1% of 16/36 sections have wildcat wells, relative to only nearly 10.9% of sections 3 miles away, a difference that is significant at the 5% level. Non-16/36 sections that are closer to 16/36 sections are even less likely to have exploratory drilling than sections 3 miles away. The hypothesis that coefficients for 1-$\sqrt{5}$ miles are all equal to zero is rejected at the 5% level. Column 2 shows that results are robust to adding controls for local geographic characteristics.[13]

The results demonstrate how firms substitute in the exploration decision: Higher costs on federal land lead firms to substitute to state land. Federal land that is far from state land has higher exploratory rates than federal land close to state land. This evidence suggests that costs on federal land are lower than on state and that firms shift exploratory drilling to low cost plots.

1.5.2 Overall drilling

The model also predicts that overall drilling will be higher on state land but is ambiguous about whether proximity to state land increases or decreases drilling on federal land. I construct a measure of whether drilling has ever happened on a section by 2010. I find that drilling is highest on state land and that proximity to state land leads to a long run decrease in drilling on federal land. Columns 3 and 4 of table 1.6 show that 16/36 sections have a 26.7% probability of ever having drilling which is higher than drilling rates on non-16/36 sections. The difference between 16/36 sections and non-16/36 sections is statistically significant with the exception of 3 miles away. Proximity to state land decreases drilling on federal land: For example, I find that sections 3 miles away have a 24.7% probability of ever having drilling, while

[13] Because wildcat wells may be relisted as part of a field if they led to a discovery, I construct an alternative measure of exploratory drilling where I also include consider a section to be the site of an exploratory well if there is a well on the section that was drilled in the first year of all wells within that oil or gas field. I find quantitatively similar results. Results available upon request.

sections 1 mile away have only a 22.1% probability of being drilled.

The productivity of exploratory wells explains why the short run substitution in exploration leads to long run differences in overall drilling patterns. Most exploratory wells are not productive and do not lead to additional drilling. I find that 26% of wildcat wells are reported as productive, whereas 84% of non-wildcat wells are productive. Furthermore, nearly half of all sections that ever get drilled are wildcat drilling sites. By shifting exploration from federal land to state land, federal land overall increases a significant decrease in drilling. The fact that state land leads to a lower threshold μ^* required for drilling is not enough to counteract this substitution effect (see equations 1.4 and 1.5).

Because exploratory wells are less likely to be productive relative to non-exploratory wells, places that have more exploratory drilling are also places that tend to have a lower likelihood of having a productive well—conditional on drilling. I explore this in columns 1 and 2 of Table 1.7 where the dependent variable is whether a section has ever had a productive well drilled, conditional on drilling ever happening. I find that sections 3 miles from the closest 16/36 section—federal land far from state land where exploratory drilling is higher—have a 60.6% probability of having a productive well conditional on drilling, while sections $\sqrt{2}$ miles away—federal land close to state land where exploratory drilling is lower—have a 64.4% probability of having a productive well conditional on drilling. Because of the small sample size, the coefficients for sections 1-$\sqrt{5}$ miles are not individually significantly different from zero, though they are jointly significant from zero at the 10% level.

I also find the even though state land is most likely to have exploratory drilling, it is also most likely to have productive drilling conditional on any drilling. Columns 1 and 2 of Table 1.7 also show additional evidence that the cost of operating on state land is lower. There is a 67.8% probability that a 16/36 section with drilling ends up being productive, in contrast with only a 60.6% probability for sections 3 miles away with drilling. This suggests that lower costs state land allows firms to develop wells with low productivity.

1.5.3 Well productivity

Next I examine how ownership affects productivity of wells. Low costs on state land imply that firms should be willing to drill lower productivity wells that would not be drilled on federal land. It is ambiguous whether proximity to state land will increase or decrease the productivity of wells on federal land.

To examine production, I compile monthly well-level production for 1978-2012. Production includes measures of natural gas—measured in thousands of cubic feet (mcf), and oil—measured in barrels.[14] To aggregate production, I use a barrel-of-oil equivalent production (BOE) measure, where 6 mcf of natural gas has approximately the same energy content as one barrel of oil. Because I do not observe future production, I proxy for total well productivity with the first 12, 24, or 36 months of production.[15]

Using this measure of production, I find that average well productivity for wells on state land is significantly lower than those on federal land. I also find that producing wells on federal land tend to have lower production if close to state land. Column 1 of Table 1.8 shows that the average producing well on 16/36 sections has only about 62% of the BOE productivity of an average producing well on a section 3 miles away. Wells close to state land also have lower production—an average producing well on sections 1 mile from the closest 16/36 section have on average 78% of the production

[14]Some natural gas wells produce natural gas liquids. These have a value similar to oil and can be measured in barrels. While firms may report natural gas liquids in either the natural gas or oil category, I find that most natural gas wells report some oil production, which suggests that natural gas liquids are reported as oil.

[15]Oil and gas production is often modeled by geologists as following the form $q_i(a) = f(a)q_i$, where a is the age of well i (Arps, 1945). Under this assumption, aggregate productivity over any subset of the well life time will be proportional to total well productivity. This assumption seems to be valid because other research has found that production is unresponsive to price changes (Anderson et al., 2014). In addition, prices for natural gas have only been deregulated fairly recently.

of a well 3 miles away. Similar numbers hold for gas (columns 4-6) and oil (columns 7-9). The assumption that production at a given age of the well is proportional to total production seems to hold, as coefficient estimates are very similar whether measuring production as the first 12, 24, or 36 months. While coefficients for 1-$\sqrt{5}$ miles are mostly statistically significant, coefficients for 16/36 sections are imprecisely estimated. However, in the Appendix I show that the coefficients are similar and more precise when controlling for field fixed effects and drilling date fixed effects. I also show that the results are similar when excluding outliers.

Well productivity regressions show that lower costs on state land lead firms to drill with lower expected productivity, which translates into lower expected production. Lower productivity discoveries on state land inform the firm about low productivity but profitable potential wells on nearby federal land, which lowers average well productivity of federal wells that are close to state land. It is important to note that these are selection effects—state land and proximity to state land does not decrease productivity, but rather affect what kinds of wells are drilled on these lands—and what kind are not.

1.5.4 Overall section level productivity

Finally, I find that ownership affects production per square mile with higher production on state land and federal land that is far from state land. In Table 1.9, I aggregate total production for all wells within a section drilled in 1980 or later, and compute total well productivity for all wells within a section. I use the MacKinnon-Magee transformation for production to reduce the effect of outliers yet keep observations with zero production (MacKinnon and Magee, 1990).[16] I find that proximity to state land decreases production. For example, in column 1, I find that barrel-of-oil equivalent production for sections 1 mile from the closest 16/36 is about 77% that

[16] The MacKinnon Magee transformation constructs a transformed dependent variable $\tilde{q} = \log(q + \sqrt{q^2 + 1})$.

of production for sections 3 miles from the closest 16/36 section and is statistically significant at the 10% level. Similar results hold for gas and oil, as well as both with and without township fixed effects. I also find that 16/36 sections have higher production unconditional on drilling relative to other land, although the difference between 16/36 sections and sections 3 miles away is not statistically significant.

I find similar results when examining whether a productive well has ever been drilled. Table 1.7 columns 3 and 4 examine whether a productive well is ever drilled within a section. I find that sections 3 miles away have a 15.0% probability of ever having productive drilling, while 16/36 sections have a 18.1% probability of ever having productive drilling—a 20.1% increase. Number of wells drilled is also higher on state land, though not significantly so (columns 5 and 6 of Table 1.7). These productivity results also suggest that proximity to state land decreases productivity, though the pattern is not statistically significant.

How ownership and proximity to state land affect production can be seen in Figure 1.8, where I graph the distribution of production, unconditional on drilling, comparing 16/36 sections, sections 1-$\sqrt{5}$ miles away, and sections 3 miles away from the closest 16/36. The graph shows that ownership has little effect on high return plots. Each category of land has about equal probability of being a section that produced more than 1,000,000 BOE from 1978-2010.[17] However ownership affects productivity for lower productivity sections. In particular, the cdf for 16/36 rises much more steeply than the cdf for 3 miles, which shows that 16/36 sections are better at drilling and producing under low productivity. At the low end of the cdf, the cdf for sections 1-$\sqrt{5}$ miles away is much higher than that of 3 miles and of 16/36 sections, because learning on from state land means that low productivity federal sections will not be drilled.

[17]In Figure 1.8, 1,000,000 BOE is approximately the point where the x axis is 14.

1.5.5 Changing policies over time

Finally, I explore drilling patterns over time to see how policy changes affect revealed search patterns. Many of the environmental policies affecting federal land were implemented in the 1970's. If these changing policies increased the cost of drilling on federal land, we would expect to see greater substitution to state land after the 1970's.

In figure 1.9 compares the rollout of drilling on 16/36 sections, sections that are 1-$\sqrt{5}$ miles away, and sections that are 3 miles away. I find that each of these types of sections have fairly similar probabilities of being drilled by up until about 1980. After the 1980's, drilling on sections 1-$\sqrt{5}$ miles away diverges from rates on 16/36 sections. However, drilling rates on sections 3 miles away did not diverge very much from 16/36 sections until the mid 2000's.

Similar results are shown for the location of wildcat drilling. In Figure 1.10 looks at the number of wildcat wells drilled on 16/36 sections and sections 1 mile away. Under homogenous policies, there should be a 4:1 ratio of wildcats on sections 1 mile away to wildcats drilled on 16/36 sections. I find that while the ratio is noisy, by the 1980's there is a sharp decrease in the ratio.

However, it is not totally clear what policy changes led to this divergence in drilling patterns. An alternative explanation is changing leasing policies: In 1980, the State of Wyoming changed how it allocated leases, switching from a first-come first-serve system to an auction system. Because under the auction the State of Wyoming published a catalog of all lands available to lease, this may have increased awareness of state leasing opportunities and in turn increased drilling. This is a topic of future research.

1.6 Ruling out Alternative Mechanisms

Revealed drilling and production outcomes show that ownership patterns have a significant effect on the oil and gas industry. Drilling and production outcomes are consistent with a model of search and learning where the cost of operating on federal land is higher. However there are other mechanisms that may be driving drilling and production outcomes. One concern is that the federal government began to withhold leases, leading to decreased drilling and production on federal land. Another concern is that there are common pools. I address each of these concerns in turn.

1.6.1 Irregular Leasing Policies

To examine whether the federal or state governments used irregular leasing policies, I digitize federal and state oil and gas leases. Federal oil and gas leases records are taken from the Bureau of Land Management website, with more recent leases also on the BLM's LR2000 database.[18] State oil and gas lease records were digitized from paper records at the Wyoming State Lands office in Cheyenne, Wyoming. For both federal and state land, lease data date back to the 1800's. I digitize lease records for 11,091 out of the 12,549 sections in my sample. I exclude sections in townships with significant private land or with very little oil and gas drilling.

I find that almost all sections of land have had oil and gas leasing: Table 1.10 shows that 98.9% of sections of land ever had a federal or state oil and gas lease on it. Both federal and state governments have been very likely to issue leases: 98.7% of non-16/36 sections had a federal oil and gas lease on them, and more than 99% of 16/36 sections with state land had a state oil and gas lease on them.

One concern is that federal land was slow to be drilled because federal land was slow to be leased. However Figure 1.11 shows that the opposite occurred—federal

[18] Lease records are taken from `http://www.wy.blm.gov/mtps/search.php`. Additional information about leases is taken from `http://www.blm.gov/lr2000/` .

land tended to be leased long before state land. I plot the rollout of the first lease for each section over time—conditional on a lease being offered. I find that federal leasing tended to happen before state leasing: More than half of federal leases were issued by 1940, while it wasn't until about 1980 that 50% of state leases had been issued.

Another concern is that though the federal government initially leased much of the land, it began withholding certain plots from leasing later on. Indeed, I find that only 28.1% of non-16/36 sections currently have a federal oil and gas lease on them, and that only 17.7% of non-16/36 sections that have never had drilling currently have a federal oil and gas lease on them. If the federal government has restricted leasing on these places, this could explain the lack of drilling on federal land.

However this change is likely driven by the nomination process. In earlier years, federal leases were offered everywhere, and the US government had a policy to issue leases on all Bureau of Land Management land. Later, the Federal Oil and Gas Leasing Reform Act of 1987 required firms or other parties to first nominate land to be offered as oil and gas leases before the Federal Government would offer leases through the auction process. Because the nomination process was costless, it likely only restricted extremely low expected productivity plots from being offered. As a result, many of the places that were not considered good oil and gas sites were not nominated after 1987. For example, I find that for non-16/36 sections that have never had drilling, 45.2% of them have a lease if the closest 16/36 section has a productive oil or gas well. However only 14.8% have leasing if the closest 16/36 section does not have a productive oil or gas well.

Even with nomination, we might still be concerned that federal land that was nominated may still have been withheld from the auction. The major reason why certain nominated lands are not auctioned is if an environmental organization protests auctioning the plot on environmental grounds. While comprehensive data on protests are not available, recent data suggests that the vast majority of nominated leases are auctioned.[19] Rather than withhold plots from auction, the BLM appears to lease these lands but impose stricter environmental stipulations for the lessee.

Figure 1.11 suggests another concern: That increased drilling on state land after the 1980's was driven by an increased willingness of the state government to issue leases. However this also does not appear to be the case. Lower rates of leasing prior to the 1980's appear to be driven by the fact that a firm had to request a lease before it was offered and no comprehensive list of lands that could be leased was listed. Starting in 1980, Wyoming switched to an auction system and began offering a more comprehensive list of sites to be auctioned. Greater awareness of possible leasing opportunities likely drove the increase in state leasing

Overall, I do not find evidence that drilling patterns are driven by irregular leasing policies. Future work will also explore the role of other changes in federal and state policies such as royalties and rental rates. However these are unlikely because firms anecdotally report that environmental compliance costs are the major reason for lower willingness to operate on federal land.

1.6.2 Common Pools

Another concern in interpreting the results is common pools. The model assumes no common pools—that high production from a well on one section of land cannot decrease the productivity of a well on a nearby section. In this section I describe institutional regulations designed to prevent common pools. I also use geological and production data to show that common pools are very unlikely to exist in this region.

[19]For example, the February 2013 Wyoming BLM auction offered 162 leases, 14 of which were protested by the Biodiversity Conservation Alliance and Western Resource Advocates. The BLM rejected all 14 of these protests and offered all 162 parcels in the auction. Records from other dates available at `http://www.blm.gov/wy/st/en/programs/energy/Oil_and_Gas/Leasing/historical_index.html`.

1.6.2.1 Well spacing and geology

A major reason that common pools are unlikely to exist in this region is well spacing rules. Well spacing rules are requirements that limit how closely a well can be drilled to another well. Another reason is the permeability of the underlying oil or gas reservoir. If permeability is low, oil and gas cannot flow long distances underground. Here I discuss well spacing rules, showing that in the Greater Green River basin wells are spaced far enough apart relative to the permeability of the region such that common pools are very unlikely.

Well spacing rules originated from early oil extraction experiences in the 1800's and early 1900's in states like Pennsylvania, Texas, and California, where the high density of wells led to inefficient extraction and common pool problems (Libecap and Wiggins, 1984). In response to this problem, a coalition of states formed the Interstate Oil Compact Commission (IOCC) in 1935 which advocated well spacing guidelines in order to eliminate common pool problems (Interstate Oil and Gas Compact Commission, 2006). Today all oil and gas producing states in the United States—and many foreign countries—have adopted well spacing rules. As a result, common pools are unlikely to be a concern for onshore oil and gas production in the United States.

In the case of Wyoming, the Wyoming Oil and Gas Conservation Commission (WOGCC) has established location-specific well spacing rules. For most of the Greater Green River basin where almost all wells are natural gas wells, there can only be up to 4 wells drilled in a section—one in each quarter section, where a quarter section measures 0.5 by 0.5 miles (or 160 acres). In oil fields, there may be one well every quarter-quarter section (or 0.25 by 0.25 mile unit of 40 acres). Gas wells must be drilled very close to the center of the quarter and oil wells must be drilled very close to the center of the quarter-quarter.[20]

Geological data on permeability suggest that these spacing rules are sufficient to

[20]Spacing rules for wells are described at `http://soswy.state.wy.us/Rules/RULES/7928.pdf`.

prevent common pools. Most of the fields in the Greater Green River basin have low permeability such that oil and gas cannot flow long distances. In figure 1.12 I graph permeability from a number of fields, using reported permeability measures taken from the 1979 and 1992 editions of the Wyoming Oil and Gas Fields Symposium (Wyoming Geological Association, 1979, 1992). The distribution of permeability in Figure 1.12 shows that permeability for most wells ranges from 0.1 millidarcys to 100 millidarcys. This is in the low range of permeability for conventional oil and gas fields (see for example Bear (1972), page 136). This translates to relatively small drainage areas. For example, the Hogsback Field, which has an estimated permeability of 26.5 milidarcys, has an estimated drainage area of 37.3 acres—just smaller than the 40 acres of a quarter-quarter section. The Bunker Hill field, which has an estimated permeability of 94 milidarcys, has a drainage area of 39.3 acres.[21] As the Hogsback and Bunker Hill fields have relatively high permeability relative to other fields in the sample, this suggests that drainage areas of other wells are even smaller and that well drainage areas do not overlap.

1.6.2.2 Testing for common pools

Given the geology and spacing rules of the region, common pools are unlikely. I test for evidence of common pools using measures of decline curves. Because well production tends to decline faster under common pools, regions with more likelihood of common pools are likely to have steeper declines in production.

Common pools are least likely to happen on federal land because of a policy called unitization. Under unitization, when there are multiple firms all extracting from the same field on federal land, the federal government can impose that production is managed under a single operator, effectively operating the land as a single firm

[21] Drainage area estimates for the Bunker Hill field and Hogsback Field are taken from `wogcc.state.wy.us`, from dockets 169-09 and 415-08. Unfortunately a comprehensive list of drainage area estimates do not exist for fields.

(Libecap and Wiggins, 1985). However there is no authority to impose unitization for operations spanning federal and non-federal land. Therefore we might expect that common pool problems and higher decline rates are more likely for wells on state land and federal land close to state land.

This is potentially a concern because it gives an alternative interpretation to well productivity results: Production regressions in table 1.8 suggest that low costs on state land lead to low productivity wells drilled on state land and federal land close to state land. An alternative explanation for this phenomenon is that low production on and near state land is driven by common pools. If wells on state land and nearby federal land are extracting from the same reservoirs, and if there is no centralized operator, this could lead to fast initial extraction and fast declines in production.

To test for common pools, I construct a measure of decline from the first year to the second year.[22] Results are in Table 1.11. I find that decline rates are not higher for sections on or close to state land. This suggests that common pools are not driving production results.

1.7 Cost estimates and other policy implications

In this section I give back-of-the-envelope estimates of costs and discuss challenges of identifying costs in this setting. I also discuss some of the policy implications of this research, including the challenges of difficulty of regulation under leakage, allocative inefficiency, and the spatial extent of policy spillovers.

1.7.1 Cost estimation

I provide a back-of-the-envelope estimate of costs both on state and federal land based on revealed drilling and production. The estimated costs include drilling costs,

[22] The dependent variable is $\log(y_2) - \log(y_1)$ where y_1 and y_2 are total production in the first and second year of production, respectively.

the costs of other well-level infrastructure such as building an access road, as well as the costs of meeting regulatory and bureaucratic requirements. A measure of the additional regulatory burden of federal land is taken by subtracting estimated state costs from estimated federal costs, as infrastructure and drilling costs should be similar between the two.

I identify costs using the structural assumption that a well will only be drilled if expected revenue exceeds costs. Costs are identified because for a given level of expected revenue, the probability that a well is drilled is the probability that the cost is less than expected revenue. I allow costs to be heterogeneous because the environmental compliance measures required by the BLM are determined on a case-by-case basis.

To construct a measure of expected revenue, I examine square mile sections of land where at least one producing well was drilled with production R_1. This becomes the basis for calculating expected production on a second well drilled within a section $E(R_2|R_1)$. Expected profits for the second well are:

$$\pi = (1-\tau)PE(R_2|R_1) - C$$

where τ is aggregate taxes and royalties, and P is the expected price. Then the probability of drilling a second well identifies the cdf of costs:

$$\text{prob}[\text{drill well 2}] = \text{prob}[C \leq (1-\tau)PE(R_2|R_1)]$$

By regressing an indicator of whether the second well is drilled on the measure of expected revenue, I identify the distribution of costs. For example, the median cost is identified from the level of expected revenue where the probability of drilling a second well is 50%. I use both a probit and a non-parametric specification to estimate the median cost. I discuss the details of this estimation in the appendix.

Figure 1.13 shows the estimated cdf of costs for non-16/36 sections. For non-16/36 sections, I estimate a median cost of \$19.1 million dollars (2010). The estimate from the non-parametric specification is very similar. The bootstrapped 95% confidence interval from the probit specification ranges from \$13.9 to \$25.8 million dollars.

Figure 1.14 shows the estimated cdf of costs for 16/36 sections. Here, I estimate a median cost of \$1.9 million dollars.[23] This estimate is very similar to engineering estimates of drilling costs, which averaged about \$1.1 million dollars (in 2010 dollars) over the period from 1980 to 2007 [24]. Because the number of observations is small the estimate of the median cost on 16/36 sections is very imprecisely estimated, with the bootstrapped 95% confidence interval ranging from less than one dollar to more than a quadrillion dollars.

The difference in the point estimates of costs suggests that federal regulation increase costs by about \$17 million dollars. Because costs on 16/36 sections are so imprecisely estimated, the difference in median costs between 16/36 and non-16/36 sections is also imprecisely estimated and not significantly different from zero.

1.7.2 Caveats to cost estimation

This cost estimate of \$19.1 million dollars is likely an upper bound because of the standard selection problem, where I do not observe the counterfactual of expected production for second wells that were not drilled. As the firm also has unobservable geological signals of productivity, this suggests that $E(R_2|R_1, 2 \text{ drilled}) > E(R_2|R_1, 2 \text{ not drilled})$. Using the regression estimate to predict $E(R_2|R_1)$ will overstate the returns to drilling second wells that were not drilled and will overstate costs.

Measurement error of the true expected productivity is also a concern as it in-

[23] Here I exclude one outlier that had very high expected revenue but no second well drilled. Including the outlier gives an estimated costs of \$0.2 million dollars

[24] Drilling cost estimates taken from `http://www.eia.gov/dnav/pet/pet_crd_wellcost_s1_a.htm`

creases the variance of the distribution of costs and could bias cost estimates either up or down. Estimated expected production $E(R_2|R_1)$ is a mismeasurement of the firms true expected production because the firm has additional geological information not observable to the econometrician. Without making additional assumptions, it is not possible to separately identify costs from unobservable shocks to expected production. To see this, suppose that estimated $E(R_2|R_1)$ is low but the firm still drills the second well. We cannot distinguish whether this is due to a high unobservable geological signal or a low draw from the cost distribution. Measurement error will tend to suggest a cost distribution with a larger variance than the true cost distribution. Measurement error may also bias the estimated median cost if either measurement error is asymmetric or if the true cost distribution is asymmetric.

There are a number of other caveats that may bias cost estimates. Costs will be overstated if drilling the second well also provides value through additional geological information about the region. This is unlikely to be important because the second well drilled within a section will likely provide little additional geological information beyond that of the first well. Another concern is that the estimate does not account for marginal costs such as the cost of transporting the oil and gas to the seller. This is not likely to be a concern since marginal costs are likely very low, especially with natural gas. A third concern is that these estimates do not allow for endogenous costs, where the regulator may adjust environmental requirements in view of expected production.

Future work will explore the extent to which costs can be at least partially identified. While selection is a significant issue, Manski (1989) shows how parameters can be sometimes at least partially identified under selection. Incorporating geological data may help to provide a more precise estimate of expected production, although it is unlikely that any econometric approach can recover the geologists precise expected production. Further identification can come from the decision of whether to drill an initial exploratory well as well as from production from wells on other nearby sections. A major challenge, however, is that firms have complicated prior beliefs about the joint distribution of reserves over multiple potential drilling sites. This large unobservable state space is a significant obstacle to identification.

1.7.3 Spillovers

Drilling and production regressions suggest suggest that local policies in one place can have relatively long ranging spillovers. In this empirical work, the difference between outcomes on sections $\sqrt{5}$ miles from state land and sections 3 miles from state land suggests that low costs on state land affect drilling outcomes for plots at least $\sqrt{5}$ miles away from state land. The spillover range of $\sqrt{5}$ miles is a lower bound—it is possible that firms are even shifting exploratory drilling activity from sections 3 miles from state land to state land. The fact that policies can range further is not surprising given that productive wells on one location predict productive wells up to 20 miles away (as shown in figure 1.3).

The two types of spillovers—the substitution effect and the signal threshold—also have implications for calculating counterfactuals. Consider the counterfactual for average drilling rates if federal costs were reduced to state levels. The currently observed rate of drilling on state land may be an upper bound under the substitution effect, because firms will not substitute from higher cost federal land if there is no federal land. However rates of drilling on state land may be a lower bound if lowering costs on federal land decreased total firm costs, such that more low-signal plots were drilled on state land.

Similarly, the counterfactual for outcomes if all land was under federal ownership is also not identified. Raising costs on state land to federal levels would lead to more drilling on federal land because firms would not substitute to state land. However it would also decrease drilling on federal land by increasing the minimum threshold signal that a firm needs to drill.

1.7.4 Incomplete Regulation and Leakage

One of the challenges of implementing environmental protections on federal land is that nearby non-federal land is not regulated and firms can re-located drilling activity to non-regulated land. Such leakage and incomplete regulation has been explored in other settings, including Fowlie (2010) and Holland (2012). In this setting, exploration on one plot is a substitute for exploration on another plot, and an environmental tax on the regulated plot will shift exploration to the non-regulated plot.

However, learning adds a twist because the firm then uses geological information from drilling on the unregulated plot to update beliefs about reserves under the regulated plot. Leakage delays drilling on the regulated plot, but learning allows the firm to develop a more precise signal about the reserves on the regulated plot. Such learning means that in extreme cases, partial environmental regulation will shift the order that plots are drilled, but have no effect on the expected number of wells that are drilled. (In the appendix I show a simple 2-plot example where imposing higher costs on federally-owned land decreases drilling on federal land but has no effect on the expected number of wells because of learning spillovers from non-federal land to federal land).

1.8 Conclusion

In this paper I examine how federal regulation affects the search for and production of oil and gas on both federal and non-federal lands. I highlight the interaction between spatially heterogeneous land management and how firms learn about geology through drilling. Using a natural experiment with exogenously located federal and state land, I find that drilling and production are relatively low on federal land, suggesting that the costs of drilling on federal land are relatively high. I find that proximity to low cost land leads to long run decreases in drilling and production on nearby high cost land, even though proximity to low cost land also helps firms develop a more precise signal about the returns to drilling on high cost land. I show that drilling and production patterns are not explained by irregular leasing policies or by common pools. A simple back-of-the-envelope calculation estimates that federal regulation costs about $17 million dollars per well.

While this paper focuses on Wyoming, preliminary work shows that state costs are relatively low in other places. I have compiled data from Montana, Colorado, Utah, and New Mexico—states where the original state land assignment from the Land Ordinance of 1785 has remained relatively robust, and where there is significant oil and gas drilling, and relatively high quality oil and gas well data. I find that the number of wells located on lands designated for state ownership through the Land Ordinance of 1785 is significantly higher than would be predicted if well location was uncorrelated with section numbering.[25] These results suggest that heterogeneous ownership and policies are likely to have spillover and leakage effects in a variety of settings.

This work suggests avenues for further research. One particular challenge is to estimate a more complete structural model that builds on the back-of-the-envelope cost estimation. Further identification can come from adding additional information such as production outcomes from other wells. An important challenge in structural estimation is to account for the firm's priors about the joint distribution of reserves over multiple well sites, and how the firm updates its geological beliefs through each well drilled. Ideally, such structural estimation could be used not only to identify costs, but also to identify the firm's priors and the value of information from drilling exploratory wells. With these parameters identified, it would then be possible to

[25] In Colorado and Montana, I find that 6.3% and 6.0% of wells are on 16/36 sections, compared to a predicted fraction of 5.6%. In Wyoming, the fraction of wells on 16/36 sections is 6.5%. In New Mexico and Utah, where sections 2, 16, 32, and 36 were initially allocated to state ownership, I find that 11.9% and 12.4% of wells are on these sections, compared to a predicted fraction of 11.1%. Treating each of these 5 states as an observation, I reject at the 5% level that the predicted fraction of wells on lands allocated for state ownership is equal to the observed fraction.

simulate important counterfactuals, such as drilling and production outcomes under homogenous all-state or all-federal ownership.

1.9 Tables

	mean	st.dev.	median	5th perc	95th perc
16 or 36	0.06	0.23	0.00	0.00	1.00
distance to closest 16 or 36	1.63	0.68	1.67	0.00	2.90
square miles	0.98	0.11	1.00	0.91	1.02
fraction state mineral	0.06	0.22	0.00	0.00	0.69
fraction federal mineral	0.86	0.29	1.00	0.01	1.00
had wildcat well by 2010	0.10	0.30	0.00	0.00	1.00
had any well by 2010	0.22	0.42	0.00	0.00	1.00
had any productive well by 2010	0.14	0.35	0.00	0.00	1.00

Table 1.1: Summary statistics for sections.

	mean	st.dev.	median	5th perc	95th perc
on 1636	0.07	0.25	0.00	0.00	1.00
oil well	0.10	0.30	0.00	0.00	1.00
gas well	0.64	0.48	1.00	0.00	1.00
oil and gas	0.01	0.10	0.00	0.00	0.00
dry or unreported	0.22	0.42	0.00	0.00	1.00
wildcat	0.12	0.32	0.00	0.00	1.00
drill year	1988.06	23.27	1998.00	1937.00	2010.00

Table 1.2: Summary statistics for wells.

