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Counterfactual Analysis of Compulsory Unitization as a Solution to the Common Pool Externality in the Oil and Gas Industry

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Counterfactual Analysis of Compulsory Unitization as a Solution to the Common Pool Externality in the Oil and Gas Industry

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DISSERTATION

Presented to the Faculty of the Graduate School of

The University of Texas at Austin

in Partial Fulfillment

of the Requirements

for the Degree of

DOCTOR OF PHILOSOPHY

THE UNIVERSITY OF TEXAS AT AUSTIN

May 2017

Counterfactual Analysis of Compulsory Unitization as a Solution to the Common Pool Externality in the Oil and Gas Industry

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The University of Texas at Austin, 2017

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The exploitation of a single oil field by several firms is a typical example of the common pool externality (CPE). As a possible solution to it, regulators have innovated policies that allow such firms to coordinate by selecting a single operator to exploit the whole field. Moreover, every state, but Texas, can even force firms to join a coalition. In this dissertation I analyze the dynamic strategic interaction of firms competing for common resources. By modeling such dynamic interactions, I will be able to counterfactually assess what would happen under different regulatory scenarios. I use the model, along with other techniques, to quantify the loss in production and profits due to the common pool externaliy; then I explore how implementing different policies that promote or enforce coalition formation would change productivity and welfare.

This research is has three main parts. In Chapter 2, I explore the most important institutional details, and simulate how the characteristics of a

reservoir, the composition of the hydrocarbons, and the distribution of firms in a field affect the outcome of coordination. In Chapter 3, I use different reduced form techniques to estimate how implementing compulsory unitization in New Mexico has improved welfare. In Chapter 4, I develop a random stopping model and estimate the parameters using the methodology developed by Bajari and Levin, 2007. Once the parameters of the model are estimated, I will be able to explore my different research questions. The results suggest that relaxing the restrictions in voluntary unitization would increase welfare at a lesser scale than implementing compulsory unitization. Nevertheless, none of these policies will nullify the entire negative effect caused by the common pool externality.

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Chapter 1

Introduction

The exploitation of a single oilfield by several firms is a typical example of the common pool externality (CPE). Pressure is the natural force that pushes oil up to the surface when firms are trying to extract it. Increasing the rate of production makes the pressure in the reservoir fall at a much faster rate, making it inefficient to extract too fast. Nevertheless, when several firms share an oilfield, they have incentives to produce faster than they would otherwise. This happens because the rule of capture in the United States dictates that regardless of where the hydrocarbons are originally found, whoever extracts them first is entitled to keep them (Homan, 2011).

If agents facing the CPE assigned a single operator to exploit the whole resource, then such operator would not face the CPE. In that sense, such operator would extract the oil efficiently. In the oil business, there is a legal contract called unitization that allows firms to coordinate in such a way when exploiting a field. Regulators across the United States impose two restrictions when firms seek to unitize: first, the field needs to be "reasonably developed"; second, the way in which firms share profits must be "fair." The problem with the first restriction is that if firms start working separately before unitizing, they might start exploiting the field inefficiently. The problem with the second restriction is that by restricting the profit sharing options, firms might not reach some unitization agreements they would otherwise.

Libecap, 1998 documented that unitization agreements do not happen as often as regulators would expect. The failure in private contracting has encouraged oil regulating agencies around the United States to incorporate compulsory unitization to their production-efficiency-enhancement toolkit. Under compulsory unitization, if the number of firms in a field that want to form a unit exceeds a certain threshold, then the regulator can force the dissidents to also join the unit. The minimum threshold varies widely in different states. Texas is the only major producing state without any form compulsory unitization.

In this dissertation, I first model how firms that share fields and extract oil and gas take the actions of others into account when deciding their production schedule. Then, using reduce form techniques, I compare Texas and New Mexico to conclude that wells in New Mexico are more productive than wells in Texas. Finally, I estimate a random stopping model that will allow me to prove three counterfactuals: how big is the welfare loss due to the common pool externality; what would happen if there was compulsory unitization in Texas; and how efficiency would improve if Texas relaxed the restrictions placed on voluntary unitization.

In Chapter 2, I review the institutional details necessary to understand the common pool externality faced by firms that share the same field. I also propose a dynamic model of how firms interact. Through a simulation exercise, I explain how a single firm exploiting a field can produce more efficiently. Also, I show that compulsory unitization could also increase efficiency in production if certain conditions are met.

In Chapter 3, I use data provided by DrillingInfo[1] to estimate a regression discontinuity (RD) and a difference in difference (DID) model. Using these techniques, I compare production between Texas and New Mexico. In particular, I try to isolate how compulsory unitization has increased efficiency in New Mexico compared to Texas. For RD, I use the fact that Texas and New Mexico share a large border and the area around it has been heavily drilled. For DID, I leverage from the fact that I have data before and after the implementation of compulsory unitization in New Mexico.

The main results of Chapter 3 suggest that wells in New Mexico are more productive than wells in Texas. The leading results I got by applying RD suggest that the increase in productivity due to New Mexico policy is between 2,239 and 2,664 barrels of oil over the lifetime of the well. The DID approach suggests that the productivity increase due to implementing compulsory unitization in New Mexico is between 2,551 and 3,872.

Chapter 4 is, by far, the most important in the dissertation. It proposes a random stopping model that rationalizes how firms take drilling and unitization decisions. I use a unique dataset I constructed from different sources[2] and

[1] http://info.drillinginfo.com
[2] DrillingInfo (http://info.drillinginfo.com), Texas Railroad Commission

the methodology proposed by Bajari and Levin, 2007 to estimate the parameters of the model. I then used the model to recompute the dynamic equilibrium for each field to compute the main counterfactuals in the dissertation.

The results in Chapter 4 suggest that if there was a single operator per field exploiting it since discovery, then profits from that field would increase in around 26%. If the Texas Railroad Commission (TRRC) relaxed both restrictions it places in voluntary unitization, then welfare would increase in around 21%. Finally, this model suggests that if compulsory unitization was allowed in Texas, then welfare would increase in around 13%.

(http://www.rrc.state.tx.us/), Energy Information Administration (http://www.eia.gov/), and RigData (https://rigdata.com/)

Chapter 2

Unitization: Is it always worth the hassle?

2.1 Introduction

Sharing a reservoir is a typical example of the common pool externality faced by the oil and gas industry. Firms have tried to deal with it using mainly two mechanisms: proration quotas and unitization of tracts. The former is usually easier to achieve through private contracting; the latter, when achieved, yields a better outcome. By 1947, only 12 of 3,000 fields in the United States were fully unitized (Libecap, 1984). This failure in private contracting motivated regulating agencies to impose severe legislation trying to increase efficiency by reducing over-exploitation. By now, every producing state regulates well spacing and enforces pooling. Moreover, they all encourage firms sharing a field to work as a unit[1]. Nevertheless, they have different stands when it comes to compulsory unitization. Texas is the only major producing state that does not enforces it. Other states will act as long as the proportion of operators that want to unitize exceeds the minimum established by the state. It goes from 50% to 85%.

Supported by the growing economic literature, there is consensus among

[1]The difference between pooling and unitization will be explained in the following section

firms and legislators that unitization is among the best ways to reduce the excessive exploitation of a resource caused by the common pool externality (Balthrop, 2016, Kaffine, 2011, Schott, 2007, Uchida, 2008). Nevertheless, making it compulsory is not as popular among stakeholders. Legislators that oppose unitization argue that this prevents small firms from learning by doing. Moreover, non-unitized firms with small tracts usually benefit by increasing their production rate. The amount of product they capture from their neighbors outweighs the depletion of pressure caused by overproducing. Coincidentally, states that oppose compulsory unitization have a large concentration of influential small firms (Libecap, 1985b).

Every reservoir is different and the economic benefits gained from having a single operator vary widely among them. For example, if the permeability of the rocks where the hydrocarbons are trapped is low, firms will not be able to capture their neighbor's product, so they will not have incentives to produce too fast. The main objective of this paper is to find out how oil recovery and profits will increase by unitizing tracts given reservoir characteristics and the composition of firms with interests in a field. As a side product, the paper will give a structural framework to analyze why small firms oppose unitization, and when it will be achieved by private contracting.

There is a vast literature in petroleum engineering that models the dynamics of a reservoir that could enlighten us with the relationship between overproduction and waste. Economics literature states that the composition -number and size- of firms with interests in a reservoir also matters (Libecap, 1984). The objective of my paper is to bring these two approaches together to explore how reservoir characteristics, and firm composition influence unitization outcomes. Moreover, the multistage general equilibrium model presented here is the only one in this literature that accounts for two substances -oil and gas- in estimating how pressure evolves. This feature is of paramount importance, since depletion of gas is the main mechanism why fast production decreases recovery.

The following section will describe the institutional details relevant to the current application, both from a legal and a technical perspective. It will also define related terms like pooling and unitization. Finally, it documents an interview with a well operator that helped understand the cost function. In section 2, I explore the existing literature. First, I describe how economists have approached pooling and unitization in different markets. Then, I briefly comment on some legal and technical papers. Section 3 presents the structural model and the optimality conditions. Section 4 shows how the model performs by simulating different instances. Finally, section 5 concludes and proposes further research.

2.2 Background

Many authors that study the oil and gas industry do not distinguish between pooling and unitization (Covert, 2014 and Balthrop, 2016). Pooling is the combining of tracts within a single well-spacing unit. Unitization, on the other hand, is a reservoir-wide combination of tracts. The objective of the former is to enable single operators to fulfill space regulations, the latter is the coalition between several operators to exploit the reservoir efficiently (Handlan, 1984). Most legislatures have similar clauses on compulsory pooling, while compulsory unitization varies greatly between states (Kramer, 2007).

Solely based on the previous definitions, it appears that the only difference between pooling and unitization is the scale. In practice there are many others, the first one being the purpose. Pooling tracts enables firms to fulfill minimum space requirements to drill, the purpose of unitization is to reduce drilling. Pooling is a contract between an operator and mineral owners, unitization happens between firms. Pooling has to be agreed or enforced before drilling, units can formed at any point. The economic implications of pooling and unitization also differ greatly. The former incites drilling. It allows firms to fulfill their requirements even if some mineral owners oppose. The further prevents firms from drilling too fast. Unitized firms (units) save on investment by reducing the number of wells[2].

Rent dissipation caused by the common pool externality in this industry comes from high capital costs - excessive storage space and duplicated wells- and from reduced recovery. When many tracts are unitized (either voluntarily of compulsory), only the operator with more acreage will exploit the reservoir. He will decide how many wells to operate and daily production rates. Moreover, if secondary recovery is needed, he will decide what wells

[2]More on this in the literature review

to transform into injectors. The other operators will pay their proportion of capital and costs and once the oil is sold, the operator will disburse the rents across stakeholders (Commission, 1984).

2.2.1 Legal Schemes

In Texas, the oil and gas regulatory agency is the Texas Railroad Commission (TRRC). The first effective spacing legislation was rule 37, in 1919, which establishes that "No well for oil, gas or geothermal resource shall hereafter be drilled nearer than 1,200 feet to any well completed in or drilling to the same horizon on the same tract or farm, and no well shall be drilled nearer than 467 feet to any property line, lease line or subdivision line". Before that, the prevailing practice was the rule of capture, where "The owner of a tract of land acquires title to the oil and gas which he produces from wells drilled thereon, though it may be proved that part of such oil and gas migrated from adjoining lands" (Hardwicke, 1948). This incentivized over investment, and overproduction, which resulted in unnecessary waste.

Texas was the last major oil producing state that took an opposing stance to compulsory pooling. It wasn't until 1965, when the TRRC passed the Mineral Interest Pooling Act (Kramer, 2007), which states compulsory pooling as an option once all voluntary efforts have been exhausted (Coe, 1977). Moreover, it states that "the production shall be allocated to the respective tracts within the unit in the proportion that the number of surface acres included within each tract bears to the number of surface acres included in the entire unit."

Unlike spacing and pooling acts, Texas does not have an analogous act that enforces involuntary unitization (Kramer, 1986). Nevertheless, the Texas Court highly encourages it, as long as it"yields a reasonable expectation of profit", and the agreement is voluntary (SC, 1981). There have been important efforts to introduce forced unitization. The latest is House Bill 100, the "Oil and Gas Majority Rights Protection Act", introduced by Rep. Van Taylor in 2013. The bill authorizes interest owners to apply to the TRRC for an order for unit operations of a common source of supply. During the hearing applicants must prove that they have exhausted all voluntary efforts and that the incremental recovery reasonably exceeds the costs. The minimum consent proposed in the act is 70%. The share of production must measure the value of each tract, taking into account acreage quality of oil, geological structure and other factors.

All of the other producing states have incorporated compulsory unitization clauses to their legislation. The usual way is to enforce it when the percentage of operators that agree is greater than a certain minimum. For example, Tennessee has a 50%, Kentucky has a 51%, New York a 60%. Ohio's minimum consent level is 65%, while Alabama is 66.66%, Mississippi has 75% and North Dakota a 50% (Kramer, 2007). They also emphasize that there needs to be an assessment that proves that there will be an important economic benefit, recovery will increase, and if the unit is not reservoir-wide they will not harm other operators.

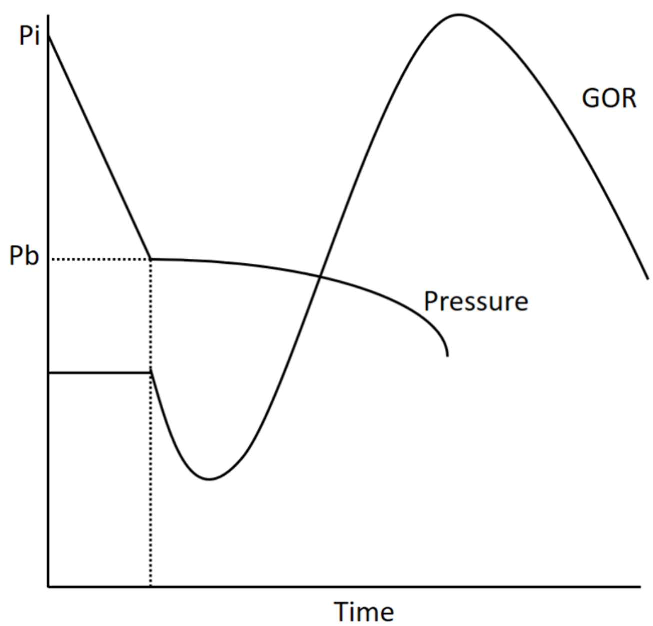
2.2.2 Reservoir Engineering Basics

Spacing rules help prevent mineral owners from capturing hydrocarbons outside their tracts. Nevertheless, operators sharing a common supply source are subject to its natural pressure, which can be reduced significantly when neighbors drill too much and produce too fast. Depletion of pressure is the main reason why overproduction leads to reduced recovery rates. A direct effect of unitization is reducing pressure depletion. Having a basic understanding of the dynamics of pressure is paramount to understand how unitization can mitigate the common pool externality and improve recovery. The objective of this section is to provide basic understanding of the mechanism driving pressure evolution in a hydrocarbons pool.

Reservoirs usually contain gas, liquid oil, and water. The gas can be completely dissolved in the liquid (unsaturated reservoir), or be partially dissolved and form a gas cap above the liquid (saturated reservoir). Most oils have lower density than water so they float above it. During the exploration phase, engineers estimate the pressure-volume-temperature characteristics of the hydrocarbons and the rocks in the reservoir to draw a map called the pressure-temperature diagram, which will determine if the reservoir is a gas or an oil one. Temperature is actually what determines if a reservoir is a gas or an oil one.

The difference in pressure between the reservoir and the wellbore is the force that make fluids travel to the well. The saturation state and water content will determine the driving mechanism that will push the oils towards

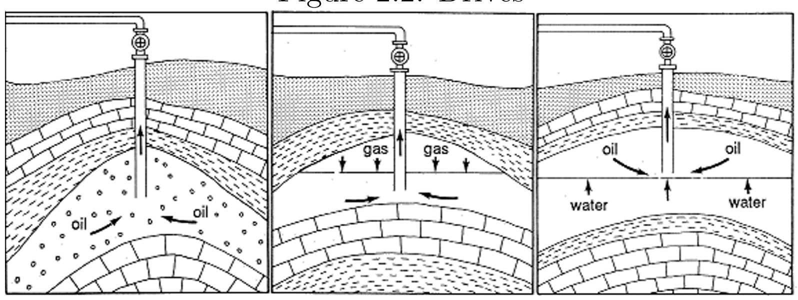
Figure 2.1: Pressure Temperature Diagram



Picture based on Owusul P., 2013

the well. An unsaturated reservoir, has a depletion-drive, which means that the oil be pushed by the bubbles of gas dissolved in it. On saturated reservoirs the expansion of the gas cap forces the oil to move, they are cap-driven. Finally, when the oil is moved by the pressure ejected by the water underneath it, it is said to be water-driven. See figure 2.2 for an illustration. This classification

Figure 2.2: Drives



Source: Kansas Geological Survey 2001 at http://www.kgs.ku.edu/Publications/Oil/primer13.html

is important because it will determine how pressure will evolve as a function of production. It turns out that depletion-driven reservoirs are the fastest to lose pressure, and have a recovery factor between 5% and 30%. Cap-driven reservoirs follow with a recovery factor between 20% and 40%. Water-driven reservoirs tend to last longer and have a greater recovery factor. The drive also determines how the gas-to-oil (GOR) ratio will evolve. Figure 2.1 shows how a depletion-driven reservoir will perform. Before point Pb (bubble point) is reached, pressure will drop very fast, and the gas will be completely dissolved in the oil. This will make the GOR constant. At Pb, a gas cap will start to grow above the oil in the reservoir. This happens because at a pressure bellow point Pb, some of the gas dissolved in the oil will stay in the reservoir, and the GOR will not be constant anymore. The functional form of pressure and the GOR of the model in this paper assumes a cap-drive reservoir, the common pool externality would be even greater in a depletion-driven one.

Reservoirs that do not have enough pressure to lift oil to surface relay on artificial lifting mechanism. Around 95% of all the producing wells in the United States use one of them. More than 80% of such use pumpjacks. A pumpjack inserts a rod into the well with a barrel attached. The barrel has a valve at the bottom which opens when the pumpjack strokes down filling the barrel with the reservoir fluid, and it closes when it moves up. Every up-stroke the bottomhole pressure decreases, and fluid from the reservoir moves towards the wellbore. To control the bottomhole pressure, they use a pump and adjust the number of strokes the pumpjack gives every minute.

To give some perspective, a well fractured in the Eagle Ford Shale can give around 400 barrels each day then decrease exponentially until it stabilizes at around 20% for several years. Of course this depends on the drive, and other characteristics of the reservoir, like the permeability of the rock. Once the reservoir pressure is not enough to move the hydrocarbon to the wellbore, operators evaluate how convenient it is to start a secondary recovery phase. During this phase operators inject energy (in form of heat, water, co2, bacteria) to the reservoir to increase pressure or reduce the viscosity of the hydrocarbon.To execute the secondary recovery phase, either more wells will be drilled, or some existing ones will be converted into injection wells. Unitizing leads to a more efficient execution of this face execution of this phase. When competing, some operators would rather wait and benefit from their neighbors injecting energy to the reservoir than doing it themselves.

2.2.3 Decision Making and Costs

The legal controversy surrounding compulsory unitization helped understand the importance of the issue at hand.The technical aspects governing a reservoir will help modeling the evolution of pressure, oil and gas in a reservoir. To complete the model, it is also important to have some perspective on the costs related to production, and how agents (operators) make decisions. To achieve that, I visited operations of a well drilled in Gonzales County above the Eagle Ford Shale. The operator explained that the business is dominated by sunk costs. The first is the drilling and hydraulic fracturing services which are usually performed by contractors, in this case Schlumberger. The second is leasing mineral rights from land owners. One horizontal well requires at least 40 acres, and in a well explored area, mineral owners could charge up to $10,000 per acre (plus a percentage of the revenue). These costs are paid upfront and will not be recovered. Firms also need a pumpjack and surface storage which will be installed for several years. These investments can be resold but after 20 years of operation its scrap value is usually negligible, especially compared to the sunk costs.

Variable costs are maintenance, transportation, fuel, taxes and the mineral rights lease. Maintenance and fuel are negligible. Mineral owners usually charge a fixed proportion part of the sale. On an explored area this proportional part could go up to 25%. Sales tax is around 7.5% in the Eagle Ford region. Transportation is usually contracted, and they also charge a fixed part per barrel of oil, it could be around 2.5%. In this case, the oil was bought by a third party that homogenize quality at around 90% of the WTI price. This means that even a well on a mature reservoir producing only 10 barrels per day will give profits of around $15,000 each month. The process is completely automated, the pumpjack feeds the storage tanks, once a week the contracted transportation gathers the oil from the tanks, and takes it to the buyer, who pay directly to each stakeholder each month.

Finally, the operator explained that bottomhole pressure and extraction rates are decide based on technical issues, and not on the market price. Price of oil, and forecasts will be considered before incurring sunk costs, but it will not affect operations after such costs are covered.

2.3 Literature Review

Oil production, at the firm's level, is an interdisciplinary topic. Important papers have been published, not only analyzing the economics of unitization, but also legal and technical aspects of it. Law scholars have focused on the comparing and contrasting the efficiency of rules in different states. Petroleum engineers focus on optimizing a well or a reservoir, but not taking into account ownership of mineral rights, nor the organization of firms exploiting a common source. Economists have studied the common pool externality in several industries, the most prominent applications have been in the fishery industry.

When analyzing different states, law scholars usually champion forced pooling and unitization. Kramer, 2007 focuses on contrasting spacing legislation, and forced pooling and unitization between different states with Texas. Throughout the paper, he proves that Texas has been a slow adopter of waste-preventing legislation. He concludes that although the TRRC facilitates starting operations more than any other agency, recovery could improve with forced unitization. Behrens, 2013 analyzes rule 37 and reaches the same conclusion than Kramer. Handlan, 1984 survey compulsory unitization laws across major producing states, they emphasize that the greatest difference comes from the rate of consent required to enforce it.

An important branch of petroleum engineering deals with well optimization (Guyaguler, 2002, Lo, 1995). Some scholars focus on the optimal rate of extraction of oil and gas. For example, Attra, 1961 uses linear programming to find the optimal rate subject to production capacities and reservoir injection. Lo, 1995 maximize daily production by allocating well rates subject to flow rate constraints. Moreover, there are commercial simulators that use ad hoc rules to optimize wells (GEOQUEST, 2000 and LANDMARK, 2001). Reservoir optimization goes beyond production rates. Another important branch combines well daily production rates and well placement. Bittencourt, 1997 use genetic algorithms to optimize a reservoir when decision variables are well placement and well production rates. Guyaguler, 2002 used utility theory to quantify the uncertainty in reservoir developments. Yeten, 2002 investigated the problem of placing horizontal wells.

Garrett Hardin's seminal paper "The Tragedy of the Commons" (Hardin, 1968) ignited a vast empirical literature describing industries facing the common pool externality (McCay, 1987, McGoodwin, 1990, Ostrom, 1990). Further studies suggest that unitization could be an efficient solution to this problem (Balthrop, 2016, Anderson, 2000). Most economists that are intrigued with pooling and unitization as a solution to the common-pool externality study either fisheries around the world (successful contracting cases), or why private contracting usually fails in the oil and gas industry.

The fishing industry offers several examples on how firms cooperate to mitigate the common pool externality. Schott, 2007 proposes a theoretical framework in which fishermen decide the effort they will exert to maximize their profits. The model he uses is a static one, so instead of focusing on resource depletion, he studies how firms reduce overcrowding. He compares different solutions, like prorationing, and concludes that the best way to achieve efficiency is by having several free-riders and a few active fishers that share profits, it is the same principle that unitization in the oil industry. Aburto et al 2008 document how fishing cooperatives in Mexico work. They propose a dynamic model to explain the common pool externality and use a natural weather shock, El Niño Southern variation, to estimate their results. They conclude that during "bad times" cooperatives are more likely to honor agreements.

Kaffine, 2011 propose a spatial dynamic model and conclude that compulsory unitization is also a good option for fisheries, as long as it is complete. They shows that partial unitization might be even worse than working separately. Uchida, 2008 describe an emblematic success story in Suruga Bay, Japan: the Sakureabi Fishery. They explain how fishermen went from individual competition to grouping up in 5 efficient units. They argue that "While competition among individuals within a group was removed, group competition among districts became intense". To deal with that new problem, the 5 districts started working as a single unit. Finally, McWhinnie, 2009 develops a theoretical model concluding that increasing productivity among competitors will exacerbate depletion of the common pool. She surveys 200 pooled fisheries around the world and concludes that overproduction is worse where there are partial cooperative agreements. She explains that when fisheries reduce their marginal cost, competition becomes more fierce accelerating production.

This set of papers shad some light on the difference between the economic implications of pooling and unitization. In the oil industry pooling enables more wells, which is analogous to increase productivity in fisheries, and that exacerbates depletion. In both markets, complete unitization incentivize operators to achieve the efficient outcome, which reduces depletion. Surveying these papers also illustrate that, although pooling contracts can be analogous in the oil and fishery industries, the characteristics of each industry makes their implementation and implications very different. First of all, papers on the fishery industry pay too much attention to nonlinear variable costs (effort), variable costs in oil recovery are linear and negligible. Moreover partial unitization (different to pooling) might help oil recovery, it will worsen fish preservation.

Some authors study how stakeholders in the oil industry have dealt with the common pool externality. Most of the literature focus on explaining why private contracting usually fails. Libecap, 1984 survey three contractual solutions that private firms tried several times during the 20th century: lease consolidation (partial unitization), production under a single firm (full unitization) and prorationing of output. The latter became the dominant solution adopted privately. Production shares were initially determined by the number of wells, which led to over-drilling and rent disruption. Unitization was implemented only when there were few interests in a reservoir. Contracts typically failed because parties needed to agree on the value of different tracts beforehand. On a different paper Libecap, 1985c argue that private contracting is usually not possible due to heterogeneous information. Firms explore different regions of a reservoir, and use different methodologies to estimate its value. When trying to assign value to different tracts, this turns out to be an important barrier.

Libecap, 1985b go beyond failure in private contracting and analyze why regulation has also failed, especially in Texas. Using a very simple reduced form model, they conclude that compulsory unitization rules were approved first in states where small firms, which are usually against unitization, are not very influential. They compare several fields in Texas, Oklahoma and

Wyoming. In Texas there are many small tracts and small firms are influential, not surprisingly compulsory unitization has not been achieved. Reservoirs in Wyoming are in federal land, and the Federal Government only allows unitized firms to exploit them. The authors attribute that to the fact that small firm hardly influence Federal legislation. Oklahoma is a middle ground between these two situations, tracts and (the median) of firms are bigger than in Texas and legislation is more progressive.

Very few empirical papers have tried to prove how unitization increases recovery. Balthrop, 2016 uses a difference in difference approach to estimate the effect of unitization in lifetime production of wells in the Anadarko region. They show that Texan wells in the Oklahoma-Texas border are less productive than Oklahomans. Although the number of unitized wells in that region is low, they attribute this increase of productivity in Oklahoma to unitization. This paper fails to recognize all the other different factors in legislation between both states.

Finally, Liabecap, 2001 develop a model that suggests that under some specific circumstances it is impossible to identify a sharing rule such that unitization Pareto-dominates the initial endowments. The main contribution of this paper is that it is the only economic paper that exploits the presence of oil and gas in the reservoir (not only oil). They explain that if there are two firms sharing a reservoir, and firm one has a bigger interest in gas than oil and vice-versa, then unitization might yield a distribution of risk that makes firms worst than they were with their initial endowments. The model

I will present here also exploits the fact that reservoirs have more than one substance. Nevertheless both models are fundamentally different, mine focuses on dynamics and Libecap's is a static one.

2.4 Model

As discussed in the background section, accelerated oil production leads to lower overall recovery. Since the viscosity of gas is lower than oil's it travels faster. Moreover, the speed difference is an increasing function of pressure change, which implies that as production rate increases, gas escapes faster. In cap-driven and depletion-driven reservoirs the gas in the reservoir generates the pressure that makes the oil move to the wellbore. Lack of gas means lack of pressure, which translates into oil trapped. The results presented here will assume that gas is flared, which is a very common practice, especially in new developments lacking pipelines (Seeley, 2014).

