

**THE EFFECTS OF TRANSACTION COSTS
ON NORTHERN PLAINS OIL UNITIZATION AGREEMENTS**

by

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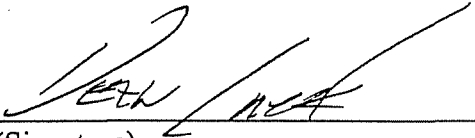
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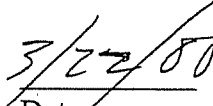
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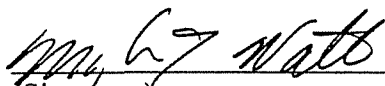
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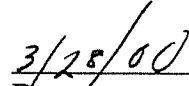

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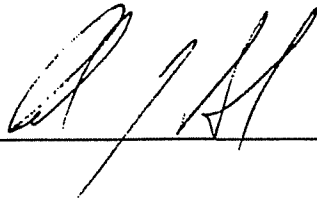
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TABLE OF CONTENTS

LIST OF TABLES	viii
LIST OF FIGURES	ix
ABSTRACT	x
1. INTRODUCTION TO OIL RESERVOIR CONTRACTING	1
Oil Production and the Rule of Capture	2
Evidence of Rule of Capture Losses	7
Organization of the Thesis	13
2. PETROLEUM AND RESERVOIR PROPERTIES	16
The Formation of Oil	16
Characteristics of Oil Reservoirs	18
Physical Reservoir Properties	19
Natural Drive Mechanisms	22
Stages of Production	26
Rule of Capture and the Rate of Production	27
3. HISTORY OF OIL PRODUCTION IN THE UNITED STATES AND ON THE NORTHERN PLAINS	32
1880-1900: The Early Years of U.S. Oil Production	32
Northern Plains: Pre Commercial Oil Developments	37
1900-1930: The Age of Waste and the Beginning of Regulation	39
Northern Plains: The Origins of Commercial Oil Production	44
1930-Present: Modern Regulation and Production	49
Northern Plains: The Development of Regulations and Discovery of the Williston Basin	54
Williston Basin	58
4. THE ECONOMICS OF OIL RESERVOIR CONTRACTING	63
Property Rights and the Transaction Costs Approach To Oil Unitization Agreements	64
Economic Models of Firm Well Choice	69

TABLE OF CONTENTS - Continued

First Best: Production under Sole Ownership	69
Rule of Capture	73
Contracting Models of Production	78
Private Contracting with Zero and Positive Transaction Costs	79
Contracting Positive Transaction Costs and Statutory Remedy	84
Contracting With Compulsory Unit Laws	87
Model Summary Predictions	
and Other Contracting Issues	87
Predictions	88
Other Considerations	90
Partial Unit Formation	90
Enhanced Recovery Units	91
Well Spacing Regulations	92
Differential Incentives: Working and Royalty Interests	93
 5. EMPIRICAL ANALYSIS:	
ECONOMETRICS AND CASE STUDIES	95
Reservoir Data Summary	95
Estimating the Probability of Unit Formation	110
Explanatory Variables and Predictions	110
Surface Ownership Variables	111
Reservoir Variables	113
Regulatory Variables	116
Comparison of Mean Values	
For Unitized and Non-unitized Reservoirs	117
Probit Estimates	120
All Reservoirs	120
Williston Basin Reservoirs	125
Discussion of Probit Estimates	130
Case Studies	131
Three Reservoirs with Unit Agreements	133
Circle Ridge, Wyoming	133
Ridgelawn, Montana	136
Stadium, North Dakota	138
Two Reservoir without Unit Agreements	138
Cutbank, Montana	138
Littleknife, North Dakota	140
Analysis of Unitized Reservoirs	142
Analysis of Non-unitized Reservoirs	146

TABLE OF CONTENTS - Continued

6. CONCLUSION	149
Limits of Econometric Analysis	151
Data Problems	152
Specification Problems	153
Further Study	153
LITERATURE CITED	157
APPENDICES	163
APPENDIX A	164
LAND POLICY AND LEASE ORIGINS	165
APPENDIX B	172
DATA	173