	(1) State	(2) State	(3) Fed	(4) Fed
is 16/36	0.781***	0.781***	-0.727***	-0.715***
	(0.067)	(0.067)	(0.070)	(0.071)
$\approx$ 1 mile away		0.004		0.011
		(0.004)		(0.009)
$\approx \sqrt{2}$ miles away		-0.001		0.017
		(0.004)		(0.011)
$\approx$ 2 miles away		-0.002		0.011
		(0.002)		(0.008)
$\approx \sqrt{5}$ miles away		0.001		0.011
		(0.003)		(0.010)
constant	0.019***	0.019***	0.904***	0.892***
	(0.006)	(0.006)	(0.021)	(0.026)
R squared	0.668	0.668	0.326	0.326
p value joint significance		0.000		0.000
p value non-16/36 test		0.073		0.149
Observations	12549	12549	12548	12548

Table 1.3: Regressions of the fraction of a section that is in state ownership (columns 1 and 2) or in federal ownership (columns 3 and 4) as a function of whether a section is numbered 16 or 36, and proximity of the section to the closest section numbered 16 or 36. The first p value is a the joint test that all coefficients—except for the constant—are equal to zero. The second p value is the joint test that coefficients for 1 mile, $\sqrt{2}$ miles, 2 miles, and $\sqrt{5}$ miles are all equal to zero. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) mean elevation	(2) range elevation	(3) wetlands	(4) checked
is 16/36	-20.294	-0.665	-0.024***	-0.004
	(19.200)	(3.841)	(0.008)	(0.011)
$\approx$ 1 mile away	1.178	4.877	-0.015*	-0.001
	(13.490)	(3.650)	(0.008)	(0.006)
$\approx \sqrt{2}$ miles away	-3.874	1.555	-0.017**	-0.004
	(12.967)	(2.725)	(0.008)	(0.005)
$\approx$ 2 miles away	-4.799	4.052	-0.007	-0.004
	(12.984)	(3.918)	(0.006)	(0.012)
$\approx \sqrt{5}$ miles away	6.520	4.259	-0.013*	0.002
	(20.324)	(3.802)	(0.007)	(0.010)
constant	2102.140***	80.981***	0.073***	0.228***
	(24.606)	(7.487)	(0.013)	(0.059)
R squared	0.000	0.000	0.001	0.000
p value joint significance	0.095	0.108	0.000	0.489
Observations	12506	12506	12549	12549

Table 1.4: Comparing mean elevation, range of elevation within section, the fraction of the section with any wetlands, and the fraction of the section that was visually checked by a surveyor (rather than estimated using geospatial methods). Elevation data is not available for all sections. Most sections missing elevation data are on the southern border with Utah. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1)	(2)	(3)	(4)	(5)	(6)
	settled	muni.	fence	dry crop	irrig.	surf. mine
is 16/36	-0.001	-0.003	-0.016	-0.001	-0.007	-0.001
	(0.001)	(0.003)	(0.017)	(0.000)	(0.006)	(0.000)
$\approx$ 1 mile away	-0.001	-0.002	-0.006	-0.001	-0.004	-0.000
	(0.001)	(0.003)	(0.014)	(0.000)	(0.005)	(0.000)
$\approx \sqrt{2}$ miles away	-0.001	-0.002	-0.009	-0.000	-0.004	-0.000
	(0.001)	(0.003)	(0.016)	(0.000)	(0.005)	(0.000)
$\approx$ 2 miles away	-0.000	0.000	-0.010	-0.000	0.002	-0.000
	(0.000)	(0.002)	(0.010)	(0.001)	(0.004)	(0.000)
$\approx \sqrt{5}$ miles away	-0.001	0.000	-0.015	-0.000	-0.001	-0.000
	(0.000)	(0.002)	(0.016)	(0.001)	(0.004)	(0.000)
constant	0.001	0.004	0.317***	0.001	0.037***	0.001
	(0.001)	(0.003)	(0.047)	(0.001)	(0.014)	(0.000)
R squared	0.001	0.000	0.000	0.000	0.000	0.000
p value joint significance	0.351	0.255	0.846	0.229	0.000	0.556
Observations	12549	12549	12549	12549	12549	12549

Table 1.5: Regression of land coverage measures within a section. Fraction of a section with any settlement (column 1), whether there is any municipality (dry crop farming (column 2), whether there is any fencing within the section (column 3), fraction of section with dry crop (column 4), fraction of section with irrigated crops (column 5), and fraction of a section with a surface mine (column 6). Whether the outcomes in columns 1 and 4-6 were visually determined or estimated by geospatial methods is given in column 4 of table 1.4. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) expl.	(2) expl.	(3) expl./first	(4) expl./first
is 16/36	0.032**	0.032**	0.020	0.020
	(0.013)	(0.013)	(0.018)	(0.019)
$\approx$ 1 mile away	-0.004	-0.004	-0.026**	-0.026**
	(0.008)	(0.008)	(0.012)	(0.012)
$\approx \sqrt{2}$ miles away	-0.009	-0.009	-0.029**	-0.030**
	(0.008)	(0.008)	(0.014)	(0.013)
$\approx$ 2 miles away	-0.022**	-0.021**	-0.028**	-0.026**
	(0.009)	(0.009)	(0.012)	(0.012)
$\approx \sqrt{5}$ miles away	-0.008	-0.008	-0.025*	-0.025*
	(0.009)	(0.010)	(0.014)	(0.014)
constant	0.109***	0.045***	0.247***	0.086
	(0.011)	(0.012)	(0.045)	(0.058)
physical chars.	No	Yes	No	Yes
R squared	0.002	0.004	0.001	0.008
p value joint test	0.005	0.008	0.000	0.001
p value non-16/36	0.032	0.046	0.100	0.123
Observations	12549	12549	12549	12549

Table 1.6: Regressions of the probability that a section has ever had an exploratory well by 2010 (columns 1 and 2) or ever had drilling by 2010 (columns 5 and 6). The first p value is the test that the coefficients for 16/36 and 1, $\sqrt{2}$, 2, and $\sqrt{5}$ miles away are all equal to zero. The second p value is the test that the coefficients for 1, $\sqrt{2}$, 2, and $\sqrt{5}$ miles away all equal to zero. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1)	(2)	(3)	(4)	(5)	(6)
	1(prod | drill)	1(prod | drill)	1(prod well)	1(prod well)	# prod wells	# prod wells
is 16/36	0.072*	0.072**	0.031**	0.031**	0.248	0.236
	(0.037)	(0.036)	(0.014)	(0.014)	(0.240)	(0.240)
$\approx$ 1 mile away	0.008	0.007	-0.014	-0.014	-0.093	-0.102
	(0.048)	(0.047)	(0.015)	(0.014)	(0.089)	(0.090)
$\approx \sqrt{2}$ miles away	0.038	0.039	-0.009	-0.010	-0.032	-0.041
	(0.038)	(0.037)	(0.011)	(0.010)	(0.072)	(0.073)
$\approx$ 2 miles away	0.049	0.050	-0.006	-0.005	-0.013	-0.012
	(0.042)	(0.043)	(0.011)	(0.011)	(0.084)	(0.080)
$\approx \sqrt{5}$ miles away	0.030	0.029	-0.008	-0.009	0.069	0.063
	(0.039)	(0.039)	(0.013)	(0.012)	(0.096)	(0.095)
constant	0.606***	0.469***	0.150***	0.024	0.835**	0.490
	(0.066)	(0.157)	(0.039)	(0.053)	(0.348)	(0.394)
physical chars.	No	Yes	No	Yes	No	Yes
R squared	0.002	0.004	0.001	0.007	0.000	0.001
p value joint test	0.090	0.082	0.036	0.041	0.004	0.005
p value non-16/36	0.096	0.090	0.739	0.654	0.574	0.519
Observations	2814	2814	12549	12549	12549	12549

Table 1.7: Columns 1 and 2 are regressions of the probability that a section ever has a well drilled on it that is reported to be productive, conditional on any well being drilled on the section by 2010. Columns 3 and 4 are regressions of the probability that a section has ever had an well drilled by 2010 that is reported to have ever been productive. Columns 5 and 6 report the total count of wells ever drilled that have been reported to be productive. The first p value is the test that the coefficients for 16/36 and 1, $\sqrt{2}$, 2, and $\sqrt{5}$ miles away are all equal to zero. The second p value is the test that the coefficients for 1, $\sqrt{2}$, 2, and $\sqrt{5}$ miles away all equal to zero. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) BOE 12	(2) BOE 24	(3) BOE 36	(4) gas 12	(5) gas 24	(6) gas 36	(7) oil 12	(8) oil 24	(9) oil 36
is 16/36	-0.48	-0.48*	-0.46	-0.60*	-0.61*	-0.59*	-0.25	-0.28	-0.27
	(0.30)	(0.29)	(0.29)	(0.33)	(0.32)	(0.31)	(0.27)	(0.26)	(0.26)
$\approx$ 1 mile away	-0.25**	-0.21**	-0.19*	-0.26***	-0.25***	-0.24***	-0.14	-0.11	-0.09
	(0.11)	(0.10)	(0.11)	(0.10)	(0.08)	(0.09)	(0.13)	(0.14)	(0.15)
$\approx \sqrt{2}$ miles away	-0.18**	-0.18***	-0.17**	-0.23**	-0.24**	-0.27**	0.02	0.00	0.01
	(0.09)	(0.07)	(0.07)	(0.11)	(0.10)	(0.12)	(0.11)	(0.11)	(0.12)
$\approx$ 2 miles away	-0.30**	-0.28*	-0.25*	-0.23	-0.23	-0.22	-0.17	-0.16	-0.15
	(0.15)	(0.15)	(0.15)	(0.14)	(0.14)	(0.14)	(0.16)	(0.17)	(0.17)
$\approx \sqrt{5}$ miles away	-0.23***	-0.23***	-0.22***	-0.23**	-0.24**	-0.31*	-0.08	-0.10	-0.10
	(0.08)	(0.07)	(0.07)	(0.11)	(0.11)	(0.17)	(0.09)	(0.10)	(0.11)
constant	10.84***	11.31***	11.53***	12.54***	13.03***	13.25***	7.85***	8.27***	8.46***
	(0.52)	(0.49)	(0.47)	(0.56)	(0.52)	(0.49)	(0.52)	(0.51)	(0.49)
R squared	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Observations	7798	7798	7798	7567	7587	7619	7238	7316	7340

Table 1.8: Regressions of log total production for the first 12, 24, and 36 months of production. Production measured in barrel-of-oil equivalent production (columns 1-3), natural gas (columns 4-6), and oil (columns 7-9). I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

	(1) BOE	(2) BOE	(3) Gas	(4) Gas	(5) Oil	(6) Oil
is 16/36	0.05	0.05	0.10	0.10	0.05	0.04
	(0.15)	(0.15)	(0.16)	(0.16)	(0.13)	(0.12)
$\approx$ 1 mile away	-0.23*	-0.25**	-0.24	-0.26**	-0.18*	-0.19*
	(0.13)	(0.11)	(0.15)	(0.13)	(0.10)	(0.10)
$\approx \sqrt{2}$ miles away	-0.21	-0.21*	-0.21	-0.21	-0.16	-0.17
	(0.14)	(0.12)	(0.16)	(0.14)	(0.11)	(0.10)
$\approx$ 2 miles away	-0.18*	-0.19*	-0.18	-0.19	-0.12	-0.13
	(0.10)	(0.11)	(0.12)	(0.13)	(0.10)	(0.10)
$\approx \sqrt{5}$ miles away	-0.21*	-0.21**	-0.21	-0.22*	-0.13	-0.15
	(0.12)	(0.10)	(0.14)	(0.11)	(0.11)	(0.09)
constant	1.48***		1.62***		1.03***	
	(0.44)		(0.50)		(0.32)	
township FE	No	Yes	No	Yes	No	Yes
R squared	0.00	0.45	0.00	0.45	0.00	0.45
p value joint test	0.25	0.02	0.27	0.01	0.11	0.01
p value non-16/36	0.42	0.13	0.55	0.21	0.40	0.04
p value not-intercept	0.24	0.02	0.19	0.00	0.10	0.03
Observations	12549	12549	12549	12549	12549	12549

Table 1.9: Dependent variable is MacKinnon-Magee transform of total 1980-2010 production for wells drilled on or after 1980, aggregated to the section level. I use Conley standard errors with uniform weights and a maximum correlation distance of 20 miles.

	Any lease	Federal lease	State lease
All sections	**98.9%**	94.5%	10.1%
Not 16/36	98.8%	**98.7%**	5.6%
16/36	99.3%	23.4%	**86.2%**
16/36, has state mineral land	99.8%	10.4%	**99.6%**

Table 1.10: Fraction of sections that ever had a lease reported on them

	(1) BOE	(2) BOE	(3) Gas	(4) Gas	(5) Oil	(6) Oil
is 16/36	-0.04	-0.01	-0.04	-0.01	-0.02	0.00
	(0.08)	(0.09)	(0.08)	(0.08)	(0.07)	(0.08)
$\approx$ 1 mile away	0.03	0.02	0.03	0.02	0.01	0.00
	(0.05)	(0.06)	(0.05)	(0.06)	(0.05)	(0.05)
$\approx \sqrt{2}$ miles away	-0.06	-0.04	-0.04	-0.03	-0.06	-0.06
	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)	(0.06)
$\approx$ 2 miles away	0.02	0.01	-0.01	-0.02	0.05	0.03
	(0.04)	(0.05)	(0.04)	(0.05)	(0.04)	(0.04)
$\approx \sqrt{5}$ miles away	-0.05*	-0.05	-0.06**	-0.06	-0.04	-0.04
	(0.03)	(0.04)	(0.03)	(0.04)	(0.04)	(0.03)
intercept	-0.53***		-0.52***		-0.64***	
	(0.07)		(0.07)		(0.07)	
Field FE	No	Yes	No	Yes	No	Yes
R squared	0.00	0.11	0.00	0.12	0.00	0.08
p value joint test	0.00	0.01	0.01	0.06	0.02	0.02
Observations	7430	7430	7235	7235	6822	6822

Table 1.11: Percentage change in production from the first year to the second year, wells drilled after 1978. I use Conley standard errors with a uniform weight and maximum correlation distance of 20 miles.

1.10 Figures

6	5	4	3	2	1	6	5	4	3	2	1	6	5	4	3	2	1
7	8	9	10	11	12	7	8	9	10	11	12	7	8	9	10	11	12
18	17	16	15	14	13	18	17	16	15	14	13	18	17	16	15	14	13
19	20	21	22	23	24	19	20	21	22	23	24	19	20	21	22	23	24
30	29	28	27	26	25	30	29	28	27	26	25	30	29	28	27	26	25
31	32	33	34	35	36	31	32	33	34	35	36	31	32	33	34	35	36
6	5	4	3	2	1	6	5	4	3	2	1	6	5	4	3	2	1
7	8	9	10	11	12	7	8	9	10	11	12	7	8	9	10	11	12
18	17	16	15	14	13	18	17	16	15	14	13	18	17	16	15	14	13
19	20	21	22	23	24	19	20	21	22	23	24	19	20	21	22	23	24
30	29	28	27	26	25	30	29	28	27	26	25	30	29	28	27	26	25
31	32	33	34	35	36	31	32	33	34	35	36	31	32	33	34	35	36

$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1
$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2
2	1	16	1	2	3	2	1	16	1	2	3	2	1	16	1	2	3
$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2
$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1
1	2	3	2	1	36	1	2	3	2	1	36	1	2	3	2	1	36
$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1
$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2
2	1	16	1	2	3	2	1	16	1	2	3	2	1	16	1	2	3
$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2
$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1	$\sqrt{2}$	$\sqrt{5}$	2	$\sqrt{5}$	$\sqrt{2}$	1
1	2	3	2	1	36	1	2	3	2	1	36	1	2	3	2	1	36

Figure 1.1: Two diagrams showing original section numbering and how to construct the distance to the closest 16 or 36 section, as used in equation 1.8.

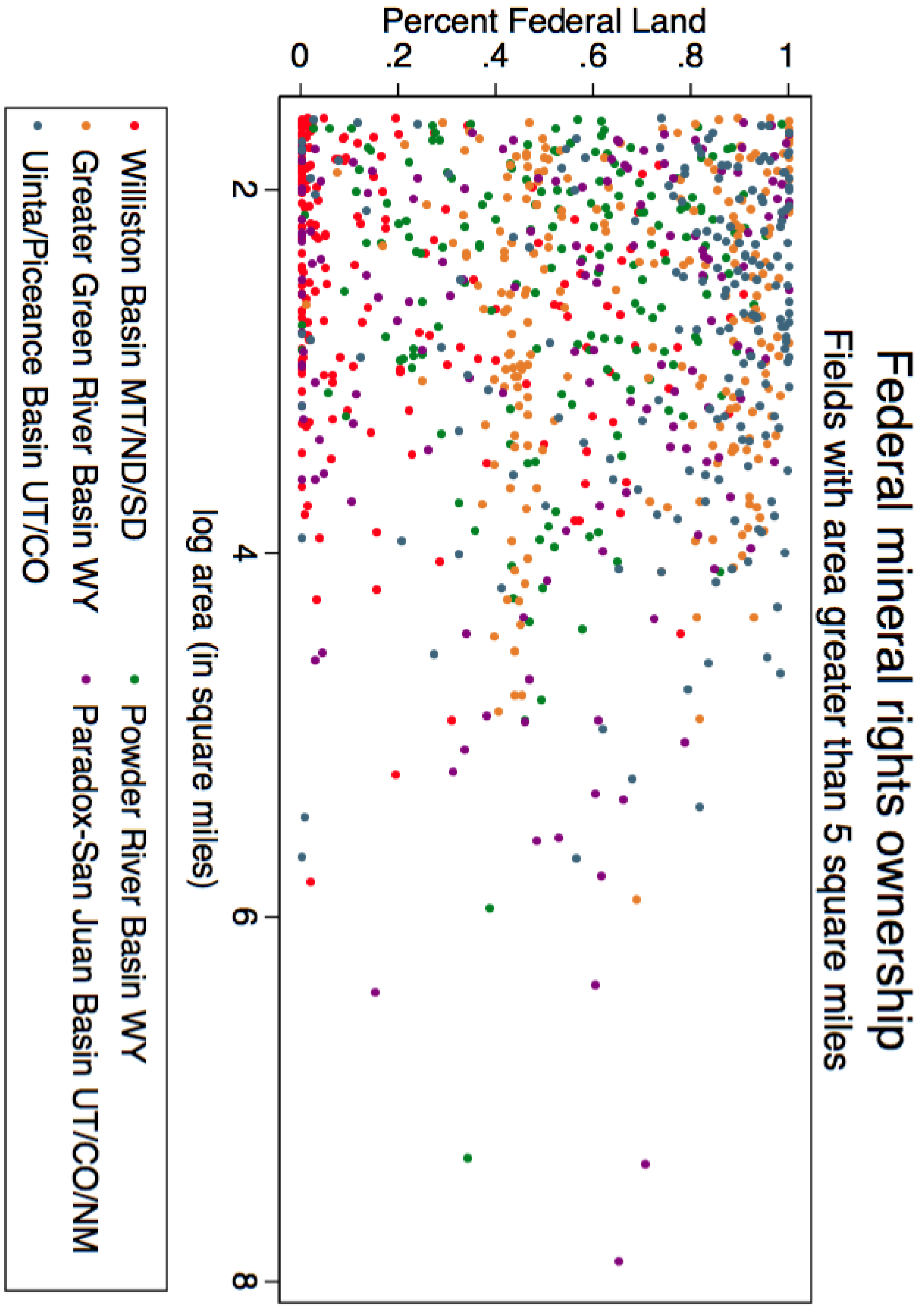

Figure 1.2: Fraction of fields that are federally owned, for a sample of basins in the Western United States.

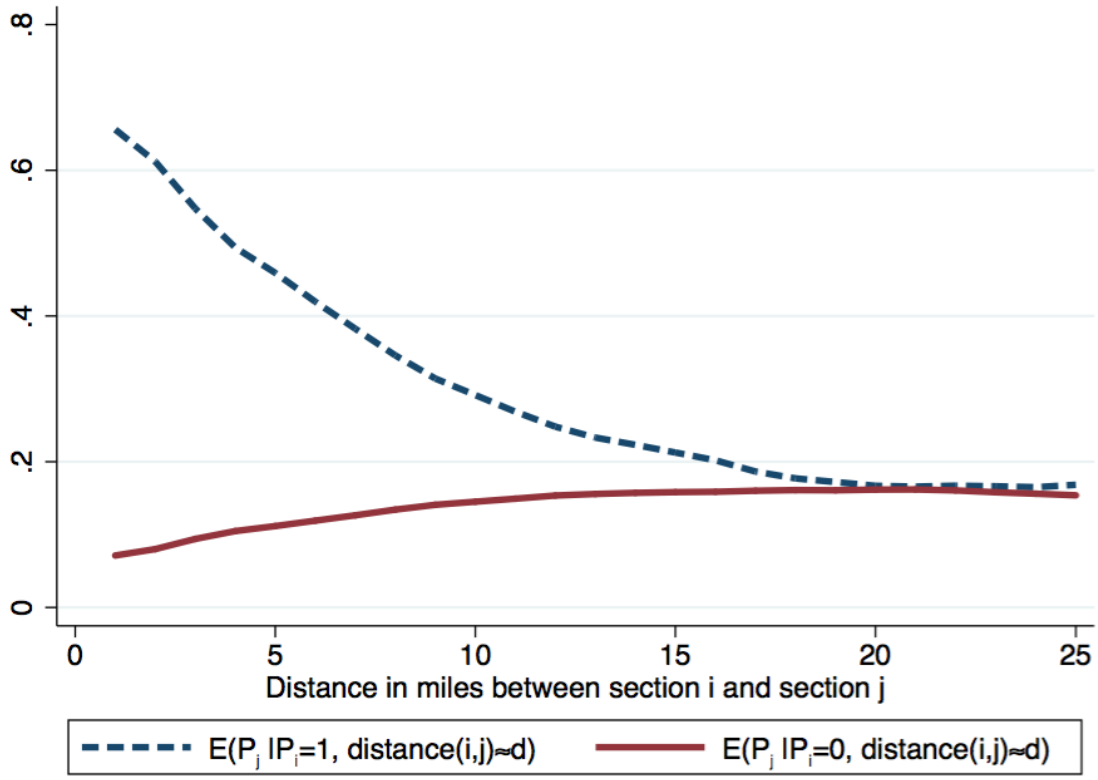

Figure 1.3: A graph showing the extent to which whether a section ever had a productive well predicts whether another section d miles away also has a productive well. Here P_i is indicator variables that indicates whether section i had a productive well, and d is the distance in miles between two sections i and j.

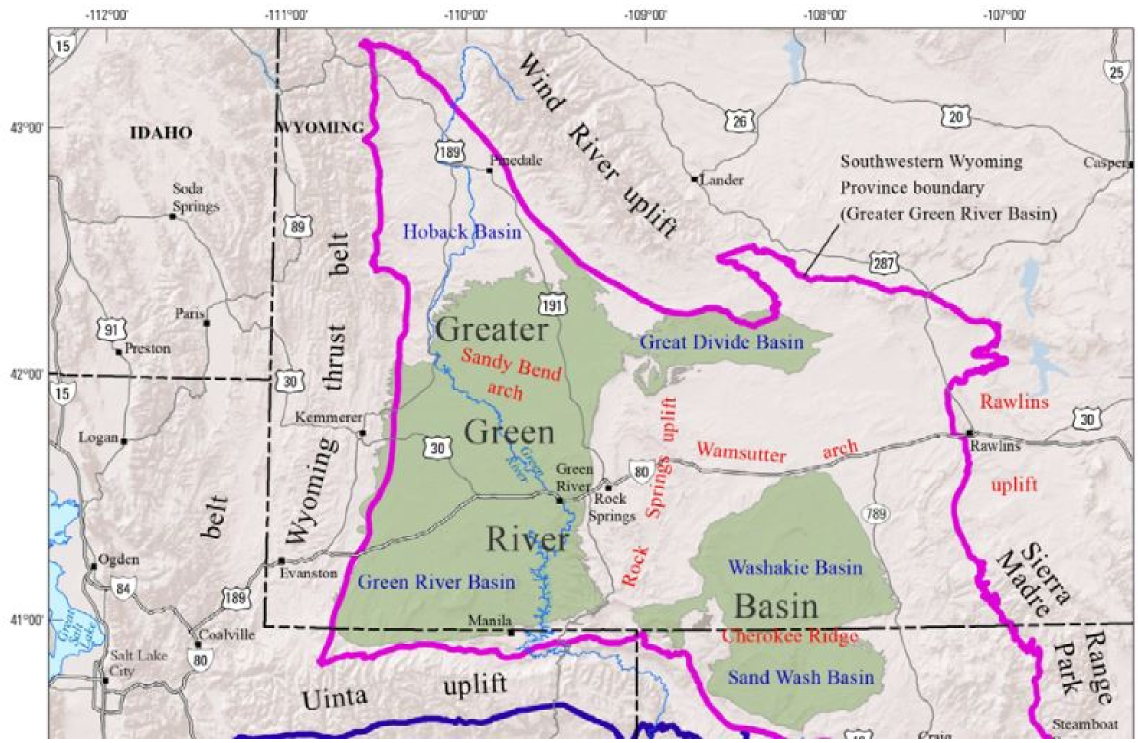

Figure 1.4: Map of the Greater Green River basin. The Greater Green River Basin is marked with a pink line. Source: `http://theenergyharbinger.files.wordpress.com/2013/04/usgs_green-river-basin.jpg`

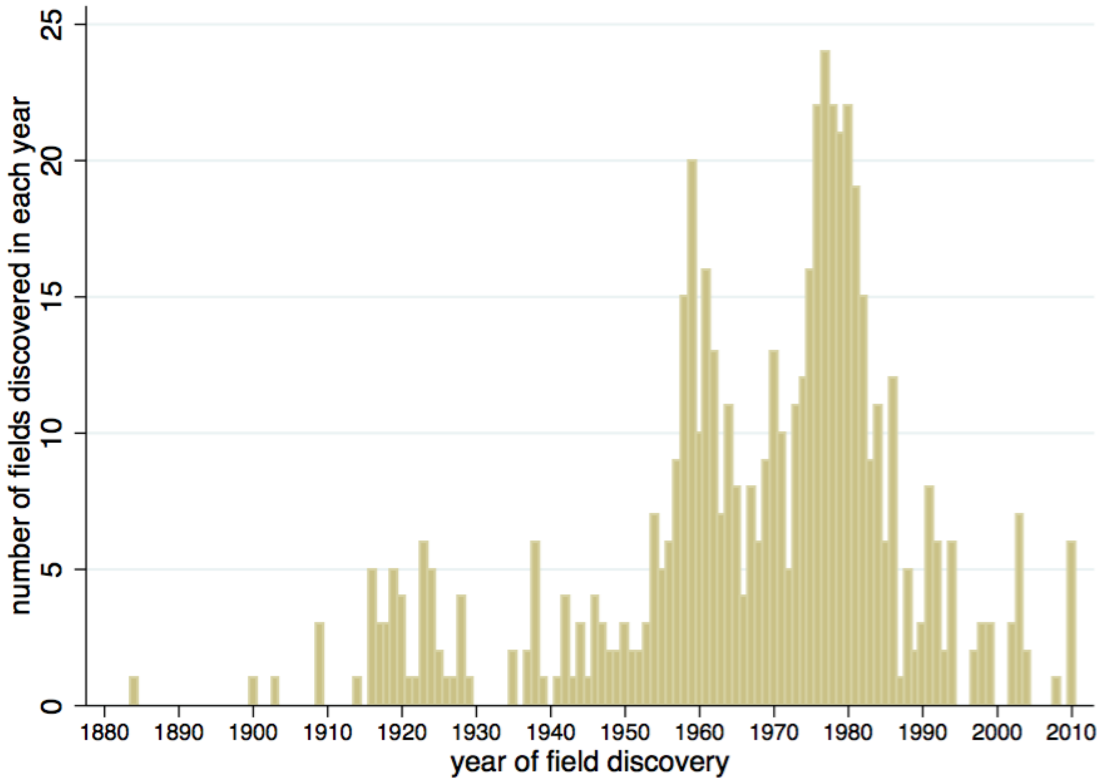

Figure 1.5: Year of field discovery for fields in Sweetwater, Sublette, Carbon, Lincoln, Uinta, Fremont, and Teton counties, which are the counties that contain the Greater Green River basin. Compiled from 2011 field master code lists. Available online at `http://www.eia.gov/naturalgas/fieldcode/`.

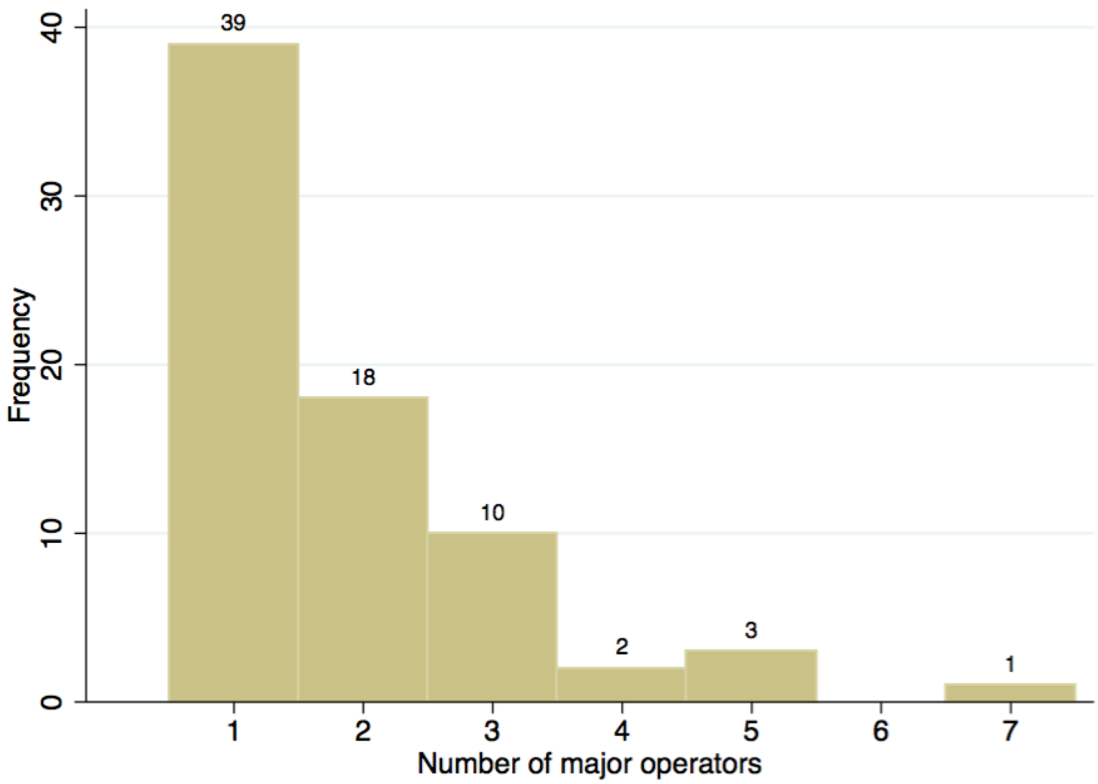

Figure 1.6: Number of major operators in 71 fields in the Greater Green River Basin. Excludes reservoirs that lie predominately under the transcontinental railroad checkerboard region.