The model proposed in this section captures these ideas to assess how the composition of firms sharing a common supply will impact overall oil recovery. The existing literature suggests that single firms, and big operators will produce slower than multiple firms and small operators. Moreover, it is documented that big firms prefer to unitize, and small firms benefit from overproduction. The model will yield all these results. Finally, the hydrocarbons and rock characteristics also matter. For example, if the oil-to-gas ratio is high and the oil viscosity low, overproduction will not hurt recovery too much. The the model will explain how this affects unitization.

First suppose there is only one operator. Assume that the initial oil and gas in the reservoir at time t are T_{ot} and T_{gt} respectively. The rate of extraction of both substances depends on the difference between the bottomhole pressure and the reservoir pressure. Let Pb_t be the bottomhole pressure induced by the operator and Pr_t be the average reservoir pressure at time t. Assume that each substance's production rate depends on this difference in pressure as shown in equation 2.1.

$$n_{it} = W\alpha_i(Pr_t - Pb_t)^{\beta_i}\frac{T_{it}}{T_{it} + T_{-it}}, \tag{2.1}$$

where $i = o$ if the substance is oil and $i = g$ if it is gas, and W is the number of wells the operator has drilled in the reservoir.

This functional form has some features worth mentioning. The parameters are α and β, they will dictate the difference in extraction rate between both substances. Since gas moves faster than oil, and the difference in speed is increasing with the change in pressure, we expect $\beta_g > \beta_o$. The difference of speed depends on viscosity, so β_o and β_g will be the viscosity parameters. The difference in αs will homogenize volume unit between oil and gas, and the scale will be a proxy for permeability[3]. Moreover, the proportion of each hydrocarbon impacts the rate of extraction. If there is much more oil than gas, regardless of the difference in pressure, production of oil will be higher. I will assume that the number of wells is given, note that having more wells

[3]Permeability of rock and viscosity are the most important characteristics that determine how substances will react to a change in pressure.

will help decrease the amount of gas wasted[4]. This happens because the same amount of oil can be extracted by inducing a higher bottomhole pressure in separate spots of the reservoir.

Pressure is a function of mass in the reservoir and its volume[5]. Initial oil, gas and pressure will also be important parameters of the model. Pressure will decrease as cumulative production of oil and gas increases. Let $T_I = T_{o0} + T_{g0}$ be the initial substance in the pool, and P_I be the initial pressure. Cumulative substance produced at time t will then be $c_t = T_I - T_{ot} - T_{gt}$. The pressure of the reservoir evolves as follows:

$$Pr_t = Pr_I \left[1 - a\left(\frac{c_t}{T_I}\right) - (1-a)\left(\frac{c_t}{T_I}\right)^2 \right], \tag{2.2}$$

where $a \in [0,1]$ establishes the linearity of the relation between pressure and production (Ahmed, 2000). Note that before production starts $c_0 = 0 \implies Pr_0 = Pr_I$, and that $C_t = T_I \implies Pr_t = 0$.

Equations 2.1 and 2.2 describe the dynamics of a reservoir. They are a very simplified version of a reservoir simulator. Petroleum engineers have developed very accurate reservoir simulators based on Darcy equation and the material balance equation. They deal with complicated features most reservoirs have, for example: multiple drives; uneven permeability, viscosity and composition throughout the reservoir; and well placement. The simplification

[4]It is straight forward to endogenize number of wells in the model. Nevertheless, it will complicate optimality conditions and make simulation slower. Remember that the focus of this paper is recovery rate and not over-investment. See further research in Conclusions.

[5]... and many other factor like temperature which will not be considered here.

used in this paper is good for its purpose, though it would be interesting to further estimate this model with real data, and using one of these simulators could yield very accurate results.

Each period, operators will observe the amount of oil and gas left in the reservoir and decide the bottomhole pressure they will induce. This policy function is the last ingredient we need to describe how pressure, gas depletion and oil production will evolve in the reservoir. I will assume operators cannot exert a minimum bottomhole pressure lower than p_{bmin}. Figure 2.3 illustrates the negative effects of accelerated production. The x-axis in both graphs is oil production, the y-axis in the left one is reservoir pressure, and in the right one it is gas flared. The red line is when production happened in two steps and the blue one when it happened in only one step. In both situations oil produced is the same, but when it happens slower less gas is wasted, and more pressure remains in the reservoir for next period.

Figure 2.3: Pressure response to accelerated production

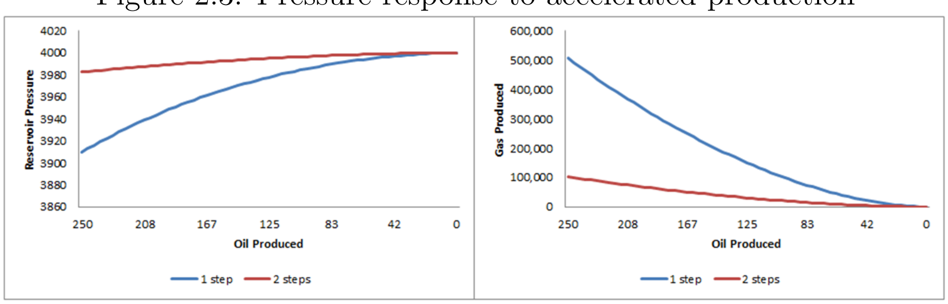
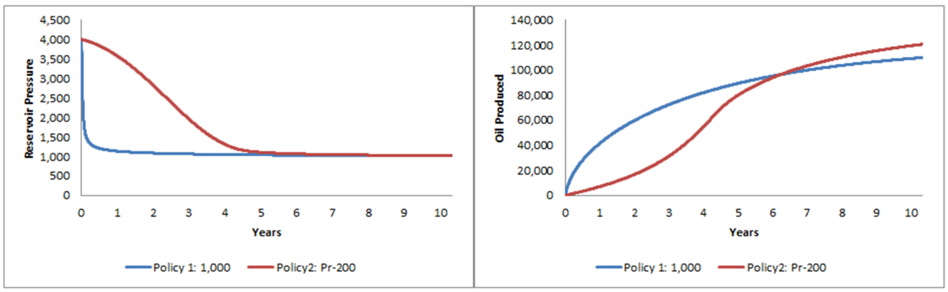


Figure 2.4 shows the evolution of pressure and cumulative production under two policies. The blue line describes the policy of inducing a bottomhole pressure of 1,000 regardless of oil and gas left. The red line describes the policy

of exerting a bottomhole pressure 200 psi lower than the reservoir pressure. Note how the first policy yields a higher production first, but depletes pressure faster, overall recovery after 10 years is higher under the second policy.

Figure 2.4: Policy comparison



Let β be the one-period discount factor. Firms will typically maximize discounted profits assuming an infinite horizon. Profits at time t will be $\pi_t = (p_t - vc)n_{ot} - FC$. Future price is unknown and stochastic, vc, and FC are constant. Since operators do not take price into account when deciding extraction rates and vc is constant, I will simplify the utility function by assuming that firms maximize discounted oil extraction. To deal with FC, I will assume that they will only produce above a minimum threshold, which will be close to 0. Summing everything together, the maximization problem single operators will solve is:

$$
\begin{aligned}
V_u(To,Tg) &= \max_{pb}(n_o + V_u(To',Tg')) \\
Pr &= Pr_I\left[1 - a\left(\frac{c}{T_I}\right) - (1-a)\left(\frac{c}{T_I}\right)^2\right] \\
c &= T_I - To - Tg \\
n_o &= W\alpha_o(Pr - Pb)^{\beta_o}\frac{T_o}{T_o+T_g} \\
n_g &= W\alpha_g(Pr - Pb)^{\beta_g}\frac{T_g}{T_o+T_g} \\
To' &= To - n_o \\
Tg' &= Tg - n_g \\
Pb &\geq Pb_{min}
\end{aligned}
\tag{2.3}
$$

To derive the optimality conditions, it will be easier to rewrite the problem eliminating pressure and gas production. One way to go about it is by combining oil and gas production to eliminate bottomhole and reservoir pressure. We can then write gas produced as a function of oil produced:

$$
n_g = G(n_o,To,Tg) = \left[\frac{\alpha_g Tg}{(To+Tg)}\right]\left[\frac{(To+Tg)}{\alpha_o To}\right]^{\frac{\beta_g}{\beta_o}} n_o^{\frac{\beta_g}{\beta_o}}
\tag{2.4}
$$

Now we only need to rewrite the inequality condition without any pressure term. Let

$$
F(To,Tg) = Pr = Pr_I\left[1 - a\left(\frac{c}{T_I}\right) - (1-a)\left(\frac{c}{T_I}\right)^2\right],
\tag{2.5}
$$

then note that the following inequalities are equivalent.

$$
Pb \geq Pb_{min} \Longleftrightarrow n \leq W\alpha_o(F(To,Tg) - Pb_{min})^{\beta_o}\frac{T_o}{T_o+T_g}.
\tag{2.6}
$$

The simplified optimization problem is:

$$\begin{aligned} V_u(To, Tg) &= \max_n (n + V_u(To', Tg')) \\ To' &= To - n \\ Tg' &= Tg - G(n, To, Tg) \\ n &\le W\alpha_o (F(To, Tg) - Pb_{min})^{\beta_o} \frac{T_o}{T_o + T_g} \end{aligned} \tag{2.7}$$

Note that when the inequality condition holds with equality, the solution of the system is trivial. Solving the strict inequality case, we will produce the intertemporal conditions shown in equation below:

$$\begin{aligned} 1 - G_{Tg}(t+2) &= \frac{1}{\beta} \frac{(1 - G_{Tg}(t+2))G_n(t+1) - G_n(t+2) - G_{To}(t+2)}{(1 - G_{Tg}(t+1))G_n(t) - G_{To}(t+1) - G_n(t+1)} \\ To' &= To - n \\ Tg' &= Tg - G(t), \end{aligned} \tag{2.8}$$

where $G(t) = G(n, To, Tg)$, $G(t{+}1) = G(n'(To, Tg), To'(To, Tg), Tg'(To, Tg))$, and $G(t+2) = G(n'(To', Tg'), To'(To', Tg'), Tg'(To', Tg'))$,

Now suppose that there are N firms, each endowed with n_i wells. The first period firms will vote for, or against unitization. If the number of firms that want to unitize is greater than a certain percentage[6], the state will enforce unitization and a single operator will exploit the reservoir. Profits will be shared according to size, and the proxy for size we are currently using is endowment of wells[7]. The single operator will solve problem 2.3, with $W =$

[6]That percentage depends on the state. For Texas it would be 100%.

[7]Libecap proved that contracts contingent on the number of wells lead to overproduction Libecap, 1984. That critic does not apply here because number of wells is given.

$\sum W_i$. If they are not unitized, each period firms will simultaneously induce p_{bi} to produce in accordance to equation 2.1. Gas and oil next period will be $Tg' = Tg - \sum n_{gi}$ and $To' = To - \sum n_{oi}$ respectively. Since reservoir pressure is a decreasing function of the oil and gas left, accelerated production will also reduce it.

The simplified version of the problem firms solve under competition is very similar to 2.7. Let $n_i(To, Tg, n_{-i})$ be the oil player i produces given To, Tg, and other player's strategies n_{-i}. Given n^*_{-i}, player i finds n^*_i to solve[8]:

$$\begin{aligned} V_i(To, Tg, n^*_{-i}) = \max_{n_i} (n_i + V_u(To', Tg', n^*_{-i})) \\ To' = To - n_i - \sum_{j \neq i} n^*_j \\ Tg' = Tg - G(n_i, To, Tg) - \sum_{j \neq i} G(n^*_j, To, Tg) \\ n_i \leq W\alpha_o(F(To, Tg) - Pb_{min})^{\beta_o} \frac{T_o}{T_o + T_g} \end{aligned} \tag{2.9}$$

The first intertemporal condition of this problem will be exactly the same as the one in 2.8. The second and the third differ in an obvious way, making it easy to identify the common pool externality. In this case, deriving the dynamics of the model based on the optimality conditions is very complicated, and maybe even impossible. A better way to further explore the model will be to simulate solutions using different sets of parameters.

[8]Note that the equilibrium condition is already defined in the problem since the value function is valuated at n^*_{-i}

2.5 Simulation

The main objective of this model is to find out how oil recovery and profits will increase by unitizing tracts given reservoir characteristics and the composition of firms (size and number) with interests a common field. I also want to assess when firms achieve unitization by private contracting (unanimously) and when they need some help from legislators. Remember that the characteristics of a reservoir that will influence its dynamics are permeability, viscosity and amount of hydrocarbons, and that the $\beta_i s$ and $\alpha_i s$ are the viscosity and permeability, respectively. In this section I will show how unitization influences outputs and dynamics for different sets of parameters. I will also show when unitization will be achieved privately.

To simulate different instances, I solved the program using the value function iteration algorithm. The value function, as well as its two variables, were discretized using a 100-point grid. The decision variable is bottomhole pressure, and it was discretized using 1,000 values. For each instance, the algorithm takes around 20 minutes to converge, so the grid could easily be extended and converge in a reasonable time. Moreover, simulating assuming number of wells is endogenous could also be achieved in a reasonable time by paralleling the algorithm.

The algorithm was run several times for different sets of parameters, although only three combinations that yield important insights will be presented here. See parameters used in table 2.1. For each combination, I computed the value function and dynamics under unitization, and under two different not unitized cases.

Table 2.1: Simulation Parameters

	Combination 1	**Combination 2**	**Combination 3**
To	$1,000,000$	$1,000,000$	$100,000,000$
Tg	$10,000,000$	$5,000,000$	0
α_o	2	1	1
α_g	0.5	1	1
β_o	1	1	1
β_g	1.8	1.5	1.5
W	6	10	6
a	0.9	0.2	0.2

One where both firms have the same number of wells, and the other where firm 2 has 1 well and firm 1 the rest. For example, combination 1 represents a reservoir with 6 wells. Under the unitized scheme a single operator manages them all. Under the symmetric case, each firm has 3 wells. Under the asymmetric case firm 1 has 5 wells and firm 2 has 1 well. There were always only two firms.

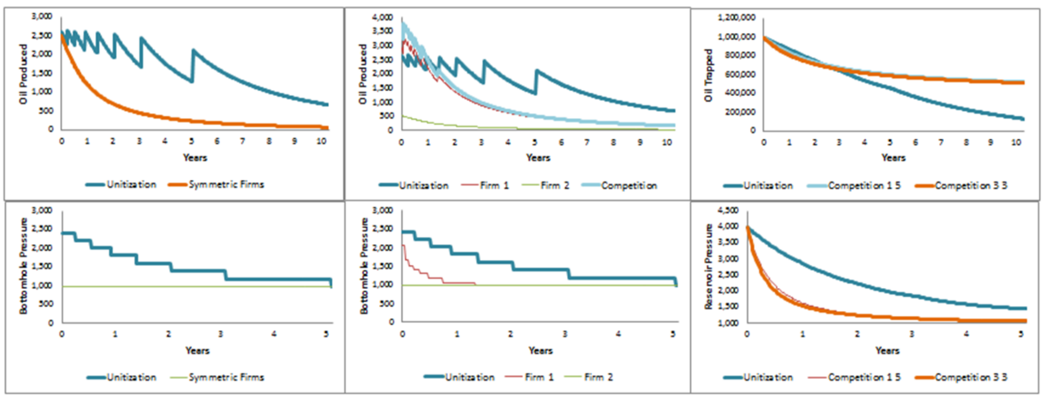
First focus on combination 1 and combination 2. The proportion of gas to oil, the viscosity difference (βs) between substances, and rock permeability are higher in combination 1 compared to those in combination 2. Moreover, in the asymmetric case in combination 2, firm 2 controls basically all the reservoir. Considering all this, we would expect that unitizing will increase overall value more in combination 1 than in combination 2. When comparing results between the same combination, we expect that unitization has a bigger impact in the symmetric case. The reason is that in the asymmetric case the most influential firm will control a greater part of the reservoir. It is in its best interest to act preserve pressure. Finally, we expect that private contracts will more likely be reached in the symmetric case than in the asymmetric case, otherwise we would be contradicting all previous literature. Combination 3, the naive one, explores what happens when there is no gas in the reservoir. Since depletion of gas is the mechanism that causes waste, we expect to always get the same results.

Simulation results are shown in figure 2.5. The table at the top summarizes how value function behaves under the scenarios studied. As expected, the difference in combination 1 is greater than the difference in combination 2, the differences are 26% and 5% respectively. Moreover for both combinations the increase in value due to unitization is greater under the symmetric case. Finally, symmetric firms unanimously decide to unitize, whereas only big firms in the asymmetric case vote for it. Here is where legislation becomes relevant. North Dakota Industrial Commission would make them work as a unit, the Texas Railroad Commission would not. The graphs below show how the dynamics of oil production, oil trap, pressure induced, and reservoir pressure differ. The left-most graphs compare unitization to the symmetric case, the middle ones compare unitization to the asymmetric case and the right-most ones compare results between unitized, symmetric and asymmetric cases. Note how under unitization (blue thick lines) overall production is lower at the beginning and higher later on. Overall recovery after 10 years is higher, and pressure depletion lower.

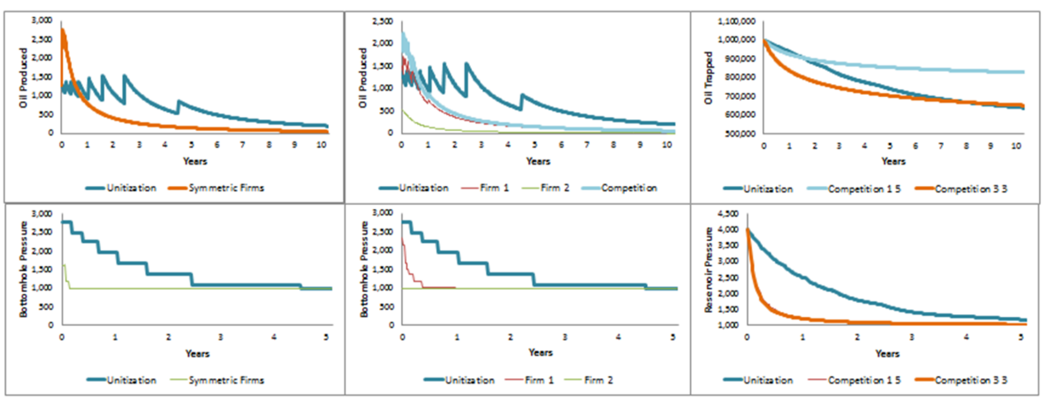
Figure 2.5: Simulation Results

VALUE FUNCTION												
	Combination 1				Combination 2				Combination 3: Naïve			
	Symmetric case (6 wells)		Firm 1: 5 w Firm 2: 1 w		Symmetric case (10 wells)		Firm 1: 9 w Firm 2: 1 w		Symmetric case (6 wells)		Firm 1: 5 w Firm 2: 1 w	
	Unitization	Competition	Unitization	Competition	Unitization	Competition	Unitization	Competition	Unitization	Competition	Unitization	Competition
Total	44,296	35,121	44,296	38,565	76,114	72,201	76,114	74,358	979,942	979,942	979,942	979,942
Firm 1	22,148	17,485	44,296	29,945	38,057	36,101	68,503	65,885	489,971	489,971	816,618	816,618
Firm 2	22,148	17,636	7,383	8,620	38,057	36,101	7,611	8,472	489,971	489,971	163,324	163,324
	100% APROVED!		50% DENIED!		100% APROVED!		50% DENIED!		INDIFFERENT		INDIFFERENT	

Combination 1



Combination 2



2.6 Conclusion

The common pool externality has intrigued many economists since Hardin's seminal paper in 1968. Many scholars have contributed to the literature by studying different industries. Sharing an oil reservoir is a typical example, and currently an important one. Private contracting has proven to be difficult to achieve, and most states have reacted by making it compulsory. Enforced unitization is currently a controversial topic in the Texas House of Representatives.

Most scholars that study unitization as a solution of the common pool externality in the oil industry focus on explaining why private contracting fails, and assume it will always improve outcomes. A few have tried to document how such outcome has improved in the past. The model in this paper achieves both things simultaneously. It quantifies the potential gains in value and recovery, while predicting if private contracting will be successful. Moreover, it achieves it by incorporating the mechanics that relate overproduction with reduced recovery: the presence of another substance. The simulations in the paper clearly show how different characteristics of a reservoir, and firms composition -number and size- will affect the likelihood to achieve private contracting, value of tracts, and overall oil recovery.

One of the main contributions of this paper is its potential for further research. Rust motivates his seminal paper using a single agent dynamic model **rust** Then he argues that to match reality, a structural stochastic error is needed. That said, an interesting line of research would be to introduce a structural error to the model that represents what firms know about the reservoir that econometricians do not, and use the widely available data to estimate the parameters in the model. On a second, and fundamentally different approach, researchers could use a reservoir simulator to predict recovery of oil in a reservoir optimized as a whole (unitized) and how it will differ if it was optimized by parts (not unitized). Comparing the results obtained using these two approaches will yield another example of how well the structural models used in economics perform when econometricians do not observe all the data.

Throughout the paper, I emphasize that overproducing diminishes recovery because more gas is wasted. When capturing that gas is not economically convenient it is flared. Recently, some states passed stringent laws to reduce flares, and there have been some signs that this is reducing production (Seeley, 2014). Up to now, the effects this new legislation seem to go on the same direction that unitizing tracts. There are several interesting questions surrounding these facts, for example: are unitized firms being less affected than the others? how will small firms that typically overproduce react? do we expect to see more units formed voluntarily? can these rules substitute compulsory unitization?

Finally, it is well documented that in the fishery industry partial unitization usually worsen overproduction. It is not obvious that the same will happen in the oil industry. As far as I know, there is no research on that. The model in this paper shows that the outcome is better when there is a small firm and a big firm than when there are two middle-size firms sharing a pool.

This might suggest that partial unititization might also make things worse in the oil and gas industry.

Chapter 3

A reduced-form approach to study well productivity changes under compulsory unitization

3.1 Introduction

A way to deal with the common pool externality that happens when several firms try to extract hydrocarbons from the same field is to assign a single operator to exploit each field. Every major state regulatory agency allows such contracts as long as every firm involved agree, such contracts are known voluntary unitization. Since legislators have not observed as many unitization contracts as they expected given the efficiency gains, they came up with a stronger version in which they can force firms to join units if there is enough consensus amonth the operators in a field that a single operator would improve efficiency and profits. By now, every major producing state, but Texas, has a form of compulsory unitization in its legislation.

In this paper, I will take advantage of the fact that New Mexico and Texas have different compulsory unitization policies to measure the that having compulsory unitization has in well productivity. As explained before, Texas does not enforce compulsory unitization, while New Mexico does. Also, New Mexico and Texas have a large border and there are important reservoirs, e.g.

the Permian Basin, which encompasse area in both states. Moreover, New Mexico passed compulsory unitization in 1977, this gives enough time to analyze how the policy affected efficiency in production. I have oil production data and location of wells from 1970 onward. I use the policy change in New Mexico to adjust a difference in difference design (DID) to analyze how compulsory unitization affected efficiency. Moreover, I use the fields in the border to also analyze the problem from a regression discontinuity (RD) perspective.

The RD results suggest that in New Mexico production throughout the life of a well is between 2,239 and 2,664 barrels higher than in Texas. There seems to be no significant differences in other variables such as depth of wells, elevation, location of wells, and drilling year. The DID estimation suggests that compulsory unitization increased the efficiency of wells in between 2,551 and 3,872 barrels. The robustness results suggest that there were not significant differences in trends before treatment.

Libecap, 1984 surveyed three contractual solutions to the CPE that firms and legislators tried during the 20th century. Their paper shows that unitization is most efficient solution, but is not as used as one would expect. Following up on this insight, Libecap, 1985c argue that a potential resason for failing to form units is private information. Importantly, Libecap, 1985a conclude that compulsory unitization was approved first in states where small firms are not very influential. Suggesting that the lobby of small firms prevents the TRRC to implement compulsory unitization. More recently, Balthrop, 2016 proposed a difference in difference approach contrasting Oklahoma and

Texas to conclude that wells in Oklahoma are more productive than wells in Texas due to the fact that there is compulsory unitization in Oklahoma. My paper directly builds on Balthrop, 2016 in two ways. First, it also fits an RD design, but applies it to a different state corroborating their results. Second, my paper further isolates the effect of compulsory unitization by leveraging from the fact that I have data before and after the policy change so I can also implement a DID approach.

In the next section of the paper, I will give the necessary institutional details to understand the research strategy and the results. In section 3, I will describe the data sources and show the summary statistics of the main variables analyzed throughout the paper. In section 4, I will review the research strategy. Section 5 shows the result, and a brief discussion of them. Finally, in section 6 I will conclude.

3.2 Background

When several operators exploit the same oil field they are entitled to the same hydrocarbons and the same pressure that helps pushing those hydrocarbons up to the ground. The rule of capture in the United States dictates that whoever extract the hydrocarbons first is entitled to keep them without any liability, regardless of where they were originally found. Oil and gas are fluids, and they will travel underneath the land to wherever there is less pressure, for example an oil well. These facts combined incentivize firms to extract oil faster than they would do otherwise in order to capture its neighbor oil.

Figure 3.1: Common Pool Externality

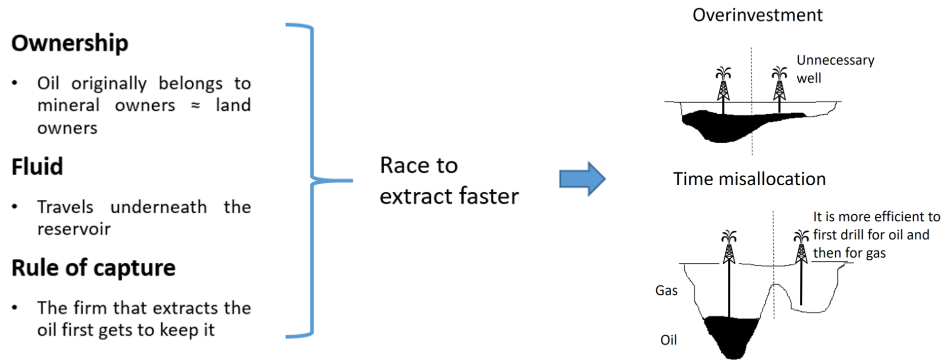


Figure 3.1 illustrates the situation.

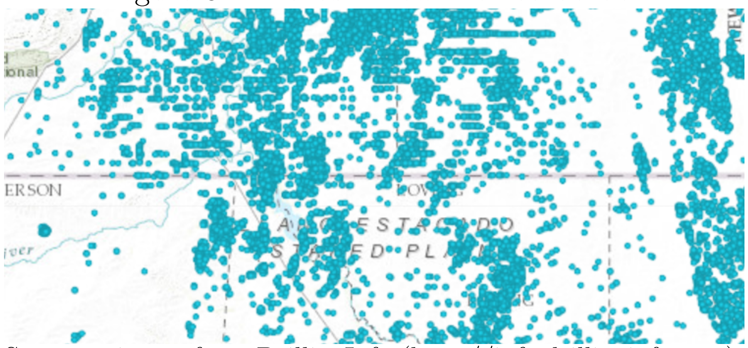
A way to mitigate the negative effect of the common pool externality (CPE) is to assign a single operator to exploit the entire field. Every state regulatory agency in the United States offers a legal mechanism that allows firms to assign a single operator called voluntary unitization. Every voluntary unitization agreement needs to specify three things: who will be the single operator; what is the area being unitized; and how firms will share profits. Moreover, to approve units, most regulators impose two conditions: the first is that the way in which firms share profits must be fair; and the second is that fields seeking unitization must be reasonably developed.

History has shown that we do not see units formed voluntarily as often as one would expect given the efficiency gains. By 1947, only 12 of the 3,000 fields in the United states were fully unitized (Libecap, 1984). Researchers have attributed this failure in unitization to several reasons. For example, Libecap, 1984 claim that contracts typically failed because parties needed to agree on the value of different tracts beforehand. On a different paper Libecap, 1985c argue that private contracting is usually not possible due to heterogeneous information. Weaver, 2011 argues that there are several reasons why this is the case: difficulty in agreeing on how to share profits; firms holding out for more favorable bargaining powers; lack of reservoir data that reduces uncertainty; there will be a change in the time pattern of production; producers value ownership and control; and mistrust on the capacity to exploit the tract efficiently by another party.