LIST OF TABLES

Table	Page
1. Reservoir Drive Mechanism Characteristics	26
2. Summary of Conservation Regulations	57
3. Sample Reservoirs	101-103
4. Reservoir Variable Definitions, Predicted Signs and Summary Statistics	104
5. State Reservoir Summary Statistics	105
6. Correlation Matrix: Pearson Correlation Coefficients: All Reservoirs	108
7. Correlation Matrix: Pearson Correlation Coefficients: Williston Reservoirs	109
8. Summary of Coefficient Predictions	111
9. Means Tests for Economic and Reservoir Variables	118
10. Probit Coefficient Estimates of Unitization: All Reservoirs	122
11. Probit Coefficient Estimates of Unitization: Williston Basin Reservoirs	127
12. Summary Data for Case Studies	135
B1. State and Regional Comparison of Production Statistics	175
B2. Distribution of Sample Reservoir Discovery Dates	180
B3. Regulations and Sample Reservoir Discovery	181

LIST OF FIGURES

Figure	Page
1. The Effect of Production Rate on Oil Recovery	29
2. Reservoir Rent Dissipation Under the Rule of Capture	67
3. Well Choice: First Best Versus Rule of Capture	75
4. The Well Choice Solution for the Unit Operator	82
5. Northern Plains Map and Distribution of Sample Reservoirs	96
6. Distribution of Wyoming Reservoirs	97
7. Distribution of Montana Reservoirs	98
8. Distribution of North Dakota Reservoirs	99
9. Locations of Case Study Reservoirs	134

ABSTRACT

Under the rule of capture, petroleum production on reservoirs with numerous surface owners leads to significant economic waste from over-drilling and reduced total oil recovery. To mitigate the economic losses from rule of capture, private and regulatory solutions emerged to limit over-production on oil reservoirs. Among these solutions, contracts known as reservoir-wide unitization agreements lead to optimal reservoir development by allowing wells to be placed according to physical and economic conditions. While unit agreements allow for a first-best productive result, the costs of reaching contractual agreement can prohibit unit formation. This thesis examines the determinants of reservoir-wide unitization agreements. The general hypothesis is that increases in costs contracting decrease the likelihood of successful unit formation. A static well-choice model is used to analyze the factors affecting the firm's decision to join a unit. Variations on the model allow the well-choice decision to be derived under various regimes: sole ownership of the reservoir, rule of capture production, and contracting. The well-choice decision for each variation can then be used to determine the value of the reservoir for each regime. Using these values, the probability of unitization can then be linked to increases in the value of the reservoir when it is unitized and increases in the costs of negotiating agreements. Two primary predictions result: 1) as surface landholdings and subsurface physical reservoir properties become more heterogeneous, the probability of unit formation decreases, and 2) laws facilitating the unitization process increase the probability of unit formation. The primary empirical analysis uses probit regressions and case studies to examine data from oil reservoirs in the Northern Plains for the probability of unitization. The estimates indicate successful unitization occurs when surface ownership and reservoir properties are more homogenous, but also that legislation enacted to facilitate the unitization process has little impact on the formation of units.

CHAPTER 1

INTRODUCTION TO OIL RESERVOIR CONTRACTING

Economists have long recognized that changes in property rights institutions that increase firm rents will occur if the benefits of change are greater than the costs of the making the change (Coase, 1960; Demsetz, 1961; Cheung, 1970). Contracts among fisherman to prevent excessive harvests and regulations limiting air pollution by manufacturing firms are practical examples of this process. In both cases the benefits of the new property rights arrangements, whether increased future fishing harvests or cleaner air, exceed the costs of changing institutions. Coase asserts that these "rerarrangements" of rights can occur privately in the marketplace via contractual agreement (as in the fishery), but if costs of negotiating become great, private attempts to realign property rights may fail. In this case, the government may enforce regulations to achieve a similar outcome with reduced transaction costs (as in air pollution). Cheung (1970) adds that if new legal arrangements require significant costs to enact and enforce, they may not be realized.