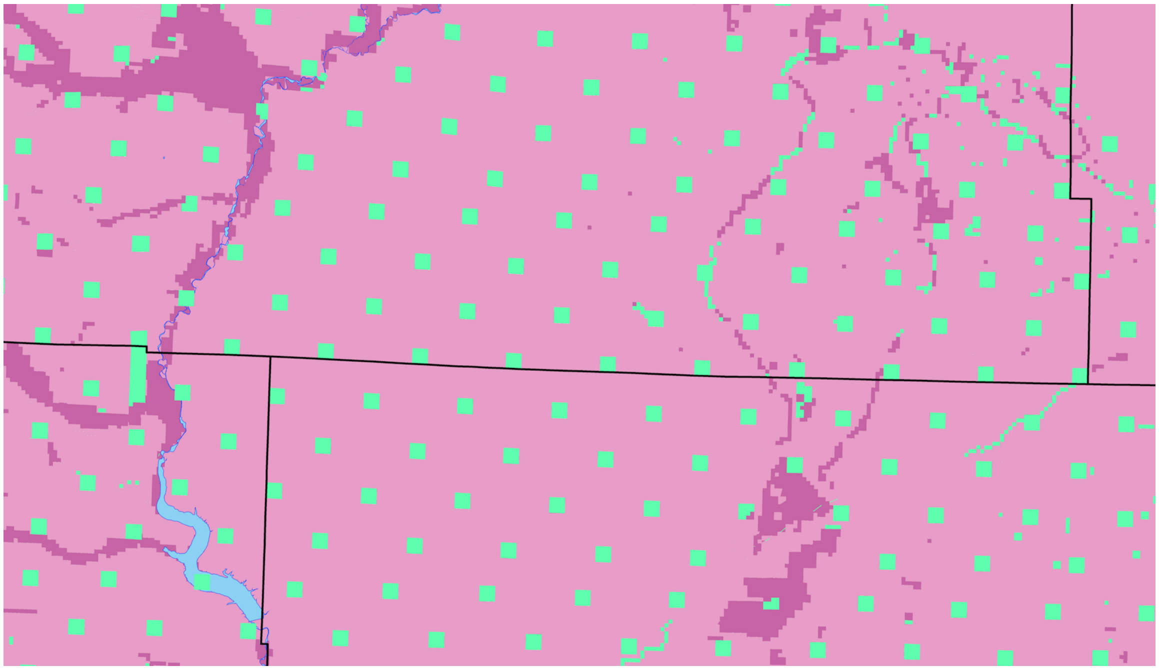

Figure 1.7: Current mineral ownership in a subset of the Greater Green River basin. Dark pink denotes private ownership, light pink denotes federal ownership, and light green denotes state ownership. The dark lines are county lines.

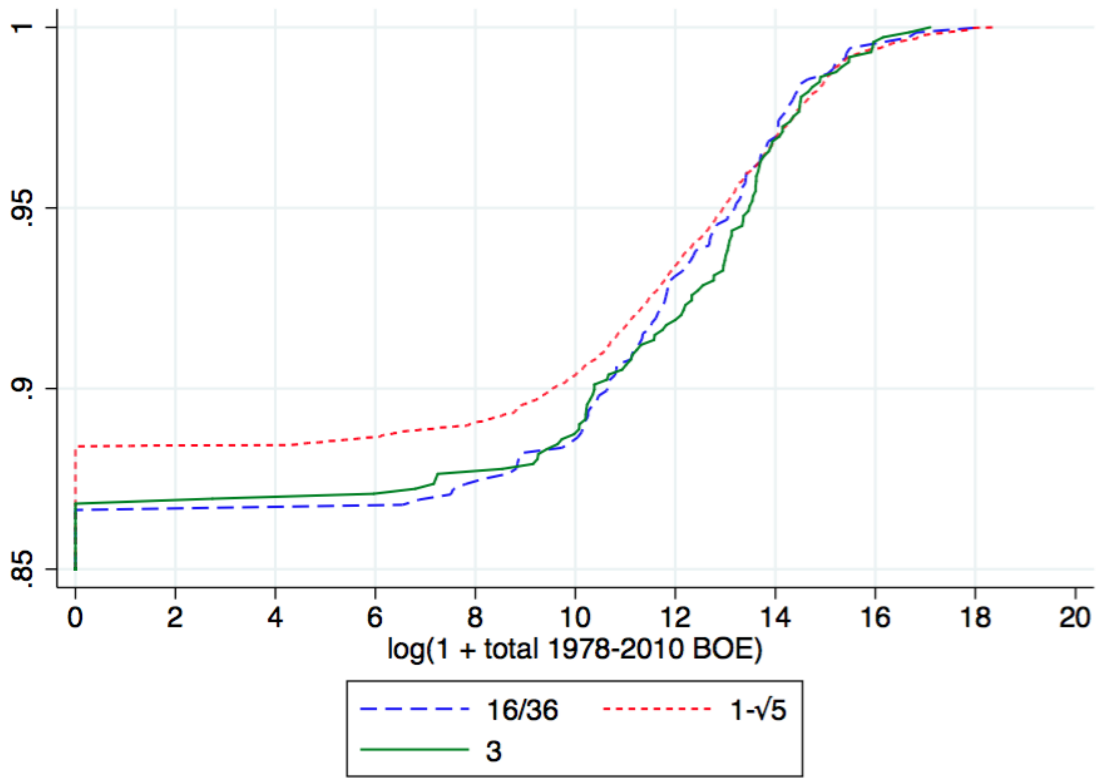

Figure 1.8: CDF of total section-level 1978-2010 BOE production, comparing 16/36, sections 1-$\sqrt{5}$ miles away, and sections 3 miles away. I do not graph the values of the cdf below 0.85.

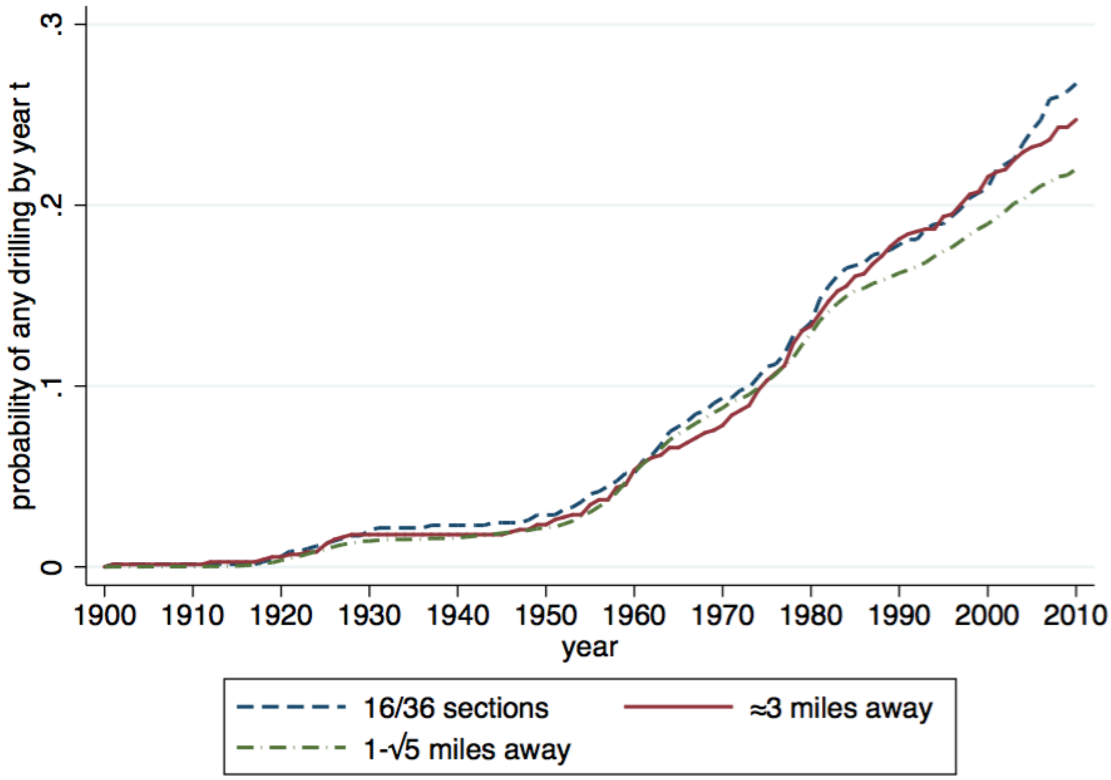

Figure 1.9: Rollout of drilling on 16/36 sections, sections ≈3 miles away, and sections that are between 1 and $\sqrt{5}$ miles away. The vertical axis measures the fraction of sections in each category that have been drilled by that date

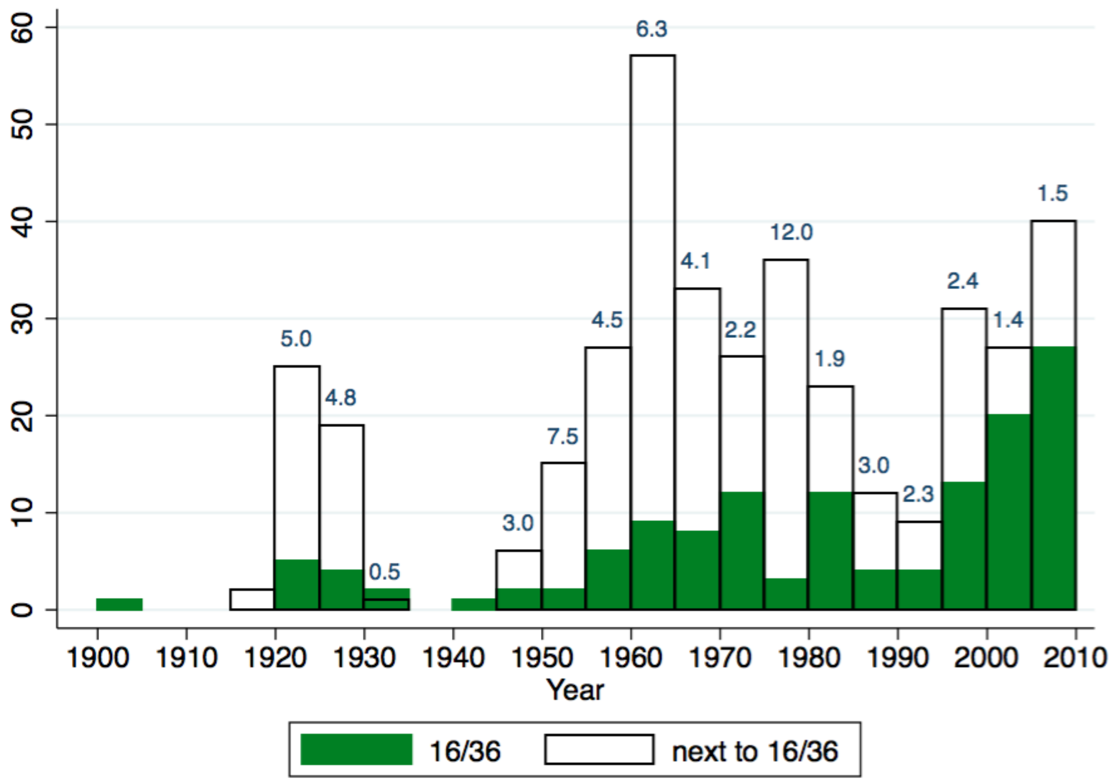

Figure 1.10: Number of wildcat wells drilled on sections numbered 16 or 36 and wells drilled on sections that are adjacent to sections numbered 16 or 36, arranged by year.

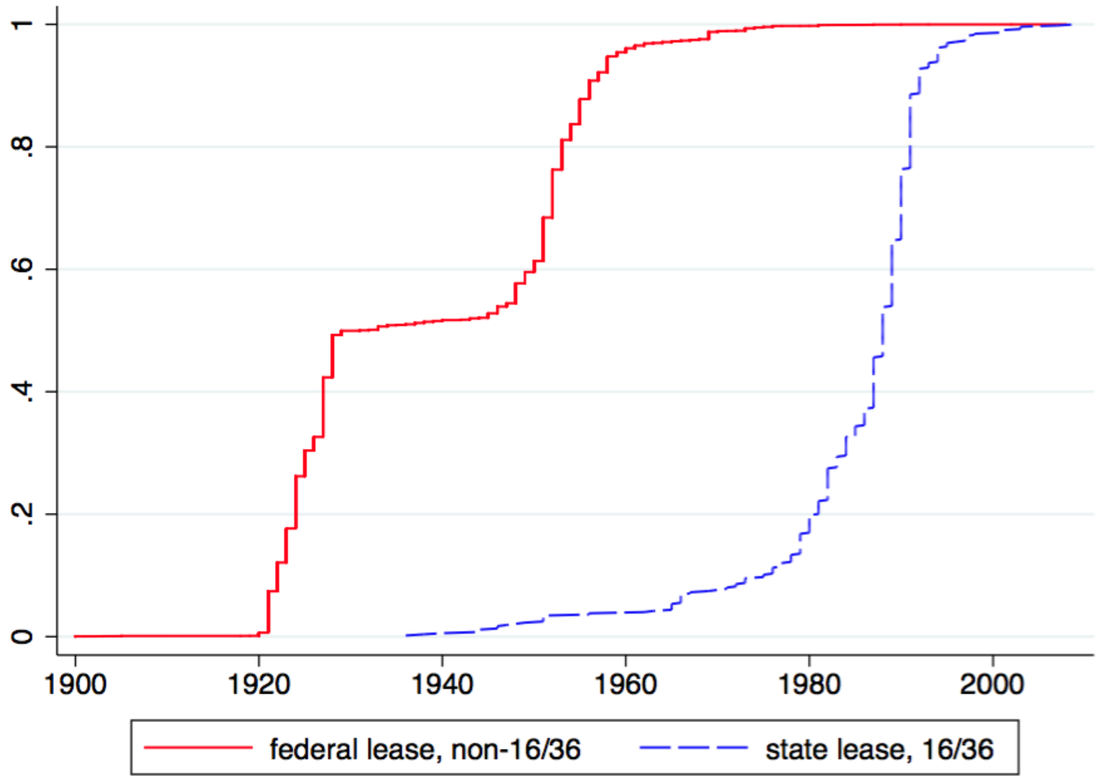

Figure 1.11: Rollout of federal leasing on non-16/36 sections (conditional on a federal lease ever being issued), as well as of state leasing on 16/36 sections (conditional on a state lease ever being issued).

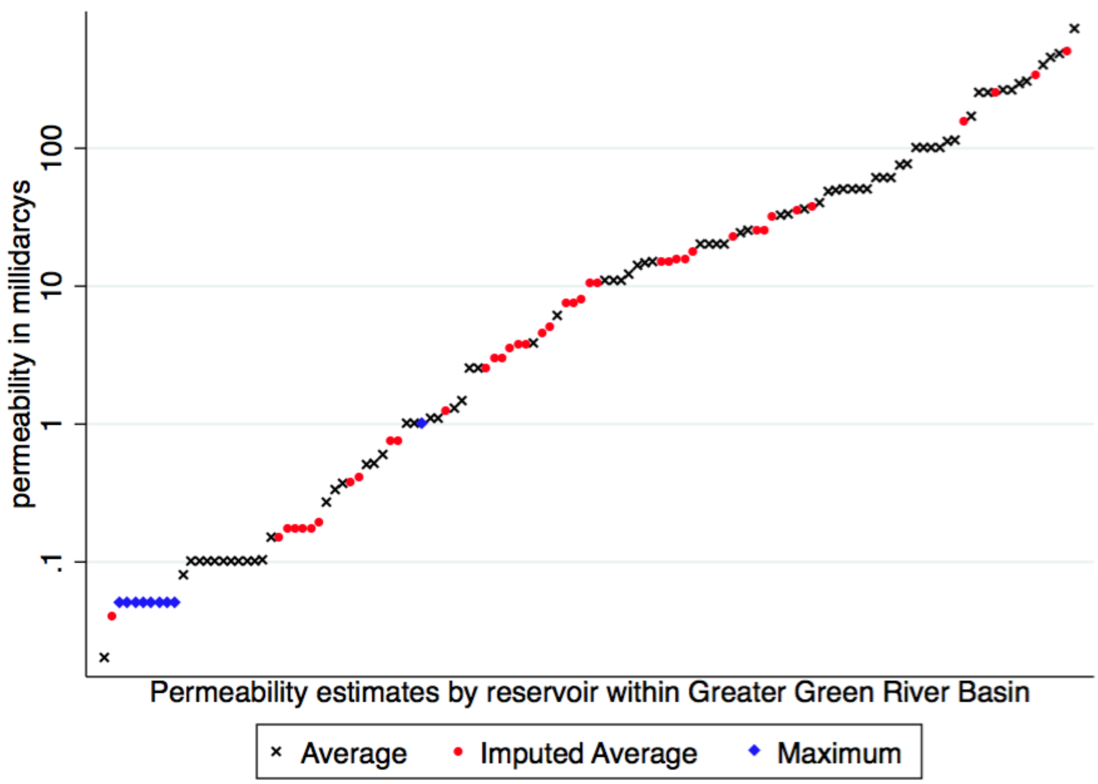

Figure 1.12: Geological estimates of permeability in reservoirs within fields in the Greater Green River Basin. Excludes reservoirs that lie predominately under the transcontinental railroad checkerboard region. This plots the average permeability if reported. If a maximum and minimum permeability is reported but not an average, this charts the mean of the maximum and minimum. In some cases only a maximum permeability is reported

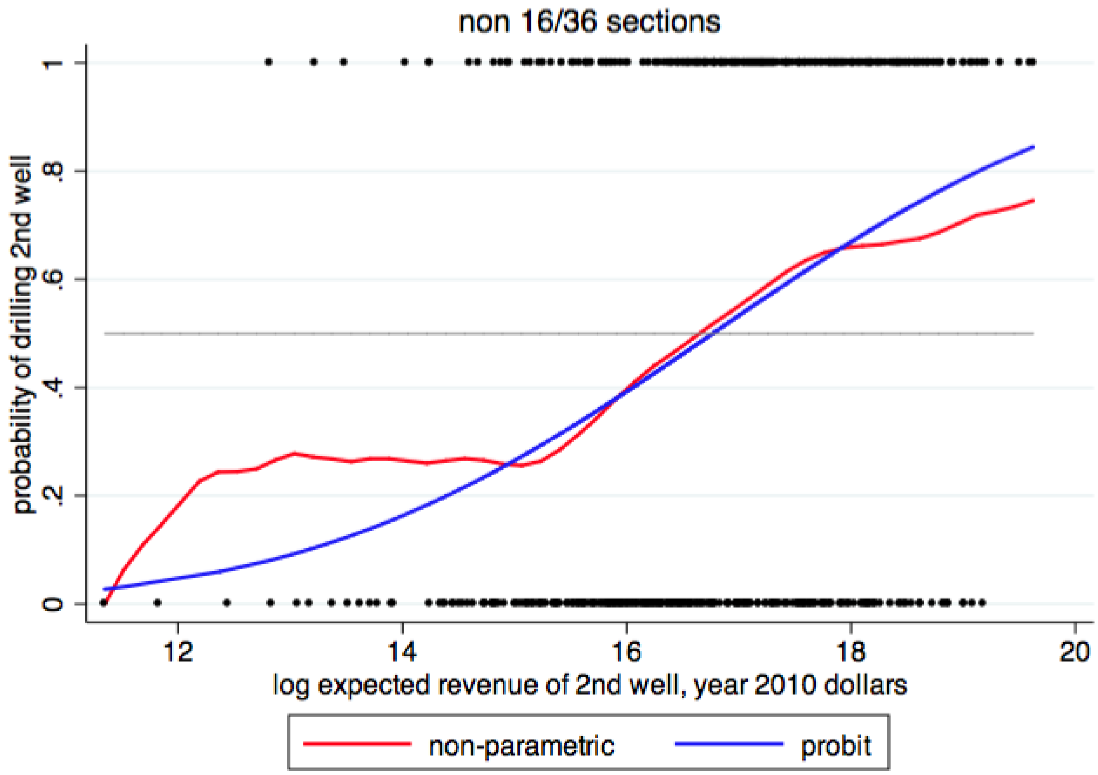

Figure 1.13: Estimates of the cdf of costs on non-16/36 sections. Probit and non-parametric regressions of whether a second well was drilled as a function of expected revenue on the second well.

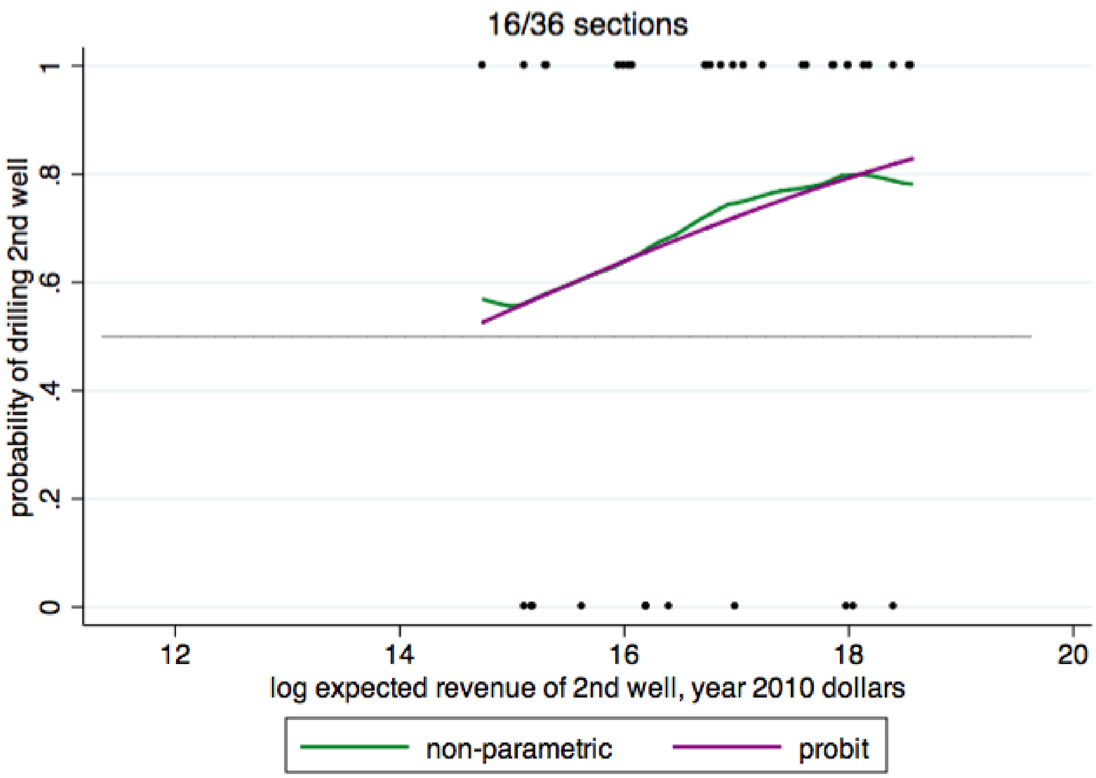

Figure 1.14: Estimates of the cdf of costs on 16/36 sections. Probit and non-parametric regressions of whether a second well was drilled as a function of expected revenue on the second well.

1.11 Appendix

In this appendix, I first present proofs of the propositions. Then I discuss some robustness results related to well-level production. Third, I discuss details of the cost estimation. Fourth, I discuss a simple case of the two plot model where regulation on federal land has no effect on the predicted number of wells drilled.

1.11.1 Proofs of the propositions in section 1.3.

I provide proofs of the propositions in section 1.3. For simplicity, I assume that if the firm drills an exploratory well, it always drills it on plot 1. This holds without loss of generality: In the state-federal case where $C_1 = C_S$ and $C_2 = C_F$, the firm strictly prefers to drill plot 1 first. In the federal-federal case where $C_1 = C_2 = C_F$, the firm is indifferent and so I assume the firm drills plot 1 first. Note that expected outcomes for a federal plot (or a federal well) will be an average of plot (or well) outcomes on both 1 and 2.

Throughout, I use the notation $F_{12}(R_1, R_2|\mu)$ for the joint cdf of R_1 and R_2, $F_1(R_1|\mu)$ to denote the marginal cdf of R_1, and $F_2(R_2|R_1, \mu)$ to denote the conditional cdf of R_2.

Propositions:

1. If $C_1 < C_2$ then $\pi_1 > \pi_2$.

   Proof. Define $X_1 = E(R_2|R_1)$ and $X_2 = E(R_1|R_2)$. Because of symmetry of beliefs, the distribution of X_1 is identical to the distribution of X_2. Therefore we can focus on $X = E(R_i|R_j)$. Re-writing the definition of π_1 by incorporating the first period cost into the integral and by using indicator functions, we have:

$$\begin{aligned}
\pi_1 &= \mu + \int\limits_X -C_1 + 1(X - C_2 \geq 0)(X - C_2)\partial F(X) \\
&= \mu + \int\limits_X -C_1 + [1(X - C_1 \geq 0) - 1(C_1 \leq X < C_2)](X - C_1 + C_1 - C_2)\partial F(X) \\
&= \pi_2 + \int\limits_X C_2 - C_1 + 1(X - C_1)(C_1 - C_2) - 1(C_1 \leq X < C_2)(X - C_2)\partial F(X) \\
&= \pi_2 + \int\limits_X 1(X - C_1 < 0)(C_2 - C_1) - 1(C_1 \leq X < C_2)(X - C_2)\partial F(X) \\
&> \pi_2
\end{aligned}$$

   $\square$

2. If $C_1 = C_2$ then $\pi_1 = \pi_2$.

Proof. If $C_1 = C_2$, then π_1 and π_2 are identical because symmetry of beliefs implies that $E(R_2|R_1 = r) = E(R_1|R_2 = r)$ for all values of r. □

3. There exists an $R_1^*(\mu, C_2)$ such that drilling only happens on plot 2 if $R_1 \geq R_1^*$.

   Proof. Expected profits on plot 2 are $E(R_2|R_1, \mu) - C_2$. Recall from the assumptions that $\partial F_2(R_2|R_1, \mu)/\partial R_1$ is strictly decreasing in R_1. This implies that $E(R_2|R_1)$ is strictly increasing in R_1. Therefore there is a value $R_1^*(\mu, C_2)$ such that $E(R_2|R_1 = R_1^*) - C_2 = 0$, and $E(R_2|R_1 = R_1^*) - C_2 > 0$ for all values of $R_1 > R_1^*$. □

4. R_1^* is increasing in C_2.

   Proof. Total differentiation of the identity $E(R_2|R_1^*(C_2, \mu), \mu) = C_2$ yields:

$$\frac{\partial R_1^*}{\partial C_2} = \left[\frac{\partial E(R_2|R_1)}{\partial R_1}\right]^{-1} > 0$$

□

5. R_1^* is decreasing in μ.

   Proof. As R_1^* is the reserves on plot 1 that make the firm indifferent between drilling plot 2 and not drilling, it satisfies the following equation:

$$\int_0^\infty R_2 f(R_2|R_1 = R_1^*(\mu, C_2), \mu)\partial R_2 = C_2 \tag{1.9}$$

   This can be re-written as:

$$\int_0^\infty (1 - F(R_2|R_1 = R_1^*(\mu, C_2), \mu))\partial R_2 = C_2 \tag{1.10}$$

   (Note: The expected value of R_2 can be written as the integral of $1 - F(R_2|R_1, \mu)$ because the bounds of integration are from zero to infinity. This holds even if there is a mass point of R_2 at zero.)

   Taking derivatives with respect to μ and re-arranging gives:

$$\frac{\partial R_1^*}{\partial \mu} = \frac{-1 + \int_0^\infty -\dfrac{\partial F(R_2|R_1, \mu)}{\partial \mu}\partial R_2}{\int_0^\infty -\dfrac{\partial F(R_2|R_1, \mu)}{\partial R_1}\partial R_2} \tag{1.11}$$

   Because $F(R_2|R_1, \mu)$ is decreasing in both R_1 and μ, this implies that $\dfrac{\partial R_1^*}{\partial \mu}$ is negative. □

6. There exists a μ^* such that the firm only drills on plot 1 if $\mu \geq \mu^*$.

   Proof. Recall that:

$$\pi_1(\mu) = \mu - C_1 + E[\max\{E(R_2|R_1, \mu) - C_2, 0\}]$$

   From the assumptions, $F(R_2|R_1, \mu)$ is strictly decreasing in μ, which means that $E(R_2|R_1, \mu)$ is strictly increasing in μ. This implies both $E[\max\{E(R_2|R_1, \mu) - C_2, 0\}]$ is weakly increasing in μ, and π_1 is strictly increasing in μ. Therefore there is a minimum $\mu^*(C_1, C_2)$ such that $\pi_1 = 0$ and for all values of $\mu > \mu^*$, $\pi_1 > 0$. □

7. μ^* is increasing in both C_1 and C_2:

   Proof. The threshold $\mu^*(C_1, C_2)$ satisfies the equation

$$\pi_1(\mu^*(C_1, C_2), C_1, C_2) = 0 \tag{1.12}$$

   Differentiating with respect to C_i, for $i \in \{1, 2\}$, and re-arranging:

$$\frac{\partial \mu^*}{\partial C_i} = -\frac{\frac{\partial \pi_1}{\partial C_i}}{\frac{\partial \pi_1}{\partial \mu}} \tag{1.13}$$

   Because π_1 is increasing in μ and decreasing in C_1 and C_2, μ^* is increasing in C_1 and C_2. □

8. The probability that a particular plot of land has an exploratory well is highest on state land, lowest on federal land next to state land, and medium for federal land that is far from state land.

   Proof. The probability of an exploratory well on state land (in the state-federal case) is:

$$1 - G(\mu^*(C_S, C_F) \tag{1.14}$$

   while the probability that the exploratory well on adjacent federal land is zero.

   The probability of an exploratory well on federal land in the federal-federal case is:

$$0.5 \cdot (1 - G(\mu^*(C_F, C_F)) \tag{1.15}$$

   This is less than the probability of exploratory drilling on state land—both because of the 0.5, as well as because $\mu^*(C_S, C_F) < \mu^*(C_F, C_F)$. □

9. The probability of ever drilling is highest on state land and lower on federal land. However it is ambiguous whether federal land close to or far from state land will have higher rates of ever drilling.

Proof. The probability of ever drilling on state land is

$$1 - G(\mu^*(C_S, C_F) \tag{1.16}$$

The probability of ever drilling on adjacent federal land (in the state-federal case) is:

$$\int_{\mu^*(C_S,C_F)}^{\infty} F_1(R_E^*|\mu)\partial G(\mu) \tag{1.17}$$

The probability of ever drilling on federal land in the federal-federal case is:

$$0.5 \cdot (1 - G(\mu^*(C_F, C_F)) + 0.5 \cdot \int_{\mu^*(C_F,C_F)}^{\infty} F_1(R|\mu)\partial G(\mu) \tag{1.18}$$

The expression in 1.16 is greater than that in 1.18 because $F_1(R_E^*|\mu) \leq 1$. The expression in 1.16 is greater than that in 1.18 both because $\mu^*(C_S, C_F) < \mu^*(C_F, C_F)$ and because conditional on $\mu \geq \mu^*(C_F, C_F)$, there is less than a 100% probability that the plot will ever be drilled.

□

10. If $0 \leq a(\mu) \leq \min\{b(\mu), c(\mu)\} \leq \max\{b(\mu), c(\mu)\} < 1$, $a(\mu) < b(\mu)c(\mu)$, $b'(\mu) \geq 0$, and $c'(\mu) \leq 0$, then:

$$\frac{\int_x^y a(\mu)\partial G(\mu)}{\int_x^y b(\mu)\partial G(\mu)} < \frac{\int_x^y c(\mu)\partial G(\mu)}{\int_x^y \partial G(\mu)} \tag{1.19}$$

Proof. Because $a(\mu) < b(\mu)c(\mu)$, we have:

$$\int_x^y a(\mu)\partial G(\mu) < \int_x^y b(\mu)c(\mu)\partial G(\mu) \tag{1.20}$$

$$\leq \left[\int_x^y b(\mu)\partial G(\mu)\right]\left[\int_x^y c(\mu)\partial G(\mu)\right] \tag{1.21}$$

$$\leq \frac{\left[\int_x^y b(\mu)\partial G(\mu)\right]\left[\int_x^y c(\mu)\partial G(\mu)\right]}{\int_x^y \partial G(\mu)} \tag{1.22}$$

where the first inequality follows by definition. The second inequality follows because $b(\mu)$ is increasing in μ while $c(\mu)$ is decreasing. As the two are negatively correlated, the expectation of the product is less than the product of the expectations (see Tao and Vu (2006), page 20 for a formal proof). Finally, the last line follows follows because $G(\mu)$ is a cdf—increasing in μ and bounded above by one and below by zero.