Regardless of the reason why voluntary unitization has failed in the past, this failure in private contracting has encouraged regulators to incorporate compulsory unitization to their efficiency-enhancement-kit. Under compulsory unitization, regulating agencies can force firms that do not want to join a unit to join. The extra condition agencies put to compulsory unitization is that there needs to be enough consensus among firms that will potentially join the unit that achieving such unit will result in more efficient operations. Every state that allows compulsory unitization puts that minimum threshold in consensus as a percentage of the field area. For example, assume a state with a minimum threshold of 70% and a field with three firms, such that firm one has 60% of the area of the field, and the other two firms have 20% each. If firm one wants to form a unit and any other of the two firms also wants, then they would reach an agreement of 80%, and they can ask the regulator of such state to make the other firm join the unit.

As stated in the introduction, the objective of this paper is to measure

Figure 3.2: Texas - New Mexico border



Source: picture from DrillingInfo (http://info.drillinginfo.com), January 16, 2017.

how having compulsory unitization in a state can increase efficiency. New Mexico and Texas offer a good natural experiment to answer this research question. The states share a border which is around 540 miles long. In terms of oil production, New Mexico is the 5th biggest state and Texas is the biggest. The area in both sides of the border has been heavily exploited. Figure 3.2 shows the drilling activity in a section of the border.

In terms of policy, the main difference between Texas and New Mexico is that in New Mexico there is compulsory unitization since 1977 (NMAC §70.2.17), but not in Texas. Balthrop, 2016 analyzes the differences in oil conservation policy between Texas and Oklahoma. They focus on differences between well spacing restrictions, production quotas, severance taxes, and compulsory unitization. I will follow the same approach to conclude that for the most part, policy in Texas and New Mexico is quite similar, and the main difference is that there is compulsory unitization in New Mexico, but not in Texas.

Starting with spacing legislation, New Mexico and Texas ask firms to have at least 40 acres of land leased in order to drill an oil well. Moreover, Oklahoma and New Mexico state that firms cannot drill wells within 330 feet from a property line, whereas Texas asks for 467 feet. Although the Texas legislation seems to be more restrictive, I will follow Balthrop, 2016 and argue that fields and leases close to the border tend to be big so this will not be a problem when implementing the regression discontinuity approach. With respect to production quotas both states establish production allowances that vary with depth of wells and acres leased. Wallace, 2011 presents the allowances for Texas. The New Mexico ones can be found in (NMAC §19.15.20). Both schedules are quit similar, for example, in New Mexico a 40 acre lease with a 5,000 feet deep well would allow a firm to extract 107 barrels of oil a day, and in Texas 102. Finally, in terms of production tax, according to Clifford, 2008, the average production tax paid in Texas is 6.5% and in New Mexico it is 7.5%. In terms of compulsory unitization, Texas only allows unitization when everyone in the unit agreed to join. New Mexico can force firms to join a unit. It states that the minimum threshold of agreement is 75%.

3.3 Data

All the data for the analysis was provided by DrillingInfo[1] (DI). DI compiles several attributes of every well and lease in most of the states in the United States. DI organizes the data by state in several tables, all the data

[1] http://info.drillinginfo.com/

for this paper comes from the production tables of Texas and New Mexico. For Texas, DI has production data since 1934, and for New Mexico since 1970. The TRRC collects production data at lease level, and the DI data comes from the TRRC. The Oil Conservation Division in New Mexico collects production at well level. To make production in both states comparable, I will follow the approach used by (diddude) and assume that every well in a lease in Texas produce the same amount of oil.

The main variable I use throughout my analysis is cumulative production of oil by lease/well. I am also analyzing production during the first 6 months and during the first 5 years. DI also provides the latitude and longitude of each well. This will be especially important when applying RD. Also, to implement robustness checks, I will analyze some geographical variables that should not change drastically with policy. These variables are depth of wells and the elevation of the terrain. Finally, the DI data also contains drilling dates. I will use this variable to select my sample and perform further robustness checks.

For the main results of the RD part of the paper, I limited the sample to wells no more than 10 miles away from the border between Texas and New Mexico. Also, since compulsory unitization exists in New Mexico since 1977, I only consider wells that were drill after 1978. For the DID part of the paper, I consider wells drilled before and after 1977. Since the New Mexico data goes back to 1970, I study the period 7 years before the policy change and 7 years after the policy change, from 1970 to 1984.

Table 3.1 presents the summary statistics of the relevant variables in both states and for different distances from the border between the states. The leading results of the paper will concern the horizontal segment of the border, so table 3.1 only considers these wells[2]. The main conclusions of the paper will be drawn by comparing the Cumulative Oil variable in the 1 mile range. Note that the summary statistics suggests that wells in New Mexico are slightly more productive than wells in Texas. Also note that the year when these wells were drilled, the depth of the wells and the elevation do not vary drastically. Interestingly, the relative difference in production was greater taking only relative production in the first 6 months than taking the overall cumulative production. This suggests that wells in New Mexico produce at a much higher rate at the beginning than wells in Texas but that difference diminishes with time. Anderson, Forthcoming suggests that firms increase or decrease production by drilling or stop drilling, and not by altering production from producing wells. So one interpretation we could give to this contrast in production is that firms in New Mexico only drill wells with bigger paybacks than those in Texas.

Figure 3.3 shows the average of the cumulative production of wells drilled each year from 1970 to 1985 by state. The figure is important for the DID approach. Note how in years previous to the treatment the trend in production is similar between both states. New Mexico consistently presents

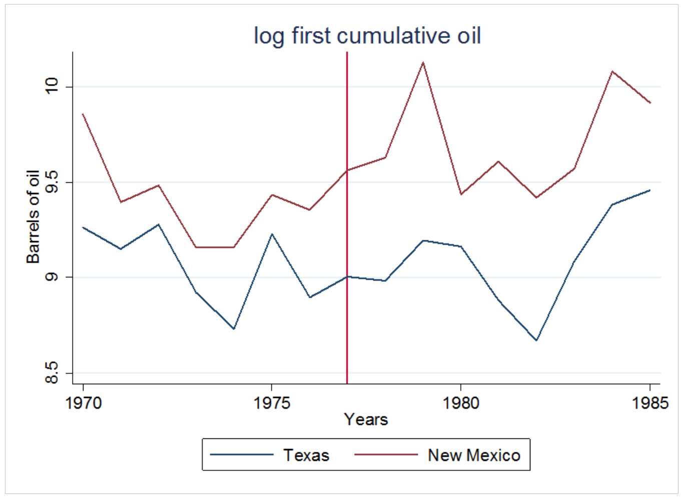
[2]The summary statistics for the vertical part of the border are in Appendix 2, along with all the other results that take the vertical segment of the border as reference

Table 3.1: Summary Statistics

Border	1 mile		5 mile		10 mile	
State	TX	NM	TX	NM	TX	NM
Ln 6 Month	6.05	7.19	6.17	7.00	6.24	7.35
	6.08	7.51	6.4	7.27	6.39	7.51
	1.22	1.5	1.54	1.62	1.4	1.79
Ln 5 Year	8.45	9.06	8.5	8.92	8.56	9.28
	8.61	9.46	8.65	9.34	8.84	9.5
	0.98	1.5	1.3	1.56	1.29	1.64
LnCummulative	9.29	9.73	9.09	9.48	9.21	9.83
	9.5	10.09	9.33	10.04	9.5	10.31
	1.08	1.74	1.61	1.92	1.41	1.97
Latitude	31.99	32.01	31.95	32.04	31.88	32.11
	31.99	32.01	31.94	32.03	31.87	32.13
	0.01	0.01	0.03	0.03	0.05	0.07
Longitude	-103.65	-103.63	-103.69	-103.59	-103.64	-103.47
	-103.9	-103.85	-103.9	-103.7	-103.55	-103.27
	0.38	0.35	0.37	0.36	0.31	0.37
Year First prod	1990	1990	1989	1990	1991	1993
	1988	1989	1989	1989	1989	1993
	8.6	6.08	8.2	7.05	9.54	6.67
Depth	5213	4824	5094	5427	5546	6656
	3800	5087	4000	5170	4870	6100
	3424	2783	3711	3119	3001	3759
Elevation	2890	2977	2920	3076	2933	3153
	2893	2933	2905	2980	2928	3133
	230	173	262	1620	271	1018
Observations	209	198	754	393	2409	1022

For every variable, the first row is the mean, the second the median and the third the standard deviation. Each column refers to a specific state and only takes wells within the specified distance from the horizontal part of the border between Texas and New Mexico.

Figure 3.3: Cumulative oil production by well in New Mexico and Texas



Notes: The lines represent the average cumulative production of each well drilled in a given year in Texas and New Mexico.

a higher average than Texas, but the gap widens after 1977. The trends are still similar after the treatment year, but the gap is larger. This suggests that applying a difference in difference approach to this data is valid[3].

Finally, figure 3.4 shows a linear trend of the value of different variables in wells drilled close to the horizontal segment of the border between Texas and New Mexico after 1978. Note that the axes of the graphs are not exactly the same in every graph. The domain of each plot was chosen to optimize the similitude in linear trend in each side of the border. Note that for both variables that represent production the graphs suggest that there will be an increase when crossing the border. We do not see a significant difference in

[3]The same graph for 6 month and 5 year production is can be found in the appendix.

the value of the rest of the variables[4].

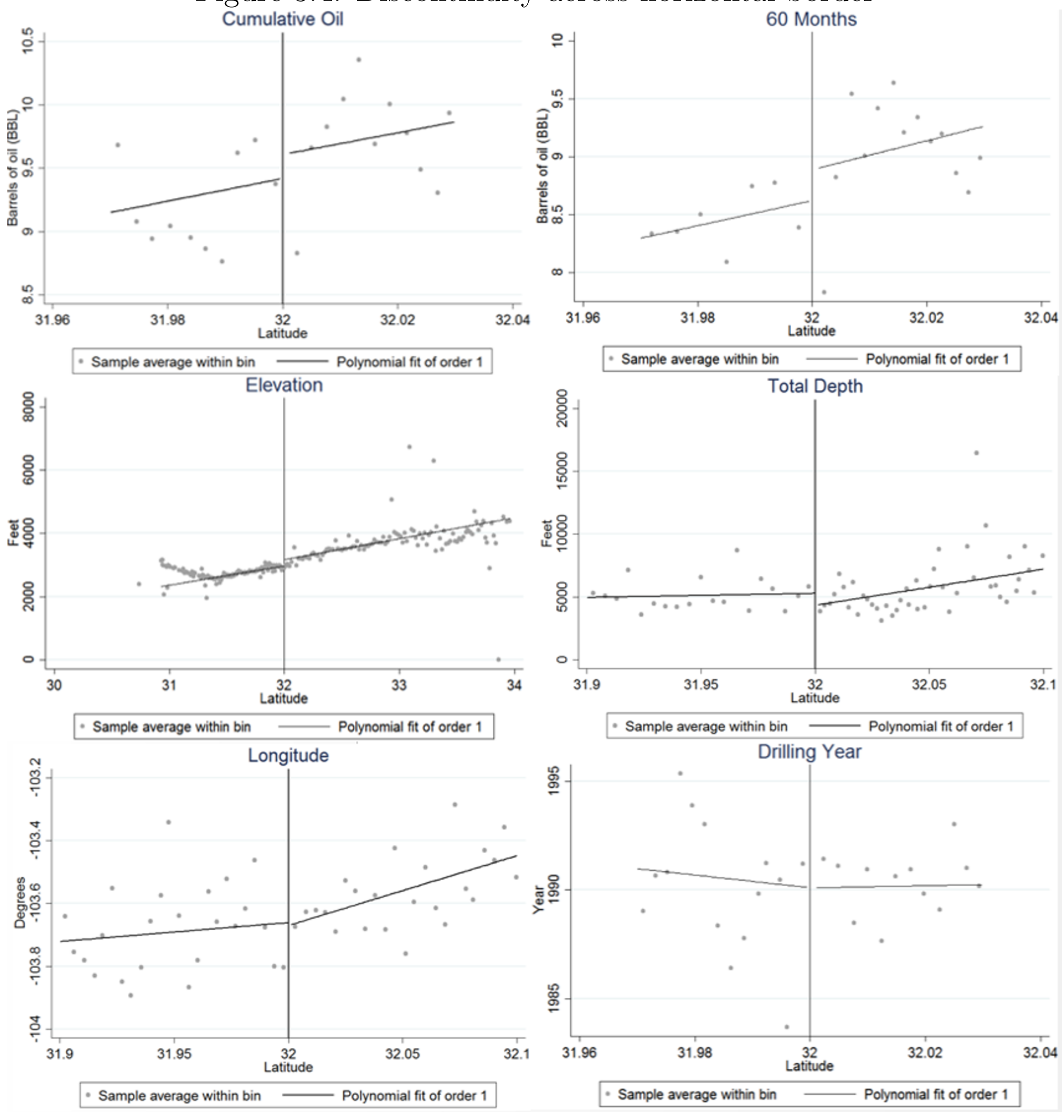
To summarize, in this section I described the main variables and data sources that will be analyzed throughout the paper. I then presented the summary statistics for those variables in both sides of the border. The last part of the section shows figures that suggest that applying DID and RD in this scenario is valid.

3.4 Research Strategy

Ideally, to estimate the effect of having compulsory unitization on the efficiency in production of oil, one would run a randomized experiment in which some fields are subject to compulsory unitization but others are not. Unfortunately, it is not feasible to implement such experiment. Other two options a researcher would have are: estimating a structural model and find the respective counterfactuals; or relay on reduced-form techniques to estimate the average effect of having compulsory unitization. As stated in the introduction, chapter four will deal with the structural model. In this chapter, I will leverage from the data described and the policy change in New Mexico to estimate the treatment effect using regression discontinuity and difference in difference techniques.

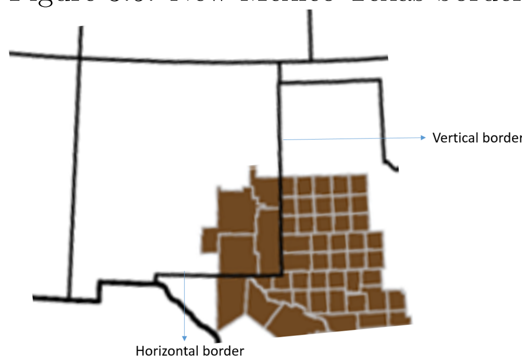
[4]I show the same graph for the vertical segment of the border in Appendix 2. Note that the pictures in Appendix 2 suggest that the assumptions for the DID approach apply better for the horizontal segment of the border.

Figure 3.4: Discontinuity across horizontal border



Notes: The line represents the linear trend of each variable before and after the 32° latitude line, which delimits Texas and New Mexico.

Figure 3.5: New Mexico-Texas border



Source: Energy Information Administration 2014 at https://www.eia.gov

3.4.1 Regression Discontinuity

To implement the regression discontinuity approach, I will leverage from the fact that within 10 miles along the Texas and New Mexico border there are 191 fields and 3492 wells [5]. Moreover, the geography of the fields close to the political borders do not change by much, as seen in figure 3.4. For all the regression discontinuity results I will focus on the horizontal segment of the border, the reason is that similar figures for the vertical segment suggest that the identifying assumptions of RD apply better when we take this part of the border as reference. [6] Figure 3.5 shows a map of Texas and New Mexico, such map shows the vertical and horizontal part of the border. It also shows the counties close to the border in both states where drilling is popular.

The identifying assumption of my RD regressions is that if policy was

[5] Along the vertical segment of the border there are 339 fields and 9465 wells

[6] See Appendix 2 for all the results applied to the vertical segment of the border.

the same in both states, then the productivity of wells on both sides of the border would depend linearly on the distance from the border. The RD approach will give the local effect in well productivity caused by state policy (not just compulsory unitization) between Texas and New Mexico. In the next subsection, I complement this approach with DID to isolate the effect of compulsory unitization.

Let y_{isft} be the oil produced by well i, in state $s \in \{T, N\}$, by field f at time t. Let D_{isft} be an indicator of well i being in New Mexico. D_i is defined by

$$D_i = \begin{cases} 0 & \text{latitude} \leq 32^\circ \\ 1 & \text{latitude} > 32^\circ \end{cases} \tag{3.1}$$

Let the baseline regression discontinuity model be:

$$y_{isft} = \alpha_f + \gamma_t + \beta * (lat_{isft} - 32) + \tau * D_{isft} + \epsilon_{isft}. \tag{3.2}$$

The model defined by 3.2 and 3.1 is specific for the horizontal segment of the border. [7] Under the identifying assumption, τ is the local average treatment effect of the New Mexico policy compared to Texas.

To increase the robustness of the results, I also estimated the regression discontinuity model assuming that production is a polynomial function of lat. In the Results section I present the results for polynomials up to order 4, I ran the regressions for higher orders but the average treatment effects did not

[7] For the vertical segment of the model, substitute lat for long in equation 3.2, and instead of 32, plug -103.06 ins equation 3.1.

change. As an example, equation 3.3 shows the third order specification of the model.

$$\begin{aligned} y_{isft} = \alpha_f + \gamma_t + \beta_1 * (lat_{if} - 32) + \beta_2 * (lat_{if} - 32)^2 \\ + \beta_3 * (lat_{if} - 32)^3 + \tau * D_{isft} + \epsilon_{isft}. \end{aligned} \tag{3.3}$$

For RD models, one needs to specify bandwidth around the threshold that defines treatment and control groups that defines which observations will be considered. To increase robustness, it is common to try different bandwidths. The results I will present in the next section are considering a radio of 1 mile, and 5 miles around the horizontal segment of the border [8].

Also, as further robustness checks, I also ran 3.2 with different dependent variables that I would not expect to change at the border. Such variables are longitude, depth of the reservoir, terrain elevation and year when the wells were drilled. The identifying assumption of my analysis suggests that the geological borders are not the same as the political borders. Running the regressions on depth and elevation help to test the identifying assumption. The fact that longitude does not drastically change at the border means that the wells are actually in the same field. The years when the wells were drilled could change as an effect of the policy, but as will be seen in the results section, there does not seem to be an effect.

To summarize, the first approach in this paper I implement to answer my research question is RD on cumulative production of oil throughout the life

[8] Results for 10 miles are presented in Appendix 2.

of wells. To prove that my results are robust, I first use different bandwidths, and polynomial orders. Finally I prove that there no effect in geological variables[9].

3.4.2 Difference in Difference

The RD design helps to quantify the effect of the New Mexico policy compared to the Texas policy. As shown in the Background section, the main difference is that there is compulsory unitization in New Mexico but not in Texas. Nevertheless, this approach does not rule out the contribution of other differences in policy. Also, there are other intangibles, for example, it might be cheaper and faster to do the paper work to drill a well in one state than the other. A way to overcome this is to estimate a DID model. To achieve it, I leveraged from having data before and after 1977, the date when New Mexico incorporated compulsory unitization in its legislation. Another advantage of DID is that the results will be generalizable to all Texas and not just to the border.

The identification assumption I rely on is that if New Mexico would have not passed compulsory unitization, then the production trend after 1977 would have been the same as before. Figure 3.3 suggests that the trends in productivity of wells before 1977 were similar in both states. After 1977 there is a jump in productivity of New Mexico wells, the identifying assumption

[9] Everything is applied to the horizontal segment of the border, the results for the vertical part are in Appendix 2.

implies that without the change in regulation we would not be able to see such jump.

Let y_{itfs} be the cumulative production of well i at field f in state s at time t. The baseline DID model in the paper is:

$$y_{itfs} = \alpha_f + \gamma_t + \rho I_{t>1977} + \sigma I_{s=NM} + \tau I_{t>1977} * I_{s=NM} + \beta X_{itfs} + \epsilon_{itfs}, \quad (3.4)$$

where α_f if a field fixed effect, γ_t is a time fixed effect, $I_{t>1977}$ is an indicator that the year is after 1977, and $I_{s=NM}$ indicates that well i was drilled in New Mexico, and X_{itf} is a vector of observables (latitude, longitude, depth and elevation). The coefficient of interest is τ, which under the identifying assumption measures the effect of having compulsory unitization in New Mexico.

I estimated the base model as presented in equation 3.4. To check robustness I also estimated 4 different specifications of the model: two without year fixed effects, but one of them with year as control; one without and X_{itf} control and the other without latitude and longitude as controls. Also, in Appendix 2 I present results changing the dependent variable to production during the first 5 years instead of overall production.

To check the assumption that trends before 1977 are similar between wells in Texas and wells in New Mexico, I also estimated model 3.5

$$y_{itfs} = \alpha_f + \sigma I_{s=NM} + \gamma * t + \tau * t * I_{s_i=NM} + \beta X_{itf} + \epsilon_{itf}, \quad (3.5)$$

I ran two versions of model 3.5, in the first, I restrict the difference in trend between New Mexico and Texas to be linear. In the second model, I assign a dummy to each year. Ideally, both models will suggest that the trends before 1977 are not significantly different.

In summary, to complement the results obtained by RD, I estimated a DID model. In the results section, I will present several specifications of the model. Also, to prove the that the difference in difference approach is valid, I estimated the difference in trend before the policy change.

3.5 Estimation Results

This section presents the main results of the paper. On the first subsection, I analyze the regression discontinuity results, and the second is about difference in difference.

3.5.1 Regression Discontinuity

The main RD results can be found in table 3.2 and table 3.3. Each row-column combination in each table represent the τ parameter of an individual regression discontinuity design. Rows represent different dependent variables, and columns polynomial orders, as labeled in the table. The results in table 3.2 are computed with a bandwidth of 1 mile around the horizontal border and table 3.3 assumes a border of 5 miles.

Table 3.2 suggests that production by well in New Mexico is higher than in Texas. Table 3.1 suggests that on average wells in New Mexico drilled at most a mile from the border with Texas produce 10,829 barrels of oil. So the first row in table implies that the increase in production attributable to New

Table 3.2: Regression Discontinuity, horizontal border, 1 mile bandwidth

Polynomial Order Dependent Variable	1	2	3	4
log cum oil	0.188*	0.199*	0.196*	0.202*
	(0.138)	(0.141)	(0.14)	(0.14)
log 6 month oil	0.339*	0.405*	0.402*	0.404*
	(0.251)	(0.252)	(0.252)	(0.252)
log 60 month oil	0.27	0.284	0.285	0.29
	(0.252)	(0.253)	(0.252)	(0.252)
depth	-372.664	-255.549	-264.292	-261.403
	(1137.46)	(1031.93)	(1039.56)	(1039.4)
elevation	46.741	38.544	37.178	36.982
	(40.933)	(42.169)	(42.249)	(42.315)
longitude	0.185	0.16	0.16	0.159
	(0.248)	(0.219)	(0.219)	(0.219)
drilling year	0.083	-0.051	-0.044	0.014
	(1.397)	(1.409)	(1.41)	(1.404)

Each pair of estimate/standard error represents the average treatment effect estimated with a different regression discontinuity design. Rows indicate different dependent variables, and columns are different polynomial orders. Wells in New Mexico and Texas drilled after 1778. Treatment means that the well is in New Mexico, control wells are located in Texas. Standard errors are clustered at field level. *** $p \leq 0.01$, ** $p \leq 0.05$, * $p \leq 0.1$

Mexico policy is between 2,239 and 2,664. The results in the second column are also statistically significant. They imply that 6 months after production started, the amount of oil by well extracted in New Mexico is between 518 and 652 barrels higher.

Depth, elevation, longitude are robustness checks. Since these variables depend on the geology and not on policy, I do not expect a significant change at the state line. As can be seen in table 3.2, for the 1 mile bandwidth we do not find any significant difference. This happens regardless of the order of the polynomial applied to the latitude variable.

Similarly, table 3.3 shows the results assuming a 5 mile bandwidth around the horizontal segment of the border. The results in the table suggest that during their lifetime, well in New Mexico are more productive than wells in Texas by between 3,497 and 3,633 barrels of oil. So this table suggests results that are substantially higher than when considering a bandwidth of just one mile.

In any RD design, there will be a trade off when deciding the bandwidth between the number of observations and the validity of the identification. Table 3.1 shows that if limiting the bandwidth to 1 mile around the border, we are left with more than 400 wells in the sample. They are enough observations apply regression discontinuity. Moreover, the 1-mile specification does not violate any robustness check. In Balthrop, 2016, they conclude that Oklahoma wells are more productive than Texas wells, in 3,361 in the life of a well. This results in is closer the 5-mile specification. Nevertheless, the minimum

Table 3.3: Regression Discontinuity, horizontal border, 5 mile bandwidth

Polynomial Order Dependent Variable	1	2	3	4
log cum oil	0.311***	0.304***	0.304***	0.305***
	(0.126)	(0.129)	(0.129)	(0.129)
log 6 month oil	0.76***	0.675***	0.674***	0.675***
	(0.121)	(0.123)	(0.123)	(0.123)
log 60 month oil	0.351***	0.256**	0.256**	0.256**
	(0.115)	(0.117)	(0.117)	(0.117)
depth	856.958	253.2	256.319	259.644
	(1218.05)	(929.12)	(929.134)	(929.347)
elevation	108.167**	64.038	64.203	64.311
	(48.753)	(50.993)	(50.974)	(50.956)
longitude	0.169	0.097	0.098	0.098
	(0.227)	(0.203)	(0.203)	(0.203)
drilling year	2.005***	0.197	0.208	0.219
	(0.693)	(0.697)	(0.697)	(0.696)

Each pair of estimate/standard error represents the average treatment effect estimated with a different regression discontinuity design. Rows indicate different dependent variables, and columns are different polynomial orders. Wells in New Mexico and Texas drilled after 1778. Treatment means that the well is in New Mexico, control wells are located in Texas. Standard errors are clustered at field level. *** $p \leq 0.01$, ** $p \leq 0.05$, * $p \leq 0.1$

threshold to enforce compulsory unitization in Oklahoma is 66%, and in New Mexico it is 75%.

Table 3.4 shows the DID results. Every column is a different specification. Everyone of them has field fixed-effects. The first column in the table does not control for anything. The second specification controls for year. The third has no controls, but it has time fixed effects. The fourth has time fixed effects, and it controls for latitude and longitude, and the last also controls for depth and elevation.

The results in table 3.4 suggest that passing compulsory unitization in New Mexico increased production by well in New Mexico in between 2,551 and 3,872 barrels of oil. These results are similar to the ones obtained by the RD approach.

Figure 3.3 suggests that the difference in trend in production by well between Texas and New Mexico before compulsory unitization was passed by New Mexico not significantly different. Table 3.5 tests for these results. In the first specification, I am testing for a linear trend. The estimate of (Treatment = 1)$\times$Year is not significant, which suggests that the linear trend before unitization is the same. The second specification sets year 1971 as base and check if there are deviations in the following years and none of the cross estimates are significant. These results suggest that the difference in difference specification is valid.

To summarize, in this section I present the estimation results of the

Table 3.4: Difference in difference, dependent variable log of cumulative oil

	(1)	(2)	(3)	(4)	(5)
$State = NM*$	0.185*	0.183*	0.242**	0.230**	0.266*
$year \geq 1977$	(0.128)	(0.128)	(0.126)	(0.123)	(0.173)
$year \geq 1977$	-0.0183	0.0764	-0.209	-0.165	-0.251*
	(0.073)	(0.093)	(0.126)	(0.112)	(0.127)
$State = NM$	0.608	0.617	0.548	0.496	-1.590
	(0.889)	(0.897)	(0.883)	(0.890)	(1.387)
Year		-0.0143			
		(0.010)			
Latitude				0.203	0.424**
				(0.157)	(0.159)
Longitude				0.0721	0.142**
				(0.050)	(0.053)
Log depth					-0.0152
					(0.021)
Log elevation					-0.0858**
					(0.029)
Constant	8.979***	37.22	9.159***	9.913***	11.07***
	(0.147)	(19.607)	(0.154)	(0.320)	(0.542)
Time FE			✓	✓	✓
Field FE	✓	✓	✓	✓	✓
Observations	121832	121832	121832	117537	76268

The first column is a field fix effects model without controlling for year. The second column is as the first, but also controls for year. The third, fourth and fifth models also has time fixed effects. The dependent variable is log of the first 60 days of production of each well. Standard errors clustered at the field level reported. Every well in the sample was drilled in either New Mexico or Texas between 1970 and 1982. *** $p \leq 0.01$, ** $p \leq 0.05$, * $p \leq 0.1$

Table 3.5: Trend before treatment, dependent variable: log of cumulative oil

	(1)	(2)
Treatment = 1×Year	0.0116	
	(0.015)	
State = NM	-22.62	0.245**
	(29.898)	(0.078)
Year	-0.0500***	
	(0.006)	
Year=1972		0.128**
		(0.045)
Year=1973		-0.229***
		(0.040)
Year=1974		-0.418***
		(0.034)
Year=1975		0.0775
		(0.042)
Year=1976		-0.254***
		(0.034)
Year=1972 × Treatment=1		-0.0406
		(0.089)
Year=1973 × Treatment=1		-0.0111
		(0.086)
Year=1974 × Treatment=1		0.183
		(0.192)
Year=1975 × Treatment=1		-0.0392
		(0.101)
Year=1976 × Treatment=1		0.215
		(0.111)
Constant	107.6***	9.151***
	(12.274)	(0.027)
Observations	57077	57077

Wells drilled before 1978. Treatment means that the well is in New Mexico, control wells are located in Texas. Standard errors are clustered at field level. *** $p \leq 0.01$, ** $p \leq 0.05$, * $p \leq 0.1$

RD and the DID specifications. Using RD and assuming a 1-mile bandwidth, the results suggests that the New Mexico policy increases efficiency of wells by between 2,239 and 2,664, using a 5-mile bandwidth, the results are between 3,497 and 3,633. The DID approach suggests that compulsory unitization contributed in making wells in New Mexico more productive in between 2,551 and 3,872 barrels per well.