Oil production in the United States provides a good example of costs and benefits of changes in property rights. Oil production in the United States has been historically characterized by a traditional set of property rights that failed to consistently lead to an efficient outcome and contracting costs often prevented the successful negotiation of

private agreements. State and federal governments subsequently introduced rules and regulations to reduce the harmful effects of overproduction and lower the costs of negotiating contracts. These rules and regulations have reduced the amount of wasteful oil production, but contracting success has been limited. This thesis analyzes the determinants of unit contracting to better understand why unitization contracts are not more prevalent.

Oil Production and the Rule of Capture

The problem of oil conservation originates in an institutional framework that fails to allocate ownership claims to oil in an optimal manner. Because oil in an underground reservoir is held in a fluid state, it is free, to a certain extent, to move throughout the reservoir. An oil reservoir refers to an underground feature created by specific geological conditions. The reservoir is considered to be a single, contiguous producing unit, containing a finite quantity of extractable oil. The migratory quality of oil caused conflicts among firms over possession of oil when numerous surface owners had access to the reservoir.

Conflicts over possession resulted from the difficulty in assigning clear ownership to a fluid, underground resource. Under the traditional U.S. common law, ownership of land implies not only rights to surface attributes but also possession from the center of the earth to the sky. For an oil reservoir entirely underlying a solely owned single tract of land, possession of the oil can unambiguously be claimed by the owner of the tract. The owner can then maximize his return by making optimal decisions based on physical

characteristics of the entire reservoir and economic factors affecting marginal production. In the case of a reservoir underlying two tracts, rights to the oil are much less clear because oil beneath one tract can flow into the well bore of the neighboring tract. Even with the most recent technology and methods of seismic analysis, determining where oil is located within a reservoir or how much is present beneath a tract is uncertain. Because the quantity of oil underlying each tract cannot be determined, ownership to underground oil cannot be assigned. Instead oil can only be claimed when it is produced.

This method of claiming ownership, known as the rule of capture, is characteristic of petroleum because more than one tract often overlies a single reservoir, allowing access to a common oil supply for numerous firms. Because ownership can only be claimed on extraction, the rule of capture provides an incentive for each firm to extract oil quickly in order to claim possession of a larger share of reservoir rents. While one firm or another may benefit from this type of production, aggregate losses occur because productive decisions based on the maximizing of returns from individual tracts differs from optimal decisions based on well-choice for the entire reservoir. Potential rents are dissipated as firms drill an excessive number of wells and invest in above ground storage for oil that has not yet been marketed. Competitive production decisions also contribute to the premature depletion of energy inherent in the reservoir. As will be discussed in Chapter 2, when a reservoir is first discovered enough pressure is present to drive oil to the surface with little if any marginal pumping costs.¹

¹See Clark (1960) for a discussion of this stage of production, known as primary production

Optimal reservoir-wide decision making can prevent premature abandonment of the reservoir and lead to higher ultimate oil recovery. With rule of capture production, as more wells are added at flush or maximum production rates to maximize tract returns, pressure within the reservoir is pre-maturely released through the numerous well holes, and in a short time, oil is no longer pushed to the surface. This early loss of reservoir energy reduces primary production to a relatively short time period and allows only a small percentage of potentially recoverable oil to be extracted. The remaining oil can only be brought to the surface with costly pumping or injection techniques.² In short, an inability to clearly define ownership and determine productive rights to the reservoir can cause too much oil to be withdrawn from too many wells compromising the productive potential of the reservoir.

The resulting losses in physical oil production from pressure depletion and over-expenditure on storage are commonly referred to in the oil industry as *waste* and are directly linked to over-drilling on the oil reservoir. The race to capture becomes more competitive as the number of firms with access to the reservoir increases. On reservoirs overlain by many surface owners, more wells are drilled and more oil extracted as owners attempt to take advantage of the low production costs early in the productive life of the reservoir, increasing the magnitude of waste and damage to the reservoir.