Note: This proof also holds if $b'(\mu) \leq 0$, and $c'(\mu) \geq 0$ ☐

11. The first well drilled will have on average lower production than the second well

Proof. The cdf of production for the first well drilled is:

$$P(R_1 < r) = \frac{\int_{\mu^*}^{\infty} F_1(r|\mu)\partial G(\mu)}{\int_{\mu^*}^{\infty} F_1(R|\mu)\partial G(\mu)} \tag{1.23}$$

while the cdf for production for the second well drilled is:

$$P(R_2 < r) = \frac{\int_{\mu^*}^{\infty} \int_{R_E^*}^{\infty} F_2(r|R_1,\mu)\partial F_1(R|\mu)\partial G(\mu)}{\int_{\mu^*}^{\infty} \int_{R_E^*}^{\infty} \partial F_1(R|\mu)\partial G(\mu)} \tag{1.24}$$

Here, we can use proposition 10 from above, where:

$$a(\mu) = \int_{R_E^*}^{\infty} F_2(r|R_1,\mu)\partial F_1(R|\mu) \tag{1.25}$$

$$b(\mu) = \int_{R_E^*}^{\infty} \partial F_1(R|\mu) = 1 - F_1(R_E^*|\mu) \tag{1.26}$$

$$c(\mu) = F_1(r|\mu) \tag{1.27}$$

and the limits of integration are $x = \mu^*$ and $y = \infty$

Because the first well will have a higher probability that $R < r$, for any r, this means that expected production for an exploratory well will be lower than expected production for a second well. ☐

12. An exploratory well on state land will have lower production than an exploratory well on federal land.

Proof. Here it is convenient to consider the log of the cdf of production on an exploratory well:

$$\log[P(R_1 < r)] = \log\left[\int_{\mu^*}^{\infty} F_1(r|\mu)\partial G(\mu)\right] - \log\left[\int_{\mu^*}^{\infty} F_1(R|\mu)\partial G(\mu)\right] \tag{1.28}$$

Taking derivatives with respect to μ^* yields:

$$\frac{\partial p(R_1 < r)}{\partial \mu^*} = g(\mu^*) \frac{\int_{\mu^*}^{\infty} [F(r|\mu) - F(r|\mu^*)] \partial G(\mu)}{\left[\int_{\mu^*}^{\infty} F(r|\mu) \partial G(\mu)\right] \left[\int_{\mu^*}^{\infty} \partial G(\mu)\right]} \tag{1.29}$$

Because $\mu > \mu^*$ implies $F(r|\mu) < F(r|\mu^*)$, the derivative is negative. If the minimum threshold for drilling is lower, the types of wells that will be drilled will have lower expected value. □

13. Expected production will be lowest for state wells and higher for federal wells. It is ambiguous whether federal wells that are close to state land will have higher or lower expected production relative to federal wells that are far from state land.

    Proof. This stems from the previous two propositions. Expected production on state wells will be lower than nearby federal wells because they tend to be drilled first. Expected production will be lower on state wells relative to federal wells that are far from state land (federal-federal case) both because federal-federal wells have a higher μ^*, and federal wells are also less likely to be the exploratory wells. □

1.11.2 Delays

In this subsection I discuss an alternate model where federal land isnt costlier to operate on but it does impose delays. In the simplest case of the model, there are three time periods, and the firm can only drill on federal land in time periods two and three. The firm discounts the future using the discount factor $\beta \leq 1$. The fixed cost for federal is equal to that on state land and is equal to C. As before, I will consider a two plot model. In one case both plots are in federal ownership. In the other case plot 1 is in state ownership whereas plot 2 is in federal ownership.

In the federal-federal case, the firm's expected profits of drilling plot 1 first are:

$$\pi_1(\mu, C, FF) = \beta(\mu - C) + \beta^2 E[\max\{E(R_2|R_1, \mu) - C, 0\}]$$

This is equal to the profits of drilling plot 2 first. While delaying drilling is costly, it does not affect the firm'minimum threshold signal $\mu^*(C, FF)$ needed to initiate exploratory drilling.

In the state-federal case, as long as $\beta < 1$, the firm prefers to drill the state plot first–if it drills at all. Profits for drilling state land first are:

$$\pi_1(\mu, C, SF) = \mu - C + \beta E[\max\{E(R_2|R_1, \mu) - C, 0\}]$$

Profits for drilling federal land first are identical to profits in the federal-federal case.

One important thing to note is that the switch from the federal-federal case to the state-federal case does not affect the minimum threshold μ^* needed to initiate drilling. As a result, revealed drilling and production outcomes will be affected by the substitution effect and the order of drilling effect, but not by the signal threshold effect. In this simplest case of the delay model, less restrictive policies will not lead to productive wells being drilled on nearby federal land that would not have been drilled if there was no nearby state land.

In the above model, delays shift order of drilling but they do not restrict the firm from operating, as there are enough time periods for the firm to drill on all plots it wants to. Importantly, the firm is never forced to drill more than one well at a time, which is sub-optimal in that drilling two wells at once does not allow the firm to use information from one of those wells to inform it whether it is worthwhile to drill the other well.

If delays become more binding, the firm will sometimes need to drill multiple wells at once, and this will also introduce the signal threshold effect. Suppose now that there are only two tim periods, and that the firm can only drill on federal land in time period 2.

In the federal-federal case, the firm has no room to learn and must drill both wells in the second time period. As the signals for both plots are identical, the firm will either drill both wells or drill none. Expected profits from drilling will be:

$$\pi_1(\mu, C, FF) = 2\mu - 2C$$

Here the minimum signal needed to drill is $\mu^* = C$.

In the state-federal case, the firm will prefer to drill state land first, and get profits:

$$\pi_1(\mu, C, SF) = \mu - C + \beta E[\max\{E(R_2|R_1, \mu) - C, 0\}]$$

Because the firm can learn, the firm does not need as high of a signal to be wiling to drill, so that $\mu^* < C$. This introduces the signal threshold effect. In this more restrictive setting, the empirical predictions as well as the ambiguity about spillover effects are identical to the model in the main section of the paper.

1.11.3 Multiple firms

In this appendix subsection I consider the case of where there are two firms, each with the right to drill on adjoining plots. I discuss a competitive game, very similar to the model of Hendricks and Kovenock (1989). I first describe the model. Then I show how this game exhibits strategic substitutes, and then show how this implies that increased costs on one plot will decrease the probability of exploratory drilling on that plot while increasing the probability of exploratory drilling on the other plot. Finally, I discuss how the empirical predictions of this model compare to the one-firm heterogeneous cost model.

1.11.3.1 Basic setup

In a given region, there are two plots of land, plot A and plot B. Firm A has the rights to drill on plot A, and firm B has the rights to drill on plot B. Each plot of land has the same quantity of oil R under it—e.g., $R_1 = R_2 = X$. However, X is unknown to the firms. Each of the firms receives a signal, s_A and s_B where $E(X|s_A) = s_A$ and $E(X|s_B) = S_B$. Each of the signals are drawn from a joint cumulative distribution function $\tilde{J}(s_A, s_B|X)$. The signals are i.i.d. where $J(s_A, s_B|x) = G(s_A|x) \cdot G(s_B|x)$ for all possible reserves x and signal s_A and s_B.

The firm constructs a posterior belief about the distribution of X conditional on the signal. The cdf of the posterior conditional on signal s_i is $H(X|s_i)$ with pdf $h(X|s_i)$. By construction, $h(\cdot)$ satisfies:

$$\int_0^\infty Xh(X|s_i)\partial X = s_i, \; \forall s_i \geq 0 \tag{1.30}$$

There are two time periods to drill. The firm discounts future profits at a rate δ. If the firm drills, it pays a fixed cost C and extracts the oil X yielding a profit $X - C$. For simplicity, I assume that all oil in the plot is extracted immediately. If the firm does not drill, it gets zero profits.

When a firm drills, it not only learns and extracts the true reserves X, it also reveals the true reserves X to the other firm. As information is hard to hide in the oil and gas industry, this seems a reasonable approximation to the truth (McKie, 1960).

Expected profits for firm i drilling in period 1 are:

$$\pi_D^i(s_i) = s_i - C$$

The expected profits to waiting are:

$$\pi_W^i(s_i) = \delta \int_C^\infty (x - C)[1 - G(s_{1j}^*|x)]\partial H(x|s_i) \tag{1.31}$$

$$+\delta \max\{0, \int_0^\infty (x - C)G(s_{1j}^*|x)\partial H(x|s_i)\} \tag{1.32}$$

The first term of this expression, on the right hand side of line 1.31, are the profits that firm i will get if firm j drills in period 1. This happens with probability $[1 - G(S_{1j}^*|X)]$. In that case, firm i only drills if $X > C$.

The second term, on line 1.32 represents what will happen if firm j does not drill in period 1, which happens with probability $G(S_{1j}^*|X)$. In that case, firm i knows that firm j had a signal less than s_{1j}^*. From there, firm i updates its beliefs about the distribution of X and decides whether it is worth drilling or not.

1.11.3.2 Assumptions

I make a number of assumptions:

Assumption 1: As in Hendricks and Kovenock (1989), I assume that $g(s_i|x)$ satisfies the monotone likelihood ratio property. This also implies that $h(x|s_i)$ satisfies the monotone likelihood ratio property, as discussed by Hendricks and Kovenock (1989). It also implies that the cdf $G(s|x)$ decreases in x and that the cdf $H(x|s)$ decreases in s.

Assumption 2: As in Hendricks and Kovenock (1989) section 5, I make the assumption that:

$$E(x|s_A, s_B) - C < \delta \max\{E(X|s_A, s_B) - C, 0\} \ \forall s_A, s_B \tag{1.33}$$

which implies that the value of information is always positive, regardless of the signal.

Assumption 3: Finally, I add an additional assumption about the posterior distribution $h(\cdot)$ that is not in Hendricks and Kovenock (1989) but is quite intuitive: I assume that the probability of getting a draw $X > s$ *decreases* as the signal s increases, while the probability of getting a high draw $X > s$ *increases* as the signal s increases:

$$\left.\frac{\partial h(x|s_i)}{\partial s_i}\right|_{x<s_i} \leq 0, \ \forall x < s_i \tag{1.34}$$

$$\left.\frac{\partial h(x|s_i)}{\partial s_i}\right|_{x>s_i} \geq 0, \ \forall x > s_i \tag{1.35}$$

1.11.3.3 Describing the equilibrium

I discuss the symmetric Nash equilibrium. Hendricks and Kovenock (1989) show that each firm has a threshold signal s^*_{1A} and s^*_{1B} respectively such that the firm will drill in the first period if its signal exceeds the threshold. This threshold is solved for by finding the level of signal such that the firm is indifferent between drilling in the first period and not drilling in the first period. The threshold signal for drilling in the first period, s^*_{1i}, is the signal s_i that sets:

$$\Phi^i(s_i) \equiv \pi^i_{1D}(s_i) - \pi^i_{1W}(s_i) = 0 \tag{1.36}$$

The first period threshold s^*_{1i} is always larger than the cost C. To see this, suppose that $s^*_{1i} < C$. In this case the expected profits for drilling in the first period are strictly negative whereas the profits to waiting are strictly positive. Therefore any signal less than cost cannot be the threshold signal. (This contrasts to the case of a single firm, where the firm can internalize the benefit of learning, and so may be willing to drill an initial exploratory well and make negative first-period profits which are compensated for as the value of information in deciding whether to drill a second well).

The threshold signal s^*_{2i} is the signal that makes the firm indifferent between drilling and not drilling in the second period, conditional on the other firm not drilling in the first. It is the signal s_i that satisfies:

$$\max\{0, \int_0^\infty (x - C)G(s_{1j}^*|x)\partial H(x|s_i)\} = 0 \tag{1.37}$$

Hendricks and Kovenock (1989) show that with the assumption in equation 1.33, that $s_{2i}^* < s_{1i}^*$. This means that for the highest signals, the firm drills in the first period; for medium signals, the firms drills in the second period; and for low signals the firm does not drill at all—unless the other firm has drilled in period 1 and found reserves greater than C.

This also implies that the second term of π_W^i, line 1.32, is strictly positive when evaluated at $s \geq s_{2i}^*$. Therefore for all values of $s > s_{2i}^*$, we can write:

$$\pi_W^i(s_i|s_i \geq s_{2i}^*) = \delta \int_C^\infty (x - C)[1 - G(s_{1j}^*|x)]\partial H(x|s_i) \tag{1.38}$$

$$+\delta \int_0^\infty (x - C)G(s_{1j}^*|x)\partial H(x|s_i) \tag{1.39}$$

This simplification means we can re-arrange terms to for $s \geq s_{2i}^*$ to re-write $\Phi(s)$ as:

$$\Phi_i(s_i|s_i \geq s_{2i}^*) = (1 - \delta)(s_i - C) + \delta \int_0^C (x - C)[1 - G(s_{1j}^*|X)]h(X|s_i)\partial X \tag{1.40}$$

1.11.3.4 Strategic Substitutes

I show that this game is a game of strategic substitutes: An increase in the threshold signal s_{1i}^* for firm i will lead to a decrease in the threshold signal s_{1j}^* for firm j.

To see this, taking total differentiation of $\Phi(s_{1i}^*(s_{1j}^*), s_{1j}^*)$ yields:

$$\frac{\partial s_{1i}^*}{\partial s_{1j}^*} = \frac{-\dfrac{\partial \Phi}{\partial s_{1j}^*}}{\dfrac{\partial \Phi}{\partial s_{1i}^*}} \tag{1.41}$$

where

$$\frac{\partial \Phi}{\partial s_{1j}^*} = -\delta \int_0^C (X - C)g(s_{1j}^*|X)h(X|s_{1i}^*)\partial X > 0 \tag{1.42}$$

and

$$\frac{\partial \Phi}{\partial s_{1i}^*} = 1 - \delta + \delta \int_0^C (X - C)[1 - G(s_{1j}^*|X)] \frac{\partial h(X|s_{1i}^*)}{\partial s_{1i}^*} \partial X > 0 \tag{1.43}$$

The signs of these derivatives are clear because for the range of integration, $X - C \leq 0$ and $\dfrac{\partial h(X|s_{1i}^*)}{\partial s_{1i}^*} < 0$. Also, $g(\cdot) \geq 0$, $h(\cdot) \geq 0$, and $1 - G(\cdot) \geq 0$. Therefore $\dfrac{\partial s_{1i}^*}{\partial s_{1j}^*} < 0$ which is the definition of strategic substitutes.

To assure stability, I assume that the best response function is not too steep, e.g., that

$$\frac{\partial s_{1i}^*}{\partial s_{1j}^*} = \frac{-\dfrac{\partial \Phi}{\partial s_{1j}^*}}{\dfrac{\partial \Phi}{\partial s_{1i}^*}} \in (-1, 0) \tag{1.44}$$

While theory does not necessarily assure that this is the case, this is a standard assumption in games of strategic substitutes (Bulow et al., 1985). It assures that the series of best responses to any strategy will converge to the Nash equilibrium strategies.

1.11.3.5 Asymmetric Costs

Because this is a game with strategic substitutes, it seems likely that if changing poliicies lead one firm to increase its first period threshold, that will lead the other firm to decrease its threshold in equilibrium. Consider one source that would shift a firm's threshold—a change in costs. Suppose that costs are potentially asymmetric—fixed cost C_i for firm i and cost C_j for firm j. I will show here that a higher cost C_i for firm i will increase the threshold signal s_{1i}^* which will in turn lead firm j to decrease its signal s_{1j}^*.

First, before solving this, it is necessary to look at how $\Phi_i(\cdot)$ responds on costs. When $s_i > s_{2i}^*$, the derivative of Φ_i with respect to C_i is:

$$\frac{\partial \Phi_i}{\partial C_i} = \delta - 1 - \delta \int_0^{C_i} (1 - G(s_{1j}^*|X)) h(X|s_{1i}^*) \partial X < 0 \tag{1.45}$$

The intuition here is that increasing costs will decrease profits of drilling immediately one-for-one. However as there is a less than 100% probability that the firm will drill in the second period conditional on not drilling in the first period, increasing costs decreases profits of drilling in the second period at a rate less than one-for-one.

Now to solve for how costs affect equilibrium strategies, I use the definition of indifference for both firm i and firm j and take total derivatives with respect to C_i.

$$\Phi_i(s_{1i}^*(C_i, C_j)), s_{1j}^*(C_i, C_j)), C_i) = 0$$

$$\Phi_j(s^*_{1i}(C_i, C_j)), s^*_{1j}(C_i, C_j)), C_j) = 0$$

This leads to a system of two equations with two unknowns—$\partial s^*_{1i}/\partial C_i$ and $\partial s^*_{1j}/\partial C_i$. Solving yields:

$$\frac{\partial s^*_{1i}}{\partial C_i} = \frac{-\dfrac{\partial \Phi_i}{\partial C_i}\dfrac{\partial \Phi_j}{\partial s^*_{1j}}}{\dfrac{\partial \Phi_i}{\partial s^*_{1i}}\dfrac{\partial \Phi_j}{\partial s^*_{1j}} - \dfrac{\partial \Phi_i}{\partial s^*_{1j}}\dfrac{\partial \Phi_j}{\partial s^*_{1i}}} > 0 \tag{1.46}$$

$$\frac{\partial s^*_{1j}}{\partial C_i} = \frac{\dfrac{\partial \Phi_i}{\partial C_i}\dfrac{\partial \Phi_j}{\partial s^*_{1i}}}{\dfrac{\partial \Phi_i}{\partial s^*_{1i}}\dfrac{\partial \Phi_j}{\partial s^*_{1j}} - \dfrac{\partial \Phi_i}{\partial s^*_{1j}}\dfrac{\partial \Phi_j}{\partial s^*_{1i}}} < 0 \tag{1.47}$$

Here, the signs of these terms are taken from signs in equations 1.42, 1.43, and 1.45, as well as the stability assumption in equation 1.44.

Therefore, increasing costs for one firm will lead the firm to increase its first period threshold signal and the other firm to decrease its first period signal. Higher costs on one plot will decrease the probability of exploratory drilling on that plot and increase the probability of exploratory drilling on nearby plots.

Shifting costs also affect second-period thresholds s^*_{2i} and s^*_{2j} although the effect is ambiguous. First consider the effect of a change in one's own costs on the second-period threshold. The payoff for drilling in the second period—conditional on neither firm drilling in the first period—is:

$$\Psi_i(s_i) = \int_0^{infty} (X - C_i)G(s^*_{1j}|X)h(X|s_i)\partial X \tag{1.48}$$

The second period threshold signal s^*_{2i} sets this equal to zero: $\Psi_i(s^*_{2i}) = 0$. Taking derivatives with respect to C_i and re-arranging gives the definition of $\partial s^*_{2i}/\partial C_i$:

$$\frac{\partial s^*_{2i}}{\partial C_i} = -\frac{\dfrac{\partial \Phi_i}{\partial s^*_{1j}}\dfrac{\partial s^*_{1j}}{\partial C_i} + \dfrac{\partial \Phi_i}{\partial C_i}}{\dfrac{\partial \Phi_i}{\partial s^*_{2i}}}] \tag{1.49}$$

The sign of this expression is ambiguous because both $\partial \Phi_i/\partial s^*_{1j}$ and $\partial \Phi_i/\partial s^*_{2i}$ are ambiguously signed.

Similarly how changes in the other firm'costs affect the second-period threshold is also ambiguous. Firm j's second period payoff function is

$$\Psi_j(s_j) = \int_0^{\infty} (X - C_j)G(s^*_{1i}|X)h(X|s_j)\partial X \tag{1.50}$$

Taking first derivatives of $\Psi_j(s^*_{2j}) = 0$ with respect to C_i gives:

$$\frac{\partial s_{2j}^*}{\partial C_i} = -\frac{\dfrac{\partial \Phi_j}{\partial s_{1i}^*}\dfrac{\partial s_{\Phi_i}^*}{\partial C_i}}{\dfrac{\partial \Phi_j}{\partial s_{2j}^*}} \tag{1.51}$$

Similarly, the signs of $\partial\Phi_j/\partial s_{1i}^*$ and $\partial\Phi_j/\partial s_{2j}^*$ are ambiguous.

1.11.3.6 Comparing the one- and two-firm asymmetric costs models

This subsection of the appendix shows that theoretical predictions with two firms are similar but not identical to that of the one-firm model. The major similarity is that in the region of state-federal ownership, exploratory drilling will be relatively more likely on state land and relatively less likely on federal land relative to the federal-federal case–where there is no low-cost state alternative.

However because we cannot characterize how the second period thresholds respond to changes in cost, we cannot determine how cost profiles will affect overall likelihood of drilling—nor can we predict how costs will affect production, neither at the section level nor at the well level.

1.11.4 Well-level production

In Table 1.8 I found that average well productivity is lowest on state land, next lowest on federal land next to state land, and highest on federal land far from state land. In this appendix subsection I discuss robustness checks:

In Table 1.12 I control for field fixed effects and date of drilling fixed effects and find very similar estimates: Column 1 shows that wells on 16/36 sections have only 63% of the BOE productivity of wells on sections 3 miles away, and wells on sections 1 mile away have 79% the productivity of wells on sections 3 miles away. Results are similar regardless of whether measuring BOE or natural gas, as well as whether using 12, 24, or 36 months of production. However oil does not show significant differences (columns 7-9), perhaps because a well produces oil or natural gas liquids tends to be much more valuable than a well that only produces natural gas such that federal costs are not high enough to prevent the development of these more lucrative wells.

As oil and gas production tends to have a long right tail, we may be concerned that production results are driven by outliers. For example, in my production data I find that the ratio of the 95th to 5th percentile of first-36 BOE production is 158. To check whether outliers are driving well productivity results, I run the same regression but excludes wells with production above the 95th percentile or below the 5th percentile (Table 1.13). I also control for field and date of drilling fixed effects. I find very similar estimates: Producing wells on 16/36 sections have 64% the productivity of producing wells 3 miles away, and producing wells on sections 1 mile from 16/36 sections have 81% the productivity of producing wells 3 miles away.

1.11.5 Cost estimation

I discuss the details of my back-of-the-envelope cost estimation. I select square mile sections where there was at least one producing well drilled on the section, and the first producing well was drilled in between 1978 and 2005. 1978 is the lower bound, both because it is the first year at which I observe well level production data and because it is approximately the time when firms began to exhibit more substitution in drilling patterns (see Figure 1.9). 2005 is the upper bound rather than later because including years that are too close to the present will lead me to assume that some plots would not have a second well, while in reality those second wells will shortly be drilled. This leads to a sample of 38 16/36 sections and 574 non-16/36 sections.

With the exception of wells that ended production by 2013, I do not observe total well production. Therefore I use a proxy–the first 3 years of well production, denoted $\tilde{R}_1$ and $\tilde{R}_2$ for the first and second well respectively. Under exponential decline, the first three years of production will be proportional to total production.

To calculate predicted three year production on the second well as a function of three year production on the first well, I regress second well gas production on first well gas (G) production for sections that had two wells, and second well oil production on first well oil (O) production for sections that had two wells:

$$\log \tilde{R}^G_{i2} = \beta^G_0 + \beta^G_1 \log \tilde{R}^G_{i1} + \epsilon^G_i$$

$$\log \tilde{R}^O_{i2} = \beta^O_0 + \beta^O_1 \log \tilde{R}^O_{i1} + \epsilon^O_i$$

I do these estimates separately for 16/36 sections and non-16/36 sections. From predicted log 3 year production, I first compute an estimated predicted three year production by computing:

$$E(\tilde{R}^G_{i2}) = \exp(\hat{\beta}^G_0 + \hat{\beta}^G_1 \log \tilde{R}^G_{i1}) \cdot E(\exp(\hat{\epsilon_i}^G))$$

$$E(\tilde{R}^O_{i2}) = \exp(\hat{\beta}^O_0 + \hat{\beta}^O_1 \log \tilde{R}^O_{i1}) \cdot E(\exp(\hat{\epsilon_i}^O))$$

The results of these regressions is available upon request and will be included in future versions of this paper.

I adjust these measures to compute total predicted production by using an estimated annual decline curve of 0.54 (see Table 1.11). I also adjust this estimate down by incorporating an estimate of the probability that a second well is dry. This gives predicted total well level oil and gas production.

To compute the value of production, I use price estimates. Crude oil prices are taken from Wyoming EIA first user crude oil price estimates. Natural gas prices are taken from EIA estimates of wellhead price. I multiple prices by total well production using only the price in the year drilled, abstracting away from issues about future expected prices. To compute prices for second wells that were not drilled, a particular challenge is not knowing what year the second well will be drilled. I assume that the second well would have been drilled in the year following the year the first well was drilled. I aggregate these measures for oil and gas to get a measure of total pre-tax revenue.

Next I subtract off taxes and royalties. I use a federal corporate income tax rate of 35%, a severance tax rate of 6%, and a county level tax of 6.2%. (County tax rates vary somewhat, but not by much; the average rate is 6.2%). I also use an estimated royalty rate of 12.5% (for federal land) for non-16/36 sections, and 15% (for state land) for 16/36 sections. This gives a measure of post-tax expected revenue.

Finally, I regress an indicator for whether a second well was drilled on log expected revenue. I do this estimate separately for 16/36 and non-16/36 sections.

$$\text{prob}(\text{2nd well drilled} = \Phi(\alpha_0 + \alpha_1 \log \text{Expected Revenue})$$

Under the probit specification, the median cost is equal to $\exp(-\hat{\alpha_0}/\hat{\alpha_1})$. To obtain asymmetric bootstrapped confidence intervals, I do 10,000 bootstrapped estimates of the probit specification.

1.11.6 Incomplete Regulation and Leakage Example

Suppose that reserves on each plot 1 and 2 can be either 1 (with probability p) or 0 (with probability $1-p$). The cost of drilling a well is C and the federal government on plot 2 imposes an additional tax T to drill. Assume that if the firm knows that there are high reserves, it is worthwhile to drill ($1 > C + T$). If there is no tax, then the firm is indifferent which plot it drills on first, and it will have expected profits:

$$p - C + p(1 - C) \tag{1.52}$$

If there is a tax, the firm places the initial exploratory well on non-federal land and gets expected profits

$$p - C + p(1 - C - T) \tag{1.53}$$

As long as equation 1.53 is positive, then equation 1.52 is also positive. Then the expected number of wells drilled in the region in both cases will be $1+p$. (Note that if p is small, then we could have cases where equation 1.53 is negative but equation 1.52 is positive, such that incomplete regulation reduces the expected number of wells.)

	(1) BOE 12	(2) BOE 24	(3) BOE 36	(4) gas 12	(5) gas 24	(6) gas 36	(7) oil 12	(8) oil 24	(9) oil 36
is 16/36	-0.46***	-0.44***	-0.44***	-0.57***	-0.56***	-0.54**	-0.10	-0.09	-0.08
	(0.12)	(0.16)	(0.16)	(0.17)	(0.20)	(0.22)	(0.14)	(0.13)	(0.13)
$\approx$ 1 mile away	-0.23***	-0.18*	-0.18*	-0.25***	-0.23**	-0.22**	-0.03	0.01	0.01
	(0.08)	(0.11)	(0.11)	(0.07)	(0.09)	(0.10)	(0.05)	(0.08)	(0.09)
$\approx \sqrt{2}$ miles away	-0.24***	-0.23**	-0.23**	-0.27***	-0.27***	-0.26**	-0.02	-0.02	-0.02
	(0.09)	(0.10)	(0.10)	(0.08)	(0.10)	(0.11)	(0.08)	(0.08)	(0.07)
$\approx$ 2 miles away	-0.18**	-0.15	-0.15	-0.14**	-0.13*	-0.12	-0.08	-0.07	-0.06
	(0.07)	(0.10)	(0.10)	(0.06)	(0.08)	(0.09)	(0.06)	(0.07)	(0.08)
$\approx \sqrt{5}$ miles away	-0.22***	-0.21**	-0.21**	-0.21***	-0.22***	-0.23**	-0.02	-0.02	-0.03
	(0.08)	(0.09)	(0.09)	(0.07)	(0.08)	(0.09)	(0.07)	(0.08)	(0.08)
R squared	0.48	0.46	0.46	0.51	0.49	0.47	0.48	0.48	0.47
Observations	7798	7798	7798	7567	7587	7619	7238	7316	7340

Table 1.12: Regressions of log total production for the first 12, 24, and 36 months of production. Results include field level fixed effects. Production measured in barrel-of-oil equivalent production (columns 1-3), natural gas (columns 4-6), and oil (columns 7-9). I use Conley standard errors with a Bartlett weight and maximum correlation distance of 20 miles.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	BOE 12	BOE 24	BOE 36	gas 12	gas 24	gas 36	oil 12	oil 24	oil 36
is 16/36	-0.44***	-0.43***	-0.42***	-0.56***	-0.56***	-0.55***	-0.09	-0.08	-0.06
	(0.10)	(0.12)	(0.13)	(0.13)	(0.15)	(0.16)	(0.15)	(0.15)	(0.14)
$\approx$ 1 mile away	-0.21**	-0.17*	-0.16	-0.26***	-0.24**	-0.23**	0.00	0.03	0.03
	(0.09)	(0.10)	(0.11)	(0.08)	(0.10)	(0.10)	(0.09)	(0.10)	(0.10)
$\approx \sqrt{2}$ miles away	-0.23**	-0.23**	-0.23**	-0.27***	-0.28***	-0.28**	0.01	0.00	0.00
	(0.09)	(0.10)	(0.11)	(0.09)	(0.11)	(0.11)	(0.10)	(0.09)	(0.09)
$\approx$ 2 miles away	-0.15*	-0.14	-0.13	-0.14**	-0.14*	-0.13	-0.06	-0.05	-0.05
	(0.08)	(0.10)	(0.10)	(0.07)	(0.08)	(0.08)	(0.07)	(0.08)	(0.08)
$\approx \sqrt{5}$ miles away	-0.20***	-0.20**	-0.20**	-0.21***	-0.23***	-0.24***	0.01	0.00	-0.01
	(0.08)	(0.08)	(0.09)	(0.07)	(0.08)	(0.09)	(0.09)	(0.08)	(0.08)
R squared	0.50	0.48	0.46	0.53	0.51	0.51	0.50	0.50	0.50
Observations	7797	7797	7797	7567	7587	7619	7237	7315	7339

Table 1.13: Regressions of log total production for the first 12, 24, and 36 months of production. Production measured in barrel-of-oil equivalent production (columns 1-3), natural gas (columns 4-6), and oil (columns 7-9). Excludes observations where production is above the 95th percentile or below the 5th percentile. Includes field and date of drilling fixed effects. I use Conley standard errors with a Bartlett weight and maximum correlation distance of 20 miles.