3.6 Conclusion

Every mayor oil producing state in the United State, but Texas, has implemented a form of compulsory unitization into its legislation. In this chapter, I compared Texas and New Mexico to find out how compulsory unitization affected efficiency in production.

By applying RD, and DID, I find that compulsory unitization did increase efficiency in production of oil. The RD approach suggested that the increase in efficiency is between 2,239 and 2,664 by well. The DID approach suggest that the number is between 2,551 and 3,872. The advantage of DID is that I did not have to limit the conclusions to a neighborhood close to the border. Moreover, it isolates the effect of compulsory unitization and not of the overall difference in policy of both states.

The main limitation of the approach implemented in this paper is that it does not allow to explore a wide range of interesting counterfactuals related to efficient legislation of oil production. For example, we are not able to explore how big is the common pool externality created by several firms trying to extract oil from the same firm. Moreover, legislators place several restrictions in voluntary unitization, currently we are not able to predict how efficiency could improve is they modified voluntary unitization. Finally, we are not able to see how different implementations of compulsory unitization might affect welfare. Next chapter proposes a structural model to address all these questions.

Chapter 4

Counterfactual analysis of compulsory unitization

4.1 Introduction

The exploitation of a single oilfield by several firms is a typical example of the common pool externality (CPE). Pressure is the natural force that pushes oil up to the surface when firms are trying to extract it. Increasing the rate of production makes the pressure in the reservoir fall at a much faster rate, making it inefficient to extract too fast. Nevertheless, when several firms share an oilfield, they have incentives to produce faster than they would otherwise. This happens because the rule of capture in the United States dictates that regardless of where the hydrocarbons are originally found, whoever extracts them first is entitled to keep them (Homan, 2011).

If agents facing the CPE assigned a single operator to exploit the whole resource, then such operator would not face the CPE. In that sense, such operator would extract the oil efficiently. In the oil business, there is a legal contract called unitization that allows firms to cooperate in such a way when exploiting a field. Regulators across the United States impose two restrictions when firms seek to unitize: first, the field needs to be "reasonably developed";

second, the way in which firms share profits must be "fair." The problem with the first restriction is that if firms start working separately before unitizing, so they might start exploiting the field inefficiently. The problem with the second restriction is that by restricting the profit sharing options, firms might not reach some unitization agreements they would otherwise.

Libecap, 1998 documented that unitization agreements do not happen as often as regulators would expect. The failure in private contracting has encouraged oil regulating agencies around the United States to incorporate compulsory unitization to their production-efficiency-enhancement toolkit. Under compulsory unitization, if the number of firms in a field that want to form a unit exceeds a certain threshold, then the regulator can force the dissidents to also join the unit. The minimum threshold varies widely in different states [1]. Texas is the only major producing state without any form compulsory unitization.

In this chapter, I analyze the dynamic strategic interaction of firms competing for common resources. This will enable me to compute the welfare loss due to the CPE firms face when they share an oilfield. Moreover, I measure how welfare would change under different regulatory policies. On one hand, I analyze welfare if the Texas Railroad Commission (TRRC), which is the agency that regulates the oil industry in Texas, relaxed the restrictions on voluntary unitization. On the other, I analyze how incorporating different

[1] For example, Tennessee has a 50%, Kentucky 51%, New York 60%, Ohio 65%, Alabama 66.66%, Mississippi 75%, and North Dakota 50% Kramer, 2007

versions of compulsory unitization to its legislation would affect the efficiency of production of oil, as well as the overall outcome.

Huang, 2014 argue that it is paramount to account for the dynamic interaction of firms when assessing counterfactual regulatory policies in industries that face the CPE. Following this logic, I model how firms develop an oilfield and how they form units throughout time. The proposed model accounts for the restrictions placed by the TRRC on voluntary unitization. The dynamic nature of the model could be argued in two ways. First, the CPE happens because excessive production today will deteriorate production tomorrow. Second, the gains of unitization will vary with the time elapsed between the discovery of a field and the date of the contract. To estimate the parameters of the model, I constructed a panel which contains monthly production, drilling dates and costs, price of oil, and information on every unitization agreement. The estimated model enables me to recover the welfare loss due to the CPE by re-computing the equilibrium of the model assuming a single operator exploited efficiently each field. To assess how welfare could improve if the TRRC relaxed the restrictions on voluntary unitization, I modify the parts of the model that resemble such restrictions. Finally, I change features of the coalition formation process to recover what would happen under compulsory unitization.

I model the development of a field, and the formation of units as a random stopping game. Firms do not know the stopping time, T, at each period $t < T$. At period 0, all firms draw a private and persistent cost of joining a unit. Firms will only have to pay that cost if they decide to join a unit. Each period $0 < t < T$, firms will draw, from an i.i.d. distribution, a private cost of drilling and will decide simultaneously whether to drill a new production well, an new injection well or do not drill. On top of the private shock, if a firm decides to drill, it will have to pay an amount common to all firms, which is a trend in the cost of drilling. Such common cost on drilling will be modeled with a Markov switching model. At time T, firms will simultaneously vote for or against unitization. If at least two firms in a field vote for a unit, a unit that contains every firm that voted yes will be formed. The continuation values received by each firm will depend on the voting results. Firms in the unit will share profits in proportion to the area in the field they have leased[2]. The fact that profits are shared based on area resembles the fairness condition placed by the TRRC. Alternatively, I will relax the area assumption let the firms share profits as a result of a Nash bargaining game, where the outcome is restricted to a sharing rules that the TRRC considers "fair." On the other hand, firms are not certain when the TRRC will consider a field to be "reasonably developed". The model captures this by making T random. I assume that firms solve a Markov Perfect Nash Equilibrium (MPNE).

I constructed the data used to estimate the parameters of my model from several sources. I acquired the "Docket" from the TRRC, which contains

[2] It is important to note that the TRRC allows firms to share profits as a weighted average of other values the TRRC can also observe. Area is, by far, the most used one.

basic information on dates and fields of unitization contracts. I manually gathered the information on how firms that unitize share profits from the TRRC hard records. Also, I built a monthly panel containing monthly oil production and drilling dates by every firm, in every field in Texas. The panel runs from 1980 to 2008. To estimate the parameters of the model, and compute the counterfactuals, I will only consider fields discovered in that time span, with more than one firm and less than five exploiting it. Finally from RigData [3], and the Energy Information Agency[4], I recovered trends in cost of drilling and price of oil.

To estimate the parameters in the data, I follow Ryan, 2012 and use the methodology proposed in Bajari and Levin, 2007, which I will refer to as BBL from now on. The BBL algorithm falls into a growing branch of the literature that estimates dynamic games while overcoming the computational burden associated with the estimation[5]. BBL proceeds in two stages. On the first stage, I recover the choice distribution of drilling and unitization conditional on observables, and transition probabilities conditional on actions. On the second stage, I recovered the structural parameters of the distribution of cost of unitization, and drilling costs. After estimating such parameters, I will use the model to recover the value that firms that unitized would have created under the alternative scenario of "have not unitized." With that, and the data

[3]https://rigdata.com

[4]http://www.eia.gov

[5]Some examples of these procedures were developed in Aguirregabiria and Mira, 2007, Pakes and Berry, 2007, and Pesendorfer, 2008.

on how those firms shared profits, I will recover the bargaining parameters of the model.

I use the estimated model to learn what would have happened if each field was exploited by a single operator. From there, it is straightforward to recover the loss due to the CPE. In a second stage, I relax the assumptions on the model that resemble the conditions placed by the TRRC on voluntary unitization. By doing so and recomputing the equilibrium, I recover how welfare would change if unitizing voluntarily was easier. In the third stage of counterfactuals, I assess what would happen under compulsory unitization by changing the voting mechanism.

The counterfactual analysis suggests that the welfare loss due to the CPE is actually substantial. Throughout the 30 years of analysis, having a single operator by field would have increased the oil produced from the 501 fields in the sample in around $70.84M$ barrels, with a value of $\$4.28B$. Such increase comes from two sources: an increase in overall production per field, and the increase in injection wells compared to production wells. Eliminating the restrictions placed on voluntary unitization would have increase production in around $55.35M$ barrels, worth $\$3.16B$. Finally, compulsory unitization could further improve production in $39.49M$ barrels, or $\$2.24B$.

This paper relates very closely to four different branches of the economics literature. The first is the study of the common pool externality and possible solutions to it. The second is on modeling coalitions in dynamic settings. The third is on the growing literature that estimates dynamic parameters using two stage methods. Finally, the paper relates to the empirical papers that use the Nash-in-Nash (NiN) assumption to estimate bargaining parameters.

Libecap, 1984 surveyed three contractual solutions to the CPE that firms tried several times during the 20th century. The authors show that unitization is most efficient solution but quite underused. Following up on this insight, Libecap, 1985c argue that the problem is private information created during the exploration period. Importantly, Libecap, 1985a conclude that compulsory unitization was approved first in states where small firms are not very influential. Suggesting that the lobby of small firms prevents the TRRC to allow compulsory unitization. More recently, Balthrop, 2016 proposed a difference in difference approach contrasting Oklahoma and Texas to conclude that wells in Oklahoma are more productive due to compulsory unitization. Similarly, Herrera (2016) compares efficiency in production between Texas and New Mexico and draws similar conclusions.

Lin, 2013 is the first to study the dynamic strategic interaction of firms sharing a common resource. She concludes that firms leasing federal tracts in the Gulf of Mexico consider their neighbor's actions when taking production decisions, especially if the leased tracts are small. She is also quantifies the welfare transfer from the firm that exploits their tract last to those that exploit it first. Like Hendricks, 1993, she acknowledges unitization in federal tracts as a solution to the CPE, but it goes beyond the scope of her paper. The two decisions taken by firms Lin models is when to start exploring and when to start producing. The main mechanism of the welfare loss due to the CPE I will study in this paper is how firms take drilling decisions differently while exploiting a field and not just at the beginning. That will allow me to measure the productivity of each well, and how it would be different if there was a single operator. Moreover, thanks to this approach, I will be able to explore counterfactuals related to compulsory and voluntary unitization.

My model can be estimated thanks to the recent methodological contributions in estimating dynamic games. Some examples of such algorithms are Aguirregabiria and Mira, 2007, Pakes and Berry, 2007, and Pesendorfer, 2008. Particularly, I use the approach proposed in Bajari and Levin, 2007. There is a growing literature applying BBL to estimate dynamic models.

The third contribution of this paper is on empirical papers based on the estimation of Nash-in-Nash (NiN) bargaining. NiN models assume that when sevaral players participate in a bargaining game, they bilateraly reach the Rubinstein (1986), assuming the outcome of the other negotiations will also be such solution. Most of the seminal papers that estimate NiN models are related to health. Gowrisankaran, 2013 model bargaining between managed care organizations and hospitals; Grennan, 2013 study hospitals and stent manufacturers; and Ho, 2014 focus on the interaction between hospitals and insurers. In the same spirit, in my model there is also a business to business interaction where there will be bargaining. My main contribution is that in my situation the bargaining will be between two competitors, instead of a client-provider relation.

In section 2, I will review the institutional details to understand the data and the model. Section 3 will describe the dynamic model. In section 4, I will present data and in section 5 explain in detail how I estimated the model using the data. In section 6, I will show the estimation results, and in section 7 the counterfactual analysis. The last section concludes.

4.2 Institutional details

The United States is one of the few countries in the world where hydrocarbons are privately owned[6]. They originally belong to mineral owners, who in many cases are also land owners. Oil is a fluid, that will travel underneath the earth to places with lower pressure; for example, where oil is being extracted. The rule of capture states that the firm that extracts the hydrocarbons first is entitled to keep them without liability, regardless of where they were originally found[7]. These factors combined incentivize firms to behave strategically sometimes at the expense of efficiency. This strategic interaction leads firms to accelerate production to capture other player's oil, to stop

[6]For example in Ohio Oil Co. v. Indiana, 177 U.S. 190, 203 (1900) the court stated: Hence it is that the legislative power, from the peculiar nature of the right and the objects upon which it is to be exerted, can be manifested for the purpose of protecting all the collective owners, by securing a just distribution, to arise from the enjoyment, by them, of their privilege to reduce to possession, and to reach the like end by preventing waste. Leaving the precedent for the rest of the states that the oil is privately owned, and owners have the right to extract it.

[7]See, for example, Acton v. Blundell, 12 Mees. 324, 354, 152 Eng. Rep. 1223, 1235 (Ex. Ch. 1843). Although the Acton v. Blundell conflict happened between a cotton mill and a coal pit competing for water, it set the precedent that draining springs of neighbor lands results in a loss without legal harm.

drilling due to rent dispersion, or to drill a greater share of production wells instead of injections wells.

According the the Energy Information Administration (EIA), on average oil in the United States has abeen extracted from a depth between 4,000 and 5,000 feet[8]. Pressure is the natural force that pushes oil up, through the wellbore, allowing firms to recover it. Usually that pressure is not enough to deplete a the area surrounding a wells production well. Around 95% of all the production wells in the United States use pumpjacks to lift the oil (Parshall, 2013). Moreover, it is often necessary to inject pressure to the reservoir so that the oil moves close to the surrounding area of producing wells. Firms increase pressure in a reservoir by drilling an injector well and injecting either methane or water. An extra production well in a reservoir will be a negative externality to the rest of the firms because it will reduce the pressure in the reservoir, drilling a new injection well will be a positive externality because it will increase the pressure of the reservoir. When there is only one firm exploiting a reservoir, such firm will cash the benefits of an extra injection well, but if the firm is sharing the reservoir, then the rents from that well will disperse among the neighbors. In the end, firms that share a field will have less incentives to drill injection wells.

Before extraction oil belong to mineral owners. Mineral owners usually lease their rights to oil producing firms. Unfortunately, it is usually not the

[8]https://www.eia.gov, the data displayed by the EIA runs from 1950 to 2008.

case that the boundaries of mineral ownership coincide with the boundaries of petroleum reservoirs. These facts are the cause of the CPE when producing oil, and they create several inefficiencies, such as drilling unnecessary wells. Legislators in different states have tried to deal with the CPE in several different ways. A way to mitigate the common pool externality is to assign a single operator to exploit the whole resource. Unitization is the joining together of tracts in order to cooperatively develop all or a large part of an oil reservoir (Weaver, 2011). This effectively means assigning a single operator to exploit the common resource. I will call the product of unitization a unit.

The oil industry is very highly regulated and unitization is not an exception. Even if a unit is formed voluntarily, it needs to comply with certain restrictions (Kramer, 1986). Every unitization agreement must, at least specify who will be that single operator and the area being unitized. Once the unitization agreement is reached, the single operator will continue extracting and selling the oil. The stakeholders will also need to agree on the percentages of the profits from future operations each firm will keep.

The way in which firms will share profits is also highly regulated. The TRRC will only approve a unit if it considers that the profit sharing rule is fair. In practice, firms use participation rules, which are weights on values the regulator can observe. Such weights translate into a way to share profits. Table (4.1) and the subsequent bullets show an example of two participation rules and their relationship to profits. Shapley, 1953 proved that if a coaliton can improve welfare, then agents involved will be able to find a Pareto-improving

Table 4.1: Example: participation rules

Factor	Firm 1	Firm 2	Firm 3
Area (A)	50%	25%	25%
Oil remaining (O)	40%	20%	40%
Cumulative production (P)	70%	10%	20%
Wells drilled (W)	58%	21%	21%
Volume (V)	50%	25%	24%

- Example 1
  - Rule: (60% A, 10% O, 10% P, 10% W, 10% V)
  - Profits: (Firm 1: 52%, Firm 2: 22%, Firm 3: 26%)
- Example 2
  - Rule: (100% A, 0% O, 0% P, 0% W, 0% V)
  - Profits: (Firm 1: 50%, Firm 2: 25%, Firm 3: 25%)

way to share profits. Imposing restrictions to profit sharing rules can (and will) prevent some units to be formed. The TRRC also states that if unitization is to be approved, the field in question must be "reasonably developed". The "reasonably developed" condition can also be very restrictive. Apart from being an ambiguously defined rule, the efficiency gains achieved by having a single operator in the field will decrease if the field have already been exploited.

As shown in Libecap, 1984, achieving unitization voluntarily has historically been hard. As a solution to this, every major production state, but Texas, has incorporated a version of compulsory unitization to its legislation. With compulsory unitization, if an important portion of the firms in the field want to unitize they can ask the legislator to force the others to join the unit.

Figure 4.1: Example

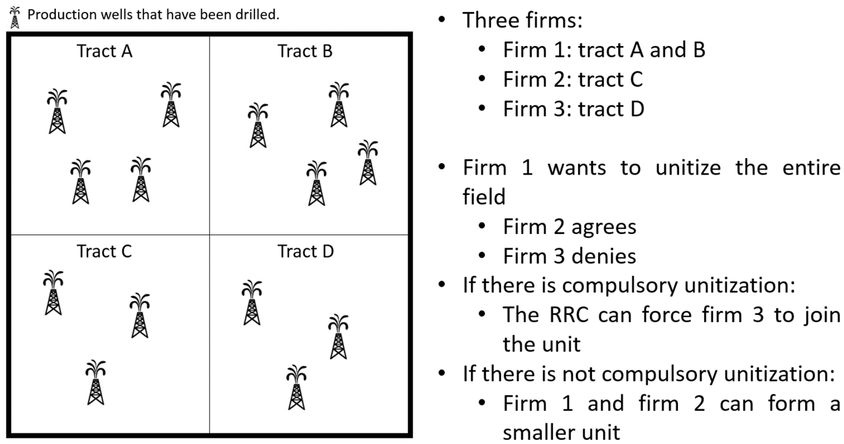


Figure 4.1 shows an example of how compulsory unitization can be petitioned. In the example, firm 1 has 50% of the area in the field and it wants to form a unit with firm 2 and firm 3 to exploit the whole field. Firms 2 wants to join the unit, but firm 3 rather not join. If there is compulsory unitization in this legislation, firm 1 can approach the regulator to force firm 3 to join the unit.

The main difference in which compulsory unitization is implemented from one state to another is the minimum threshold in agreement that firms need to achieve to petition compulsory unitization. For example, Tennessee has a 50%, Kentucky has a 51%, New York a 60%. Ohio's minimum consent level is 65%, while Alabama is 66.66%, Mississippi has 75% and North Dakota a 50% (Kramer, 1986).

4.3 Theoretical Model

I model the development of a field and the formation of units as a random stopping model. The model has three stages. In stage 0, each firm will draw a private and persistent cost of unitization from a common distribution. Stage 1 has multiple periods, it models the development of a field by separate firms before they decide whether to unitize or not. In each period of stage 1 firms will simultaneously make drilling decisions. The last period of stage 1 is $T-1$, since the TRRC is ambiguous with the time when it will allow firms to unitize, the time when voting for unitization happens, T, will be drawn from a random distribution where the parameters depend on the actions of the firms. In stage 2 firms will decide whether to form a unit or not and bargain over how to share profit. The continuation value firms get at period T depends on who unitized, how they agree to share profits, and the state of the game at $T-1$.

Firms have rational expectation of when voting for unitization will happen. This uncertainty models the ambiguity of the "reasonably developed" condition imposed by the TRRC to firms that want to unitize. Moreover, since the distribution of T also depends on the actions of the firms, firms can influence the probability of T by drilling more.

In the following sub-sections, I describe in more detail the different stages in the model. For every period between 1 and $T-1$ in stage 1, I untangle the states, payoffs and transitions. For stage 2, I explain the voting mechanism, the bargaining protocol, and the continuation values. I then describe the equilibrium firms will play.

4.3.1 Stage 0: exploration

There are N_f firms in each field f that will potentially start drilling (or enter the market) and join a unit. Those N_f firms are the ones that have leased the mineral rights to extract oil from field f. Each firm $i \in \{1, ..., N_f\}$ will draw a private and persistent cost of unitization, θ_{if}, from the distribution $G_u(\theta^U_{if}; \alpha_u)$. The cost of unitization can be interpreted as litigation costs, consulting costs, and it also captures the loss in "learning by doing" of firms that will not be the main operators, and the fact that they are giving out control. Such cost will be firm-field specific. Firms will only incur such cost if they decide to unitize in stage 2. So in the end, the overall cost of unitization will depend on the number of firms that joined a unit.

The land leased by each firm is taken as given, and will also be revealed to every firm in stage 0. Each firm i has A_i acres. The relative size of a firm in a field is

$$a_i = \frac{A_i}{\sum_{j=1}^{N_f} A_j}.$$

The relative area will be important because according to the TRRC the way in which firms share profits must be fair. In stage 2, relative area, as well as other factors will limit the space of possible sharing rules.

Finally, in stage 0 the characteristics of the field will be revealed to each firm. Such characteristics will be summarized by the oil transition functions. These functions describe how much oil a firm can expect to extract by drilling an extra well (negative if it is a production well, and positive if it is an injection well). Also, these functions will quantify the externality caused by other firms drilling in the same field.

There are no actions, nor payoffs in stage 0. Nevertheless, the outcome of stage 0 provides a persistent part of the state for the rest of the game. Such part could be summarized in the vector, $\{\{\theta_{if}^U\}_{i=1}^{N_f}, \{a_{if}\}_{i=1}^{N_f}, \beta_f\}$, where:

- a_{if} is the relative area of every firm in the field,
- $\{\theta_{if}^U\}$ is the private and persistent cost of unitization,
- β_f are the parameters of the oil transition function in field f.

4.3.2 Stage 1: development

Stage 1 has $T-1$ periods in which firms will be developing the field individually. Each period, each firm will observe a common state and a private state, and subsequently decide whether to drill an extra production well, an extra injection well or do nothing. In stage 1, firms do not know the value of T, but they have rational expectations of it. Also, since the distribution of T depends on the actions taken by the firms, they are able to influence T. In the following subsections, I describe the states, the actions, and the transitions in stage 1.

4.3.2.1 States

The outcome of stage 0, Ω_{Pi}, will be a persistent part of the state throughout stage 1. At the beginning of each period, $t \in \{1, ..., T-1\}$, all firms observe a dynamic and public part of the state,

$$\Omega_c^t = (p_t, c_t, \{W_{ift-1}^P, W_{ift-1}^I, O_{ift-1}\}_{i=1}^{N_f}),$$

where p_t is the price of oil, c_t is a trend in cost of drilling a new well, W_{ift-1}^P is the cumulative number of production wells drilled up to $t-1$ by firm i in field f, similarly W_{ift-1}^I is the cumulative number of injector wells, and O_{ift-1} is the oil produced in period $t-1$ by firm i in field f. Moreover, each firm will draw a private shock to costs, $\Omega_i^t = (\xi_{ift}^P, \xi_{ift}^I, \xi_{ift}^N)$. ξ_{ift}^P is an heterogeneous part of the cost a firm would have to pay on top of c_t if it drills a new production well. ξ_{ift}^N is a shock to the fixed cost of firm i in field f at period t if it decides not to drill. All shocks will be drawn from independent distributions g_k where $k \in \{P, I, N\}$. Such distributions are common to every firm in every field.

All these components together, define the state each period,

$$\Omega^t = \{\{\Omega_{Pi}, \Omega_i^t\}_{i=1}^N, \Omega_c^t\}.$$

Firms deciding whether to drill an extra well mainly care about three things:

- how production will increase if they drill a new (production or injection) well,

- the cost of drilling a new well (trend and shock),

- how the probability of T changes by having an extra well.

Note that the probability of next period being T is not an explicit part of the state. Nevertheless, it will be a function of the state variables.

4.3.2.2 Actions and payoffs

After observing the state firms decide whether to drill a new production well, a new injection well or do nothing. Let d^k_{ift} with $k \in \{P, I\}$ be the decision variable of drilling an injection or production well, such that:

$$d^k_{ift} = \begin{cases} 0 & \text{Do nothing} \\ 1 & \text{Drill.} \end{cases} \tag{4.1}$$

There will be a sunk cost associated with drilling a well. If $d^k_{ift} = 1$, firm i in field f has to pay $c_t + \xi^k_{ift}$. If, on the other hand, $d^k_{ift} = 0$ firm i will have to pay ξ^D_{ift}. ξ^D_{ift} can be interpreted as the maintenance cost firms have to pay each period if they do not drill a well.

Firms' revenues come from selling the oil produced last period at a price discounted by the variable cost, vc. The variable cost comes from paying state production taxes, tax, and royalties companies have to pay to mineral owners, r. So $vc = r + tax$. So the profits firm i makes form their operations in field f at time t are:

$$\pi_{ift} = O_{ift} p_t (1 - vc) - \sum_{k \in \{P,I\}} \left[d^k_{ift}(c_t + \xi^k_{ift}) - (1 - d^k_{ift})\xi^N_{ift} \right].$$

4.3.2.3 Transition

The three parts of the state will have very particular transitions. The persistent part of the state, Ω_{Pi}, does not change. The shocks $\{\xi^P_{ift}, \xi^I_{ift}, \xi^N_{ift}\}_{i=1}^{N_f}$ are drawn each period from independent distributions. The common part of the state will transition according to parametric functions.

The transition of oil production is particularly important, it models the source of the common pool externality. The oil transition function is broadly a function of three things: oil production the previous month, new wells, and wells drilled by others. All that said, the oil transition function is:

$$\begin{aligned} O_{ift} = & \overbrace{f_O(O_{ift-1}, \beta_f)}^{(1)} + \overbrace{g_O\left(d^k_{ift-1}, d^k_{ift-1} pw_{ift-1}, , \beta_f\right)}^{(2)} \\ & + \overbrace{h_O(\sum_{j \neq i} d^k_{ift-1}, \beta_f)}^{(3)} + \alpha_{if} + \epsilon_{ift} \end{aligned} \tag{4.2}$$

where:

- O_{ift}: production, d^k_{ift} with $k \in \{P, I\}$: drilling indicator, pw_{ift}: cumulative wells, , β_f: field parameters
- (1) Production from previously drilled wells
- (2) Production from new wells
- (3) Interference factor - decrease in production from competitors drilling

Element (1) in equation 4.2 reflects a feature commonly observed in oil wells; since the pressure of the reservoir is decreasing with production, if nothing changes in a field we would expect production do decrease from one period to the next (Fetkovich, 1980). Element (2) reflects that new injection and new production wells will bring in more production to a firm in a field, but the amount of new production will depend on how many wells have previously been drilled in the field. Element (3) will capture how a firm's production varies whenever some other firm drills a new well.