Numerous solutions have emerged to mitigate the losses resulting from rule of capture. In the early years of production, attempts were made by firms to draw up

² Secondary or enhanced recovery refers to the stage of production characterized by investment in injection or lifting equipment and rising marginal costs of extracting oil (Clark, 1960).

contracts to share costs and production whereby, the reservoir was managed as a unit with well number, well placement, and extraction rates determined by a single operator or operating committee. Rent dissipation could be largely eliminated because production rights were transferred to a single entity capable of optimally placing wells in a similar fashion to the sole owner case. As Libecap and Wiggins (1984 and 1985) and Libecap (1989) discuss, because of the costs involved with determining relative and absolute values of oil underlying tracts, negotiating firms could not achieve necessary consensus on formulas to share production, and many attempts at voluntary units failed.

Emerging from the general failure of the formation of private contractual agreements was a set of institutional arrangements consisting of federal and more importantly state regulations attempting to reduce waste through production controls on the tract and at the wellhead. State regulations are critical to the conservation of oil because state governments, through oil and gas conservation agencies, have assumed primary responsibility for administering rules regarding waste. These laws included setting well density limits, production quotas, and rules on waste disposal.

Another set of rules attempts to generate unit operation by legalizing the process of compulsory unitization. Compulsory unitization laws compel firms holding out of unit agreements to participate in the joint operation of the reservoir when certain conditions are satisfied. The rules stipulate that after a statutorily determined super-majority of ownership interests agree to a contracted plan of operation, including the designation of a single operator, and a formula for cost and production sharing, the non-consenting

interests can be forced to join the management plan.³ Reservoir-wide unitized production is recognized as the optimal method of production because, like the pre-production agreement process and sole ownership of the reservoir, it allows the reservoir to be the natural producing unit.⁴ The operator, not numerous self-interested producers, makes decisions based on reservoir dynamics. Wells are only placed in the best locations and production may occur optimally. If the reservoir has already been producing under rule of capture, some non-optimal wells may be shut-in or cease production. With firms acting together, the concern over capture is eliminated and production proceeds by evaluating physical reservoir conditions and economic factors.

Many studies have documented waste and proposed solutions, including unit agreements, but very few have attempted to identify the determinants of production and quantify their relationship to optimal production of oil. Libecap and Wiggins (1984 and 1985), Wiggins and Libecap (1985), and Libecap (1989) attribute failures to reach contractual solutions (unit agreements) to uncertainty and information asymmetry regarding tract values. Their empirical analysis is limited to a small sample of reservoirs in Texas, Oklahoma and Wyoming.

This thesis will extend the work of Libecap and Wiggins by analyzing 189 oil reservoirs in Montana, North Dakota, and Wyoming to determine the factors that

³ For example, in Montana, eighty percent of ownership interests must agree to the plan of unitization before the state regulatory agency will force the remaining twenty percent to join the unit.

⁴ As well as realizing the gains from contracting, compulsory unit agreements also face the costs of negotiating, similar to voluntary units. Compulsory unit agreements are seen as more effective because they reduce the costs involved with reaching agreement. These costs will be modeled and explained in Chapter 4, but can be significant enough to prevent agreements from occurring. See Libecap, 1989.

significantly contribute to the formation of successful units. A better understanding of the obstacles in the Northern Plains can clarify the economic behavior and decisions of firms in other states. More generally, understanding allocation decisions with regard to oil production may have implications on the use and administration of other natural resources which are accessible to multiple parties such as wildlife, fisheries, groundwater, and air. The users of these resources face similar property rights conflicts resulting in inefficiency and overuse. The thesis will explain the factors contributing to successful oil reservoir contracting and may have implications for the use of these other resources.

Evidence of Rule of Capture Losses

Indications of overproduction and waste began as soon as the first commercially productive oil was discovered in the United States. The initial discovery by Colonel Drake in Titusville, Pennsylvania in the summer of 1859 brought with it a mad rush to drill wells, resulting in excess production and falling oil prices. After two years, oil prices plunged from \$10.00 to \$0.10 a barrel as operators flooded the market (Yergin, 1992). Because oil was extracted faster than it could be sold, operators invested in storage facilities consisting of wooden whiskey barrels and open vats. Many producers realized added costs as wooden whiskey barrels and open vats caught on fire, burning thousands of barrels of oil.