CHAPTER II

How Efficient are Secondary Markets? Evidence from Oil and Gas Lease Lotteries

2.1 Introduction

A fundamental assumption of much of neoclassical economics is that assets are efficiently allocated. When there is misallocation, Coase (1960) shows that markets should efficiently re-allocate assets through trade as long as transaction costs are not too large. A number of other papers explore other barriers to efficient trade, including information asymmetry (Myerson and Satterthwaite, 1983) and market power (Hahn, 1984). In this paper we test how efficiently markets correct for inefficient initial misallocation using data from the oil and gas industry.

In particular, we examine the secondary market for US Federal Government onshore oil and gas leases. From 1960 to 1987 the Bureau of Land Management (BLM) used a lottery system to allocate the rights to drill for oil and gas on government land. Because the costs to enter the lottery were low—only $10 per entry during our sample period of 1975-1978—a significant number of winners were individual who presumably lacked both industry expertise and the capital to effectively utilize their leases.[1] We hypothesize that allocating leases to such individuals was inefficient, and

[1] $10 in 1975-1978 is about $41 in 2015.

that unless secondary markets re-allocated these assets to firms, such leases won by individuals would be less likely to have drilling and production.

Our identification relies on the randomized assignment resulting from the lottery system. The random draw of the lottery assures that all entrants are equally likely to win. We exploit this randomization and compare leases won by individuals with leases won by firms. We also correct for bias resulting from endogenous entry by limiting our analysis to a subset of lotteries where the probability that a firm wins is fixed and is uncorrelated with unobservables.

We find little evidence that allocating leases to individuals leads to any efficiency loss. Relative to leases won by firms, those won by individuals are no less likely to experience drilling or production. We also divide our sample into two other groups groups—those who appear many times in our data, and those who appear relatively little. We presume that those who appear more frequently are more likely to have industry experience and therefore are more capable of utilizing leases. Similarly, we find no evidence to those that appear relatively infrequently in the data leads to any efficiency loss.

The one piece of evidence we find that misallocation has efficiency consequences is in lease length. We find that leases won by individuals were slightly more likely to be abandoned early. In contrast, firms tended to retain the leases for the full primary term of the contract. It appears that the types of leases that were abandoned early by individuals but retained longer by firms were leases with especially low expected productivity such that the efficiency loss from abandoning them early is small.

As parcels won by individuals do not have different drilling or production outcomes from firms, we hypothesize that either that secondary markets re-allocated drilling rights or that individuals were just as able as firms to manage and use their leases. We find evidence that secondary markets were quite effective in transferring drilling rights. We find that trade happens quickly—the majority of leases transferred from individual to firm are transferred within two years. We also find that it was fairly rare for individuals to retain their leases.

Overall, our research finds that at least in the oil and gas industry, secondary markets for leases are efficient. We suggest a number of potential mechanisms that facilitate efficient trade in our setting in spite of the information asymmetries that exist between buyers and sellers.

Our research complements some other papers that test the Coase theorem in other settings. Akee (2009) shows that land markets in California equilibrate quickly when restrictions on trade were lifted. In contrast, Bleakley and Ferrie (2014) find that misallocation in Georgia land markets takes more than 100 years to be corrected. We speculate that the higher rates of trade in our setting and in Akee (2009) happen because misallocation is easily observed and because the number of potential buyers is large—conditions that were unlikely to hold in the agricultural land markets of Bleakley and Ferrie (2014).

Section 2.2 discusses industry background including the lottery system and leasing rules. In section 2.3 we describe our data sources and discuss how we correct for endogeneity. Section 2.4 contains the data analysis, and section 2.5 concludes.

2.2 Industry Background

This paper focuses on the oil and gas leasing, drilling, and production activity on United States Federal Government owned land. The Bureau of Land Management (BLM), a division of the Department of the Interior, allocates leases to drill for and produce oil and gas on US federal government-owned lands. We focus our study on Wyoming, where approximately 52% of the land is owned by the federal government, and where there has been significant oil and gas production (Fairfax and Yale, 1987).

The BLM has used a variety of mechanisms to allocate leases, including lotteries. The BLM began using a lottery system in 1960 to provide an orderly and fair allocation (Bureau of Land Management, 1983). The types of leases that were allocated by lottery were those on parcels which had previously been leased, but where no oil or gas had been discovered and that were at least a mile from any known oil and gas production (Fairfax and Yale, 1987). This lottery system ended in 1987 when the BLM switched to using auctions to allocate these kinds of leases. (However, the BLM continues to use lotteries to this day for that receive no bids in the auction.)

While the specifics of how lotteries were run changed somewhat over time, we discuss the specifics of these lotteries for 1975 to 1978, the time period of our data. Lotteries were held once a month. Each month, the BLM offices for each region would compile a list of the parcels that will be offered in the lottery. Interested individuals and firms typically had about a week to submit an entry card to the regional BLM office for each parcel that they were interested in (Bureau of Land Management, 1983). The entrant also submitted a \$10 filing fee for each entry card submitted. As this entry fee was very low, it was unlikely to restrict individuals who had less industry experience and capital from entering.

The regional BLM office would then hold a drawing. Three entry cards were drawn—one for the winner, and two back ups—-which we refer to as the first-, second-, and third-place winners. The holder of the first place winning entry card had 30 days to submit a rental payment, equal to \$1 per acre, in order to secure the lease. If the first place winner did not respond with a rental payment within 30 days, the BLM contacted the second place winner with a notification that the first place winner had not responded and that the second place winner was now eligible to submit the rental payment and obtain the lease. In the case of no response, the BLM then turned to the third place back up winner. Those whose entry cards were not among the three entry cards drawn were informed of the fact by the return of their entrance cards (Bureau of Land Management, 1983).

After paying the rental fee, the newly assigned lessee was required to continue to comply with BLM leasing rules in order to retain the lease. The lessee was required to pay the rental fee of $1 per acre annually prior to any oil or gas production. After the lease began oil or gas production, the lessee paid a royalty of 12.5% on revenues from production. If the parcel leased had oil or gas production within 10 years of the lease start date, the lease continued until production ended. Otherwise, the lease expired and was returned to the BLM. The lease also ended if the lessee formally abandoned it or failed to pay rental fees (Fairfax and Yale, 1987). These expired and abandoned leases were then re-recycled to be re-offered through lottery—or via auction, if they expired after 1987.

2.3 Data

In this section we describe our data sources and give summary statistics. We also describe how we limit our analysis to a subset of the data which eliminates bias caused by endogenous entry.

2.3.1 Data Description

We compile data from BLM lease lotteries in Wyoming from January 1975 to December 1978. Lotteries were held monthly, giving us a total of 10,760 parcels offered over 48 months. The data include information on the precise boundaries of the parcels. This allows us to link these parcels with later drilling and production activity. The data include the names of the first, second, and third place winners as well as the address of the first place winner. Importantly, we use the winner's recorded name to identify whether the winner is a a firm or an individual. The data also include the total number of entry cards submitted for each parcel to be leased. In the appendix, we discuss in more detail the data sources and how we determine whether a name belongs to a firm or an individual.

We measure drilling and production activity using data from the Wyoming Oil and

Gas Conservation Commission. These data include both the date and the location for each well drilled within Wyoming, which we use to construct a measure of whether a lease ever had drilling. We also use monthly well-level production data to construct measures of productivity.[2]

Finally, we compile data on the date when leases were transferred from the BLM LR2000, an administrative database. It includes detailed information on all oil and gas leases on BLM land, including when leases were transferred, allowing us to measure how quickly markets correct for misallocation. The BLM LR2000 is somewhat limited in that early leases that expired early may not have been digitized and included in this database. However we find that approximately 95% of leases from our lottery data can be linked to the LR2000. Extending this match rate to 100% is not possible as paper records of leases and lease transfers are destroyed fifteen years after lease expiration (email exchange with Wyoming BLM public room, Feb 13, 2015).

2.3.2 Descriptive Statistics

Table 2.1 shows summary statistics about the parcels offered in the lottery. We find that the typical parcel had around 600 entries submitted, although the variance was large, with 13 entries as the 5th percentile and about 2,170 as the 95th percentile. The typical lease was about 1 square mile in area. With Wyoming well spacing rules, this would imply a maximum of about 4 natural gas wells or 16 oil wells.[3]

[2] Production data are only available starting in 1978. The fact that our first leases begin in 1975 but our first production does not appear until 1978 is potentially problematic in that a short-lived well drilled in 1975 may start and stop production before 1978. However this is extremely unlikely for two reasons. First, few parcels had drilling happen immediately as drilling requires first building infrastructure like roads as well as acquiring permits. Second, even if drilling happened within 3 years of the start date, most wells have long production lifetimes, such that we would still observe the well producing by 1978 when production data begin. For example, we find that of all wells drilled in Wyoming between 1979 and 1985, less than 10% of wells have a lifetime less than 3 years.

[3] To eliminate common pool problems, Wyoming restricts where wells can be located. Within each square mile section, land is divided into four square quarter-mile sections and further subdivided into sixteen sixteenth-of-a-square-mile squares known as quarter-quarters. Wyoming allows there to be one natural gas well per quarter, and the wells must be located at the center of the quarter. For oil wells, there can be only one well per quarter-quarter, and each well must similarly be located at the center of the quarter-quarter.

We find that firms made up a relatively small fraction of winners. Only 6% of parcels had a firm as the first place winner. Similarly, 6% of the first-, second-, and third-place winners were firms.

These leases typically had low expected productivity as they had previous leasing activity but no known oil nor gas productivity. As a result, we find that only 7% had drilling on them within 10 years of the lease start date, and only 4% had production. Even 30 years after the start of the leases, we find that only 14% had drilling and 8% had production.

2.3.3 Correcting for Endogeneity

We look for evidence of endogenous entry, where the number and type of entrants may be correlated with unobservables that also affect parcel profitability. In Table 2.2 we examine the correlations between a number of variables: We find that the total number of entries submitted for a parcel is positively correlated with both ex-ante measures of profitability (area of the lease) as well as ex-post measures (whether there was ever production on the lease). For higher expected productivity leases, individuals tend to crowd out firms—firms are the most likely to win when then number of entrants is low. As a result, firms are the least likely to win parcels that eventually had drilling or production: A naive comparison of firms with individuals that does not correct for endogenous entry would lead us to incorrectly conclude that allocating leases to firms is inefficient and that individuals are better at utilizing leases.

To correct for endogenous entry, we limit our analysis to parcels where exactly one firm was among the first-, second-, and third-place winners. Within this subset of the data, the probability that a firm is the first-place winner is fixed at one-third and therefore uncorrelated with observables and unobservables.

When we limit our analysis to this subset, we have 1,734 parcels. Table 2.3

contains summary statistics for this subsample. Parcels in this subsample tend to have fewer entrants on average (423 versus 598 in the full sample), slightly smaller acreage (0.97 square miles versus 1.11 in the full sample), and lower likelihood of eventual drilling and production.

We check for whether there is manipulation of the lottery within this sample—whether firms are more likely to be the first-place winner. Within this sample of 1,734 parcels, we find that 603 (34.8%) parcels were won by firms, larger than the 33.3% expected by random assignment. While this fraction is somewhat high, the binomial distribution predicts that there would be a 10.6% chance of observing 603 or more parcels won by firms win given that the true probability of a firm winning is one third. Therefore we cannot reject the null hypothesis that there was no manipulation that pushed firms into first place. In future work we will explore other ways of testing whether there was any other evidence of corruption in this lottery.

2.4 Analysis

We first discuss whether there is evidence that who the lease is allocated to affects drilling and production. We explore both firms versus individuals, as well as those who appear relatively more or less frequently in the winner data Then we turn to data on lease transactions to see how quickly secondary markets transferred leases.

We compare outcomes between parcels won by individuals with those won by firms, limiting our analysis to the subset where a firm appeared exactly once among the first-, second-, and third-place winners. Our empirical specification is simple:

$$Y_i = \beta_0 + \beta_1 F_i + \epsilon_i \tag{2.1}$$

Here, F_i is an indicator variable for whether the parcel was won by a firm and Y_i are a variety of outcome measures, including drilling, production, lease re-assignment, and lease end times. Throughout our analysis, we use Conley spatial standard errors, where we allow outcomes to be correlated if parcels lie within 20 miles of each other (based on chapter I).

2.4.1 Firms versus individuals: Drilling and production outcomes

For drilling and production outcomes, we identify whether the leased parcel ever experienced drilling within 1, 2, . .. 30 years after the start of the lease, and whether it had production within 3, 4, . . . 30 years of the start of the lease.[4]

Figure 2.1 contains results for the rollout of drilling. We graph the probability of any drilling by any age of the lease, for both individuals and firms, as well as the p value of the test of equality. We find that few parcels are drilled immediately after the lease starts, but that by the 10th year, about 6% of parcels experience drilling. We find no difference between leases won by individuals and those won by firms—regardless of time since the lease started. The p value of a test that the two groups are equal is typically above 0.4. The lack of difference persists up to 30 years out.

Similar results hold for production. Figure 2.2 shows the timing of production. Again, we find no statistical difference between parcels won by firms and parcels won by individuals. If anything, we find that parcels won by individuals are slightly more likely to experience production at any point in time, although the difference is not statistically significant.

We also examine drilling and production differences between firms and individuals using our entire sample. This addresses the concern that the lack of difference between firms and individuals in the small subsample is driven by a small number of observations. Using our full sample of 10,760 parcels, We examine drilling and production outcomes over time with two specifications. In the first, we do not attempt to correct for endogeneity. However In the second, we attempt to correct for endogneity

[4] We exclude production for the first few years because our lottery data begin in 1975 but our production data does not begin until 1978.

by including a linear spline in the total number of entrants. If the number of entrants is higher for parcels that have higher ex-ante expected profitability, then this is a way to correct for omitted variable bias.

In Table 2.5 contains the results for drilling, for whether there is any drilling within 3, 10, and 30 years of the start of the lease. Columns 1, 3, and 5 do not add additional controls, where as columns 2, 4, and 6 control flexibly for the number of entries. Here, consistent with Table 2.2, we find that plots won by firms are less likely to be drilled. When we flexibly control for the number of entries, however, we find no difference in the likelihood of drilling on parcels won by individuals versus parcels won by firms. Similar results hold for production, as in Table 2.5. As with drilling, we find that when we don't control for the total number of entrants, parcels won by firms are significantly less likely to experience production. However after controlling for the number of entrants, we find no statistically significant difference.

2.4.2 Sophisticated and less-sophisticated winners

Our analysis relies on the assumption that individuals who won leases typically have less experience in the oil and gas industry and less capital to utilize their leases. Anecdotally, at least some of the individuals who entered the lottery fell into this category. Fairfax and Yale (1987) report that many individuals entered the lottery using the services of middlemen as part of get-rich-quick schemes.[5] Such individuals apparently knew very little about the characteristics of the lease they won or even which parcels the middlemen had submitted entries for. The tactics of such middlemen led to a number of fraud investigations and was a major reason that the US switched in 1987 to allocate these leases using auctions rather than lotteries.

In spite of such uninformed individuals, there is also evidence that at least some individuals who entered were capable of utilizing their leases effectively. For example,

[5] Middlemen typically charged \$200 to \$500 to facilitate each application, a steep increase from the \$10 official entry fee.

we find that many people living in New Mexico with the last name of Yates won parcels—which suggests that they were tied to the Yates Petroleum Company, headquartered in New Mexico. Similarly, we find that some individuals appear to submit entries for multiple parcels and over multiple years as they appear multiple times in our data as the first-place, second-place, or third-place winner. We refer to such people as "sophisticated "participants. If sophisticated individuals are lumped with unsophisticated individuals, our measure of individuals will suffer from measurement error, which may lead us to fail to reject the null hypothesis of no difference between firms and individuals.

To check whether sophisticated participants are better at utilizing leases relative to less sophisticated participants, we divide our sample into sophisticated and unsophisticated winners. We define sophisticated winners as appearing at least 12 times among our first-, second-, and third-place winners, and less sophisticated winners as appearing fewer.[6] As with the previous firms-versus-individuals analysis, we limit our sample to the leases where there was exactly one sophisticated winner among the three winners.

Figure 2.3 shows the results for drilling. Again, we find no evidence that initial mis-allocation has any effect on driling outcomes. Similarly Figure 2.4 shows that sophisticated owners were not statistically significantly faster to begin production.

We also find that similar result hold when limiting our analysis to the subset where there are exactly two sophisticated winners among the three. Drilling results are in figure 2.5 and production results are in figure 2.5. Again, we find no statistically significant difference. In this case, point estimates suggest that unsophisticated winners are faster to drill and produce.

These results are robust to a variety of ways of defining sophisticated winners. Tables 2.6 and 2.7 examine the probability that drilling happens within 3 and 10

[6]We use 12 as the cutoff because we find that approximately 50% of leases were won by winners who appear 12 or more times in the data.

years from the start of the lease. Similarly, Tables 2.8 and 2.9 examine the probability that production happens within 3 and 10 years from the start of the lease. I use a variety of definitions of sophisticated—including whether winners appear at least twice, at least six times, at least twelve times, and at least seventeen times in the data. We examine drilling and production outcomes within three and ten years. And we include two different types of samples–either where one of the three winners was sophisticated or where two of the three winners was sophisticated. This leads to 32 different specifications, where in only one regression is the difference between the groups statistically significant at the 5% level.[7]

Overall we find that regardless of how we cut the data, there are no significant differences in drilling and production outcomes, suggesting either that secondary markets work or that there is no misallocation. We next turn to administrative data about lease transfers for evidence on how well secondary markets work.

2.4.3 Lease transactions

We link records from the lottery to records of oil and gas leases in the BLM LR2000, an administrative database. This database includes information on lease transfer dates and dates when leases ended.

One concern with the LR2000 is that the digitization of lease records appears to not have started until the late 1980's, and so it is possible that many of our leases, especially those that were abandoned, would not appear in the data. However we are able to find 95% of our lottery leases within the LR2000. Importantly, we find using our subset that whether a lease cannot be matched to the LR2000 is not statistically different between firms and individuals (Table 2.10, column 1). We presume that leases that do not appear in the LR2000 are most likely to have expired early, although

[7]For this specification, in the first column and row of table 2.8, those who appear in the data at least 2 times are less likely to begin production within three years relative to those who only appear in the data once. This suggests that if anything, less sophisticated winners are better at utilizing their leases.

there may be other reasons why they cannot be matched.

To examine how ownership affects lease length, we compute the amount of time between lease start and the end of the lease. Leases that do not appear in the LR2000 or that ended prior to 10 years were typically abandoned. Leases that lasted 10 years typically ended because the lessee failed to drill and begin producing oil or gas. Leases that lasted longer than 10 years typically were productive, although it was sometimes possible for lessees to negotiate longer leases in some cases even without production.

Again, we limit the analysis to cases where exactly one firm was among the three winners, and compare cases where an individual was the first place winner (Figure 2.7) versus cases where the firm was the first place winner (Figure 2.8). Regression results are in Table 2.10.

If markets are efficient at transferring leases, initial assignment should have no effect on lease length. We find in Table 2.10 that this mostly appears to be the case. We do find that individuals seem to be slightly more likely to abandon the leases before the 10 year deadline–approximately 16% of leases won by individuals were abandoned early, whereas firms abandoned only about 12% of them. This difference is nearly offset by the probability of keeping leases for 10 years: Firms were 2.7 percentage points more likely to keep leases exactly 10 years relative to individuals, though this difference is not statistically significant. We find that leases won by individuals versus by firms were similarly likely to extend more than 10 years.

We also test the extent to which secondary markets facilitated the transfer of leases: We compute the amount of time from the start of the lease until the lease is transferred. Limiting our analysis to our unbiased subset, we create histograms of the time until lease transfer for the case where an individual was the first place winner (Figure 2.9) versus cases where the firm was the first place winner (Figure 2.10). Comparisons using regressions are in Table 2.11.

We find here that lease transfers were an important mechanism to develop productive leases. About 44 percent of leases won by individuals were transferred within 0 or 1 years of the start of the lease. In contrast, firms were much less likely to transfer leases early on—this happened only 19% of the time. Instead, firms are the most likely to hold on to the lease without any transfers—firms did this 42% of the time, whereas individuals only did this 20% of the time. This suggests that the secondary market was an important mechanism to correct for misallocation. Not only were a large fraction of leases transferred from individuals to firms, but there was also a significant amount of firm to firm transfer.

2.5 Discussion and Conclusion

Overall we find evidence of both initial misallocation as well as efficient secondary markets. We do see some evidence of misallocation—that leases won by individuals are more likely to abandoned early. However we also see that many individuals quickly transfer leases to firms. As a result, leases won by individuals have very similar drilling and production outcomes to leases won by firms.

We suggest two possible mechanisms which facilitated trade in this setting. One mechanism is low search costs: The BLM maintains an open records office where anyone can easily look up the name and contact information of current lessees. Low search costs also increase the number of potential buyers who might contact a lessee. More potential buyers may increase buyer willingness to sell both through raising the price via competition, as well as by giving the individual more signals about the expected value of the lease.

A second mechanism that likely facilitated trade is the fact that misallocation is easily observed. When firms visit the BLM open records office, it is easy to determine whether a current lessee is an oil and gas firm or an individual. Firms were very aware that many individuals entered the lotteries hoping to strike it rich, which presumably they could only do if they transferred their lease to a firm. In these cases, the individual's valuation of the lease in the absence of transfer was likely very low, and possibly negative, as the lease required paying annual rental fees. In contrast, firms typically had positive valuations. Myerson and Satterthwaite (1983) show that when the range of typical seller valuations does not overlap with the range of typical buyer valuations, efficient trade can occur that is both individually rational and incentive compatible—even though buyers and sellers still have uncertainty about each other's valuations.

These two mechanisms highlight reasons why Akee (2009) finds that the Coase theorem holds in land markets in California but that Bleakley and Ferrie (2014) finds that agricultural land markets are slow to adjust. In Akee (2009), removing restrictions on land use in a residential area led to fast increases in land value and land use. This is likely both because the sites that previously had restrictions were easily observed and also because there were potentially many entrants who were interested in developing this land.

I contrast, these two conditions were likely not satisfied in the agricultural setting of Bleakley and Ferrie (2014). There it was very difficult for a farmer to observe whether he or his neighbor valued his farm more. Furthermore, the number of buyers who had valuations greater than the farmer's valuation was likely small: Economies of scale with respect to land mean that the set of potential buyers would be limited to those who are neighbors.

This research suggests two avenues of further research. The first is examining the welfare impact of the lottery system versus the auction system that replaced it. While the lottery led to misallocation, secondary markets corrected it. In contrast, auctions do a better job at allocating assets to the buyer with the highest valuation. However a drawback is that auctions may reduce competition, where larger firms with higher valuations continue to win leases while small firms are more likely to exit the industry if they cannot win leases. In a similar vein, we also hope to research the effect of winning on future individual and firm outcomes, exploring how winning may lead individuals to start firms and allow small firms to expand. These types of questions are important in policy, as governments almost exclusively use auctions to allocate contracts and goods. Auctions allocate the good to the highest bidder and maximize revenue Myerson (1981). However as long as secondary markets are efficient, lotteries may be preferable if they encourage increased competition in the long run.

2.6 Tables

	mean	st.dev.	median	5th perc	95th perc
Number of entries	598.14	824.32	271.00	13.00	2170.50
Area in square miles	1.11	1.09	0.75	0.06	3.66
Number of firms among winners	0.18	0.41	0.00	0.00	1.00
Firm is first place winner	0.06	0.24	0.00	0.00	1.00
Any drilling within 2 years	0.02	0.14	0.00	0.00	0.00
Any drilling within 10 years	0.07	0.26	0.00	0.00	1.00
Any drilling within 30 years	0.14	0.35	0.00	0.00	1.00
Any production within 2 years	0.01	0.10	0.00	0.00	0.00
Any production within 10 years	0.04	0.19	0.00	0.00	0.00
Any production within 30 years	0.08	0.28	0.00	0.00	1.00

Table 2.1:]
Summary statistics at the parcel level. Total number of parcels is 10,760.

	1	2	3	4	5	6
1: Number of entries	1.00					
2: Area	0.41	1.00				
3: Drilling within 10 years	0.20	0.07	1.00			
4: Production within 10 years	0.19	0.04	0.71	1.00		
5: # of winning firms	-0.10	-0.06	-0.02	-0.02	1.00	
6: firm is 1st place winner	-0.06	-0.04	-0.02	-0.02	0.58	1.00

Table 2.2: Correlations between selected variables. Unrestricted sample, N=10,760.

	mean	st.dev.	median	5th perc	95th perc
Number of entries	423.33	633.35	150.00	10.00	1606.00
Area in square miles	0.97	1.05	0.50	0.06	3.56
Number of firms among winners	1.00	0.00	1.00	1.00	1.00
Firm is first place winner	0.35	0.48	0.00	0.00	1.00
Any drilling within 2 years	0.01	0.11	0.00	0.00	0.00
Any drilling within 10 years	0.06	0.24	0.00	0.00	1.00
Any drilling within 30 years	0.12	0.32	0.00	0.00	1.00
Any production within 2 years	0.01	0.08	0.00	0.00	0.00
Any production within 10 years	0.03	0.17	0.00	0.00	0.00
Any production within 30 years	0.06	0.25	0.00	0.00	1.00

Table 2.3: Summary statistics at the parcel level. Sample restricted to the subset where there is exactly one firm among the first-, second-, and third-place winners. Total number of parcels is 1,734.

	(1)	(2)	(3)	(4)	(5)	(6)
	3	3	10	10	30	30
Firm in 1st place	-0.011	-0.004	-0.018*	-0.003	-0.030**	-0.001
	(0.007)	(0.006)	(0.010)	(0.009)	(0.015)	(0.013)
intercept	0.029***	0.004*	0.076***	0.019***	0.141***	0.024***
	(0.005)	(0.002)	(0.012)	(0.005)	(0.019)	(0.006)
spline in number of entries	No	Yes	No	Yes	No	Yes
R squared	0.000	0.030	0.000	0.043	0.000	0.091
Observations	10760	10760	10760	10760	10760	10760

Table 2.4: Regressions of whether drilling ever happened on a given parcel within 3, 3, 10, 10, 30, and 30 years respectively, comparing parcels where a firm was the winner with parcels where an individual was a winner. Columns 2, 4, and 6 include a linear spline in the total number of entries. Inference uses Conley spatial standard errors.

	(1)	(2)	(3)	(4)	(5)	(6)
	3	3	10	10	30	30
Firm in 1st place	-0.008**	-0.003	-0.018***	-0.008	-0.026**	-0.004
	(0.004)	(0.003)	(0.007)	(0.006)	(0.012)	(0.010)
intercept	0.016***	-0.000	0.040***	0.003**	0.085***	0.003
	(0.003)	(0.001)	(0.007)	(0.002)	(0.016)	(0.002)
spline in number of entries	No	Yes	No	Yes	No	Yes
R squared	0.000	0.029	0.001	0.041	0.001	0.083
Observations	10760	10760	10760	10760	10760	10760

Table 2.5: Regressions of whether production ever happened on a given parcel within 3, 3, 10, 10, 30, and 30 years respectively, comparing parcels where a firm was the winner with parcels where an individual was a winner. Columns 2, 4, and 6 include a linear spline in the total number of entries. Inference uses Conley spatial standard errors.

A	2+ times	6+ times	12+ times	17+ times
"Sophisticated" winner	-0.020	-0.012	-0.006	-0.006
	(0.013)	(0.008)	(0.007)	(0.005)
intercept	0.074***	0.046***	0.036***	0.028***
	(0.015)	(0.008)	(0.006)	(0.005)
R squared	0.001	0.001	0.000	0.000
Observations	889	2488	3287	3572

A: Drilling within 3 years, exactly one sophisticated winner among three

B	2+ times	6+ times	12+ times	17+ times
"Sophisticated" winner	0.005	-0.004	-0.003	-0.001
	(0.005)	(0.005)	(0.005)	(0.005)
intercept	0.030***	0.023***	0.018***	0.012***
	(0.005)	(0.005)	(0.004)	(0.004)
R squared	0.000	0.000	0.000	0.000
Observations	3023	3817	3486	2980

B: Drilling within 3 years, exactly two sophisticated winners among three

Table 2.6: Regressions of any drilling within 3 years as a function of whether the winner is "sophisticated". Sophisticated winners are defined as whether they appear in the data 2 or more times (first column), 6 or more times (second column), 12 or more times (third column), or 4 or more times. Row A limits the sample to cases where one sophisticated winner was among the first-, second-, and third-place winners. Row B limits the sample to cases where there were two sophisticated winners among the first-, second-, and third-place winners.

C	2+ times	6+ times	12+ times	17+ times
"Sophisticated" winner	0.001	-0.010	-0.005	0.002
	(0.017)	(0.011)	(0.009)	(0.008)
intercept	0.140***	0.107***	0.095***	0.081***
	(0.026)	(0.016)	(0.015)	(0.014)
R squared	0.000	0.000	0.000	0.000
Observations	889	2488	3287	3572

C: Drilling within 10 years, exactly one sophisticated winner among three

D	2+ times	6+ times	12+ times	17+ times
"Sophisticated" winner	0.011	0.003	-0.005	-0.005
	(0.010)	(0.009)	(0.009)	(0.007)
intercept	0.078***	0.060***	0.053***	0.047***
	(0.014)	(0.014)	(0.011)	(0.009)
R squared	0.000	0.000	0.000	0.000
Observations	3023	3817	3486	2980

D: Drilling within 10 years, exactly two sophisticated winners among three

Table 2.7: Regressions of any drilling within 10 years as a function of whether the winner is "sophisticated". Sophisticated winners are defined as whether they appear in the data 2 or more times (first column), 6 or more times (second column), 12 or more times (third column), or 4 or more times. Row C limits the sample to cases where one sophisticated winner was among the first-, second-, and third-place winners. Row D limits the sample to cases where there were two sophisticated winners among the first-, second-, and third-place winners.

A	2+ times	6+ times	12+ times	17+ times
"Sophisticated" winner	-0.017**	-0.004	0.000	0.001
	(0.008)	(0.006)	(0.006)	(0.004)
intercept	0.046***	0.023***	0.020***	0.015***
	(0.011)	(0.005)	(0.005)	(0.004)
R squared	0.002	0.000	0.000	0.000
Observations	889	2488	3287	3572

A: Production within 3 years, exactly one sophisticated winner among three

B	2+ times	6+ times	12+ times	17+ times
"Sophisticated" winner	0.006	0.002	0.001	0.002
	(0.005)	(0.002)	(0.003)	(0.003)
intercept	0.015***	0.010***	0.007**	0.003*
	(0.005)	(0.003)	(0.003)	(0.002)
R squared	0.000	0.000	0.000	0.000
Observations	3023	3817	3486	2980

B: Production within 3 years, exactly two sophisticated winners among three

Table 2.8: Regressions of any production within 3 years as a function of whether the winner is "sophisticated". Sophisticated winners are defined as whether they appear in the data 2 or more times (first column), 6 or more times (second column), 12 or more times (third column), or 4 or more times. Row A limits the sample to cases where one sophisticated winner was among the first-, second-, and third-place winners. Row B limits the sample to cases where there were two sophisticated winners among the first-, second-, and third-place winners.