I follow Kellogg, 2014 in assuming that the price of oil, p_t, and cost of drilling, c_t are exogenous. He asserts that this assumption almost certainly holds institutionally. The argument Kellogg gives is that crude oil is a world market and the production from Texas wells represented around 3% of global production. There is a vast literature trying to forecast the price of oil (Perron, 1989, Cabedo, 2003, Yu, 2008). Again, I will follow Kellogg, 2014 and forecast changes in price and cost as an autorregressive process. The baseline models of price and cost are:

$$\ln p_{t+1} = f_p(\ln p_t, \gamma_t^p, \alpha^p) + \epsilon_{t+1} \tag{4.3}$$

$$\ln c_{t+1} = f_c(\ln c_t, \gamma_t^c, \alpha^c) + \epsilon_{t+1}^c \tag{4.4}$$

As stated before, all the shocks are drawn from independent distributions. The shock on cost of drilling a production and an injector well will be drawn each period from the distributions $G_P(\theta_{ift}^P; \alpha^P)$, and $G_I(\theta_{ift}^I; \alpha^I)$, and the shock in fixed cost if a firm does not drill will be drawn from $G_n(\theta_{ift}^n; \alpha^n)$.

Remember that if a firm drills, it will pay a trend c_t, which is common to everyone and only depends on time and also the shock of drilling, which will be different for production and injection wells. Usually, well operators subcontract service firms to drill wells (Kellogg, 2011). The drilling shocks, that are unobservable to the econometrician, represent factors such as the specific agreements reached by a certain firm with the driller, or difficulties particular the the well in question. With respect to the fixed cost shock, when a well is drilled production can go for several years with minimum maintenance. The equipment installed to extract the oil uses natural gas to run. Often, that natural gas comes as a collateral the the oil produced. The shock in fixed cost represent the cost of that natural gas, as well as eventual maintenance costs.

The period transition is also quite important. At the beginning of period t, firms do not know if $T = t+1$. Nevertheless, they know the probability of $T = t+1$. For example, if we assume a log-normal survival function:

$$1 - \Phi \left\{ \frac{log(t_j) - \mu_j}{\sigma} \right\}, \tag{4.5}$$

where

$$\mu_j = x_j \beta. \tag{4.6}$$

The log-normal hazard rate, related to this survival function will be:

$$h(t) = \frac{\phi\left(\frac{log(t)-\mu}{\sigma}\right)}{\Phi\left(\frac{log(t)-\mu}{\sigma}\right) t\sigma}. \tag{4.7}$$

Equation 4.6 shows how the probability of T changes depending on the action of the firm. In the estimation section, I will give a detailed description of the variables that will go into x_j. Nevertheless, as figure 4.5 in the data section suggests, time without drilling and the ratio of production rate in the current month to previous production will play an important role.

4.3.3 Stage 2

Stage 2 is when firms make unitization decisions. Firms will first decide whether to join a unit or not. Then, the firms that decided to join the unit will bargain over how to share the profits of future operations. The payoffs at period T will depend on the state of the game, the voting results in period T, and the bargaining outcome.

The willingness of firm i in field f to join a unit is captured in variable u_{ift}:

$$u_{ift} = \begin{cases} 0 & \text{do not join} \\ 1 & \text{join} \end{cases} \tag{4.8}$$

A unit will be formed if more than one firm wants to unitize, or if $\sum_i u_{ift} > 1$. If that is the case, the continuation value will capture the future profits of the field assuming the field will be exploited by a consolidated firm and the ones that did not join. After a unit is formed, the firms that agreed to unitize will bargain over the future profits of the unit. The bargaining game is described in the following subsection. Also, every firm that voted to join the unit, will pay the cost of unitization drawn at the beginning. If a unit is not formed, the continuation value will be the discounted profits if firms continue developing the firm assuming there will not be another opportunity to unitize. Although it is not mandatory by the TRRC that firms can only vote once for unitization, of the 89 fields in my sample I only observe 2 where unitization happened more than once. With respect to failed units at a different moment in time, checking the TRRC records, I only observed 3 none-successful applications to unitize. This suggest that in practice, in most fields unitization decisions happen only once. So the only gains (or loses) firm will generate at time T come from the unitization cost and the continuation value.

4.3.3.1 Bargaining over unit profits

The share of profits each firm in the unit gets is set in a static bargaining game that takes place at time T among the firms that expressed interest in joining a unit. In this bargaining game, each firm negotiates the share of profits it will keep separately and simultaneously with the biggest firm (in terms of area leased in a particular field) that will join the unit. The outcome of each bilateral negotiation will be the bilateral Nash bargaining solution, taking all other negotiations as given.

As a result of the "fair sharing rule" restriction placed by the TRRC, firms will bargain over wights in the hyperplane derived from the space of variables the TRRC can observe. Such variables are number of wells drilled up to now, $W = \{W_i\}_{i \in N_f}$, relative area leased by each firm, $a = \{a_i\}_{i \in N_f}$, oil produced up to now, $O = \{O_i\}_{i \in N_f}$, estimate of oil left in the reservoir, $R = \{R_i\}_{i \in N_f}$, and production rate, $o = \{o_i\}_{i \in N_f}$.

If, for example, we have a field with only two firms and we only focus on area and cumulative oil produced. Assume that firm 1 has 80% of the area leased and has produced 50% of the oil. Let α be the proportion of the profits firm 1 will keep. The fairness of the sharing rule will imply that $\alpha \in [0.5, 0.8]$.

The bargaining problem each pair of firms, (i,1), solve is:

$$\max_{\alpha_i \in [l,L]} \left[\Pi^U * \alpha_i - V_i \right]^{b_i} \left[\Pi^U * (1 - \sum_{j=1}^{N_f} \alpha_j) - V_1 \right]^{b_1}, \tag{4.9}$$

where $b_i > 0$ and $b_1 > 0$ are the bargaining power parameters of firms i and 1. Π^U is the discounted sum of future profits created by the unit. V_i is the disagreement value firm i would get if a unitization agreement is not achieved. I am assuming that if firms that want to unitize cannot reach an agreement on how to share profits, then they will not form a unit at all. Each ecuation is maximized over α_i taking $\alpha_j \forall j \neq i$ as given the solution to the other problems. In practice, this assumption means that the biggest firm is negotiating with each firm separately.

4.3.3.2 Continuation value

The continuation value will come from solving another general equilibrium game. The new game will be the same as the one played by firms in stage 1, but voting for unitization will not happen again.

Assume there were originally N_f firms in field f, and they voted for unitization at time T. The game played from time $T+1$ on will have:

$$N_f^U = N_f - \sum_{i=1}^{N_f} u_{ift} + 1 \tag{4.10}$$

firms. Again, each period firms will face a common state, and a private state. The payoffs for each player will again come from selling the monthly production of oil. The transitions of price, cost, number of wells, and oil production will be the same as before. Again, each period firms will draw a shock on cost of drilling from the same normal distribution.

4.3.4 Equilibrium Concept

In stage 0, firms take no actions. Each period in stage 1, firms will observe their state and choose whether to drill a production well, an injection well, or do nothing. In stage 2, firms will observe the final state, and decide whether to join a unit or not. Firms that join a unit will subsequently bargain over profits. Throughout the game, strategies will only depend on the current state, in that sense firms solve a Dynamic Markov Equilibrium. That said, a strategy in this game is a set of four functions for each firm in the field, $\sigma_i^P(\Omega_{pi}, \Omega_c^t, \Omega_i^t) \in \{0, 1\}$, $\sigma_i^I(\Omega_{pi}, \Omega_c^t, \Omega_i^t) \in \{0, 1\}$, $\sigma^U(\Omega_{pi}, \Omega_c^T) \in \{0, 1\}$, $\sigma^a(\Omega_c^T, U) \in [0, 1]$, which are the decision of drilling a production well, drilling an injection well, unitizing, and bargaining share. Each firm finds such functions to solve two problems in stage 2, and two in stage 1. I will start by defining the problems firms solve at stage 2 and move backwards.

The two decisions firm i has to take in stage 2 are, whether to join a unit or not, and what share of the profits they are willing to keep. Starting by the end, firms interested in joining a unit, will find the strategy, $\sigma^a(\Omega_c^T, U)$, that solves the bilateral Nash bargaining problem:

$$\sigma^a(\Omega_c^T, U) = arg\max_{a_i} \left[\Pi^U * f(a_i, a_{-i}) - V_i\right]^{b_i} \\ \left[\Pi^U * f(1-a_i, a_{-i})) - V_j\right]^{b_j}, \tag{4.11}$$

where Ω_c^T is the final state of the field, and U defines the set of firms that want to unitize. The solution to all these problems simultaneously would be $a^* = (a_1^*, ..., a_U^*)$, such that:

$$a_i^* = \frac{b_i\left[\Pi^U(1-\sum_{j\neq i} a_j^*) - V_1\right] + V_i}{\Pi^U(b_i+1)}. \tag{4.12}$$

Before entering such bargaining game, firms simultaneously decided whether to join a unit, by finding the strategy $\sigma^U(\Omega_{pi}, \Omega_c^T) \in \{0,1\}$ that solves:

$$V_i(\Omega, \Omega_i, \Omega_c) = \max_{u_{ift}} -\theta_i u_{ift} + \mathbb{E}\left[V_i^U(\Omega, \{u_i ft\}_{i=1}^{N_f})|\theta_i u_{ift}\right] \tag{4.13}$$

In stage 1, from period 1 to period $T-1$, firms will find $\sigma_i^P(\Omega_{pi}, \Omega_c^t, \Omega_i^t)$ and $\sigma_i^I(\Omega_{pi}, \Omega_c^t, \Omega_i^t)$ that solve:

$$V_i^t(\Omega, \Omega_i, \Omega_c) = \sum_{r=t}^{T} \beta^t \\ \mathbb{E}\left[O_{ift}p_t(1-vc) - \sum_{k\in\{I,P\}}\left[d_{ift}^k(c_t+\xi_{ift}^D) - (1-d_{ift}^k)\xi_{ift}^N\right]|\Omega, \Omega_i, \Omega_c\right] \\ + \beta^T\mathbb{E}\left[V_i(\Omega, \Omega_i, \Omega_c)\right] \tag{4.14}$$

which could also be characterized with the following Bellman equation:

$$V_i^t(\Omega, \Omega_i, \Omega_c) = \max_{d_{ift}^P, d_{ift}^I} \pi_{ift} + \beta\mathbb{E}\mathbb{P}(t+1=T)V_i^U(\Omega, \{u_i ft\}_{i=1}^{N_f})|\theta_i u_{ift} \\ + \mathbb{P}(t+1\neq T)V_i(\Omega, \{u_i ft\}_{i=1}^{N_f})|\theta_i u_{ift} \tag{4.15}$$

To summarize, the model has three stages. In stage 0, firms will not take any action, but they will learn what their cost of unitization is and who they will be sharing their fields with. Each period in stage 2, firms will decide whether to drill a production well, an injection well or do nothing. Finally, in stage 3, firms will decide whether to unitize or not, and bargain over the future profits from the unit.

4.4 Data

4.4.1 Data Sources

To estimate the parameters in my model, I used data from four different sources. The first is DrillingInfo[9] (DI), from where I got monthly production and drilling dates. From the Texas Railroad Commission (TRRC), I have information on unitization agreements. Finally, from the Energy Information Administration[10], and RigData[11], I got information on drilling costs and oil prices. I am limiting the sample to fields that were discovered between 1980, and 2000, where drilling stopped before 2008[12].

Unfortunately, the TRRC does not collect oil production data for each well separately, instead it gathers production from leases. Several wells can be drilled in each lease, and leases can be linked back to a company than

[9] http://info.drillinginfo.com
[10] http://www.eia.gov
[11] https://rigdata.com
[12] The starting date is 1980 because all the area related information I have starts in 1977. The data quality in the first few years is dubious. The upper bound of the data is to avoid fields that are currently being exploited.

owns them and operates them. DrillingInfo gathered data from the TRRC and consolidated it in several tables. From those tables, I am using monthly production of oil, drilling date, and the area each firm has leased.

The TRRC also holds oil related information in separte tables in a database. I acquired their Docket table, which lists every legal case processed by the TRRC. Every unitization contract needs to be approved by the TRRC, and therefore will be registered in the Docket. It also contains the date of the contract, who signed it and the tracts involved. Unfortunately, The Docket does not contain the participation rules. Nevertheless, the TRRC was very generous providing access to their physical archives, from where I manually recovered such participation rules.

The Energy Information Administration (EIA) publishes historic West Texas Intermediary (WTI) spot prices. Such information can also be found in several different public sources. EIA also publishes an estimate of the cost of drilling in different areas in the United States. I also gathered more information from the weekly publications of RigData on the daily cost of renting a drill.

4.4.2 Sample Selection

To estimate the parameters in my model, I will only consider fields that were discovered between 1980 and 2000. Moreover, the last well in these fields was drilled before 2008. These restrictions were imposed for two reasons: the first is that in 2008 fracking became popular and the dynamics of the

CPE in fracked fields are quite different; the second is to avoid fields that are currently being developed. Unitization could still help in fracked wells, but the dynamics would be substantially different. Moreover, the cost of a fracked well is substantially different to the cost of a well drilled conventionally. A further restriction is that I am only considering fields where more than 5 wells have been drilled. The reason to omit these fields is that most of these fields only have a single operator. In fields with a single operator there is no CPE. Finally, due to computational limitations, I am omitting fields that were exploited by more than 4 firms. Table 4.2 shows that by adding this last restriction I only exclude 18% of the fields and 35% of the oil form the working sample I would have otherwise.

4.4.3 Data Analysis

This section has two objectives: the first is to provide a general understanding of the dynamics of how firms develop fields, and the second is to empirically support, and explain some of the assumptions that I will did while modeling.

4.4.3.1 General Information

The sample I selected consists of 501 fields. 86 out of the 501 fields have been unitized. In the 30 years I studied, 9,088 wells have been drilled. Table 4.2 shows more detail in terms of number of firms in each field. There are three important points to note in this table. The first is that, among this sample

Table 4.2: Fields by # of firms

Firms	Not-Unit	Unit	% Unit	Oil p.f.	Oil	Oil Dist.	Field Dist.
2	203	43	17%	788k	192M	33%	41%
3	115	25	18%	620k	82M	48%	63%
4	97	18	16%	893k	100M	65%	82%
5	56	13	19%	128k	88M	80%	94%
6+	53	26	33%	153k	116M	100%	100%

Firms: number of firms, Not-Unit: number of fields that never unitized, Unit: number of fields that unitized at some point, % Unit: percentage of the fields that unitized, Oil p.f.: production per field (in barrels), Oil: total production from all fields in that category, Oil Dist.: distribution of total production Field Dist.: distribution of total number of fields.

of wells, unitization is actually quite important, it happens in over 17% of the cases. The second point is that the rate of unitization increases substantially in fields with 6 or more firms. The final point is that I will estimate the parameters and compute the counterfactuals for 82% of the potential fields in the sample. Those 82% of the fields produce 65% of the oil.

The following tables and graphs will show systematic differences in behavior of firms in fields that were eventually unitized to firms in fields that were never unitized. First of all, in table 4.3 we can observe some of those difference in several dimensions. Notice how unitized fields tend to be bigger (in area) than not unitized fields. Since unitized fields are larger, we expect their production is higher. The interesting part is that the area of unitized fields is less than 1.5 times the area of non-unitized fields and their production is around 5 times higher. Also, the productivity of a well in unitized fields is substantially higher. The two last variables in table 4.3 are the Herfindahl Hirschman Index with respect to area and original oil in place. They suggest

Table 4.3: Field Summary Statistics

Variable	Unitized	Not-Unit
Production	1.10 M	0.26 M
Oil per well	39 k	25 k
Area	1,148	891
HHI Area	0.2	0.12
HHI Oil	0.37	0.32

Production is in barrels of oil, area is in acres, HHI Area is the Herfindahl Hirschman index based on area, HHI oil is the Herfindahl Hirschman index based on oil production

that when firms leased similar acreage in a field, they are more likely to form units.

Another pattern that differentiates fields that were eventually unitized from fields that were never unitized is that, right after discovery, fields that eventually unitized tend to be exploited at a slower rate than fields that never unitized. Table 4.4 supports the previous assertion. The data in the table

Table 4.4: Drilling throughout time

Month	Unitized	Not-Unitized
24	1.95	1.85
36	3.28	2.40
48	3.85	2.77
60	3.30	2.88
120	5.71	3.50

Read: By month 120, in fields that unitized, firms have drilled 5.71 times the number of wells they drilled in the first year. In fields that did not unitized, only 3.50 times what they drilled in the first year.

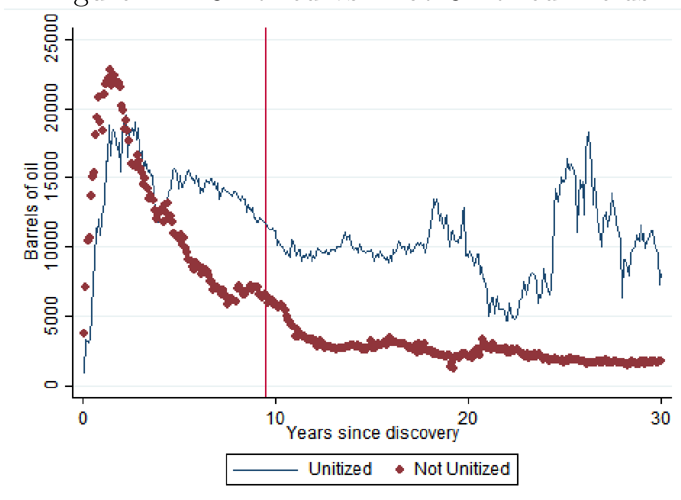
shows how many wells were drilled after certain years as a factor of the number of wells drilled during the first year. For example, if in month 24 we observe a 2.0, it means that the wells drilled up to month 24 are twice of those drilled up to month 12. If in the long run we find factors closer to 1, it means that most of the wells in such field were drilled during the first year. Notice how, in the long run fields that were eventually unitized have factors that are substantially higher.

Figure 4.2 again supports the fact that fields that eventually unitized were exploited slower. The red dots in the graph show monthly production of oil in fields that never unitized, and the blue line shows production in fields that were eventually unitized. The vertical line is the moment when, on average, unitization happened. All the fields in this sample are roughly the same size. The figure highlights how fields that were never unitized produce more oil right after discovery.

Figure 4.3 offers two examples of how fields that eventually achieve unitization are typically exploited. The blue line in the figures is the overall production in the field. The green dots are production wells. In these two examples, drilling happened right after discovery. Suddenly, drilling stopped and production started decreasing. At that time, the TRRC received a signal that the field is reasonably developed, and allows firms to unitize. After unitization, the single operator finds it profitable to continue exploiting the field without facing the CPE.

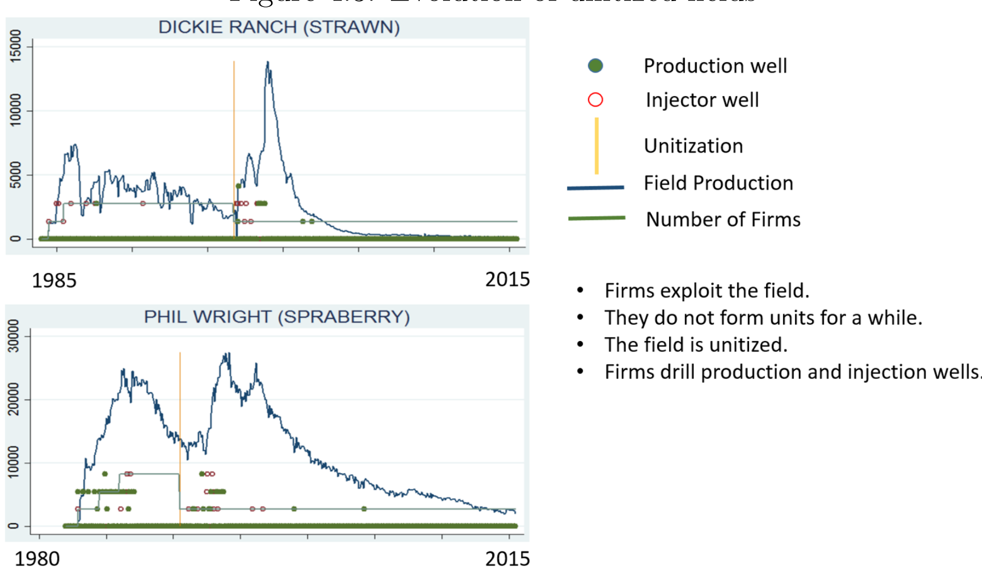
I mentioned in the Background Section that units are not necessarily

Figure 4.2: Unitized vs. Not Unitized Fields



Notes: Average monthly production of unitized vs. not unitized fields. Fields of similar size in terms of maximum production.

Figure 4.3: Evolution of unitized fields



complete, in the sense that they might not include every firm in the field. Achieving an incomplete unit potentially diminishes the CPE, but does not eliminate it completely. Also, compulsory unitization can improve efficiency by enhancing more units, but also by helping firms achieve bigger units. Table

Table 4.5: % of field unitized

% of Field Unitized	# of Fields	
0% - 25%	1	1%
25% - 50%	20	23%
50% - 99%	21	24%
100%	45	51%

4.5 shows the relative size of units. The most important takeaway is that in most cases, units encompass more than 50% of the participants in the fields. Moreover, around 40% of all the fields in the sample that are unitized are fully unitized. This suggests that compulsory unitization can improve efficiency not only in the extensive margin (more units will be formed), in the intensive one (units will be bigger).

4.4.3.2 Data Backing Assumptions

In the baseline model, I assumed that if unitization happens voluntarily, firms will choose a participation rule based solely on area. In table 4.6, I summarize how units share profits. Note that area is used by more than 80% of the units, with a weight of over 70%. Moreover, several of the possible variables that go into participation rules are highly correlated. The reason is straight forward: fields with more area will have more wells, it is very likely that they

Table 4.6: Factors of Participation Rules

	Area	Original	Prod. Rate	Remaining	Wells	Oil
Times positive	84%	10%	21%	18%	24%	36%
Average if positive	71%	42%	46%	44%	18%	36%

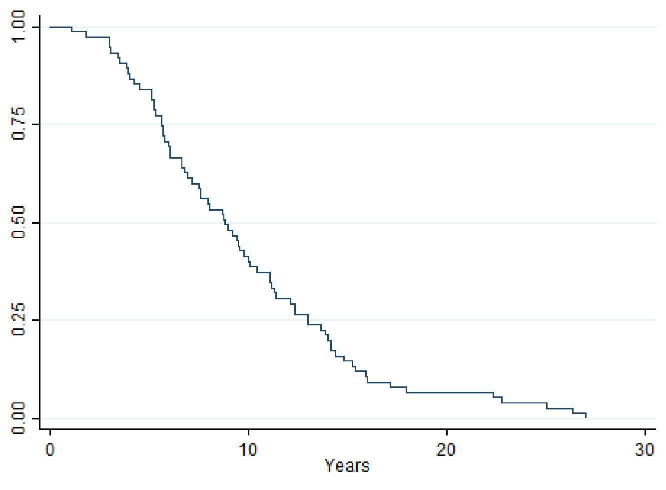
Based on the 86 cases of unitization I observed in the fields that were voluntarily unitized in my sample.

will hold more oil, and they will probably be producing more oil. For those reasons, the assumption that if a unit were to happen it would be based on percentage of area leased could make sense. In the counterfactual analysis, when I analyze what would happen under different implementations of compulsory unitization, I will relax this assumption and estimate the bargaining-power of firms that joined units.

The TRRC allows fields to unitize only if they are "reasonably developed." Although the TRRC does not explicitly define what fully developed means, it is unlikely that it will allow unitization right after discovery. Figure 4.4 shows the Kaplan-Meier Estimate of time to uniization. Notice how the earliest unitization agreement happened around a year after the field was discovered. Nevertheless, we observe very few unitization agreements between 0 and 5 years after the field was discovered and most happen between 5 and 15 years after discovery.

It is not clear how TRRC decides that a field is "reasonably developed." Nevertheless, it is very likely that they consider the drilling and production activity of the field in their decision rule. I modeled time to unitization using a Weibull survival model, but letting λ vary with actions taken by the firms.

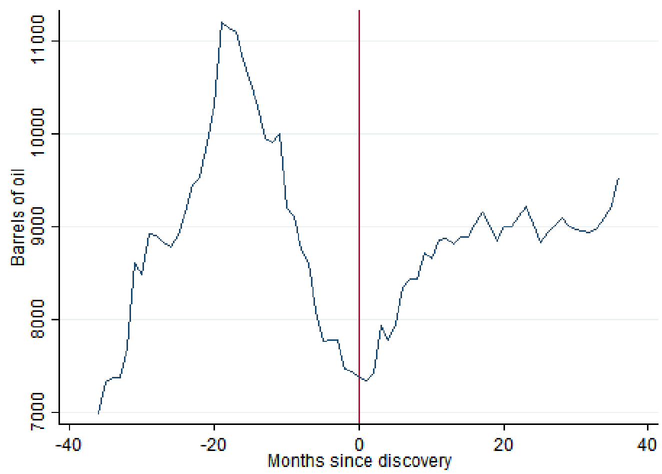
Figure 4.4: Kaplan-Meier Estimate of Time to Unitization



Notes: Kaplan-Meier estimate of the time between the discovery of the field and the year when it was unitized.

In figure 4.4 one can observe what happens before unitization. Right after discovery firms ramp up production by drilling more wells. Before unitization production decreases, which means that firms stopped drilling. A possible interpretation is that this sequence of events signals the TRRC that the field is reasonably developed, and unitization can then be sought. In the estimation results section I will confirm this observation by fitting a Weibull and a log-normal model, where the mean of the distributions depend on the action of the firms. I find that drilling activity in the last year, as well as decrease in production are good predictors of T.

Figure 4.5: Monthly Production of Unitized Fields



Notes: Average monthly oil production by field. Only fields that unitized. Time is normalized, 0 is when the field was unitized.

4.5 Estimation Strategy

A recent innovation on estimating dynamic models is the development of two stage algorithms[13]. Before such innovation, solving dynamic games was computationally unfeasible most of the times. The burden of one-stage methodologies comes from the need of finding a fixed point for every combination of parameters. The backbone of my estimation strategy will be the methodology developed in Bajari and Levin, 2007. I will refer to such algorithm as BBL. With BBL, I will estimate the transition parameters (first stage), and the parameters in the distribution of shocks (second state). I

[13]Some examples of these procedures were developed in Aguirregabiria and Mira, 2007, Hotz, 1994, and Pesendorfer, 2008.

will then use the estimated parameters, and other equilibrium conditions to estimate the bargaining parameters. The idea of computing the different elements of the maximization problem firms solve when bargaining was also used in Crawford, 2012 and Gowrisankaran, 2013.

The BBL estimator is a two stage one. In the first stage, one finds reduced form estimates for the state transition functions and choice probabilities conditional on observables (CCP). The second part of the first stage is to forward simulate value functions assuming that agents behave according to their CCPs. An innovation of BBL is that it draws random shocks from the distribution of shocks instead of drawing actions from conditional choice probabilities.

In the second stage, one exploits the optimality conditions to estimate the structural parameters. If $\sigma(\Omega, \xi) = \{\sigma_i(\Omega, \xi_i)\}_{i=1}^{N}$ are policy functions, optimality implies that for every strategy $\sigma^g(\Omega, \xi)$ such that $\sigma^g(\Omega, \xi) \neq \sigma(\Omega, \xi)$, then

$$V_i(s; \sigma_i, \sigma_{-i}, \theta) \geq V_i(s; \sigma_i^g, \sigma_{-i}, \theta). \tag{4.16}$$

The idea behind the second stage of BBL is to construct several σ_i^g as slight alterations to σ_i and forward simulate the value functions under these policy functions. Then one optimizes a function over a parameter space that penalizes whenever equation 4.16 does not hold. If the solution to the optimization problem is unique, we would say that the parameters are identified.

In the last stage of my estimation, I will recover the bargaining parameters. To achieve that, I will use the optimality condition derived from the

NiN solution. Using data on how firms that unitized shared profits, and by counterfactually computing the value obtain by those firms if the would have not unitized (disagreement value), I will have all the components that go into the NiN optimal conditions. Having all the elements, I am able to recover the bargaining power of firms. In the rest of this section I will first explain the details of the first stage of the BBL algorithm, then the second stage, and finally how I recovered the bargaining parameters.

4.5.1 First Stage

In the first stage of this particular application, I will estimate four state transition functions and three conditional choice probabilities. The transition functions are oil production, price of oil, trend in cost of drilling, and the hazard of T. The CCPs I will need to compute are: drilling a production well, drilling an injection well, and the decision to join a unit.