Not long after these first discoveries, the courts began hearing cases to define rights to oil. Because physical properties of oil and gas were not well understood by oil producers or judges, the courts formed legal rules by making analogies between oil and

other more familiar resources such as water and wild animals.⁵ The application of common law rule of capture in oil production originated in these first important cases, and institutionalized a system that paid little attention to conservation of the petroleum resource or optimal methods of production. From the time of these early cases until the mid 1900's, the oil industry and state and federal governments worked to form a set of conservation institutions that better defined rights to oil and gas.⁶

Early productive history in California provides a clear indication of waste created by rule of capture production. During the first major oil boom in the late 1890's with the discovery of the Los Angeles Field, annual productive output grew in ten years from 470,000 barrels to 24 million barrels (Yergin, 1992). In 1910, four to eight million barrels of oil were lost to fires and evaporation from storage ponds (Libecap, 1989). The development of Signal Hill in Long Beach, beginning in 1921, took the notion of dense drilling to an extreme. Wells were drilled so closely that wooden derrick structures overlapped each other. By 1928, non-marketable gas produced along with oil from California reservoirs was estimated at 180 million cubic feet a day, or over \$5 million a year (Rush, 1928). In 1997 dollars, that same production would be worth over \$141 million a year.⁷

⁵ See *Frazier v. Brown*, 12 Ohio St. 294 (1861); *Funk v. Haldeman*, 53 Pa. St. 229, 236 (1866); *Westmoreland & Cambria Gas v. DeWitt*, 130 Pa. 235, 18 Atl. 724 (1889); and *Barnard v. Monogahela Natural Gas Company*, 216 St. Pa. 362, 65 Atl. 801 (1907).

⁶ Hardwicke (1961) reviews in detail federal, state, and private attempts to institute rules and regulations to reduce or eliminate the waste of petroleum.

⁷ 1997 average price of \$2.15/mcf from Energy Information Administration, Annual Energy Review 1997, DOE/EIA-0384 (97) (Washington D.C.: Department of Energy, 1998), Table 6.8.

While California quickly became a major oil producing state in the early 1900's, Oklahoma and Texas were the dominant national producers. Accompanying this position as productive leader was the more dubious recognition the region received for its firsthand contribution to the understanding of wasteful production of oil. Libecap and Wiggins published many details of rule of capture losses in this region in a series of papers analyzing oil reservoir contracting. In Oklahoma, Libecap and Wiggins (1987) point to the discovery of the Seminole Field and subsequent flush production by all firms that led to a decrease in oil prices from \$2.29 to \$1.28 a barrel in less than a year. Near its peak production in 1927, Seminole had a 3 million barrel storage capacity as rule of capture drove producers to overdevelop a field lacking pipelines to market the extracted oil. Oklahoma City, Oklahoma's largest field, was subject to martial law numerous times as overproduction led to the need for the armed enforcement of proration quotas that set daily limits on the amount of oil produced from individual wells (Libecap and Wiggins, 1987).

In Texas, classic examples of rule of capture waste characterized early oil development. On January 10, 1901, the discovery well at the Spindletop field in southeast Texas defined the term gusher for the industry as oil blew hundreds of feet into the air at the rate of 75,000 barrels a day. Frenzied drilling followed so that within months, 214 wells were producing oil, some on leased tracts barely large enough for one derrick. Oil prices by June were as low as \$0.03 a barrel as hundreds of different companies rushed to extract oil (Yergin, 1992). By 1903, due to over-drilling and flush

production, pressure that initially forced oil hundreds of feet into the air was no longer able to raise a barrel of oil to the surface. Production plunged as quickly as it had risen.