C	2+ times	6+ times	12+ times	17+ times
"Sophisticated" winner	0.011	-0.004	0.006	0.010
	(0.018)	(0.010)	(0.009)	(0.008)
intercept	0.074***	0.056***	0.052***	0.041***
	(0.017)	(0.010)	(0.010)	(0.009)
R squared	0.000	0.000	0.000	0.001
Observations	889	2488	3287	3572

C: Production within 10 years, exactly one sophisticated winner among three

D	2+ times	6+ times	12+ times	17+ times
"Sophisticated" winner	0.011*	0.007	-0.001	-0.007
	(0.007)	(0.006)	(0.006)	(0.005)
intercept	0.040***	0.031***	0.025***	0.024***
	(0.010)	(0.009)	(0.007)	(0.006)
R squared	0.001	0.000	0.000	0.001
Observations	3023	3817	3486	2980

D: Production within 10 years, exactly two sophisticated winners among three

Table 2.9: Regressions of any production within 10 years as a function of whether the winner is "sophisticated". Sophisticated winners are defined as whether they appear in the data 2 or more times (first column), 6 or more times (second column), 12 or more times (third column), or 4 or more times. Row C limits the sample to cases where one sophisticated winner was among the first-, second-, and third-place winners. Row D limits the sample to cases where there were two sophisticated winners among the first-, second-, and third-place winners.

	(1)	(2)	(3)	(4)
	Not in LR2000	Lease<10 years	Lease=10 years	Lease>10 years
Firm in 1st place	0.009	-0.039**	0.027	0.003
	(0.013)	(0.018)	(0.025)	(0.015)
intercept	0.056***	0.162***	0.663***	0.119***
	(0.010)	(0.018)	(0.021)	(0.014)
R squared	0.000	0.003	0.001	0.000
Observations	1735	1735	1735	1735

Sample of lease with exactly one firm among the three winners

Table 2.10: Regressions for the subsample where there was exactly one firm among the three winners, and comparing cases where the firm was the first place winner versus not. The first column dependent variable is whether the lease appears in the LR2000. The second through fourth are for cases where the lease can be found in the LR2000. The second is an indicator that the lease lasted less than 10 years, the third is an indicator that the lease lasted 10 years, and the fourth is an indicator that the lease lasted more than 10 years.

	(1)	(2)	(3)	(4)
	0-1 years	2-10 years	11+ years	Never transferred
Firm in 1st place	-0.253***	0.013	0.014***	0.218***
	(0.018)	(0.021)	(0.005)	(0.021)
intercept	0.442***	0.295***	0.004**	0.202***
	(0.023)	(0.014)	(0.002)	(0.014)
R squared	0.064	0.000	0.005	0.054
Observations	1735	1735	1735	1735

Sample of lease with exactly one firm among the three winners

Table 2.11: Regressions for the subsample where there was exactly one firm among the three winners, and comparing cases where the firm was the first place winner versus not. The first column dependent variable is whether the lease was transferred within 0-1 years of the start. The second column variable is whether it was transferred within 2-10 years. The third column is whether it was transferred more than 10 years after start date. And the fourth column is an indicator for whether it never was transferred. For each of these dependent variables, leases that do not appear in the LR2000 take on the value of zero.

2.7 Figures

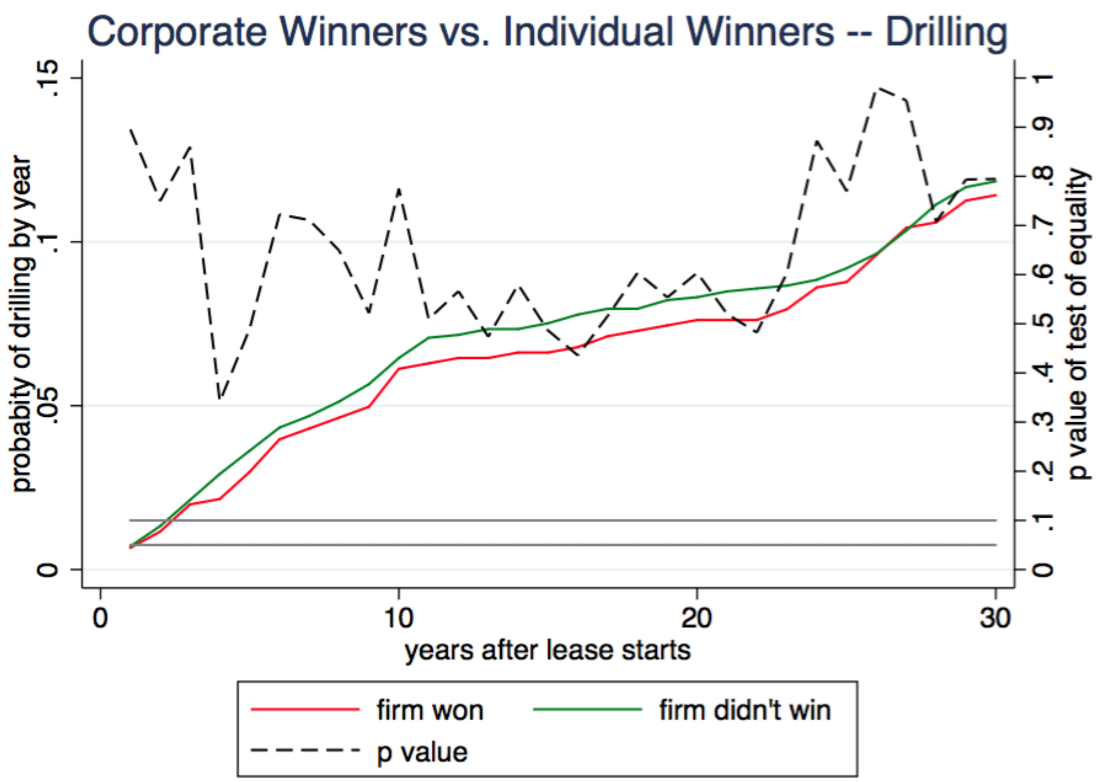

Figure 2.1: The probability of drilling within X years of lease signing, for X ranging from 1 year to 30. Graph compares probabilities for leases won by individuals with leases won by firms. The sample size 1,743. The right vertical axis gives the p value of a test that the two means are not equal.

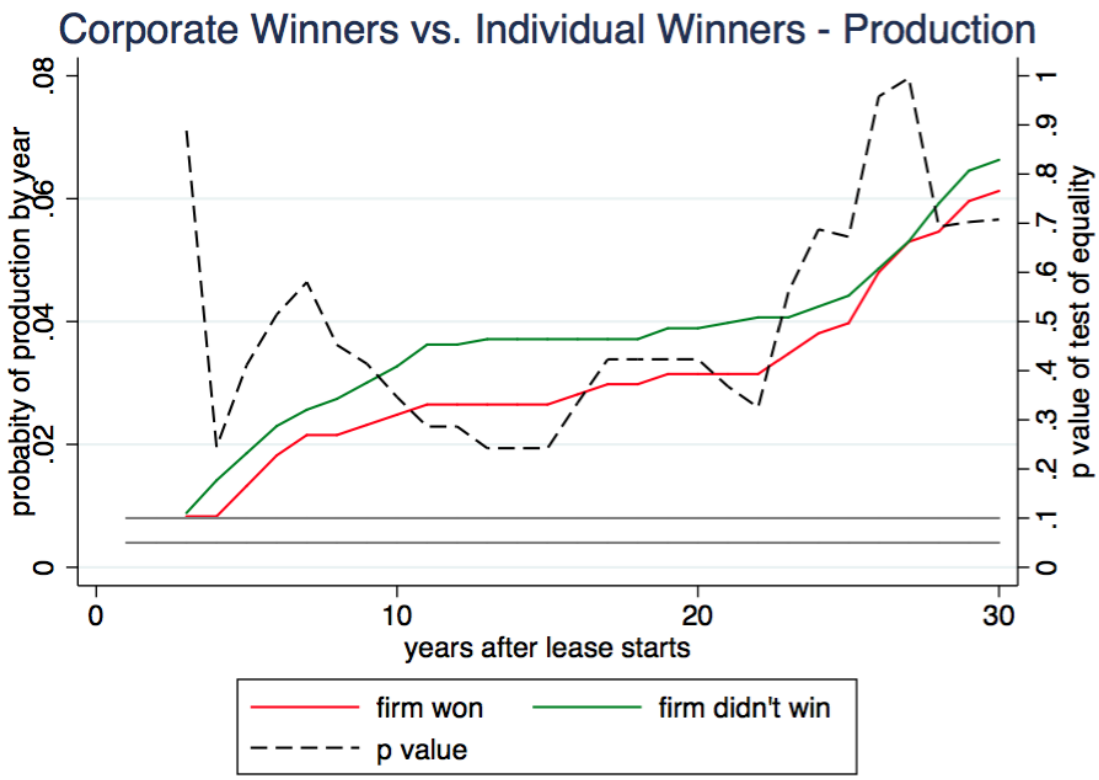

Figure 2.2: The probability of production within X years of lease signing, for X ranging from 1 year to 30. Graph compares probabilities for leases won by individuals with leases won by firms. The sample size 1,743. The right vertical axis gives the p value of a test that the two means are not equal.

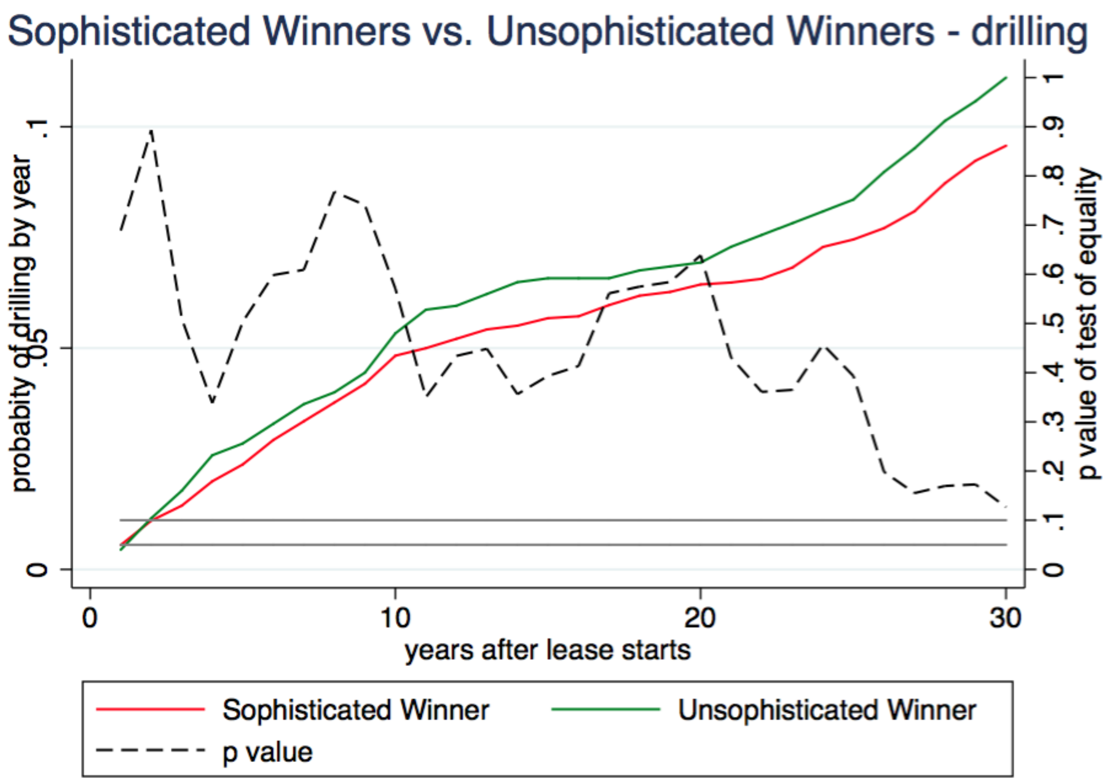

Figure 2.3: Comparing drilling outcomes on parcels won by “sophisticated ”individuals versus those won by “unsophisticated winners ”. Sample limited to cases where exactly one sophisticated winner appeared among the first-, second-, and third-place winners.

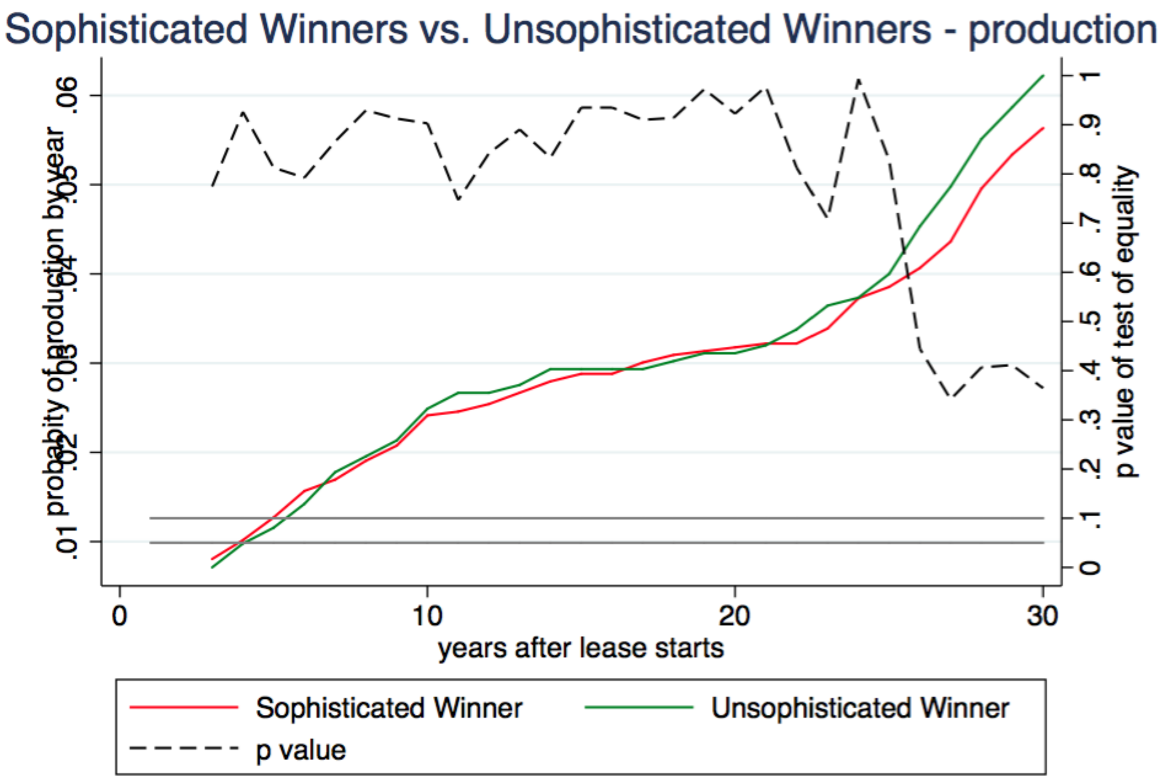

Figure 2.4: Comparing whether production ever happened on parcels won by "sophisticated "individuals versus those won by "unsophisticated winners ". Sample limited to cases where exactly one sophisticated winner appeared among the first-, second-, and third-place winners.

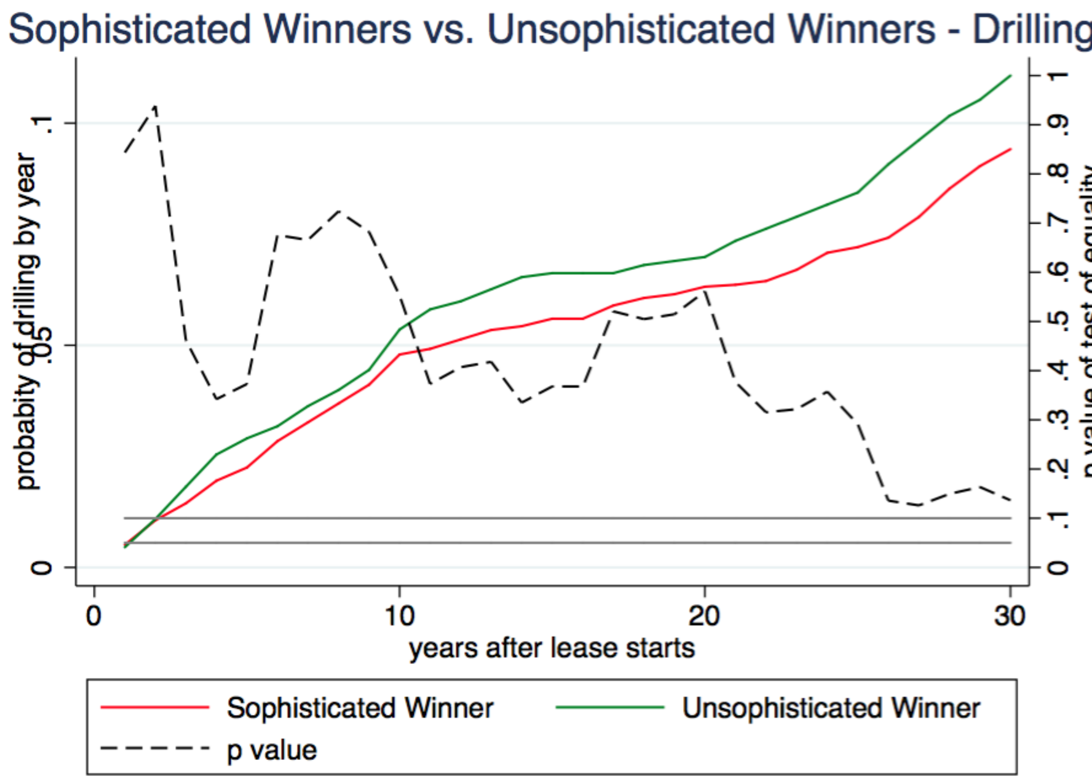

Figure 2.5: Comparing drilling outcomes on parcels won by "sophisticated "individuals versus those won by "unsophisticated winners ". Sample limited to cases where exactly *two* sophisticated winners appeared among the first-, second-, and third-place winners.

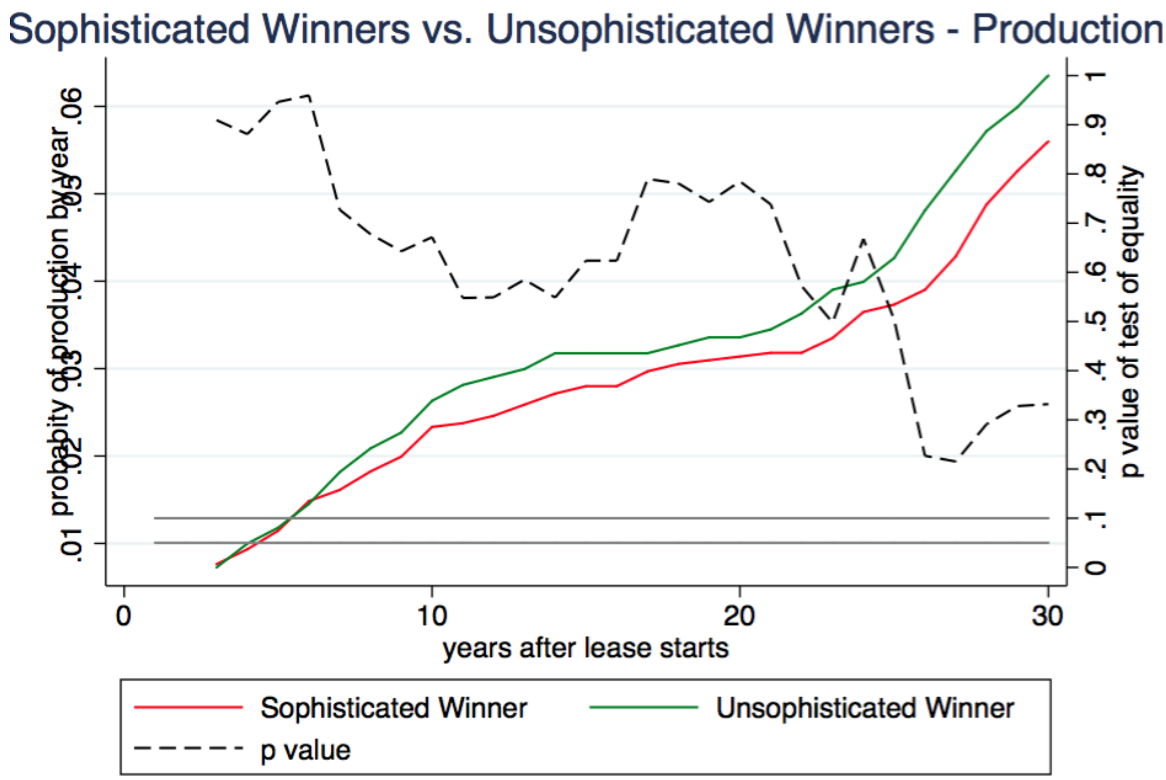

Figure 2.6: Comparing whether production ever happened on parcels won by “sophisticated ”individuals versus those won by ”unsophisticated winners ”. Sample limited to cases where exactly *two* sophisticated winners appeared among the first-, second-, and third-place winners.

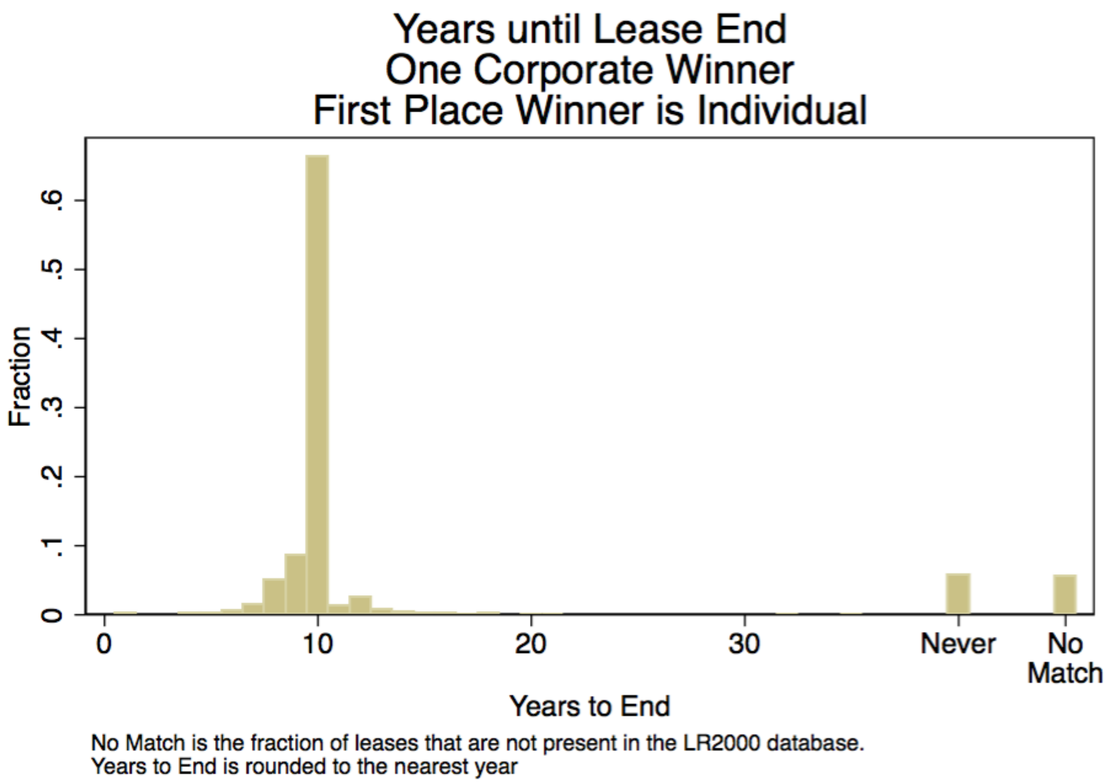

Figure 2.7: Histogram of the time, in years, until a lease expires. Sample includes leases where there was exactly one firm among the top 3 winners, and where an individual was the first place winner. Leases that were still active in 2012 when we downloaded and compiled LR200 data are in the "Never"category, while leases that could not be linked to the LR2000 data are in the category "No Match".

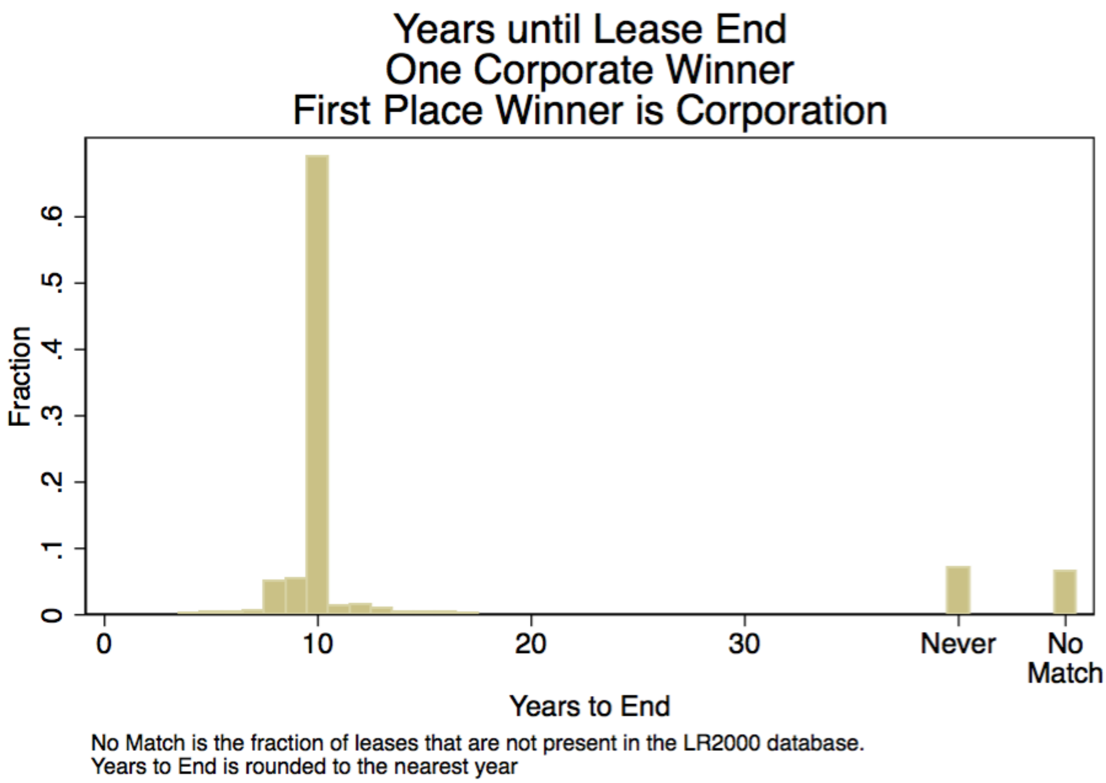

Figure 2.8: Histogram of the amount of times, in years, until a lease expires. Sample includes leases where there was exactly one firm among the top 3 winners, and where that firm was the first place winner. Leases that were still active in 2012 when we downloaded and compiled LR200 data are in the "Never"category, while leases that could not be linked to the LR2000 data are in the category "No Match".

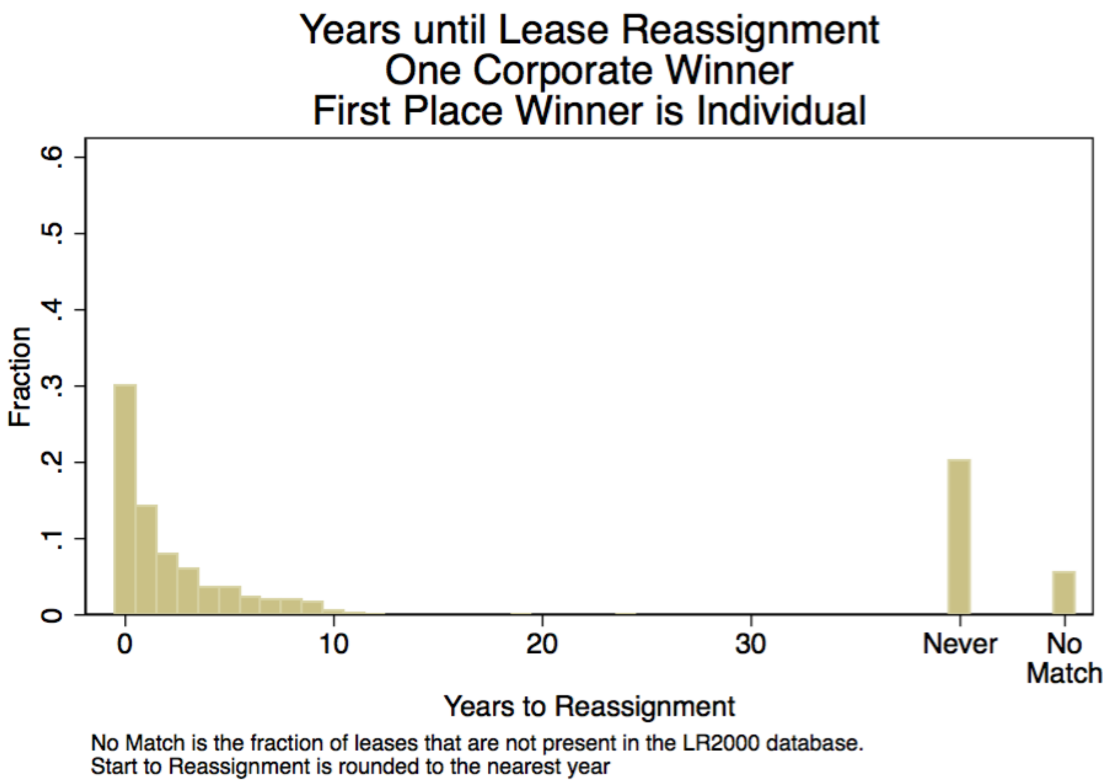

Figure 2.9: Histogram of the amount of time, in years, until a lease is transferred. Leases where exactly one firm appeared among the first-, second-, and third-place winners and where an individual was the winner.