4.5.1.1 Transitions

Oil

As mentioned in the model section, the oil transition function is particularly important because it models the common pool externality of sharing an oilfield. Thanks to the detailed data I have, I will be able to estimate a separate oil transition model for each field. These oil transition functions basically describe how production will evolve depending on drilling decisions and previous production.

I modeled the oil transition function in several ways. I tried dynamic panel data models, in which slopes had a single parameter. The downside of those models is that, although different fields can have different intersects, they won't allow variability in slopes. I also tried dynamic Tobit models, but faced the same downside. To allow different fields to produce differently, I modeled each one separately as a linear regression. The model I estimated using OLS is detailed in equation 4.17. I ran a different regression for every single field.

$$
\begin{aligned}
O_{ift} = {} & \beta_f + \beta_f^O O_{ift-1} + \beta_f^P d_{ift}^P + \beta_f^{LP} d_{ift-1}^P + \beta_f^I d_{ift}^I + \beta_f^{LI} d_{ift-1}^I \\
& + \beta_f^{CP} d_{ift}^P w_{ift-1}^P + \beta_f^{CI} d_{ift}^I w_{ift-1}^I \\
& + \beta_f^{IP} \sum_{j \neq i} d_{ift}^P + \beta_f^{II} \sum_{j \neq i} d_{ift-1}^I + \epsilon_{ift},
\end{aligned}
\tag{4.17}
$$

where:

- O_{ift} is the oil produced at time t, in field f, by firm i
- $d_{ift}^P \in \{0, 1\}$ is an indicator of drilling a production well
- $d_{ift}^I \in \{0, 1\}$ is an indicator of drilling an injection well
- w_{ift}^P is the cumulative number of production wells drilled by time t
- w_{ift}^I is the cumulative number of injection wells drilled by time t

One might interpret the parameters as follows: β_f^O is the percentage of oil (the reference point is the oil produced last period) that a firm in a field will extract if nobody else drills in the same field. β_f^P, β_f^{LP}, and β_f^{CP} describe the extra oil a firm in a field will produce if it drills a new production well given the state of the field. β_f^I, β_f^{LI}, and β_f^{CI} summarize the extra oil a firm would extract if it drills an injection well in a given state. Finally, β_f^{IP} and β_f^{II} will be the value of the common pool externality if a different firm in the field drills a production or an injection well, respectively.

Price and Cost

As mentioned before, I followed Kellogg, 2014 in treating oil prices and drilling costs as exogenous. All the approaches I used to model the transition of these variables are variations of autoregressive models. The approach presented in equations 4.18 and 4.19 are Markov-switching models (MSM), in which the price of oil can be in a good stage or a bad stage. If the price is in a good stage, it is expected to increase (or remain the same) in the next period; if it is in a bad stage, it is expected to decrease. To estimate these models, I followed the methodology proposed in Hamilton, 1989. I assume two possible states for the MSM, $s_t \in \{L, H\}$. The price model is

$$p_t = \begin{cases} \mu_L^P + \phi_L^P p_{t-1} + \epsilon_{Lt}^P & \text{if } s_t^P = L \\ \mu_H^P + \phi_H^P p_{t-1} + \epsilon_{Ht}^P & \text{if } s_t^P = H \end{cases} \tag{4.18}$$

and the model of cost is

$$c_t = \begin{cases} \mu_L^C + \phi_L^C c_{t-1} + \epsilon_{Lt}^C & \text{if } s_t = L \\ \mu_H^C + \phi_H^C c_{t-1} + \epsilon_{Ht}^C & \text{if } s_t = H. \end{cases} \tag{4.19}$$

The state variable s_t^i for $i \in \{P, C\}$ follows the Markov distribution

$$p(s_t^i = j | s_{t-1}^i = k) = p_{kj}^i. \tag{4.20}$$

Hazard of T

The last period of the game is when firms vote for or against unitization. Every period t firms face a probability that period $t+1$ will be T. I assumed that such probability follows a Weibull hazard rate given by:

$$h(t) = p\lambda t^{p-1}, \tag{4.21}$$

where

$$\lambda = \gamma + \gamma_F F_f + \gamma_A \ln A_f + \gamma_{PMO} PMO_t + \gamma_{YND} YND_t \tag{4.22}$$

In equation 4.21, F is the number of firms in field f, $A_f = \sum_{i=1}^{N_F} A_{if}$ is the area of the entire field, PMO is

$$PMO_t = \frac{\sum_{i=1}^{N_f} O_{ift-1}}{\sum_{j\in\{0,t-1\}} \sum_{i=1}^{N_f} O_{ifj}}, \tag{4.23}$$

and YND_t is the time in which there has been no drilling in the field.

The main consequence of the model in equation 4.21 is that firms will increase the chance of the last period happening sooner if they exploit a field at the beginning, and then stop drilling for a more than a year. One sensible explanation to this fact is that this behavior signals the TRRC that the field is “reasonably developed”, which means that they will approve a unit. The parameters of the model were estimated via maximum likelihood, for a detail description see Cleves and Marchenko., 2010. Unfortunately, I cannot observe if voting for unitization happened in a field, and none units were formed. So I must relay on the identifying assumptions that the distribution of T is independent of voting results.

4.5.1.2 Conditional Choice Probabilities

Conditional Choice of Drilling

Every period, firms will decide simultaneously whether to drill a new production well, an injection well, or do nothing. I estimated several specifications using logit and probit models. Specifically, since these are choice functions conditional on the observable part of the state, the covariates are functions of state variables. For the second stage, I modeled the choice of drilling an injection well and a production well with two different probit functions described in equation 4.24 and equation 4.25.

$$P(d_{ift}^{k} = 1) = \Phi(\alpha_k^{Choice} X_{ift}^{Choice}), \tag{4.24}$$

where

$$k \in \{P, I\},$$

and the product $\alpha^{Choice} X^{Choice}$ is given by

$$\begin{aligned} \alpha_k^{Choice} X_{ift}^{Choice} &= \alpha_k^P \ln(p_t) + \alpha_k^C \ln(c_t) + \alpha_k^O \ln(O_{ift}) + \alpha_k^W w_{ift} + \alpha_k^I \sum_{j \neq i} w_{jft} \\ &+ \alpha^{WQ} WQ_f + \alpha^{DQ} DQ_f + \alpha^{IQ} IQ_f + \alpha^t t + \alpha, \end{aligned} \tag{4.25}$$

where p_t, c_t are price of oil and cost of drilling at time t. O_{ift} and w_{ift} are oil produced and cumulative wells drilled by firm i in field f by time t. WQ_f, DQ_f and IQ_f are measures of the quality of field. Such measures come from the coefficients estimated in the oil transition equations. WQ_f will be a measure of the oil expected from the first well if nothing else happens in the field, it was calculated by

$$WQ_f = \ln\left(\frac{\beta_f^P}{1-\beta_f^O}.\right) \tag{4.26}$$

DQ_f will be a measure of how new wells from the same firm will perform. The formula of DQ_f is:

$$DQ_f = \frac{\beta_f^{CP}}{\beta_f^P}. \tag{4.27}$$

IQ_f will be a measure of the externality imposed by other firms when they drill new wells. It will be

$$IQ_f = \frac{\beta_f^{IP}}{\beta_f^P}. \tag{4.28}$$

I used maximum likelihood to estimate the parameters in the probit function. I ran the model with all the observations I have of price, cost, and number of wells from the sample I described in the data section. The quality parameters came from the oil transition functions.

Unitization policy function

At time T, firms will decide whether they will join a unit or not. Such decision will also be modeled by a probit function described in equation 4.30.

$$P(d_{ift}=1) = \Phi(\alpha^{Unit}X^{Unit}). \tag{4.29}$$

The product $\alpha^{Unit}X^{Unit}$ is given by

$$\begin{aligned}\alpha^{Unit}X^{Unit}_{ift} = {} & \alpha_i^W W_{fT} + \alpha_i^{WQ} WQ_f + \alpha_i^{DQ} DQ_f + \alpha_i^{IQ} IQ_f + \alpha_U^N N_f \\ & + \alpha_U^{MIN} MIN_f + \alpha_U^{MAX} MAX_f + \alpha_U^{RA} RA_{fi} + \alpha_U^{AW} AW_{ifT} + \alpha_U,\end{aligned} \tag{4.30}$$

where W_f is the total number of wells drilled in field f by T, WQ_f, DQ_f, and IQ_f are as in as in 4.26 to 4.28, N_f is the number of firms in field f, MIN_f and MAX_f are the minimum and the maximum relative areas a firm has leased in field f. They are measures of how unevenly distributed a field is. RA_{if} is the relative area firm i has in field f , and AW_{if} is the acreage per production well drilled. To be more specific, the mathematical expressions of such quantities are:

$$MIN_f = \min_{i \in \{1,\ldots,N_f\}} a_{if} \tag{4.31}$$

$$MAX_f = \max_{i \in \{1,\ldots,N_f\}} a_{if} \tag{4.32}$$

$$RA_{if} = \frac{A_{if}}{\sum_{i=1}^{N_f} A_{if}}, \tag{4.33}$$

$$AW_{if} = \frac{A_{if}}{w_{if}}, \tag{4.34}$$

The results of this conditional choice probability will describe the dependence of the willingness to unitize on how heterogeneous a field is.

Value function

The goal of obtaining the state transition functions and the conditional choice probabilities is to be able to forward simulate the value functions. There are several ways to forward simulate the value functions. The main variation is whether to draw shocks from the structural error distribution and using those shocks recover the actions from the conditional choice probabilities, as in Bajari and Levin, 2007; or to draw actions and recover shocks, as in Ryan, 2012. I followed the approach taken by Bajari and Levin, 2007. The following lines describe the algorithm I implemented to estimate the value function.

1. Draw the cost of unitization for each firm ξ_i^u, and set the initial state of the game

$$s_0 = (p_0, c_0, \{W^P_{ift-1} = 0, W^I_{ift-1} = 0, O_{ift-1} = 0\}_{i=1}^{N_f}).$$

2. Draw private shocks $x_{it} = (\xi^P_{it}, \xi^I_{it}, \xi^N_{i0})$ from $N_3(0, \mathbb{I})$ for each firm i.

3. Calculate the action (drill injection and production wells) taken by firms given the set of shocks, and the inverted policy function: $a_{it} = \hat{\sigma}_i(s_t, xi_{it})$, for each firm i.

4. From the hazard function $\hat{h}(t)$ draw I_t, which indicates if the next period will be the last.

5. Compute the resulting profits, $\pi_i(a_t, x_t, xi_{it}; \theta)$.

6. Draw a new state s_{t+1}, using the transition probabilities $\hat{P}(s_{t+1}|s_t, a_t)$.

7. If $I_t = 1$, move on to compute the continuation value, otherwise go back to step 2.

To compute the continuation value. I follow the same procedure as above taking the following bullets into consideration:

- If a unit is not formed, the initial values of every firm are the last iteration of the previous algorithm.

- If a unit is formed, the initial oil of the unit is:

$$O_{uft} = \sum_{i=1}^{N_f} O_{uft} u_{if}, \tag{4.35}$$

and the initial number of wells is

$$w_{uft} = \sum_{i=1}^{N_f} w_{uft} u_{if}. \tag{4.36}$$

- The last period is $T = 30$ years.

4.5.2 Second Stage

The objective of the second stage is to estimate the structural parameters of the model. In this case, such parameters are:

- mean and variance of fixed cost, μ^N, σ^N
- mean and variance of cost drilling a production well, μ^P, σ^P
- mean and variance of cost drilling an injection well, μ^I, σ^I
- mean and variance of cost of unitization, μ^u, σ^u.

In the second stage, I will take the estimates of the value function from the first stage. Then, I will slightly perturb the policy functions and with those perturbations, I will forward simulate new value functions. Finally, I will find the parameters that optimize a function that penalizes violations of the optimality conditions.

The expression of the value function I forward simulated is in equation 4.37. To create the perturbations to the policy functions, I followed Ryan, 2012 and added random draws from $N(0, 0.1)$ to the expressions inside the normal distribution of the probit conditional choice probabilities.

$$V_i(\Omega; \hat{\sigma}; \theta) = \mathbb{E}\left[\sum_{t=0}^{\infty} \beta^t \pi_i(\hat{\sigma}(\Omega_t, \xi_t), \Omega_t, \xi_t; \theta) | s_0 = s; \theta\right] \tag{4.37}$$

Note that in this case, the profit function is linear in parameters in the sense that,:

$$\begin{aligned}\pi_{ift} = &\left[p_t O_{ift} - (d^P_{ift} + d^I_{ift})c_t, -d^P_{ift}, \xi^P_{ift} d^P_{ift}, -d^I_{ift}, \xi^I_{ift} d^I_{ift}, -u_{ift}, \xi^U_{if} u_{if}\right] \\ &\left[1, \mu^P, \sigma^D, \mu^I, \sigma^I, \mu^U, \sigma^U\right]'.\end{aligned} \tag{4.38}$$

This is important because it will simplify the computation of the search of the optimal parameters for two reasons. The first is that, as shown in Bajari and Levin, 2007, the fact that the parameters I estimate appear in the distribution functions will not cause an extra problem. The second is that $V_i(\Omega; \hat{\sigma}; \theta)$ could be rewritten as

$$V_i(\Omega; \hat{\sigma}; \theta) = W(\Omega, \hat{\sigma}) \cdot \theta, \tag{4.39}$$

where

$$W_i(\Omega; \hat{\sigma}) = \mathbb{E}\left[\sum_{t=0}^{\infty} \beta^t \left[p_t O_{ift} - d_{ift} c_t, -p_t O_{ift}, -\epsilon^D_{ift} d_{ift}, -u_{ift}, \epsilon^U_{ift} u_{ift}\right] | s_0 = s\right] \tag{4.40}$$

With this simplification, I will be able to estimate the value function $V_i(\Omega; \hat{\sigma}; \theta)$ for several different sets of parameters, θ, and the same policy function, $\hat{\sigma}$ by estimating $W_i(\Omega;\hat{\sigma})$ only once. Without linearity, I would need to estimate a different $W_i(\Omega;\hat{\sigma})$ for every variation in parameters.

The equilibrium conditions imply that for any $\sigma^i \neq \sigma$, then

$$g(\sigma^i, \sigma, \theta) = V_i(s; \sigma_i, \sigma_{-i}, \theta) - V_i(s; \sigma_i^g, \sigma_{-i}, \theta) \geq 0. \tag{4.41}$$

Under linearity,

$$g(\sigma^i, \sigma, \theta) = \left[W_i(\Omega;\hat{\sigma}) - W_i(\Omega;\sigma^i)\right] \cdot \theta. \tag{4.42}$$

Bajari and Levin, 2007 proves that a way to find the real value of θ is to minimize

$$Q(\theta, \alpha) = \int \min\left[g(\sigma^i, \sigma, \theta), 0\right]^2 \partial H(\sigma^i) \tag{4.43}$$

with respect to θ. Note that the expression inside the integral of equation 4.43 will always be greater than 0. The only way it will be 0 is if the optimality condition holds. So equation 4.43 penalizes every time the optimality does not hold, and the "right" parameters are those for which optimality fails less. I minimized the sample analog of equation 4.43 by drawing 1,500 alternative policy functions. To search for the parameters I used the Metropolis-Hasting methodology described in Chernozhukov V, 2003.

4.5.3 Bargaining Parameters

To estimate the unobserved bargaining parameters, I will follow the same framework that Crawford and Yurukoglu (2012), and Gowrisankaran, et al (2015). After recovering all the shock parameters, I compute the counterfactual of the value firms that unitized would have created if they would have not unitized. Equation 4.44, the first order condition of the bargaining game firms play, shows how I combined sharing rules, firms profits, and the counterfactual of the future profits firms would have made if the worked separately to recover the bargaining power of each firm.

$$b_i = \frac{\Pi^U a_i^* - V_i}{\Pi^U (1 - \sum_j a_j^*) - V_1}, \tag{4.44}$$

In equation4.44 b_i, are the bargaining parameters, a_i^* are the negotiation outcomes Π^U is the discounted future profits of the unit, and V_1 and V_i are the profits firms would get if they did not reach a unitization agreement. Note that all the elements in 4.44, but b_i, are are either observed in the data, or can be inferred using the parameters estimated. We observe how firms split profits in every unit, that gives a^*. V_1 and V_i can be computed solving the equilibrium firms would have achieved without unitization.

4.6 Estimation Results

The estimation results will be presented by parts. I will start with the state transition probabilities. In the second subsection, I will show the conditional choice probabilities. In the third subsection, I will display the parameters of the distribution functions governing the shocks in cost of drilling and unitization. In a final subsection, I will summarize the bargaining power estimates.

4.6.1 State transition probabilities

Several variables in the state evolve deterministicaly given the current state and actions. As shown in the estimation section, some of the components of the state evolve stochastically. Such variables are: oil production, price of oil, trend in cost of drilling, and T (final period). In this subsection, I will go over the results of all those estimations.

Oil

In table 4.7, I present the summary statistics of the distribution of the oil transition parameters. Pesaran, 1995 argues that computing the simple averages, even with dynamic variables, gives an unbiased estimator of the summary statistics. The mean of "Lag oil" is 0.91 and the median is 0.93. That means that if nobody drills in a field from one period to the next, production will be around 93% of what it was the previous month. Adding the mean of "Prod Well" and "Lag Prod Well" gives 2,220, which is the average production from the first well the period after drilled. Similarly, adding the mean of "Inj Well" and "Lag Inj Well" gives 2,166. The estimates of "Total Prod Wells" and "Total Inj Wells" are -213 and -38 respectively, which means that every subsequent production and injection well will be a little less productive than the previous one. Finally, "Others Prod Wells" and "Others Inj Wells" indicate that on average, whenever a neighbor drills a new production well, a firm's production will fall in around 39 barrels, and if they drill a new injection well production will likely increase. These last parameters are important because they show that when neighbors drill, a firm's production is affected. If a neighbor drills a production well, the firm will be worse off, but if they drill an injection, the firm will be slightly better off.

Table 4.7: Oil Transition Coefficients

	Mean	Median	St. Div.
Lag Oil	0.91	0.93	0.08
Prod Well	729.09	519.26	1095.43
Lag Prod Well	1491.44	788.56	3494.58
Inj Well	653.02	325.39	1043.49
Lag Inj Well	1513.36	815.89	3447.33
Tot Prod Wells	-213.95	-89.70	1450.18
Tot Inj Wells	-38.54	-8.79	230.25
Others Prod Well	-39.07	-0.88	666.70
Others Inj Well	0.38	10.23	672.36
N	501	-	-
R^2	0.93	0.95	0.08

The estimates for each field were computed independently. The numbers displayed are the summary statistics of such estimates.

Price and Cost

I modeled the evolution of price of oil as a Markov-Switching-Models. I did not use simple autorregressive models because because prices and costs do not increase (or decrease) monotonically. Table 4.8 shows the results of running a Markov-Switching-Model for price of oil and cost of drilling. On the first column I present the results for price of oil. When the state is "bad", we would expect the price of oil to decrease in around 2%. If we are in a "good" state, then we would expect the price of oil to increase in around 8%

Table 4.8: Price and Cost Transitions

		Price	Cost
St1	Lag ϕ_1	0.98	0.95
		237.44	82.82
St2	Lag ϕ_2	1.08	1.06
		110.19	240.13
St1	p_{11}	0.92	0.78
St2	p_{21}	0.38	0.26

$p_t = \mu^p + \phi_{s_t} p_{t-1} + \epsilon_{s_t}$, $P(s_t|s_{t-1}) = \mathbb{P}$
t statistics in parentheses
Methodology: Hamilton, J. (1990)

the following period. If we are in a "bad" state, the probability of staying in a bad state is 92%. If we are in a "good" state, the probability of staying in the good state is 62%. Note that the parameters of the evolution of cost are quite similar.

Hazard of T

T is the last period in the game, and it is also when unitization happens. I modeled T as Weibull and log-normal survival function, where the mean depends on the state of the game. The results are displayed in table 4.9.

Since the Weibull specification is, in general, more flexible than the log-normal, I will rely on it for the second stage BBL. The parameters presented in table 4.9 are consistent with what we would expect given current legislation. In particular, firms decrease the drilling activity after producing heavily at the begining. This signals the TRRC that the field is "reasonably developed",

Table 4.9: Time to unitization

	(Log-Normal)	(Weibull)
firms	0.696	-0.210
	(0.606)	(0.169)
log acres	0.667	-0.261
	(0.499)	(0.193)
log oil	-2.616*	0.906***
	(1.033)	(0.170)
pct. oil	1.667	-0.923*
	(1.618)	(0.440)
years without drill	-2.208*	0.678**
	(1.084)	(0.254)
constant	30.309**	3.629
	(10.982)	(2.692)
log σ^2	0.999***	
	(0.257)	
log p		-13.710***
		(2.275)
Observations	23107	23107

The first column is the results of a survival analysis assuming T follows a Weibull distribution and the second assumes T follows a log-normal one. Only considering fields where unitization was achieved. *** p $\leq$ 0.01, ** p $\leq$ 0.05, * p $\leq$ 0.1

and firms can seek unitization. The variable "Pct. Oil" is defined as the oil produced in a certain period, divided by the maximum oil produced in a period up to now. The negative estimate in the Weibull model, means that $\mathbb{P}(T = t+1)$ is lower if oil production at t is smaller relative to previous years. The positive estimate of "Years without drill" suggests that $\mathbb{P}(T = t+1)$ increases when firms stop drilling. Finally, the variable "log oil" is the cumulative oil produced up to now. The positive sign suggests the probability of $T = t + 1$ increases with cumulative production.

4.6.2 Conditional choice probabilities

To implement BBL, it is also necessary to estimate the probabilities of firms' action conditional on observables. During the development phase, firms will drill production wells, injection wells or do nothing. In the final period, they will decide whether to join a unit or not. The estimates of these three conditional choice probabilities will be shown in the following subsections.

Conditional Choice of Drilling a Well

I modeled the conditional choice probability of drilling a production well and an injection well with probit functions, as well as linear specifications. The results for the conditional choice of drilling a production well and an injection well are in tables 4.10 and 4.11, respectively.

Tables 4.10 and 4.11 suggest that firms will drill more production wells in fields with a larger area. Also, firms tend to drill more when the price of oil is higher, and when cost of drilling is lower. Drilling, specifically injection

Table 4.10: Conditional choice of drilling a production well

	(1)	(2)	(3)	(4)	(5)	(6)
firms = 1	0.04***	0.052***	0.03***	0.429***	0.413***	0.22***
	(0.001)	(0.001)	(0.00)	(0.018)	(0.023)	(0.02)
log acres	2.36***			38.54***		
	(0.312)			(7.30)		
log price	0.01***	0.019***	0.00**	0.194***	0.240***	0.24**
	(0.001)	(0.001)	(0.00)	(0.025)	(0.032)	(0.08)
log cost	-0.01***	-0.004**	0.00	-0.081*	0.071	0.12
	(0.001)	(0.001)	(0.00)	(0.035)	(0.041)	(0.15)
log oil	-0.10	-1.283***	-1.85***	16.786***	-8.283*	-18.56***
	(0.183)	(0.202)	(0.20)	(3.483)	(3.692)	(3.73)
own w.	2.28***	-0.184***	-0.14***	13.924***	4.129***	3.91***
	(0.020)	(0.034)	(0.03)	(0.366)	(0.480)	(0.61)
others w.	-0.06*	-1.905***	-1.83***	1.225***	-5.771***	-9.81***
	(0.026)	(0.035)	(0.03)	(0.346)	(0.480)	(0.61)
years	-0.30***	-0.331***	-0.21***	-9.179***	-9.684***	-7.86***
	(0.005)	(0.007)	(0.01)	(0.174)	(0.199)	(0.23)
cons.	-0.16***	0.004	-0.01	-3.856***	-3.682***	-5.113*
	(0.015)	(0.016)	(0.05)	(0.404)	(0.488)	(2.10)
log σ^2					-1.944***	-1.74***
					(0.085)	(0.084)
Field Q.	✓			✓		
Field FE		✓	✓		✓	✓
Year FE			✓			✓
Obs.	205060	205060	205060	205060	205060	203623

The first three columns are linear models, and the last three are probit models. The first is linear regression, the second with field fixed effects and the last also with year fixed effects. The fourth is simple probit, the fifth has field fixed effects and the sixth also has year fixed effects. *** p $\leq$ 0.01, ** p $\leq$ 0.05, * p $\leq$ 0.1

Table 4.11: Conditional choice of drilling an injection well

	(1)	(2)	(3)	(4)	(5)
firms = 1	0.026***	0.023***	0.016***	0.341***	0.309***
	(0.001)	(0.001)	(0.001)	(0.021)	(0.029)
log acres	0.672**			4.306	
	(0.244)			(8.666)	
log price	0.008***	0.009***	0.005*	0.229***	0.266***
	(0.001)	(0.001)	(0.002)	(0.029)	(0.040)
log cost	0.002	-0.000	-0.000	-0.125**	-0.122*
	(0.001)	(0.001)	(0.004)	(0.040)	(0.049)
log oil	2.218***	1.747***	1.470***	80.304***	40.124***
	(0.143)	(0.158)	(0.159)	(4.808)	(5.165)
own wells	1.174***	-0.943***	-0.916***	6.417***	-0.597
	(0.016)	(0.027)	(0.027)	(0.237)	(0.377)
others wells	0.122***	-1.434***	-1.395***	2.794***	-5.257***
	(0.020)	(0.028)	(0.028)	(0.389)	(0.515)
years disc.	-0.154***	-0.134***	-0.068***	-6.796***	-7.293***
	(0.004)	(0.005)	(0.008)	(0.197)	(0.235)
constant	-0.034**	0.022	0.023	-1.337**	-1.546*
	(0.012)	(0.013)	(0.043)	(0.469)	(0.602)
log σ^2					-1.205***
					(0.095)
Field quality	✓			✓	
Year FE			✓		
Field FE		✓	✓		✓
Observations	205060	205060	205060	205060	205060

The first three columns are linear models, and the last thwo are probit models. The first is linear regression, the second with field fixed effects and the last also with year fixed effects. The fourth is simple probit, and the fifth has field fixed effects. *** $p \leq 0.01$, ** $p \leq 0.05$, * $p \leq 0.1$

wells, will increase if production is high, and if there has been more wells drilled in the field. For the second stage of BBL, I chose specification 4, which is a probit model without field fixed effects. I did this to avoid relying on estimates of field fixed effects in the second stage of BBL. Moreover, for choice models I prefer a probit than a linear specification.

Conditional Choice of Unitization

I also modeled the conditional choice of joining a unit with probit and linear functions. The estimation results are in table 4.12. Interestingly, table 4.12 suggests that units are more likely to happen in fields that are "more homogeneous." Particularly, the probability of having a unit increases in fields where the biggest firm has a relatively smaller share of the land leased in the field. This result ecos previous qualitative research that suggests that units are more likely to happen within firms that are "more alike" in size. The "Minimum Area" coefficient is also positive, being further supports such claim. Again, the preferred specification for the second state is number 4, which is a probit model without fixed effects, but controlling for field quality estimates. On the one hand, the sign of the estimates align with anecdotal evidence, but more importantly, I do not rely on estimate of field fixed effects for stage 2 of BBL.

To summarize, using a wide variety of reduced form methods, we estimate the "first stage" parameters of the model. Those parameters feed into the state transition functions and the conditional choice probabilities. The state transition functions we estimated are oil production, price of oil and the

Table 4.12: Conditional choice of unitization

	(1)	(2)	(3)	(4)	(5)	(6)
wells	0.152***	0.065	0.044	0.946***	1.226***	1.473***
	(0.033)	(0.033)	(0.038)	(0.193)	(0.286)	(0.403)
WELLQ	0.098***			0.325***		
	(0.018)			(0.072)		
INTERF	0.005***			0.350		
	(0.001)			(0.229)		
EXTER	0.003			-0.011		
	(0.070)			(0.241)		
firms	-0.051	-0.033	-0.080	-0.183	-0.259	-0.414
	(0.030)	(0.086)	(0.122)	(0.101)	(0.224)	(0.314)
pct. min area	0.112			0.079	0.500	0.756
	(0.152)			(0.490)	(0.852)	(1.099)
pct. max area	-0.046			-0.126	-0.419	-0.876
	(0.030)			(0.155)	(0.500)	(0.774)
relative area	0.055	0.111	0.120	0.168	0.543	0.471
	(0.112)	(0.107)	(0.114)	(0.376)	(0.545)	(0.677)
constant	-0.575**	0.406	0.265	-3.707***	-6.955***	-8.878*
	(0.211)	(0.235)	(0.403)	(0.877)	(2.099)	(3.566)
log σ^2					0.606	0.914
					(0.495)	(0.617)
Field quality	✓			✓		
Field FE		✓	✓		✓	✓
Year FE			✓			✓
Observations	262	262	262	262	262	240

The first three columns are linear models, and the last three are probit models. The first is linear regression, the second with field fixed effects and the last also with year fixed effects. The fourth is simple probit, the fifth has field fixed effects and the sixth also has year fixed effects. *** $p \leq 0.01$, ** $p \leq 0.05$, * $p \leq 0.1$

hazard of T. With respect to conditional choices, we estimated the probability of drilling a new well given a state, and the probability of unitization given T and other characteristics of the field.

Second Stage - moments of shock functions

In the second stage, I estimate the moments of the distribution of four sets of random shocks. The first set is the mean and the variance of the shock in cost of drilling a production well. The second set is the same but for injection wells. The next is set is the shock in fixed costs. Finally, I will estimate the mean and the variance of the shock in cost of unitization.

The estimates are shown in table 4.13. Remember that the total cost each company has to pay when drilling a production well is $C_t + \xi^P$. To put things in perspective C_0, on average starts at 543k. That would mean that if a firm draws a shock of cost of drilling a production well at the mean, they would pay $543 - 67 = \$476k$. Note that the standard deviation of the cost of a production well is substantial with respect to the mean of the shock. Nevertheless, it is a less than 25 % of the overall cost of drilling a production well. That is still economically important, but reasonable.

Injection wells are on average \$30k cheaper than production wells. It is interesting that the variance in the shock is a substantially less than the variance of production wells. This could be because at the stage when injection wells are drilled, firms know a lot more about the fields than when they drill production wells. Also, if firms do not drill anything during a period, on

Table 4.13: Shock parameters

Production Well	μ^P	-67.579
	σ^P	131.612
Injection Well	μ^I	-97.954
	σ^I	74.101
Fixed Cost	μ^F	.408
	σ^F	1.3815
Unitization Cost	μ_θ	30.808
	σ_θ	22.160

Estimates obtained running the second stage of BBL with 1,500 perturbations. The profit function and the rest of the measures while running the algorithm was normalized to thousand of dollars. These estimates should be interpreted in thousand of dollars.

average they pay close to 0. That could be interpreted as the fixed cost of operating a field. These numbers are consistent the the fact that in extracting oil from the ground, it is expensive to drill new wells, but cheap to operate them. Finally, the estimates suggest that the cost of unitizing is on average $30k per firm in the unit. That means that a 4 firm unitization agreement is around $ 120k.

Third Stage - bargaining parameters

In the last stage I estimated the bargaining parameters. To do that, I first recovered the counterfactual value functions of what would have happened if firms that unitized would have not done so. By doing that, I have all the elements in the first order conditions of the NiN equilibrium. The only unknown elements are the bargaining parameters.

The summary statistics of the bargaining parameters are in table 4.14. The first row shows the mean of the bargaining parameter. The next column is the standard deviation. The third and the fourth column are the summary statistics of the bargaining parameter divided by the relative size of a firm in a field. Firm 1 is always the biggest in the field and firm 4 is the smallest. Note how bigger firms have higher bargaining parameters. Nevertheless, relative to their share in the field, smaller firms are better off than bigger ones. These results support the anecdotal evidence that smaller firms are relatively better than larger ones in terms of negotiation.

Table 4.14: Estimates of bargaining parameters

	Firm 1	Firm 2	Firm 3	Firm 4
b_i	0.63	0.32	0.05	0.01
	0.22	0.23	0.10	0.02
$\frac{b_i}{a_i}$	0.91	1.73	2.33	1.09
	0.37	2.22	3.47	0.02

I estimate bargaining parameters for every firm in every field. Above are the mean and the standard deviation of the distribution by firms. Firms are ordered by area size, firm 1 is the biggest in the field. The second panel show the summary statistics of the bargaining parameters divided by the relative size of a firm in a field.

Finally, to extrapolate the bargaining parameters to fields where unitization never happened, I regressed such parameters on several variables. The results of such regressions are in table 4.15. Note that more than 70% of the variation can be explained by the relative area of a firm in a field as a percentage of the total. From the regression it is clear that firms with a bigger area will have a greater bargaining power. Nevertheless, if the relative size of a firm in a field increases in 10%, the bargaining parameter will only increase in .03[14].

4.7 Counterfactuals

Originally, my goal was to quantify the welfare loss due to the CPE that happens when several firms try to exploit the same oilfield. The machinery developed in the paper also allows me to evaluate some interesting policy implication related to forcing or encouraging cooperation among firms. In this section, I will describe how I adapted the model to achieve such goals. Moreover, since I ran each counterfactual separately for each field, I will be able to distinguish how the different policies affect fields depending on the field's specific qualities.

The five counterfactuals I will compute are:

- Central planner's solution
- Compulsory unitization
    - Make firms unitize if firms that have leased over 60% of the area in a field want to unitize

[14] Bargaining parameters are normalized such that they add up to 1.

Table 4.15: Bargaining Extrapolation

	(1)	(2)	(3)	(4)	(5)
area, a_i	0.467***	0.413***	0.413***	0.413***	0.413***
	(0.068)	(0.089)	(0.089)	(0.089)	(0.090)
firm order	-0.107***				
	(0.019)				
firm=2		-0.107	-0.107	-0.107	-0.107
		(0.056)	(0.056)	(0.056)	(0.057)
firm=3		-0.308***	-0.308***	-0.308***	-0.308***
		(0.068)	(0.069)	(0.069)	(0.069)
firm=4		-0.331***	-0.331***	-0.331***	-0.331***
		(0.072)	(0.072)	(0.073)	(0.073)
EXTER			-0.053	-0.056	-0.050
			(3.534)	(3.662)	(3.966)
INTERF			0.279	0.327	0.506
			(8.520)	(8.573)	(9.204)
field area				0.000	0.000
				(9.221)	(9.723)
pct. max area					-0.030
					(7.281)
[1em] constant	0.400***	0.333***	0.333***	0.333***	0.333***
	(0.064)	(0.068)	(0.069)	(0.069)	(0.079)
Observations	188	188	188	188	188
r^2	0.706	0.720	0.720	0.720	0.720

Estimated by OLS, where the dependent variable is the bargaining parameter of the firm. The independent variables are relative area a_i, and the relative size of the firm, in the sense that firm 1 is the biggest in the field, and firm 4 is the smallest in the field.

- Voluntary unitization
    - Let firms vote for unitization each period
    - Omit the fair sharing rule restriction
    - Firms can vote for unitization whenever they want, and there is no sharing rule restriction

4.7.1 Definition of Counterfactuals

Welfare loss due to common pool externality - "Planner"

To recover the welfare loss due to the CPE, I computed the equilibrium assuming that each field was owned exploited by a single firm. In this case, the central planner is trying to maximize the discounted sum of profits, just like firms do. An alternative to this assumption could be that instead of maximizing profits, the central planner is maximizing oil production as long as it is economical, or oil by well, or some other measure of efficiency. I prefer to stick with the assumption that the central planner maximizes profits since I am isolate the loss due to the CPE. If on top of assuming there is a single operator, I assume that such operator maximizes a different value function, the number I would be recovering would be the welfare loss due to the fact that firms maximize profits, confounded with the fact that the CPE caused by competition for the common resource.

Compulsory unitization as implemented in other states - "Compulsory"

To recover the results of how compulsory unitization would change production and profits, I assumed that each field was being exploited by the firms original number of firms in it. The TRRC still restricts voting for unitization to happen only when the field is reasonably developed, and there is still uncertainty of when that will happen. The difference with the base case comes in the voting mechanism. Now, if firms that encompass more that 60% of the area in a field voter for unitization, then the whole field will be worked as a unique unit starting from that moment. This will potentially change welfare in several ways. On the extensive margin, we expect more units to happen, especially in fields where there are only two firms. On the intensive margin, we are expecting units to be bigger, specifically in fields where there are more than two firms.

There is not restriction in the way firms share profits -"Sharing"

To recover how the production and profits would change if the TRRC relaxed the restriction the the sharing rule must be fair, I assumed that if the overall profits from unit operations minus the cost of unitization is higher than the firms' profits working separately, then unitization will happen. In other words, if there are gains from unitization in terms of profits, firms will find a sharing rule that is Pareto improving.

Omit the reasonably developed rule -"Time"

To assess what would happen if the TRRC did not force firms to vote for unitization until the field is reasonably developed, I assumed that firms vote for unitization the first period. As before, a unit will be formed with the firms that wanted to join the unit, and profits will be shared based on area.

Omit both voluntary unitization restrictions - "Voluntary"

Finally, I was interested in recovering the effect of omitting both restrictions to voluntary unitization at once. To achieve that, I assumed that firms could vote during the first period, and if there are gains from working as one firm, then a unit will happen. It is important to note here, that it is very likely that the number of units will increase substantially, but since there is a transaction cost unitization does not necessarily have to happen.

4.7.2 Counterfactual Results

I ran the five counterfactuals separately for each field. The results are summarized in tables 4.16 and 4.17. Table 4.16 summarizes how firms' profits would change under the different counterfactuals. Each column refers to a specific counterfactual. The first and the second rows show the median and the mean of the distribution of increase in profits a percentage of profits under the current policy. The third row is the mean increase in profits, but weighted by current profits. Analyzing these three rows together give interesting results. Taking for example the "Planner" counterfactual we can see that half of the fields would increase rents in more than 17.3% if they were operated by a central planner maximizing profits. Nevertheless, weighting by profits, the number would only be 26.2%. The fourth row in table 4.16 suggests that taking just the 501 fields in sample, the planner would increase welfare in around $\$4.28B$ dollars. That would mean that the rents of each field would increase in over \$8.54.

Table 4.16: Counterfactuals summary

	Planner (1)	Compulsory (2)	Sharing (3)	Time (4)	Voluntary (5)
Overall	26.2 %	13.9 %	7.1 %	1.7%	21.8%
Median	20.0%	6.5%	1.1%	1.0%	13.9%
Mean	31.0%	12.9 %	7.5 %	7.8%	16.2%
In sample	\$8.54M	\$4.47M	\$2.71M	\$1.12M	\$6.31M
By field	4.28B	\$2.24B	\$1.36B	\$0.56B	\$3.16B

Each column in the table summarizes what would happen under different counterfactuals. Each counterfactual was run in the 364 fields with either 2 or 3 firms. The first and the second rows show the median of the increase or decrease in welfare of each counterfactual compared to the base case. The third takes the overall production of all fields under each counterfactual over the overall production of the base case. The fourth row is the dollar amount increase considering every field in the sample, the fifth is the dollar amount increase by field. The last row extrapolates the dollar amounts to every field in Texas.

Comparing between counterfactuals, note that making voluntary unitization easier by omitting both restrictions is the policy that would get us closer to the potential gain of eliminating the CPE. Eliminating the CPE could potentially increase profits in 26%, while facilitatiting voluntary unitization would increase profits in 21%. Nevertheless, when eliminating one restriction on voluntary unitization without the other will not be as substantial. If the TRRC eliminated the sharing rule restrictions firms would increase profits in around 7.1%. There are two opposing forces that influence this change in efficiency: the negative one is that looking forward firms know that they will eventually unitize and they will try to capture the common resource faster; the positive one is that more units will be achieved. Finally, allowing firms to unitize the first stage would increase overall profits in just 1.7%. On the one hand, there will not be a loss due to inefficient exploitation of the field at the beginning, but on the other, firms that did not want to unitize, will still be skeptical of it. Finally, compulsory unitization would increase profits in around 13.9%, which is higher than eliminating each voluntary unitization restriction separately, but lower than eliminating both at the same time. Moreover, it represents around 50% of the profit loss due to the CPE.

Table 4.17 helps understand where the increase in profits comes from. Also, one could argue that although firms will maximize profits given the legislation, regulators care more about overall production and drilling activity than firms' profits. Table 4.17 analyzes 5 variables: overall oil production by field, number of producing wells, number of injector wells, percentage of wells that are injectors, oil extraction by production well, and oil extraction by well (taking injectors into account). The first column gives the mean, median and standard deviation under the current policy, the other five analyze the counterfactuals.

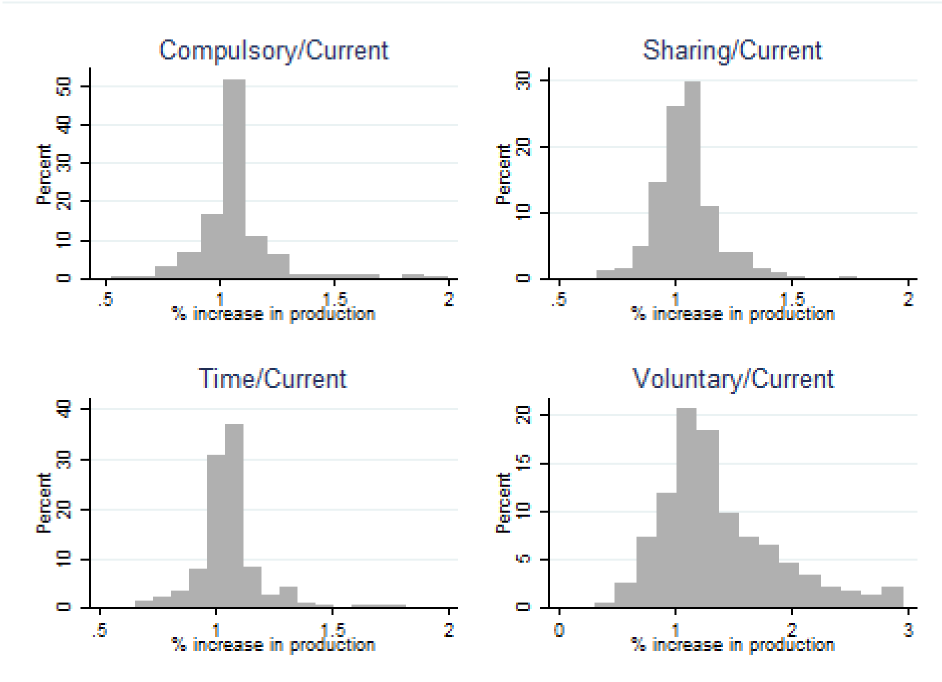
Table 4.17 shows that by eliminating the CPE production by field would increase from an average of 503,740 to 645,157. That is almost a 28% increase in overall production. The drilling statistics below show that this increase comes from three sources: overall, there will be more drilling in these fields; also, the proportion of injector wells will be higher, so the negative externality of having more production wells will be lower; and the timing of drilling will be optimal. Each production well will increase its output from 94k barrels per

Table 4.17: Counterfactuals: production summary

	Current	Planner	Comp.	Sharing	Time	Vol.
Oil by Field	503,740	645,157	582,582	528,642	519,394	614,230
	284,756	360,719	318,625	295,981	325,846	364,835
	597,748	818,756	729,072	674,013	606,436	769,691
PW by Field	5.76	6.28	6.3	5.65	5.84	6.33
	7	8	7	7	7	7
	2.08	3.1	2.76	2.17	2.33	2.88
IW by Field	3.24	4.43	3.9	3.24	3.39	4.2
	2	4	3	2	3	4
	3.29	4.28	3.91	3.34	3.32	4.11
Pct. Inj.	0.28	0.33	0.3	0.29	0.3	0.31
	0.3	0.45	0.36	0.25	0.35	0.4
	0.27	0.31	0.29	0.28	0.28	0.3
Oil by PW	94,665	108,363	91,025	100,645	94,498	101,627
	48,017	63,091	50,891	50,891	52,451	60,301
	145,086	155,656	108,026	152,830	116,729	174,388
Oil by W	51,962	51,276	49,617	54,304	49,612	52,974
	32,671	31,391	31,236	32,467	31,131	32,313
	64,308	60,986	57,601	75,249	57,858	64,551

For every variable, the first row is the mean, the second the median and the third the standard deviation. Each column represents a a counterfactual: current = current policy, Planner = planner's solution assuming rent maximization, compulsory = compulsory unitization, No Sharing = firms are not restricted to any sharing rule, No Time = firms can form units the first period.

Figure 4.6: Distribution of increase in production



Notes: The counterfactual was run once for each of the 501 fields with either 2, 3 or 4 firms. The histograms shows the distribution of the percentage increase in production under each of the counterfactuals compared to the increase the current legislation.

production well to 108k. Surprisingly, when also taking injection wells into account, productivity by well remains almost unchanged.

The histograms in figure 4.6 give a more detailed view of the distribution of the increase in profits by field due to each policy. The important takeaway from these counterfactuals is that for most of the fields, the increase or decrease under the new policy are modest. The histograms also rise the question of how the characteristics fields affect if they are affected by the counterfactual policies studied in the paper. To achieve that, I ran a linear regression of the increase in profits due to the counterfactuals against number of firms, quality of the field and distribution of firms in the field. The results are in table 4.18. As expected, the interference and the externality factors are negatively related with the increase in profits. That means that if the potential of a well does not decrease with the sequence of drilling then the potential increase in efficiency is smaller. Also, if drilling by other companies do not affect the current production do not impact the current production of a well, then the potential increase in profits is also smaller.

Unexpectedly, efficiency can potentially increase more in fields with 3 firms than in fields with 2 or 4 firms. One would expect that in fields with more firms, the potential to increase profitability when eliminating the common pool externality is greater. In fields with 4 firms, I had to apply a further computation restriction in which firms only produced for 12 periods instead of 15. This makes the potential increase in profitability due to efficiency smaller.

The counterfactuals analyzed up to now give a general picture of the average potential increase each policy has in terms of profits and production. Also, they show that the increase comes from drilling more wells and drilling more productive wells. Nevertheless, they do not show how timing of drilling also affects these measures. Figures 4.7 and 4.7 are an example of how production is affected in two fields by the different counterfactuals. Both examples show fields with 2 firms. The upper left graph shows the current policy vs. the central planner's solution. The green line is the planner's production and the yellow the addition of production by both firms. The rest of the plots com-

Table 4.18: Correlations between Counterfactuals

	(1)	(2)	(3)	(4)
interf	-0.453	-0.320***	-0.108*	-0.048
	(0.254)	(0.090)	(0.044)	(0.057)
exter	-0.578*	-0.076	-0.095*	-0.153**
	(0.230)	(0.081)	(0.040)	(0.050)
wellq	-0.276***	0.002	0.007	0.009
	(0.044)	(0.016)	(0.008)	(0.010)
f_maxcompanies=2	-0.312**	-0.124**	-0.048*	-0.011
	(0.117)	(0.041)	(0.020)	(0.025)
f_maxcompanies=3	0.000	0.000	0.000	0.000
	(.)	(.)	(.)	(.)
f_maxcompanies=4	-0.762***	-0.135*	-0.043	0.013
	(0.164)	(0.059)	(0.029)	(0.036)
pctmaxarea	0.167	-0.153	0.015	-0.068
	(0.271)	(0.096)	(0.047)	(0.059)
pctminarea	-0.075	0.104	-0.022	0.083
	(0.229)	(0.081)	(0.039)	(0.049)
Constant	4.682***	1.243***	0.939***	0.990***
	(0.485)	(0.171)	(0.084)	(0.105)
Observations	250	245	247	243
r2	0.211	0.107	0.073	0.075

The first three columns are linear models, and the last thwo are probit models. The first is linear regression, the second with field fixed effects and the last also with year fixed effects. The fourth is simple probit, and the fifth has field fixed effects. *** $p \leq 0.01$, ** $p \leq 0.05$, * $p \leq 0.1$

pare the current schedule vs the different policies. The table below shows the drilling activity and productivity of wells under the counterfactual policies.

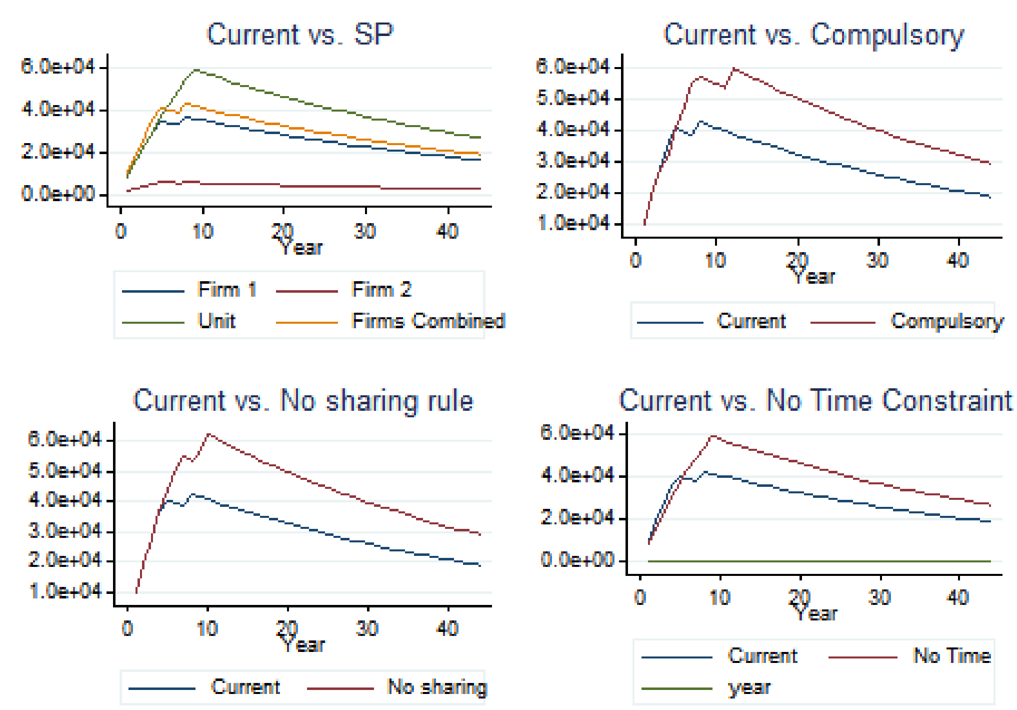
Note in figure 4.7 that the increase in production comes from the fact that the central planner drills more. In this case, compulsory unitization and omitting the sharing rule restriction would also increase profits. The reason is that unitization is achieved (and wanted) under these policies, but not under the current policy. In this case, unitization would also be achieved if firms were allowed to vote the first period instead of waiting until the field is reasonably developed. When comparing production by firms vs. the central planner, note how the central planner takes longer to reach potential production compared to the firms working separately.

In figure 4.8 the dynamics are a little different. Here, it is clearer that the central planner produces a little slower than the firms working separately. Nevertheless, There is virtually no gain from any of the coutnerfactual policy. Contrasting figure 4.8 with 4.7, one can see in 4.7 that the firms in the field are very different in size, in 4.8 they are very similar[15].

To summarize, in this section I present five counterfactuals, the first measures the loss in profits and production due to the CPE. The other four explore three alternative policies that the TRRC could implement in the Texas legislation. Easing voluntary unitization by getting rid of the two restrictions placed by the TRRC is the alternative that recovers more of the planner's

[15]That can be inferred by production.

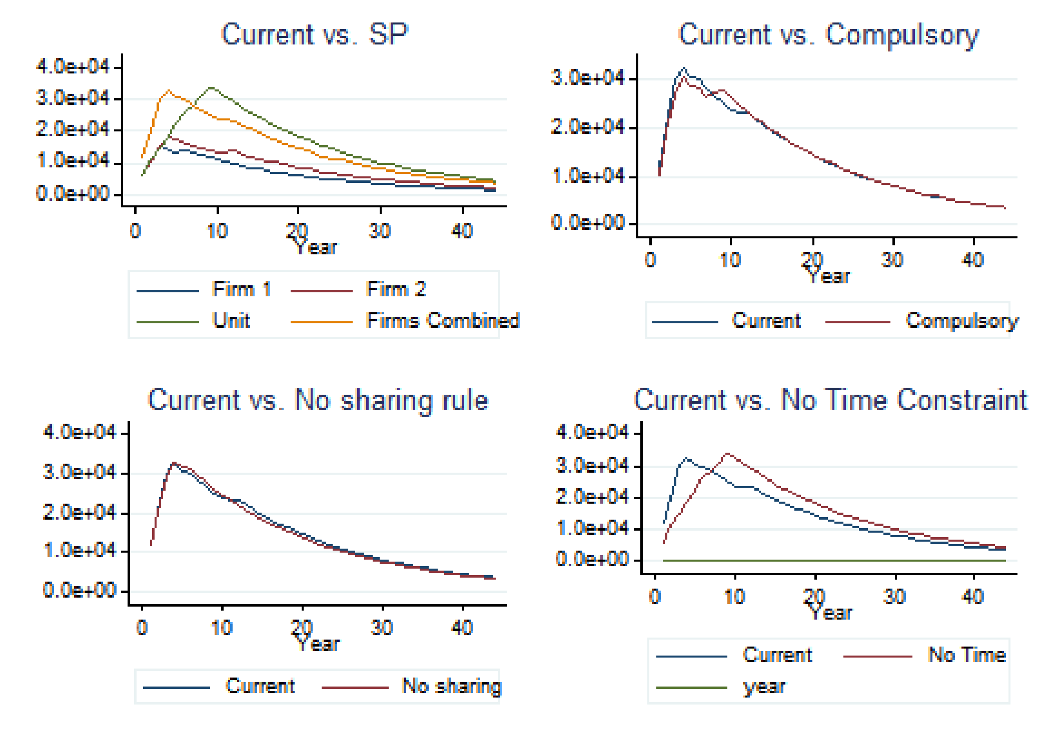
Figure 4.7: Field Development under Counterfactuals



	Base	Compulsory	Forced	No Time	Planner
	(1)	(2)	(3)	(4)	(5)
ProdW	6	8	8	5	9
InjProd	0.4	0.5	0.5	0.5	0.5
ProdPW	215307	293529	294330	313437	192976
ProeW	129184	146765	147165	156718	96488
Unit	No	No	No	NA	NA

Notes: Each plot compares the development of this specific field under the current policy vs. under a counterfactual. The table shows how many production wells, the percentage of injection wells, production per well, and unitization decisions under each counterfactual.

Figure 4.8: Field Development under Counterfactuals



	Base (1)	Compulsory (2)	Forced (3)	No Time (4)	Planner (5)
ProdW	7	7	7	7	9
InjProd	0.5	0.5	0.46	0.5	0.44
ProdPW	89677	95425	92888	95464	76400
ProeW	44838	47713	50017	47732	42975
Unit	No	No	No	NA	NA

Notes: Each plot compares the development of this specific field under the current policy vs. under a counterfactual. The table shows how many production wells, the percentage of injection wells, production per well, and unitization decisions under each counterfactual.

solution. Omitting only one of the restrictions would increase profits and production, but less than incorporating compulsory unitization. As seen in figure 4.6, fields are affected differently by the counterfactuals. As expected, fields where the externality and the interference factors are high are more susceptible to changes in legislation. Surprisingly, fields with three firms are the ones with the highest potential increase. Finally, in this section shows two examples of how specific fields are developed under the different counterfactuals.

4.8 Conclusion

The exploitation of a single oilfield by several firms is a typical example of the common pool externality (CPE) that has hunted the oil industry for decades. If agents facing the CPE assigned a single operator to exploit the whole resource, then such operator would not face the CPE. In the oil and gas business, there is a form of contract that achieves that called voluntary unitization. Every major producing state, but Texas, go beyond voluntary unitization and can make firms that do not want to join units to join. In this paper, I first measure the loss in profits and production due to the CPE in Texas. I also, evaluated three alternative policies: relaxing voluntary unitization, implementing compulsory unitization as in other states, and forcing firms to unitize even if they do not want to.

I modeled how firms develop an oilfield and how they form units throughout time. The proposed model accounts for the restrictions placed by the TRRC on voluntary unitization. To compute the welfare loss due to the CPE, I assumend that each field was exploited by a single operator. To assess how welfare could improve if the TRRC relaxed the restrictions on voluntary unitization, I modify the parts of the model that resemble such restrictions. Finally, I change features of the coalition formation process to recover what would happen under compulsory unitization.