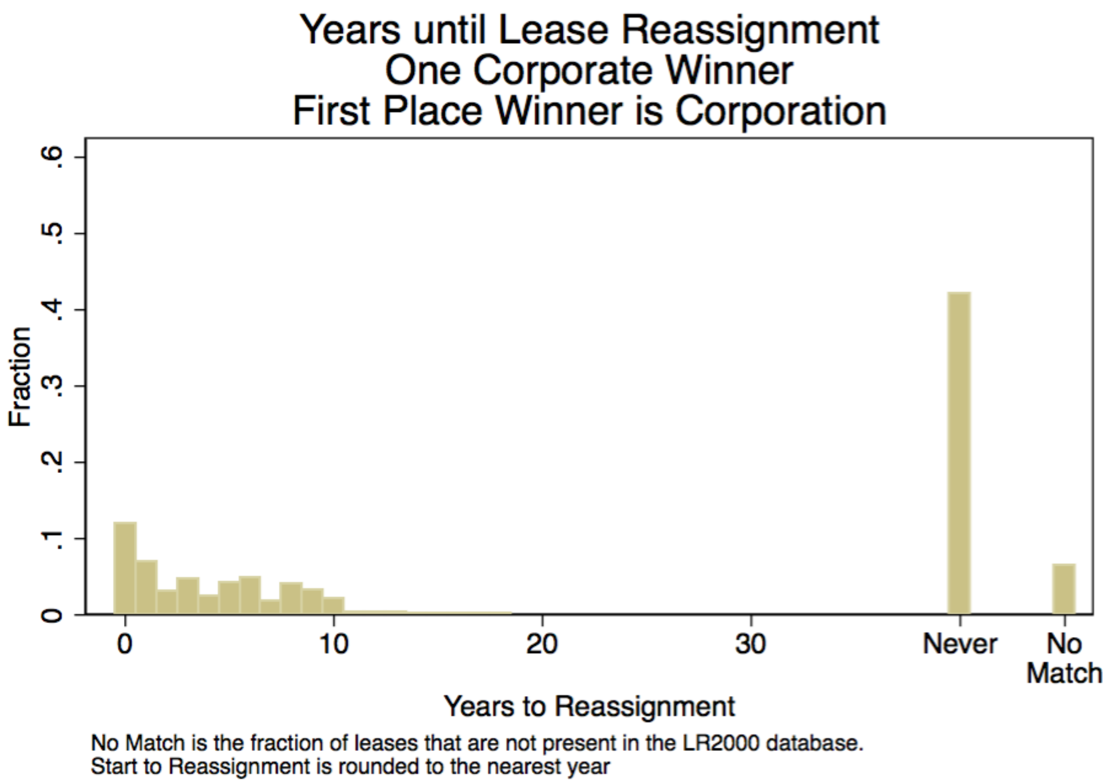

Figure 2.10: Histogram of the amount of time, in years, until a lease is transferred. Leases where exactly one firm appeared among the first-, second-, and third-place winners and where the firm was the winner.

2.8 Appendix

2.8.1 Data Sources and Identification of Firm and Individual

Records on lotteries were scanned from paper records at the BLM office in Laramie Wyoming. These records include first information on parcels that would be offered in the lottery, with an example from June 1975 in figure 2.11. These records also contain information on the first-, second-, and third-place winners as well as the total number of entries. The first place winner has information both on name as well as address; the second- and third-place winners only have names.

This data is publicly available from the Wyoming BLM. The Michigan IRB panel ruled that this data is not regulated.

Data were double-blind entered using a data digitization service.

We identify firms from whether words such as "Co.", "Corp. ", "Corporation", "Co.", "Inc. ", "Ltd.", "Limited ", "Assocaites", "Oil", "Gas", and "Industries"appear in the name of the winner. We also include as firms those that are obviously firms but not easily categorized from this rule (one case only—"Michigan Wisconsin Pipe Line").

We also explicitly list first-place individuals as individuals rather than firms even if their address information suggests that they are associated with a firm (e.g., John Doe, Acme Energy Co., Acme Wyoming 80000) We do this for two reasons. First, if these individuals had appeared as second- or third-place winners, we would not observe the address/firm information, and we would categorize them as individuals. Second, we cannot determine whether these individuals were entering the lottery on behalf of the firm or merely using the firm as a personal address.

SIXTH PRINCIPAL MERIDIAN

WYOMING

#1096 W 0316078
T 17 N, R 60 W, Laramie
Sec 6: Lots 3, 7, S½NE¼, SE¼NW¼,
E½SW¼, N½SE¼
8: N½NW¼
T 18 N, R 60 W
Sec 29: NE¼NW¼, W½SW¼
30: Lot 1, NW¼NE¼, NE¼NW¼,
NE¼SE¼
31: NE¼, E½SW¼, W½SE¼
32: S½NE¼, W½
1444.21 A

#1097 W 23542
T 26 N, R 60 W, Goshen
Sec 3: SW¼NW¼, NW¼SW¼
4: SE¼NE¼, E½SW¼, NE¼SE¼
8: SE¼NE¼, SE¼NW¼
10: Lot 4
15: Lot 1, SE¼NW¼, NE¼SW¼
22: Lot 3, SE¼NW¼, NE¼SW¼
28: NE¼SE¼
29: E½SW¼
32: SW¼, S½SE¼
33: SW¼NE¼, NW¼SE¼
1099.17 A

#1098 W 5212
T 35 N, R 60 W, Niobrara
Sec 18: NE¼NE¼
40.00 A

#1099 W 43988
T 36 N, R 60 W, Niobrara
Sec 31: Lot 1, NE¼, E½NW¼, NE¼SE¼
32: S½
638.78 A

#1100 W 0309148
T 36 N, R 62 W, Niobrara
Sec 13: W½NE¼, E½NW¼
160.00 A

#1101 W 0316090
T 39 N, R 62 W, Niobrara
Sec 35: NW¼
160.00 A

#1102 W 0310335
T 43 N, R 62 W, Weston
Sec 11: W½SW¼, W½SE¼
14: Lots 1, 4, E½NW¼, W½SE¼
394.53 A

#1106 W 5223
T 38 N, R 63 W, Niobrara
Sec 13: S½NE¼, SE¼
14: NW¼NE¼, S½NE¼, NW¼, SE¼
23: NW¼NE¼
720.00 A

#1107 W 0316100
T 43 N, R 63 W, Weston
Sec 29: SE¼SE¼
40.00 A

#1108 W 0324155
T 37 N, R 64 W, Niobrara
Sec 13: N½SW¼
80.00 A

#1109 W 23556
T 40 N, R 64 W, Niobrara
Sec 7: Lot 3, S½NE¼, NE¼SW¼
166.31 A

#1110 W 0220694-A
T 40 N, R 64 W, Niobrara
Sec 13: SW¼
25: SW¼NW¼, E½SE¼
280.00 A

#1111 W 0220694
T 40 N, R 64 W, Niobrara
Sec 14: W½NW¼
80.00 A

#1112 W 39112
T 41 N, R 64 W, Weston
Sec 4: S½SE¼
14: S½SE¼
160.00 A

#1113 W 0314722
T 46 N, R 64 W, Weston
Sec 17: NW¼NW¼
40.00 A

#1114 W 11816-A
T 48 N, R 64 W, Weston
Sec 4: SE¼SW¼, NE¼SE¼, S½SE¼
160.00 A

#1115 W 0316107
T 35 N, R 65 W, Niobrara
Sec 9: E½SE¼
10: SW¼NW¼, W½SW¼
200.00 A

Figure 2.11: Example from raw data on what parcels were offered in the lottery. June 1975 lottery

CHAPTER III

Oil and Gas Development on Private and Public Land: Evidence from the Wyoming Checkerboard

3.1 Introduction

A major economic question in the energy economics is the role of resource ownership and how the identity and policies of a resource owner affect resource extraction. For example, the types of contracts and costs that government imposed on firms operating on government-owned land may differ from the contracts and costs imposed by private owners. Furthermore, the types of policies on one type of land can have spillover effects on resource extraction on nearby plots. As the United States has significant amount of both government and privately owned land, understanding the effect of each ownership regime and the corresponding costs and contracts is also an important policy question.

Kunce et al. (2002) was one of the first papers to explore this type of question. They ask whether federal environmental protection and bureaucracy has increased the costs that oil and gas firms pay to operate on federal government land. Their analysis utilizes a natural experiment in southwest Wyoming where alternating blocks of land were assigned either to private ownership or government ownership, assuring that geology is uncorrelated with ownership. Using estimates of well drilling costs, they compare reported drilling costs on private land with costs on government land. While this paper was later retracted due to data errors (Gerking and Morgan, 2007), the setting it uses has still been considered to be a valid natural experiment (Harrison and List, 2004; Fitzgerald, 2010).

In this paper I revisit this setting, known as the Wyoming Checkerboard, and analyze the oil and gas development. Rather than use well drilling cost estimates, I use data on the location, drilling date, and production of wells drilled. These data allow me to describe the development of the oil and gas fields over time and space and to show how ownership patterns and policies have affected this development.

I discuss the history of the Wyoming Checkerboard, highlighting four mechanisms by which ownership and policy may have affected oil and gas development. First, costs of operating on federal land may be higher, as hypothesized by Kunce et al. (2002), and the first chapter of this dissertation finds further evidence of these costs. Second, leases on private and government land had different lengths—firms were required to drill and begin production within 5-10 years to keep leases on government land, but there was no deadline nor production requirement for private land. Third, typical lease sizes were generally larger on government land, which may have made them more profitable relative to private land. Fourth, private land may have been poorly managed, as the owner—until recently—was a large firm that did not specialize in oil and gas production and may have failed to maximize profits.

I discuss brief models of how each of these mechanisms may have affected oil and gas drilling. While higher environmental compliance costs on government land may have reduced drilling on government land, the other three mechanisms—longer leases on private land, smaller lease areas, and inefficient management of private land—would likely lead to higher drilling rates on government land relative to private land.

Using data on drilling, I test whether the cost effect or the other three mechanisms dominate. I find that drilling rates are higher on government land. In addition, exploratory wells were more likely to be drilled on government land. In spite of this, I find that productive wells drilled on government land had similar productivity to those on private land.

In 2000, Anadarko Petroleum took over management of private mineral lands from the Union Pacific Railroad, and I study the effect of this change. I find that that in the 2000's, the drilling rate gap between government and private land disappeared. In addition, wells drilled on private land after 2000 were less productive on average relative to those on government land, suggesting that with the takeover, the firms began to be willing to drill lower productivity wells that would not have been drilled in the previous regime. This suggests that prior to 2000, the Union Pacific failed to maximize profits. An alternate explanation is that federal environmental regulations became more restrictive in 2000—however in the first chapter I do not find evidence of a large shift in federal policy in 2000.

Overall, I find that ownership patterns have a significant impact on drilling and production outcomes in the Wyoming Checkerboard. While it is not possible at this stage to disentangle perfectly all of the mechanisms that may have driven drilling and production activity, I discuss evidence for each mechanism as well as future research plans to further explore this region.

Section 3.2 discusses industry background and the history of the Wyoming checkerboard. Section 3.3 discusses the models of how costs and asymmetric deadlines affect drilling and production. Section 3.4contains the empirical analysis, and section 3.5 concludes.

3.2 Background

In this section I describe the historical developments that led to the Wyoming checkerboard. I also discuss the lease deadline asymmetries, origins of lease size differences, and ownership and management of private land.

3.2.1 Origins of the Checkerboard

In the Wyoming Checkerboard, every other square-mile plot of land was assigned to private ownership. The origin of this land assignment was the construction of the first transcontinental railroad to cross the United States. The United States government came up with a novel mechanism to finance the railroad construction. As part of the Railroad Acts of 1862 and 1864, the US Federal Government awarded to the Union Pacific and Central Pacific Railroad companies every other square-mile block of land that lay within 20 miles of the the railroad route. The rationale for these land grants was that it helped the railroads capture more profits if the railroad was built and land values appreciated, but be low cost to the government if the railroad was not built and the land remained relatively low value (Atack and Passell, 1994).

Because of this, the Union Pacific Railroad became a major land and mineral rights owner along the railroad route stretching from Promontory Summit, Utah to Omaha, Nebraska. The Central Pacific Railroad, which completed the railroad from Sacramento, California to Utah, became a major land owner along the western portion of the transcontinental railroad.

The exact boundaries of the land grants to the railroad were determined using the public land survey system. Land had ben surveyed into six mile by six mile squares known as townships which were subdivided into 36 square-mile parcels known as sections. These lots were numbered sequentially from 1 to 36, as shown in figure 3.1. The odd-numbered sections were granted to the railroad. In southwest Wyoming, even-numbered sections were for the most part retained by the federal government, with the exception of the 16th and 36th sections which were transferred to the Wyoming state government (chapter 1).

I limit the analysis to the Greater Green River Basin of southwest Wyoming where this land ownership pattern has remained remarkably robust. However, there have been some deviations: Federal land has sometimes been transferred to private ownership through homesteading or sale. In some cases the railroad was not granted land if as of the 1860's the land had already been awarded to private ownership through homesteading. Privately owned mineral rights have remained largely in private ownership, although there are some places where land exchanges were made with the federal government (Kunce et al., 2002). A major reason for the persistence of the ownership pattern is that this region is arid, windy and cold, and as a result there has been little other demand for the land.

3.2.2 Oil and Gas Contracts on Federal and State Land

The US Federal Government and the State of Wyoming have well-defined rules governing oil and gas leasing and drilling. Oil and gas leasing is very similar on government land regardless of whether it is in federal or state ownership. An oil and gas lease starts with the firm paying an initial fee. The lease specifies a primary term, currently 10 years on federal land and 5 years on state land. During the primary term the firm can drill for oil and gas. If the firm finds and begins producing oil and gas, the lease enters the secondary term which extends until the end of production. If the firm does not begin producing oil or gas during the primary term the lease expires. During the primary term the firm pays an annual rental fee. During the secondary term the firm pays a royalty on production. The lease ends when production on all wells ends.

For much of the United States, private mineral rights owners generally use similar contracts to those used on federal and state government land with primary and secondary terms, initial payments, a royalty, and sometimes rental payments. The major difference between government and private leases is that leases on private land are typically bilaterally negotiated, which leads to some variation in the terms of leases. In contrast, state and federal leases have typically been allocated using lotteries and auctions.

One major difference between oil and gas operations on federal, state, and private land is environmental protection. As discussed in the first chapter, federal land tends to require relatively more environmental protection measures be met before a permit to drill is issued. State and private land also require some environmental protection, but at least in Wyoming is perceived to be less strict. Because of environmental requirements on federal land and the costs of bilateral negotiation on private land, one industry representative said that state government land was the easiest to operate on and that federal land was the most difficult to operate on, with private land in between.

3.2.3 Union Pacific Management of Oil and Gas Leasing

In the Wyoming Checkerboard, the way that the Union Pacific managed oil and gas contracting differed markedly from most other private mineral rights owners: Instead of using contracts with a limited primary term, the Union Pacific use a long run contract with no primary term deadline: In 1970 the Union Pacific forged an agreement with Amoco that gave Amoco nearly exclusive rights to drill oil and gas wells. Amoco was given the right to drill on the northwest, southwest, and southeast quarters of each odd-numbered square mile section (see figure 3.2). Amoco was required to pay a royalty to Union Pacific on any production. Later, BP acquired Amoco including the right to drill on this land (Conversation with George Peters, November 8 2011).

While it granted Amoco drilling rights on three of the four quarters of each section, the Union Pacific retained drilling rights on the northeast quarter of each odd-numbered section. In about 1970, the Union Pacific acquired the Champlin oil company to manage oil and gas resources on these northeast quarters. Similarly, as the owner, the Union Pacific/Champlin oil company had no deadline for drilling on its own northeast quarters as it owned, rather than leased, the rights to drill on those plots (Conversation with George Peters, November 8 2011).

This arrangement of drilling rights affected how many wells a firm could drill on a lease. The Wyoming Checkerboard has largely natural gas wells. Wyoming allows there to be typically one well per quarter (see Figure 3.3. As the Union Pacific typically had 1/4 of a square mile section, this implied that the Union Pacific could drill at most one well within a section, whereas Amoco, which had 3/4 of a square mile section, could drill 3. As leases on even-numbered government sections typically covered the entire square mile, a firm drilling there could typically drill up to 4 wells.

Private land management changed in in 2000 when Anadarko Petroleum Corporation merged with the Union Pacific Resources Group. This marked a significant change because Anadarko had significant oil and gas industry experience relative to the Union Pacific. A second possible result of the merger was increased ease in drilling—one industry representative mentioned that Amoco had some difficulty in the drilling process in spite of the contract that gave Amoco an unlimited lease because of issues like building roads to access drilling sites. A third possibility is that there were further agreements written where operating rights changed hands or where Anadarko and BP combined operations. Regardless of the mechanism, it seems that Anadarko takeover would likely increase the likelihood of drilling on private land.

3.3 Theory

The history of the Wyoming Checkerboard suggests a variety of mechanisms that may have affected drilling and production. In this section I briefly discuss the role of federal environmental protection, firm mismanagement, asymmetric lease lengths, and variation in lease size. First I formally discuss environmental protection and firm mismanagement, and then turn to the models about asymmetric deadlines and lease sizes.

Federal Environmental Protection: In the first chapter I show how higher costs on some land would affect drilling and production. In that chapter, I show that relatively higher environmental compliance costs on federal land should lead to less exploratory drilling, less overall drilling, and lower production on federal land. In addition, firms operating on federal land will be less likely to drill low productivity wells.

Mismanagement: it is possible that Union Pacific was not good at managing oil and gas leasing. Other research has found evidence that firms are not always perfect profit maximizers. For example, Hortaçsu and Puller (2008) find that small firms appeared to lack the expertise or computing capability to bid best responses in the Texas electricity spot market. Similarly, the Union Pacific may have lacked the expertise or desire to effectively manage oil and gas resources.

3.3.1 Asymmetric Deadlines

In this setting whatever firm had the rights to operate on federal or state land had either 10 or 5 years to drill before losing the lease, whereas Amoco/BP had an unlimited time. I show here that government land may have had more drilling because it had a shorter lease deadline. I construct two examples. The first, of a single firm, corresponds to the case where Amoco/BP would have been the lease holder on both the government and the private land. The second, of two firms, explores the case where some other firm had the rights to operate on government land. Both cases use a simple two-plot set up, similar to that in chapter 1 and to Hendricks and Kovenock (1989).

3.3.1.1 Single firm model

If a single firm has the rights to drill on two plots, one with a longer lease period and the other with a shorter lease period, the firm will (weakly) prefer to drill on the shorter lease period first first in order to secure the lease before deciding whether to drill on the other lease.

To see this most extreme case, consider a model similar to that of the first chapter where the firm has access to two plots. However here the lease deadlines are asymmetric—the first plot has only one period before the lease expires whereas the second plot has two periods before expiration. The firm has a signal μ of the expected reserves for each plot such that $E(R_1) = E(R_2) = \mu$. The costs for drilling on each plot are identical and equal to C.

Drilling on plot 1 first and then deciding whether to drill on plot gives expected profits:

$$\mu - C + \beta E[\max\{E(R_2|R_1, \mu) - C, 0\}]$$

where as drilling on plot 2 first without drilling on plot 1 first only gives profits $\mu - C$. This is (weakly) less than the profits from sequential drilling. Therefore a firm would prefer to drill the shorter-deadline lease first because it is more likely to expire early.

Another option is for the firm to drill on both plots at the same time. This gives profits $2(\mu - C)$, which will typically be less than $\mu - C + \beta E[\max\{E(R_2|R_1, \mu) - C, 0\}]$—provided β is sufficiently close to 1 or that there is a large enough chance that a second well would be unprofitable. Anecdotally it is extremely uncommon for firms to drill two exploratory wells in close proximity at the same time. Therefore in this simple model we would expect drilling to be more likely and to happen earlier on land with the shorter lease.

3.3.1.2 Two firms

Now consider the case where there are two firms. Here I build on the two-firm exploration model of Hendricks and Kovenock (1989) . Firms i and j each receive signals s_i and s_j about the expected reserves of their plots, where the true reserves for each plot is X, and $E(s_i|X) = E(s_j|X) = X$. Firms have a difficult time hiding information such that one firm drilling first reveals information about the other sites productivity (McKie, 1960). I assume that the first firm to drill perfectly reveals the true reserves X to the other firm.

Hendricks and Kovenock (1989) discuss this type of drilling timing game where each firm has two periods in which it might drill. In the symmetric equilibrium, each firm chooses first period thresholds $s^*_{1i} > C$ and $s^*_{1j} > C$ that determine whether they will drill in the first period. They also choose second period thresholds s^*_{2i} and s^*_{2j} that determine whether they will drill in the second period, conditional on there being no drilling in the first period. I show in chapter 1 that this is a game of strategic substitutes in first period thresholds, such that an increase in s^*_{1j} will lead to a decrease in s^*_{1i}.

Now consider the case of where firm i has 2 periods to drill, but firm j only has 1 period to drill. In this case firm j has no hope of learning from firm i. Therefore firm j will drill if $s \geq C$, such that $s^*_{1j} = C$, which is a lower threshold than in the two period-two period game. As this is a game of strategic substitutes, firm i will respond by raising its first-period threshold signal s^*_{1i} relative to what it would be in the two period-two period game. As a result, the land with the shorter lease deadline will be more likely to have exploratory drilling. However, as it is somewhat difficult to completely characterize the equilibria in these types of games, it is not clear how overall drilling and productivity rates will differ between the two plots.[1]

[1]The major challenge, as discussed in the appendix of the first chapter, is that it is is difficult to characterize the comparative statics of second period drilling threshold signals.

3.3.2 Lease Parcel Sizes

In addition to private and government land differing in environmental protection and lease deadlines, they also differed in size of leases. Typical federal leases in the area were one square mile, with space for 4 natural gas wells. In contrast Amoco/BP had lease areas of 3/4 of a mile, with room for 3 natural gas wells, and Union Pacific/Champlin had 1/4 of a mile, with room for only 1 natural gas well. Here I briefly show how larger leases may increase drilling rates both through search and learning as well as through field-level fixed costs.

First to see why search and learning implies that larger parcels are more likely to have drilling, suppose that a firm has a lease with sites to drill up to N wells where $i = 1, ..., N$ indexes the well sites. If well i is drilled, it will have production R_i. The firm has a signal of expected productivity μ, where $E(R_i) = \mu$, $\forall i$.

To see how increasing the parcel size increases the likelihood of drilling, consider the shift from $N = 1$ to $N = 2$. If $N = 1$, then the firm has no returns to learning, and will only drill if $\mu \geq C$.

In contrast, if $N = 2$, then expected profits of drilling the first well include the information value of drilling a second. Expected profits are:

$$\mu - C + \delta E[\max\{E(R_2|R_1, \mu) - C, 0\}]$$

Because this expression is greater than $\mu - C$, this means that for parcels with $N = 2$ well sites, the minimum signal threshold μ^* needed to initiate drilling is lower. Similarly profits would be even higher as we increase N above 2.

Another reason small plots might be less likely to be drilled is because of decreasing costs. Often there are large field-level fixed costs such as roads, monitoring equipment, and storage tanks. Larger leases are more profitable as these fixed costs are effectively split over a larger number of producing wells.

These types of economies of scale imply that we would expect to see the lowest probability of drilling on Union Pacific northeast quarters within odd-numbered sections, and a medium probability of drilling on northwest, southwest, and southeast quarters of odd-numbered sections—the area managed by Amoco/BP. The highest probability of drilling would be on quarters within even-numbered sections.

3.4 Data and Empirical Results

I now turn to the data. I limit the analysis to the Greater Green River Basin of southwest Wyoming and to sections with centroids that are within 19.5 miles of the Transcontinental Railroad. Summary statistics for these sections are in Table 3.1. The total number of sections in the sample is 8,080. There are 4,042 even-numbered sections (federal and state land) and 4,038 odd-numbered sections (private land). Sections are typically about one square mile, although there is some variance due to surveyor errors and the curvature of the earth. Thirty percent of these sections experienced drilling by 2010, with nine percent of them being the sites of exploratory wildcat wells. Twenty-two percent of sections are reported to have produced oil or gas.

Table 3.3 shows that within this region, the original land pattern assignment has remained fairly robust. Using current reported mineral ownership from GIS shapefiles, I calculate the fraction of each section that is in federal mineral ownership and in state mineral ownership. I find that the mean level of federal ownership is only 2% on odd-numbered sections and only 3% on 16/36 sections. In contrast, it is 93% on even-numbered non-16/36 sections. Similarly, the mean level of state ownership is 2% on odd-numbered sections and 0% on even-numbered non-16/36 sections, but 95% on 16/36 sections.[2]

[2]Throughout the analysis I use an intent-to-treat specification, comparing sections by the original numbering rather than by current ownership. While it would also be possible to instrument for current ownership using the assignment rule, I do not observe when and how land changed hands,

I find that the agreement with Amoco/BP and the later merger with Anadarko had a significant effect on the identity of firms operating on private land. Table 3.2 shows the identity of firms as of 2010.[3] BP (Amoco) is by far the most important operator on odd-numbered sections, with Anadarko the next largest operator. Other firms also appear, although with relatively few wells—presumably these wells were the result of agreements with Union Pacific either before the agreement with Amoco in 1970 or agreements forged after 1970 where for reasons of economies of scale it was useful for other firms to manage wells on Union Pacific.

In contrast, the identity of firms on even-numbered sections is much more diverse. Anadarko and BP are still major players. However Devon, Wexpro, Marathon, Samson, Chevron, and Kerr-McGee all have at least 100 wells on even-numbered sections, and Devon has more wells on even-numbered sections than BP. I also find that far more wells on even-numbered sections were operated by small firms, where I arbitrarily define small firms as those that operate less than 60 wells in the sample area. There 1,308 wells on even-numbered sections operated by such small firms, while there were only 634 wells on odd-numbered sections operated by such firms.

In Table 3.2 I also examine well identity for wells on the northeast quarter of odd-numbered sections versus those that are on the northwest, southwest, or southeast quarters.[4] I find that firm identities are similar. Even though Amoco/BP did not have rights to the northeast quarter, the fraction of wells in Amoco/BP ownership is in the northeast quarter is similar to that fraction in Amoco/BP ownership in the other three quarters of odd-numbered sections.

making it difficult to instrument for land ownership in previous years. An additional difficulty is that some sections are split between state-, federal, and/or private ownership. This leads to challenges in specifying an instrumental variable: There is no instrument in this setting for such split ownership, which is problematic if there is a non-linear relationship between the fraction of land in a given type of ownership and drilling and production outcomes.

[3]Unfortunately, firm ownership of wells is only available as of 2010 or later, and not at the time of drilling.

[4]Not all wells have a reported quarter, such that the total of these two groups is weakly less than that in the odd-numbered sections.

While this suggests that Amoco/BP at least in some cases did have rights to drill in the northeast quarter, I find later that drilling and production outcomes in the northeast quarter do differ significantly from outcomes in the other quarters. Therefore it is unlikely that the northeast quarter of odd-numbered sections has been managed the same as the other quarters in odd-numbered sections.

3.4.1 Analysis

To examine the impact of institutions and policies on the oil and gas industry, I examine revealed drilling and production patterns. The typical regression specification is simple: I estimate how functions differ as a function of initial land assignment, e.g.:

$$Y_i = \alpha + \beta \cdot \text{Even}_i + \epsilon_i$$

where each square mile section is indexed by i, and Even_i is an indicator variable that the section is an even-numbered section. For inference, I use Conley spatial standard errors with a distance band of 20 miles, as in the first chapter (Conley, 1999). As recommended by Conley (2008), I use a uniform weight except in the cases where the estimated variance-covariance matrix is not positive-definite, in which case I use a Bartlett weight (Newey and West, 1987).

3.4.1.1 Drilling on even- and odd-numbered sections

First I examine the timing and location of drilling. Figure 3.4 shows the rollout of drilling on even- and odd-numbered sections. It graphs the cdf of the year that drilling first occurred on a given section, aggregated to odd- and even-numbered sections. Tables 3.4 and 3.5 give the equivalent outcomes in regression form for 10 year increments.

I find that for most of time, even-numbered sections are more likely to have experienced drilling by any given date. The difference between even- and odd-sections is statistically significant at at least the 10% level for all years except 1910 and 2010. Drilling levels are overall quite low until about 1960, but dramatically increase from around 1960 to the 2000's. The largest gap in drilling rates happen in the 1960's and 1970's, when even-numbered sections are about twice as likely to have experienced drilling. The differences are persistent until about 2005 when the rates converge. By 2010, even-numbered sections are slightly less likely to have experienced drilling. The greater willingness to drill on government land suggests that federal environmental costs were not large enough to dominate other mechanisms that made federal land favorable to drill on.

Figure 3.5 shows that state-owned land (sections 16 and 36) do not appear to be very different from federal-owned land (other even-numbered sections). Both tend to have higher drilling rates relative to odd-numbered sections.

The theory on asymmetric leases suggests that exploratory drilling will be more likely on places with shorter lease deadlines. This appears to be the case. I construct a measure of whether a well was an exploratory well—either reported as being a "wildcat"well or if it is drilled in the first year of any well within its field. Tables 3.6 and 3.7 use this measure of whether such an exploratory well has ever been drilled in a section by a given date. I find that even-numbered sections are significantly more likely to have had such exploratory drilling.

While federal land has higher drilling rates for most of the period in question, the gap starts to narrow in around 2000, such that by 2010 there even and odd numbered sections are not different in the probability that they experience drilling. The timing of this change suggests that the Anadarko takeover may have increased the willingness of firms to drill on private land.

3.4.1.2 Production on even- and odd-numbered sections

Production also differs somewhat between even- and odd-numbered sections. I construct measures of the first three years of production for wells drilled after 1978, the date when well-level production data begins. This initial productivity is a proxy for total productivity.[5] I measure production in barrel-of-oil equivalent, where one barrel of oil has the same energy content as approximately 6 mcf of natural gas.

First, I examine well level production for wells drilled between 1978 and 1999—prior to the Anadarko takeover. The histogram of production is in Figure 3.6. I find that the distribution of productivity is very similar between the two groups. And a regression comparing log production finds that finds that wells on even-numbered sections are about 7% less productive on average relative to those on odd-numbered sections. This difference is not statistically different from zero.

However after 2000 there is a difference in productivity. Figure 3.7 shows the distribution of production for wells in this period. Here, wells on even numbered sections tend to be about 25% more productive than those on odd-numbered sections, and this difference is statistically significant at the 5% level.

These production results suggest that after the Anadarko takeover in 2000, firms became increasingly willing to drill low productivity wells on private land. Another piece of evidence to this is that the number of wells drilled on private land from 2000 to 2010 was 2,296, whereas there were only 1,013 drilled on even numbered sections. While this may have been driven by new Anadarko ownership, an alternate explanation is that federal environmental compliance costs increased in about 2000.

[5] Under an exponential decline curve, production over any given period of time will be proportional to total production.

3.4.1.3 Comparing outcomes at the quarter level

I also examine outcomes at the quarter level. Recall that Union Pacific gave Amoco/BP drilling rights to the northwest, southwest, and southeast quarters of each section, while Union Pacific retained the rights to the northeast section. To examine whether this division affected drilling and production, I examine drilling and production outcomes at the quarter-square mile level.[6]

I find that the drilling was especially slow to be started on the northeast quarters of the odd-numbered sections. Tables 3.8 and 3.9 show the probability of drilling on given quarter by date. From 1980 to 2010, drilling rates on the northeast quarter of odd-numbered sections were significantly lower relative to both other quarters within the odd-numbered sections, as well as relative to even-numbered sections.

Low rates of drilling on the northeast quarter may have been driven by low willingness of the Union Pacific to drill exploratory wells, but that they would be willing to drill productive follow up wells if nearby firms discovered oil or gas.However this does not appear to be the case. I construct an indicator variable of whether a section had a productive well. Table 3.10 shows that the northeast quarter also has lower rates of productive drilling by any date. Therefore it appears that the Union Pacific failed to drill even in areas where it would be known to be productive.

I also examine well-level production for productive wells, categorizing wells by which quarter they appear in. I divide the sample into wells drilled between 1978 and 1999, and wells drilled in 2000 and later. Results are in Table 3.11. I find that prior to 2000, well productivity was fairly similar between wells on even-numbered sections and those in the northwest, southwest, and southeast quarters of odd-numbered sections. However average well productivity was much higher for wells on northeast quarters of odd-numbered sections. This suggests that prior to 2000, Union Pacific

[6]One challenge in analyzing outcomes at the quarter level is that a small fraction of wells do not have information on quarter.

was particularly unwilling to drill low-productivity wells.