The counterfactual analysis suggests that the welfare loss due to the CPE is actually substantial. Throughout the 30 years of analysis, having a single operator by field would have increased rents from the 501 fields in the sample in around \$4.28B, which is an increase of 26.2% from the rent of those fields. The source of this increase in rents comes from two sources: an increase in overall production per field, and the increase in injection wells compared to production wells. Eliminating both restrictions placed on voluntary unitization would have improve rents of around 21.8%, which adds up to \$3.16. Finally, compulsory unitization could further improve welfare in 13.9%, or \$2.24B.

Appendices

Appendix A

Chapter 2

As described in the paper, my data allows me to try several different specification of both, the regression discontinuity and the difference in difference design. The main tables are presented in the paper, the objective of this appendix is to present the results that are not central to the paper.

A.1 Regression Discontinuity

The main RD results presented in chapter 2 are considering bandwidth of 1 mile and 5 miles around the New Mexico and Texas horizontal part of the border. In this appendix I will present the regression results and the graphs for 10 miles around the horizontal part of the border. Moreover, I will present the tables of results for the three bandwidths of the vertical part of the border, as well as the regression discontinuity figures. I decided to take the horizontal part of the border as the leading experiment, because the respective robustness checks are stronger, suggesting a better natural experiment.

Table A.1: Regression Discontinuity, horizontal border, 10 mile bandwidth

Polynomial Order Dependent Variable	1	2	3	4
log cum oil	0.564***	0.615***	0.614***	0.614***
	(0.188)	(0.191)	(0.191)	(0.191)
log 6 month oil	1.516***	1.468***	1.467***	1.468***
	(0.17)	(0.173)	(0.173)	(0.173)
log 60 month oil	0.729***	0.696***	0.695***	0.696***
	(0.16)	(0.163)	(0.163)	(0.163)
depth	-678.717	-1011.65	-1011.14	-1009.56
	(1154.84)	(1032.13)	(1032.35)	(1032.49)
elevation	14.659	-71.399	-70.989	-71.234
	(106.378)	(109.69)	(109.686)	(109.652)
longitude	0.003	-0.01	-0.01	-0.01
	(0.241)	(0.232)	(0.232)	(0.232)
drilling year	-1.008	-1.084	-1.081	-1.078
	(0.854)	(0.869)	(0.869)	(0.869)

Each pair of estimate/standard error represents the average treatment effect estimated with a different regression discontinuity design. Rows indicate different dependent variables, and columns are different polynomial orders. Wells in New Mexico and Texas drilled after 1778. Treatment means that the well is in New Mexico, control wells are located in Texas. Standard errors are clustered at field level. *** p $\leq$ 0.01, ** p $\leq$ 0.05, * p $\leq$ 0.1

Table A.2: Regression Discontinuity, vertical border, 1 mile bandwidth

Polynomial Order Dependent Variable	1	2	3	4
log cum oil	-0.33	-0.327	-0.324	-0.353
	(0.327)	(0.328)	(0.328)	(0.327)
log 6 month oil	-0.136	-0.143	-0.13	-0.148
	(0.276)	(0.276)	(0.276)	(0.276)
log 60 month oil	-0.263	-0.263	-0.271	-0.274
	(0.246)	(0.247)	(0.247)	(0.247)
depth	692.016	723.325	720.646	701.985
	(687.976)	(693.157)	(692.473)	(700.397)
elevation	91.6623	93.0643	89.628	92.5322
	(109.475)	(105.235)	(103.106)	(107.063)
longitude	0.023	0.024	0.017	0.016
	(0.158)	(0.155)	(0.154)	(0.149)
drilling year	-0.595	-0.69	-0.469	-0.413
	(2.216)	(2.132)	(2.039)	(2.031)

Each pair of estimate/standard error represents the average treatment effect estimated with a different regression discontinuity design. Rows indicate different dependent variables, and columns are different polynomial orders. Wells in New Mexico and Texas drilled after 1778. Treatment means that the well is in New Mexico, control wells are located in Texas. Standard errors are clustered at field level. *** p $\leq$ 0.01, ** p $\leq$ 0.05, * p $\leq$ 0.1

Table A.3: Regression Discontinuity, vertical border, 5 mile bandwidth

Polynomial Order Dependent Variable	1	2	3	4
log cum oil	0.256*	0.308**	0.309**	0.307**
	(0.156)	(0.157)	(0.157)	(0.157)
log 6 month oil	0.574***	0.572***	0.57***	0.576***
	(0.157)	(0.158)	(0.158)	(0.158)
log 60 month oil	0.251**	0.288**	0.29**	0.292**
	(0.135)	(0.136)	(0.136)	(0.136)
depth	1059.49*	909.526*	914.588*	907.872*
	(719.598)	(700.304)	(701.041)	(698.103)
elevation	0.768957	-1.68839	-1.20903	-1.23137
	(92.2801)	(92.8205)	(93.4422)	(93.0591)
longitude	-0.186	-0.176	-0.175	-0.175
	(0.187)	(0.18)	(0.179)	(0.179)
drilling year	5.219***	5.856***	5.832***	5.833***
	(2.241)	(1.967)	(1.955)	(1.963)

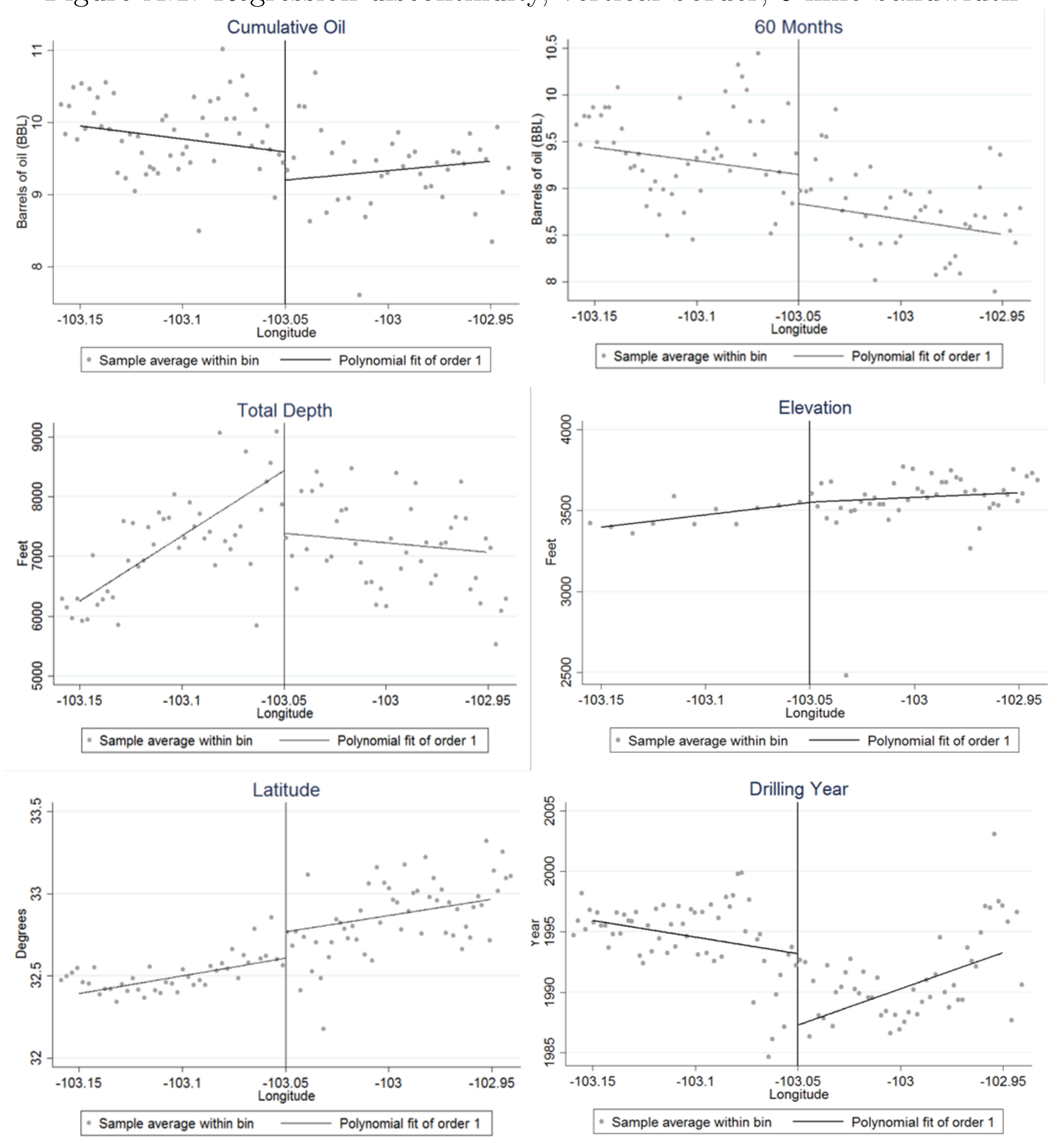
Each pair of estimate/standard error represents the average treatment effect estimated with a different regression discontinuity design. Rows indicate different dependent variables, and columns are different polynomial orders. Wells in New Mexico and Texas drilled after 1778. Treatment means that the well is in New Mexico, control wells are located in Texas. Standard errors are clustered at field level. *** p $\leq$ 0.01, ** p $\leq$ 0.05, * p $\leq$ 0.1

Table A.4: Regression Discontinuity, vertical border, 10 mile bandwidth

Pol. Order	1	2	3	4
Dep. Variable				
log cum oil	0.858***	0.801***	0.801***	0.802***
	(0.095)	(0.097)	(0.097)	(0.096)
log 6 m. oil	0.939***	1.036***	1.036***	1.036***
	(0.091)	(0.093)	(0.093)	(0.093)
log 60 m. oil	0.481***	0.566***	0.565***	0.565***
	(0.084)	(0.086)	(0.086)	(0.086)
depth	-224.007	52.099	53.418	53.415
	(690.991)	(660.026)	(660.039)	(660.321)
elevation	-241.015***	-260.707***	-259.623***	-260.807***
	(124.076)	(132.092)	(131.554)	(132.006)
longitude	-0.459***	-0.452***	-0.452***	-0.452***
	(0.238)	(0.218)	(0.218)	(0.218)
drilling year	2.829	3.325*	3.331*	3.33*
	(2.523)	(2.392)	(2.394)	(2.394)

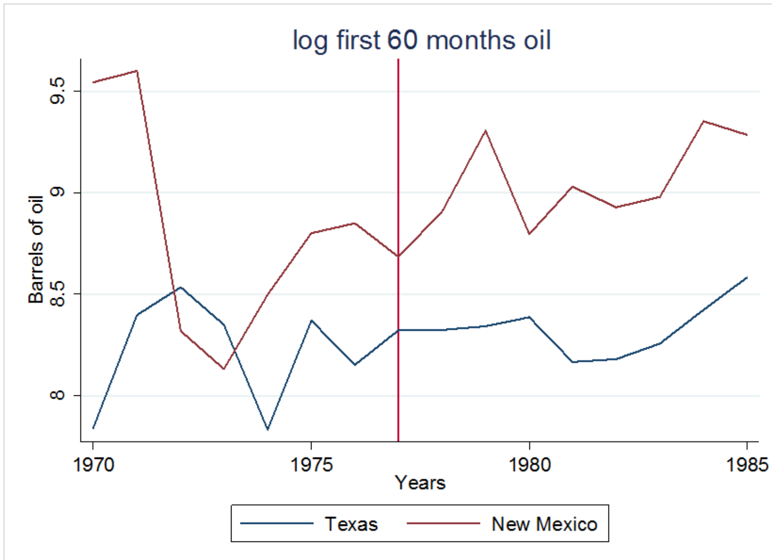
Each pair of estimate/standard error represents the average treatment effect estimated with a different regression discontinuity design. Rows indicate different dependent variables, and columns are different polynomial orders. Wells in New Mexico and Texas drilled after 1778. Treatment means that the well is in New Mexico, control wells are located in Texas. Standard errors are clustered at field level. *** $p \leq 0.01$, ** $p \leq 0.05$, * $p \leq 0.1$

Figure A.1: Regression discontinuity, vertical border, 5 mile bandwidth



Notes: The line represents the linear trend of each variable before and after the -103 longitude line, which delimits Texas and New Mexico. The data in the graph is limited to latitudes between 30° and 34°.

Figure A.2: Oil production in the first 60 months by wells in New Mexico and Texas



The lines are the aerage cumulative production in the first 60 years of a well drilled during the x-axis year.

A.2 Difference in Difference

The main DID result is for cumulative oil produced over the lifetime of the well. In this appendix, I will present the results of the DID model where the dependent variable represents the first 60 months of production instead of the overall cumulative production.

Table A.5: Difference in difference, dependent variable: log 60 months of production

	(1)	(2)	(3)	(4)	(5)
Ind NN af. 1977	0.418*	0.418*	0.537***	0.526**	0.509*
	(0.171)	(0.170)	(0.162)	(0.163)	(0.202)
After 1977	0.189*	0.194	-0.0752	-0.0257	-0.412**
	(0.091)	(0.100)	(0.124)	(0.162)	(0.152)
Treatment	0.459	0.460	0.291	0.228	-2.455
	(0.819)	(0.818)	(0.792)	(0.794)	(1.289)
Year		-0.000828			
		(0.015)			
Latitude				0.236	0.0397
				(0.142)	(0.154)
Longitude				0.0788	0.0146
				(0.045)	(0.049)
Log depth					0.0545**
					(0.018)
Log elevation					0.122***
					(0.023)
Constant	8.118***	9.752	8.365***	8.734***	8.371***
	(0.137)	(29.848)	(0.154)	(0.233)	(0.219)
Time FE			✓	✓	✓
Field FE	✓	✓	✓	✓	✓
Observations	109396	109396	109396	105317	69320

The first column is a field fix effects model without controlling for year. The second column is as the first, but also controls for year. The third, fourth and fifth models also has time fixed effects. The dependent variable is log of the first 60 days of production of each well. Standard errors clustered at the field level reported. Every well in the sample was drilled in either New Mexico or Texas between 1970 and 1982. *** $p \leq 0.01$, ** $p \leq 0.05$, * $p \leq 0.1$

Appendix B

Chapter 3

Table B.1: Counterfactuals summary

	Planner (1)	Compulsory (2)	Sharing (3)	Time (4)	Voluntary (5)
Overall	26.2 %	10.0 %	7.2 %	5.2%	22.9%
Median	20.0%	7.4%	.02%	027%	12.3%
Mean	31.0%	11.0 %	1.7 %	8.0%	11.7%
By field	\$8.54M	\$2.75M	\$1.91M	\$2.2M	\$6.91M
In sample	4.28B	\$1.38B	\$0.95B	\$1.14B	\$3.46B

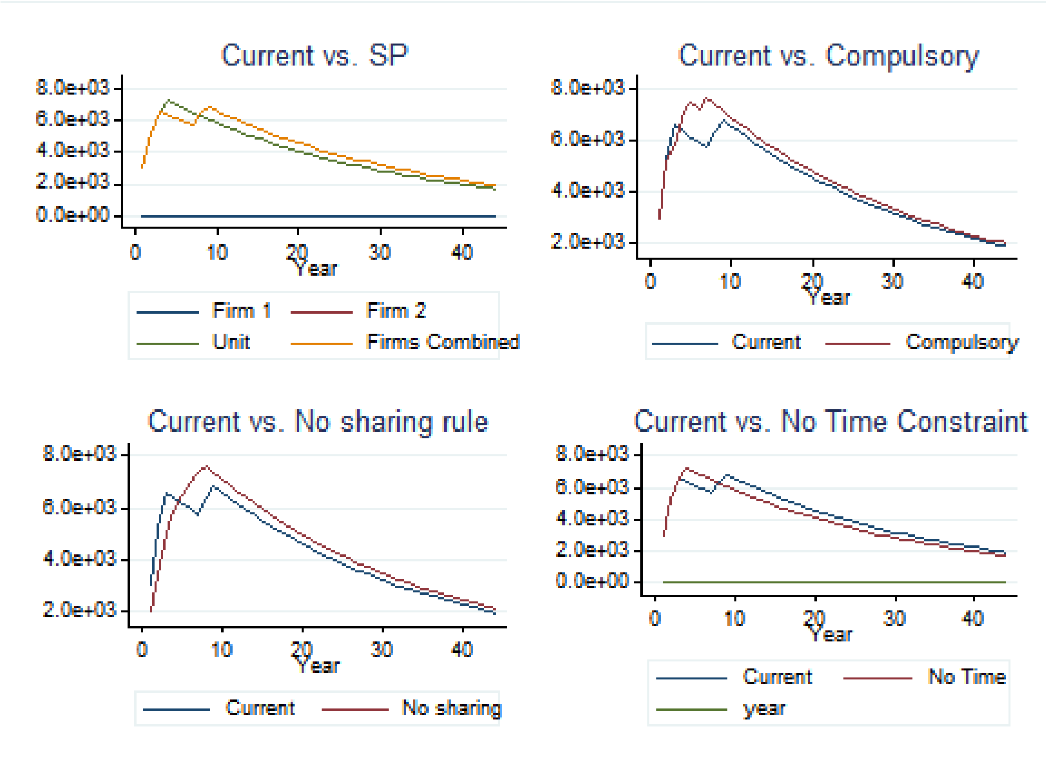
Each column in the table summarizes what would happen under different counterfactuals. Each counterfactual was run in the 501 fields with either 2, 3 of 4 firms. The first and the second rows show the median of the increase or decrease in welfare of each counterfactual compared to the base case. The third takes the overall production of all fields under each counterfactual over the overall production of the base case. The fourth row is the dollar amount increase considering every field in the sample, the fifth is the dollar amount increase by field. The last row extrapolates the dollar amounts to every field in Texas.

Table B.2: Counterfactuals: production summary

	Current	Planner	Comp.	Sharing	Time	Vol.
Oil by Field	503,740	645,157	582,796	554,574	586,511	638,445
	284,756	360,719	304,311	254,942	306,480	305,945
	597,748	818,756	722,311	769,439	754,011	845,519
PW by Field	5.76	6.28	6.15	5.53	5.82	6.24
	7	8	7	7	7	8
	2.08	3.10	2.79	2.2	2.09	3.03
IW by Field	3.24	4.43	3.83	3.01	3.38	3.99
	2	4	3	1	3	1
	3.29	4.28	3.89	3.29	3.28	4.21
Pct. Inj.	0.28	0.33	0.31	0.28	0.29	0.3
	0.3	0.45	0.42	0.2	0.3	0.36
	0.27	0.31	0.29	0.3	0.27	0.3
Oil by PW	94,665	108,363	94,528	121,658	103,325	105,485
	48,017	63,091	58,845	46,870	52,502	53,870
	145,086	155,656	112,206	222,788	144,355	150,817
Oil by Well	51,962	51,276	51,539	58,660	57,052	51,655
	32,671	31,391	31,236	31,278	30,957	31,212
	64,308	60,986	62,482	85,473	71,247	62,897

For every variable, the first row is the mean, the second the median and the third the standard deviation. Each column represents a a counterfactual: current = current policy, Planner = planner's solution assuming rent maximization, compulsory = compulsory unitization, No Sharing = firms are not restricted to any sharing rule, No Time = firms can form units the first period.

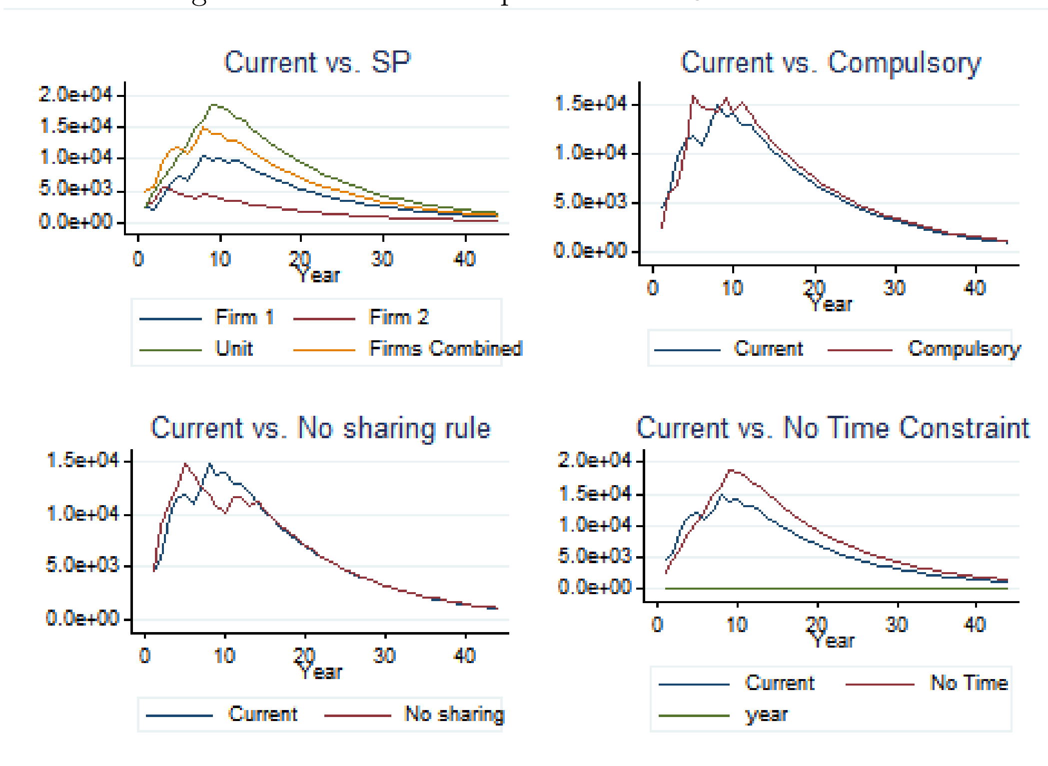
Figure B.1: Field Development under Counterfactuals



	Base	Compulsory	Forced	No Time	Planner
	(1)	(2)	(3)	(4)	(5)
ProdW	4	5	4	5	4
InjProd	0.56	0.58	0.6	0.55	0.5
ProdPW	46100	45252	56308	43010	43100
ProeW	20489	18855	22523	19550	21550
Unit	No	No	No	NA	NA

Notes: Each plot compares the development of this specific field under the current policy vs. under a counterfactual. The table shows how many production wells, the percentage of injection wells, production per well, and unitization decisions under each counterfactual.

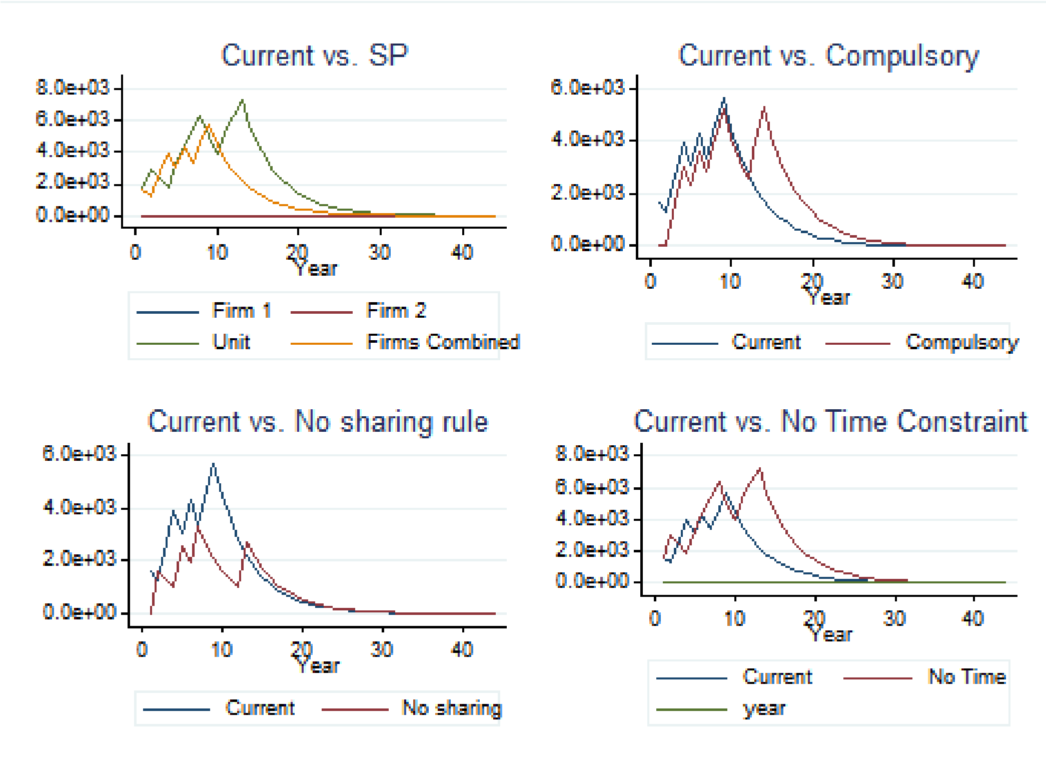
Figure B.2: Field Development under Counterfactuals



	Base	Compulsory	Forced	No Time	Planner
	(1)	(2)	(3)	(4)	(5)
ProdW	5	7	5	7	5
InjProd	0.58	0.5	0.58	0.5	0.64
ProdPW	56319	45043	58398	44787	68697
ProeW	23466	22522	24333	22393	24535
Unit	No	No	No	NA	NA

Notes: Each plot compares the development of this specific field under the current policy vs. under a counterfactual. The table shows how many production wells, the percentage of injection wells, production per well, and unitization decisions under each counterfactual.

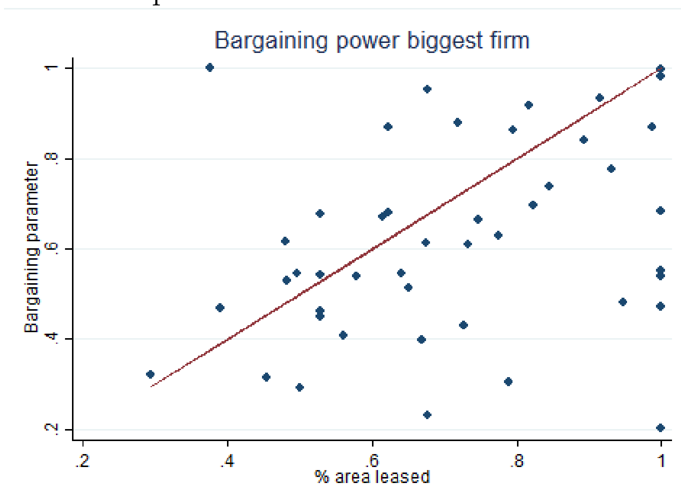
Figure B.3: Field Development under Counterfactuals



	Base	Compulsory	Forced	No Time	Planner
	(1)	(2)	(3)	(4)	(5)
ProdW	6	7	4	7	9
InjProd	0	0	0	0.13	0
ProdPW	8632	8827	8246	9559	9212
ProeW	8632	8827	8246	8364	9212
Unit	No	No	No	NA	NA

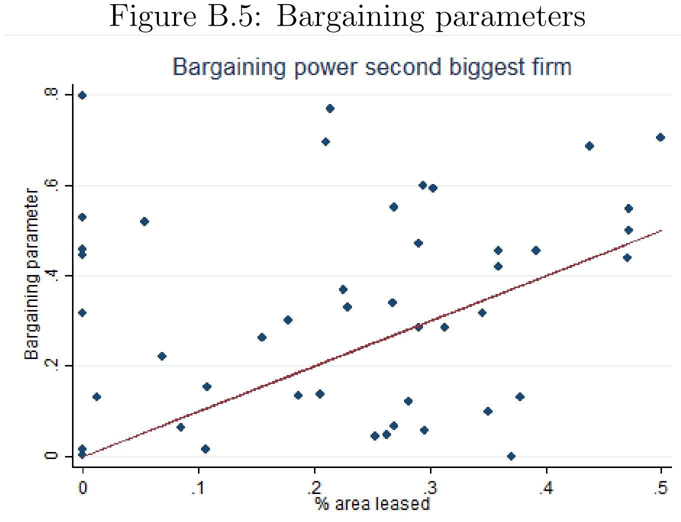
Notes: Each plot compares the development of this specific field under the current policy vs. under a counterfactual. The table shows how many production wells, the percentage of injection wells, production per well, and unitization decisions under each counterfactual.

Figure B.4: Kaplan-Meier Estimate of Time to Unitization



Area vs bargaining parameter

Figure B.5: Bargaining parameters



Area vs bargaining parameter

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