After 2000, this pattern changes. I find that the types of wells that are drilled on the northeast quarter of odd-numbered sections have similar productivity to other wells in other quarters of odd-numbered sections. This suggests that the Anadarko takeover helped lead to more similar management across the various quarters within odd-numbered sections. Furthermore, firms operating on odd-numbered sections are more willing to drill low productivity wells relative to firms operating on even-numbered sections.

3.5 Conclusion

In this paper I find evidence that federal versus private ownership significantly affect drilling and production. I find that prior to 2000, drilling rates were relatively high on government land relative to private land. I also find that after 2000 the gap in drilling decreases and then disappears. I also find that after 2000 firms on private land were much more willing to drill low-productivity wells. Therefore if federal environmental requirements were costly to firms, as I find in the first chapter, then this effect was counteracted by other mechanisms that increased willingness to drill on government land relative to private land.

I also find evidence that how private land is managed significantly affects drilling outcomes on private land. Prior to 2000, the smaller areas retained by the Union Pacific had relatively lower drilling and less willingness to drill productive wells relative to the areas operated by Amoco/BP. After 2000 the differences between these two types of private land regions tend to disappear.

Of the many mechanisms that could explain these drilling patterns, one of the most promising is inefficient private management. When Anadarko took over management of Union Pacific land, drilling increased, various types of private land began to have more similar outcomes, and firms operating on private land were more willing to drill lower productivity wells. Further evidence that the shift was driven by the Anadarko takeover comes from the first chapter, where I find no shifts in drilling or production on government land in the 2000's. This suggests that changes in drilling and production were driven by changes on private land rather than on federal land.

Other mechanisms may play a role in determining drilling activity. The fact that firms on private land had smaller parcels to operate on and longer lease deadlines may have further decreased willingness to drill on private land. Low rates of drilling on the northeast quarter may have also been driven by the fact that these Union Pacific parcels were especially small.

Further research will focus on other ways to identify the role of these mechanisms. The other two chapters of this dissertation are good places to examine these mechanisms. For example, the research in the first chapter might be extended to examine asymmetric lease deadlines and heterogeneous lease sizes. A richer specification might explore how the decision to drill is affected by when one's own lease expires and by when neighbors's leases expire. This extension might also include information on lease area to capture the role of economies of scale. Similarly the second chapter might be extended to explore whether some firms are more efficient than others at utilizing their leases than others. This type of research will help quantify the relative importance of each of these mechanisms in driving the development of oil and gas resources.

3.6 Tables

	mean	st.dev.	median	5th perc	95th perc
Even numbered section	0.50	0.50	1.00	0.00	1.00
Odd numbered section	0.50	0.50	0.00	0.00	1.00
Even section, not 16/36 section	0.44	0.50	0.00	0.00	1.00
Area in square miles	0.99	0.07	1.00	0.93	1.02
Fraction federal mineral	0.43	0.47	0.02	0.00	1.00
Fraction state mineral	0.06	0.22	0.00	0.00	0.96
Had wildcat well by 2010	0.09	0.28	0.00	0.00	1.00
Had any well by 2010	0.30	0.46	0.00	0.00	1.00
Had productive well by 2010	0.22	0.41	0.00	0.00	1.00

Table 3.1: Summary statistics at the section level. Total number of sections is 8,080

	Even	Odd	Odd NW/SW/SE	Odd NE
Anadarko	589	774	543	210
BP America Production Company	452	2278	1784	494
Cabot Oil & Gas Corporation	100	13	9	2
Chevron USA Inc	125	99	80	19
Devon Energy	486	26	20	6
Kerr-Mcgee Oil & Gas Onshore LP	114	161	116	42
Luff Exploration	28	64	54	10
Marathon Oil Company	150	48	43	5
Merit Energy Company	45	35	28	7
Questar	104	35	27	8
Samson Resources Company	126	63	41	19
Saurus Resources Inc	13	53	42	11
Wexpro Company	294	183	138	45
Yates Petroleum Corporation	88	14	10	2
Other firms	1308	634	508	119
Total	4022	4480	3443	999

Table 3.2: Well counts by firm on even- and odd-numbered sections (columns 1 and 2). Well counts by firm for NW, SW, and SE NE quarters in odd-numbered sections in column 3. Well counts by firm for NE quarters of odd-numbered sections in column 4. Only firms with at least 60 total wells listed.

		mean	25th perc	median	75th perc
Odd-numbered	Federal	0.02	0.00	0.01	0.01
Odd-numbered	State	0.00	.	0.00	0.00
Even-numbered, not 16/36	Federal	0.93	0.98	0.99	0.99
Even-numbered, not 16/36	State	0.00	.	0.00	0.00
16 or 36	Federal	0.03	0.00	0.00	0.00
16 or 36	State	0.95	.	0.99	0.99

Table 3.3: Fraction of mineral rights within sections owned by Federal Government and State government. Divided into odd-numbered sections, even-numbered non-16/36 sections, and 16/36 sections.

	(1)	(2)	(3)	(4)	(5)	(6)
	1910	1920	1930	1940	1950	1960
Even-numbered, not 16/36	0.003	0.004**	0.005*	0.010**	0.013***	0.033***
	(0.003)	(0.002)	(0.003)	(0.004)	(0.004)	(0.005)
16/36 section	-0.001	0.001	0.002	0.003	0.003	0.007
	(0.001)	(0.003)	(0.007)	(0.006)	(0.007)	(0.007)
Intercept	0.001	0.003*	0.011***	0.013***	0.017***	0.031***
	(0.001)	(0.002)	(0.004)	(0.005)	(0.006)	(0.008)
R squared	0.001	0.001	0.000	0.002	0.002	0.006
Observations	8080	8080	8080	8080	8080	8080

Table 3.4: Regressions of the probability that an oil or gas well has been drilled on a given section by the year 1910 (column 1), 1920 (column 2), . . . up to 1960 (column 6).

	(1) 1970	(2) 1980	(3) 1990	(4) 2000	(5) 2010
Even-numbered, not 16/36	0.054***	0.043***	0.040***	0.028*	-0.001
	(0.011)	(0.016)	(0.014)	(0.016)	(0.020)
16/36 section	0.047*	0.045*	0.043	0.047*	-0.002
	(0.027)	(0.024)	(0.028)	(0.028)	(0.031)
Intercept	0.055***	0.165***	0.199***	0.240***	0.305***
	(0.019)	(0.032)	(0.035)	(0.045)	(0.071)
R squared	0.010	0.003	0.002	0.001	0.000
Observations	8080	8080	8080	8080	8080

Table 3.5: Regressions of the probability that an oil or gas well has been drilled on a given section by the year 1970 (column 1), 1980 (column 2), . . . up to 2010 (column 5).

	(1) 1910	(2) 1920	(3) 1930	(4) 1940	(5) 1950	(6) 1960
Even-numbered, not 16/36	0.001	0.002***	0.002**	0.005***	0.007***	0.023***
	(0.001)	(0.000)	(0.001)	(0.002)	(0.002)	(0.004)
16/36 section	-0.000*	0.002	-0.002	-0.002	-0.004	-0.007
	(0.000)	(0.002)	(0.002)	(0.002)	(0.003)	(0.006)
Intercept	0.000*	0.002***	0.006***	0.007***	0.009***	0.016***
	(0.000)	(0.001)	(0.002)	(0.002)	(0.003)	(0.004)
R squared	0.000	0.000	0.000	0.001	0.001	0.005
Observations	8080	8080	8080	8080	8080	8080

Table 3.6: Regressions of the probability that an exploratory ("wildcat") oil or gas well had been drilled on a section by the year 1910 (column 1), 1920 (column 2), ..., and 1960 (column 6).

	(1) 1970	(2) 1980	(3) 1990	(4) 2000	(5) 2010
Even-numbered, not 16/36	0.040***	0.036***	0.029**	0.026*	0.021
	(0.009)	(0.014)	(0.014)	(0.014)	(0.013)
16/36 section	0.026	0.020	0.017	0.015	0.013
	(0.019)	(0.013)	(0.018)	(0.018)	(0.018)
Intercept	0.027***	0.062***	0.076***	0.085***	0.098***
	(0.009)	(0.013)	(0.016)	(0.017)	(0.017)
R squared	0.009	0.004	0.002	0.002	0.001
Observations	8080	8080	8080	8080	8080

Table 3.7: Regressions of the probability that an exploratory ("wildcat") oil or gas well had been drilled on a section by the year 1970 (column 1), 1980 (column 2), ..., and 2010 (column 5).

	(1) 1930	(2) 1940	(3) 1950	(4) 1960
odd, NE quarter	-0.002*	-0.004**	-0.005***	-0.008***
	(0.001)	(0.002)	(0.002)	(0.001)
odd, NW quarter	-0.002**	-0.004**	-0.004*	-0.009***
	(0.001)	(0.002)	(0.002)	(0.002)
odd, SE quarter	-0.001	-0.002	-0.003**	-0.008***
	(0.001)	(0.001)	(0.001)	(0.002)
odd, SW quarter	-0.003**	-0.004**	-0.005***	-0.011***
	(0.001)	(0.002)	(0.002)	(0.002)
Intercept	0.005**	0.007**	0.010***	0.020***
	(0.002)	(0.003)	(0.004)	(0.005)
R squared	0.000	0.001	0.001	0.001
test odd quarters	0.000	0.000	0.095	0.282
test NW,SW,SE=0	0.001	0.000	0.034	0.000
Observations	32320	32320	32320	32320

Table 3.8: Regressions of the probability that any oil or gas well has been drilled on a *quarter section* by the year 1910 (column 1), 1920 (column 2), ..., and 1960 (column 6). The dependent variables are whether the quarter is the NE in an odd-numbered section, NW in an odd-numbered section, SE in an odd-numbered section, or SW in an odd-numbered section. Quarters in even-numbered sections are the excluded group. The first p value test gives a test that all odd-section quarter coefficients are equal to each other. The second p value test is whether the NW, SW, and SE quarters are all equal to zero.

	(1) 1970	(2) 1980	(3) 1990	(4) 2000	(5) 2010
odd, NE quarter	-0.016***	-0.040***	-0.043***	-0.030***	-0.024***
	(0.003)	(0.007)	(0.008)	(0.007)	(0.006)
odd, NW quarter	-0.016***	-0.020**	-0.018*	-0.014**	0.002
	(0.005)	(0.008)	(0.009)	(0.006)	(0.010)
odd, SE quarter	-0.015***	-0.020***	-0.015*	-0.010*	-0.001
	(0.004)	(0.005)	(0.008)	(0.005)	(0.004)
odd, SW quarter	-0.020***	0.014	0.018	0.015	0.024
	(0.006)	(0.019)	(0.021)	(0.015)	(0.016)
Intercept	0.035***	0.067***	0.080***	0.119***	0.153***
	(0.012)	(0.016)	(0.017)	(0.025)	(0.040)
R squared	0.003	0.005	0.004	0.002	0.001
test odd quarters	0.582	0.000	0.000	0.000	0.000
test NW,SW,SE=0	0.001	0.000	0.276	0.049	0.162
Observations	32320	32320	32320	32320	32320

Table 3.9: Regressions of the probability that any oil or gas well has been drilled on a *quarter section* by the year 1970 (column 1), 1980 (column 2), ..., and 2010 (column 5). The dependent variables are whether the quarter is the NE in an odd-numbered section, NW in an odd-numbered section, SE in an odd-numbered section, or SW in an odd-numbered section. Quarters in even-numbered sections are the excluded group. The first p value test gives a test that all odd-section quarter coefficients are equal to each other. The second p value test is whether the NW, SW, and SE quarters are all equal to zero.

	(1) 1970	(2) 1980	(3) 1990	(4) 2000	(5) 2010
odd, NE quarter	-0.001**	-0.015***	-0.016**	-0.005***	0.001
	(0.001)	(0.005)	(0.007)	(0.002)	(0.003)
odd, NW quarter	-0.003**	-0.007	-0.007	-0.004**	0.011**
	(0.001)	(0.005)	(0.007)	(0.002)	(0.006)
odd, SE quarter	-0.002	-0.007**	-0.003	0.000	0.009*
	(0.002)	(0.003)	(0.005)	(0.002)	(0.005)
odd, SW quarter	-0.005	0.020	0.020	0.014	0.022***
	(0.003)	(0.014)	(0.015)	(0.009)	(0.008)
Intercept	0.009*	0.027***	0.037***	0.073***	0.103***
	(0.005)	(0.008)	(0.010)	(0.025)	(0.030)
R squared	0.000	0.003	0.003	0.000	0.001
test odd quarters	0.117	0.001	0.004	0.165	0.072
test NW,SW,SE=0	0.097	0.137	0.347	0.052	0.042
Observations	32320	32320	32320	32320	32320

Table 3.10: Regressions of the probability that any oil or gas well that was reported to be productive has been drilled on a *quarter section* by the year 1970 (column 1), 1980 (column 2), ..., and 2010 (column 5). The dependent variables are whether the quarter is the NE in an odd-numbered section, NW in an odd-numbered section, SE in an odd-numbered section, or SW in an odd-numbered section. Quarters in even-numbered sections are the excluded group. The first p value test gives a test that all odd-section quarter coefficients are equal to each other. The second p value test is whether the NW, SW, and SE quarters are all equal to zero. I use uniform weights for the Conley standard errors for all years except 2010, where I use Bartlett standard errors to achieve a positive-definite estimate of the variance-covariance matrix.

	(1) 1978-1999	(2) 2000-2010
odd, NE quarter	0.380***	-0.213**
	(0.058)	(0.097)
odd, NW quarter	0.079	-0.207**
	(0.080)	(0.084)
odd, SE quarter	-0.325	-0.318**
	(0.308)	(0.130)
odd, SW quarter	0.093	-0.286*
	(0.071)	(0.168)
Intercept	10.963***	10.620***
	(0.169)	(0.138)
R squared	0.014	0.007
test odd quarters	0.000	0.678
test NW,SW,SE=0	0.113	0.027
Observations	1946	3553

Table 3.11: Regressions of well-level productivity, dividing wells up by which quarter they are located in. Both use log barrel-of-oil equivalent production for the first three years of production as the dependent variable. The first column limits the analysis to wells drilled between 1978 and 1999; the second to wells drilled in 2000 and later.

3.7 Figures

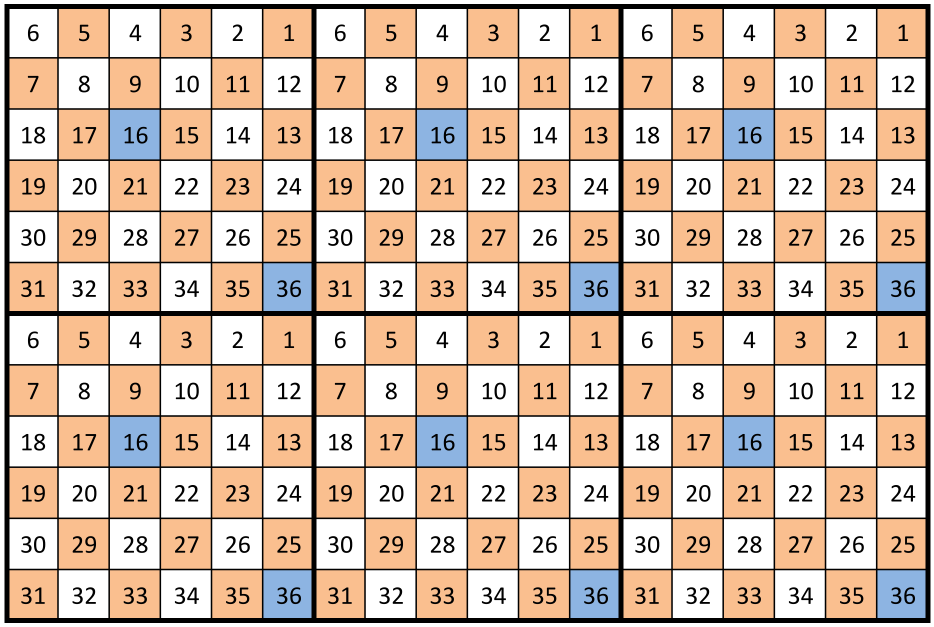

Figure 3.1: Allocation of sections among Union Pacific (orange), federal government (white), and state government (blue). Odd-numbered sections are Union Pacific, even-numbered non-16/36 are federal government, and 16 and 36 are state government.

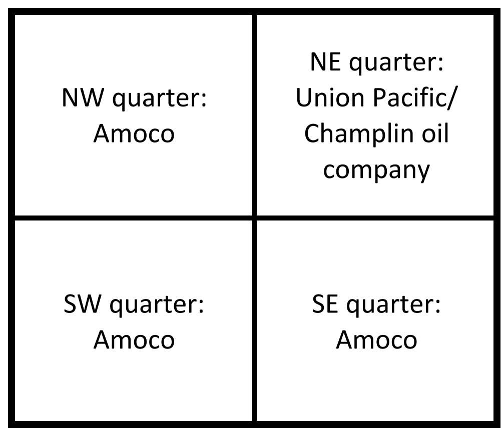

Figure 3.2: Allocation of quarters within Union Pacific-owned sections. Amoco (later BP) was given rights to three of the four quarters, and Union Pacific (Champlin oil company) retained the fourth quarter.

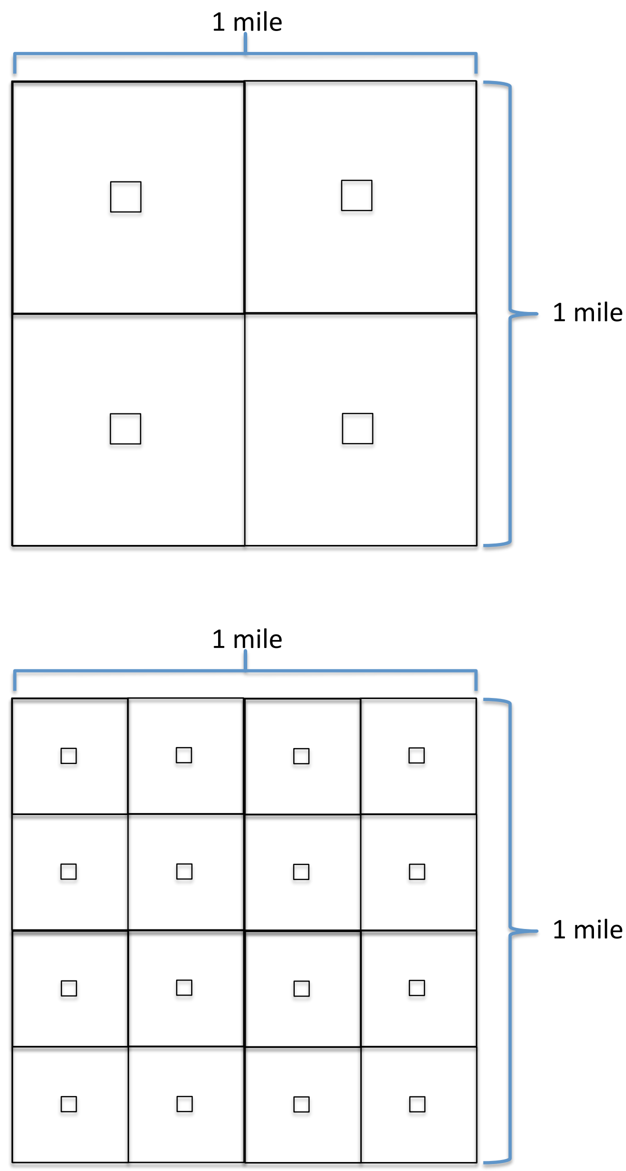

Figure 3.3: Spacing of wells. In the top panel, there can be 16 oil wells per section, with each well located at the center of a 1/16th-square mile quarter-quarter. For natural gas (lower panel), there can be one well per 1/4th-square mile quarter. Wells must be located near the center of the allocated space.

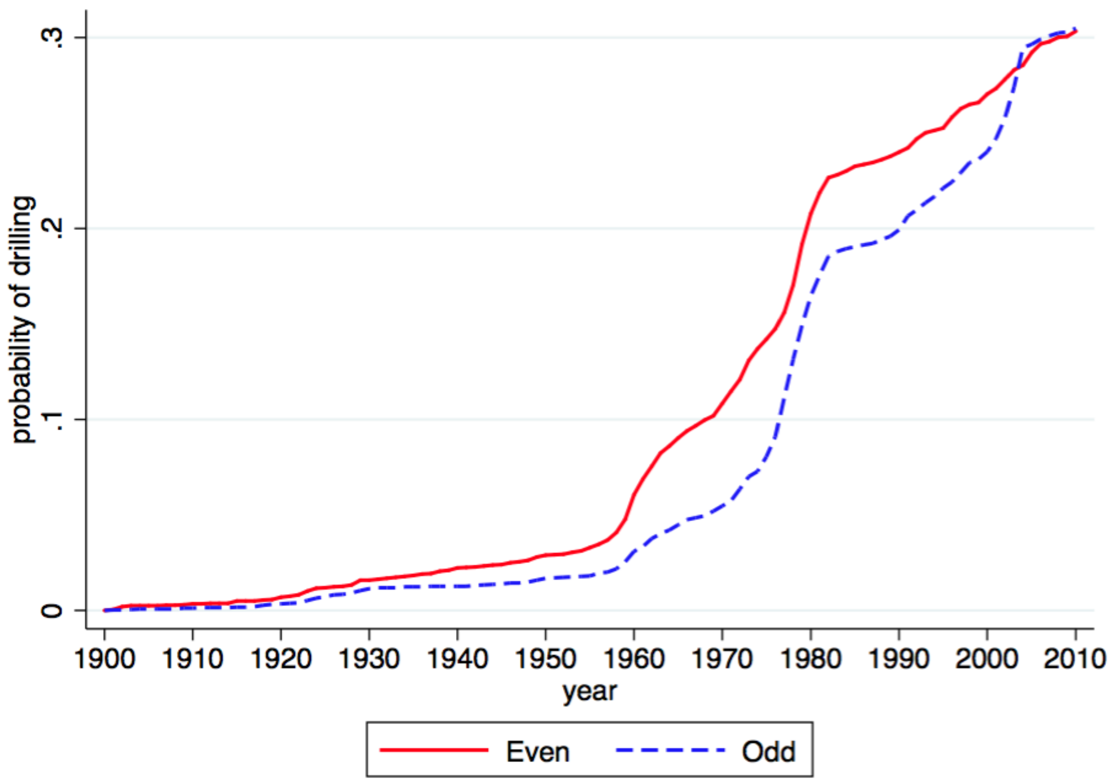

Figure 3.4: Rollout of drilling over time, comparing odd- (private) and even-numbered (federal or state) sections

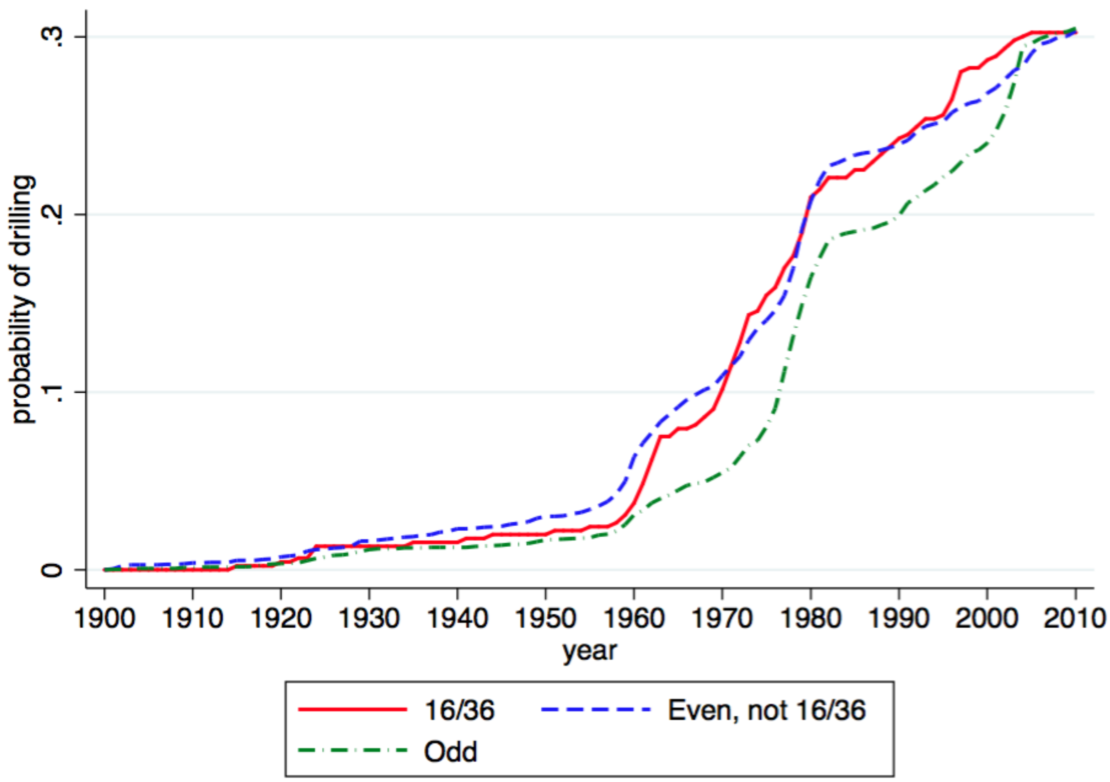

Figure 3.5: Rollout of drilling over time, comparing odd-numbered sections (private), non-16/36 even-numbered sections (federal), and 16/36 sections (state).

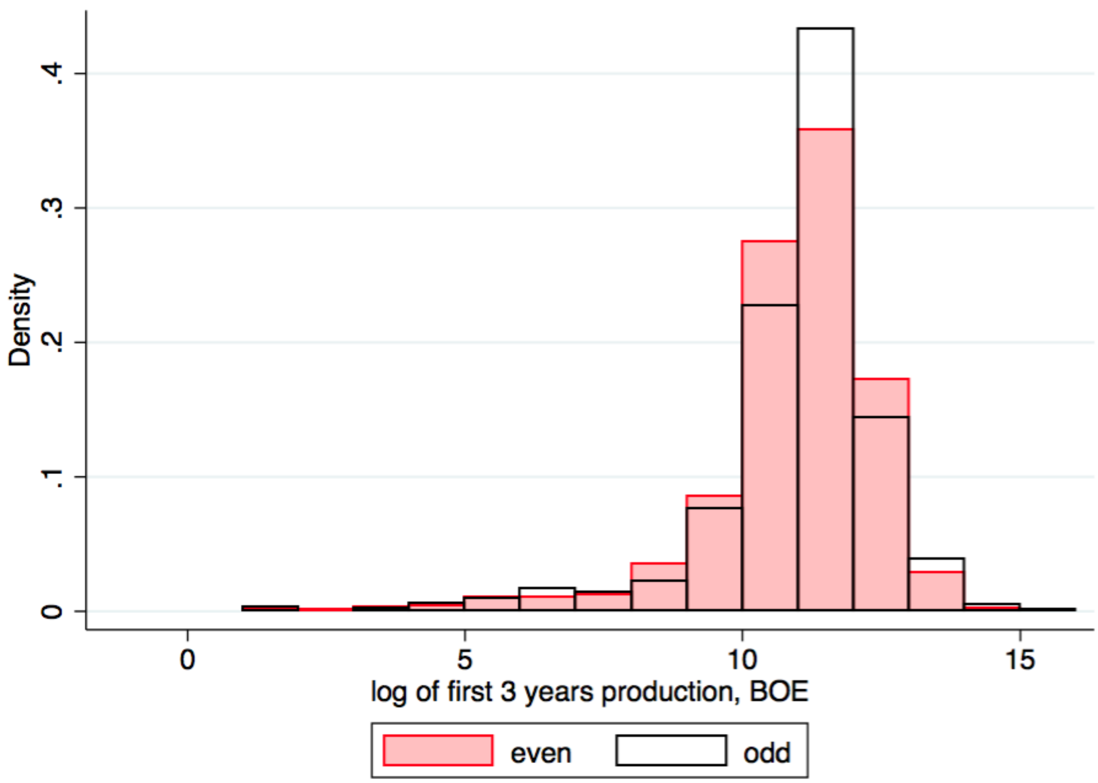

Figure 3.6: Log of first-three years of production for wells drilled between 1978 and 1999

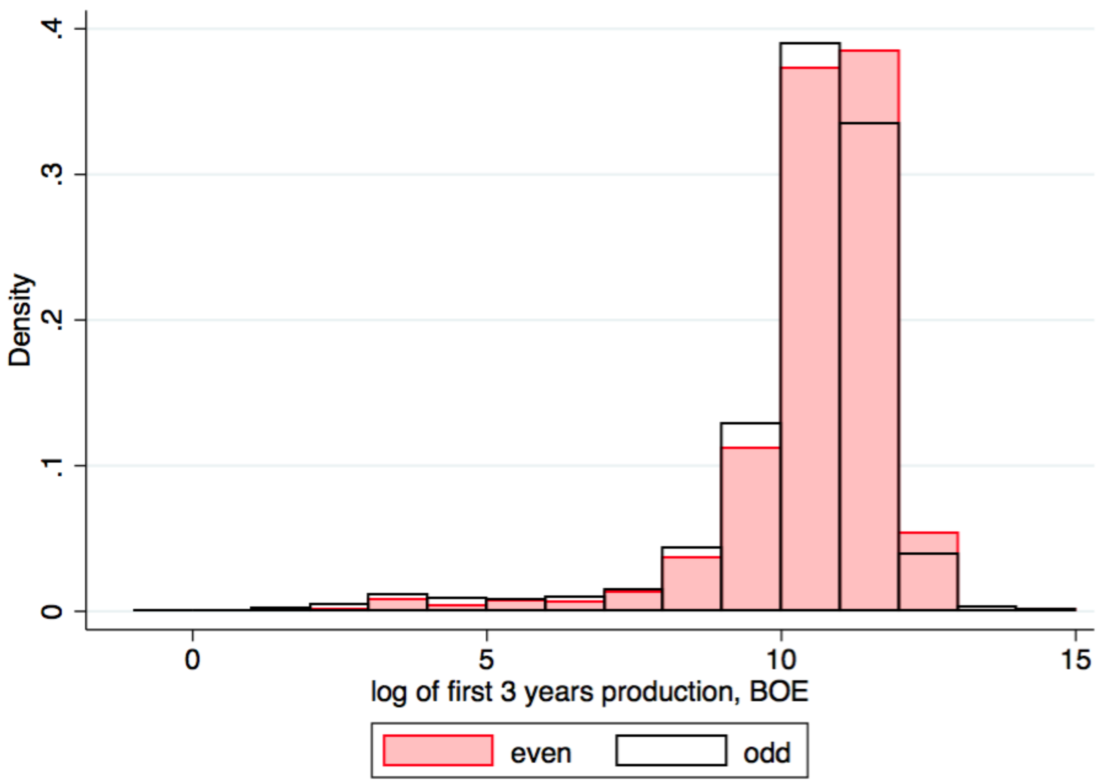

Figure 3.7: Log of first-three years of production for wells drilled between 2000 and 2010

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