The pattern of over-drilling repeated itself regularly in Texas culminating with the discovery of the East Texas Field in 1930, one of the most significant oil finds in the history of the industry. The huge East Texas reservoir, tapped in the midst of a worldwide depression, quickly became the largest producing pool in the United States, epitomizing the excesses of unrestricted competitive production and the need for regulated development of oil reservoirs. The reservoir covered five Texas counties and was forty-three mile long and three to ten miles wide. (Carleton, 1998). Libecap and Wiggins (1987) note that within nine months of development, oil produced from this pool alone represented 50 percent of Texas' oil output and 20 percent of U.S. production. Over 3,000 firms, more than all those operating in Oklahoma, leased land and drilled wells. Wells were flowing flush at maximum rates and drilling of new wells continued at a frenzied pace as producers raced each other to extract oil. By 1938, 23,951 wells were producing oil on East Texas. Due to over-drilling and depletion of reservoir pressure, over 600 million barrels of oil were lost to primary production techniques at a cost of at least \$108 million (Murphy, 1949).⁸

Evidence of rule of capture waste is well documented for Pennsylvania, California, Oklahoma, and Texas because of the prominent roles these states have played in the history of oil development in the United States. But, these states are not alone in

⁸ These cost calculations are based on the lowest reported oil price of \$0.18 a barrel and are reported in 1930 dollars.

confronting issues of resource conservation, reservoir-energy maintenance, and prevention of economic waste. All oil-producing states have experienced or witnessed the effects of unrestricted oil reservoir development and considered the consequences of uncontrolled development. While Northern Plains oil production does not approach that of other of major producing states, the problems of waste appear regularly. As early as 1921, the Wyoming state legislature had already enacted laws to eliminate waste and assembled a Department of Oil and Gas Conservation to oversee oil production. By 1926, Wyoming's state geologist and director of the Department of Conservation wrote of the conservation problem, "If the history of the waste of oil and gas in the prior years were fully known, the figures would be staggering." In the mid 1920's, an unidentified gas well in central Wyoming was reported to have burned 50 million cubic feet of flared gas a day for three years at a financial cost of \$1,850,000 a year.

As the oil industry grew in the 1920's and 1930's in the Northern Plains, examples of waste also appeared. A 1930 study of Wyoming's oldest and largest reservoir, Salt Creek, documented an increase in wells from 685 to 1,600 in the three-year period from 1923 to 1926. The study indicated that 1,300 wells would have sufficiently drained the reservoir, saving over \$6 million in drilling and production costs (American Institute of Mining and Metallurgical Engineers, 1930). In Montana, similar indications of over-drilling, although not as well documented, can be found. The Kevin Sunburst reservoir in northern Montana was discovered in 1922. By 1926, it was producing almost 6,500,000 barrels of oil per year, close 85 percent of Montana's production (Montana Department of Agriculture and Labor, 1928). From 1924 to 1926, production on Kevin Sunburst rose by

5,400,000 barrels, a 475 percent increase. By 1928, production had already decreased by more than half to 3,149,183 barrels and in 1930, by more than 70 percent to 1,910,893 barrels. The reservoir never again produced over 2 million barrels of oil in a year. Along with dense drilling (as many as 9 wells per 40 acres as late as 1940) and relatively numerous firms (over 50 firms operating in the area), the rapid drop in productivity indicates over-drilling likely occurred. More recently, on the Ridgelawn-Duperow reservoir, the state regulatory agency ordered production to cease until a central management plan among producers could be agreed upon to prevent the premature dissipation of reservoir energy.

North Dakota has little evidence of waste because the state enacted a set of conservation rules in the late 1940's before commercial production began. Many reservoir simulation studies have shown the additional production gained from controlled reservoir development, but few outstanding cases of waste in North Dakota can be found.⁹ A study on North Dakota oil development in the mid 1960's by David Fisher and John Bluemle (1988) reports that North Dakota did impose production quotas in the 1950's and 1960's to prevent an oversupply of oil in the region. Fisher and Bluemele also note production restrictions and temporary orders stopping production on the small Dolphin Field in order to preserve rapidly falling reservoir energy. Unlike Pennsylvania, California, Oklahoma, and Texas, the Northern Plains is characterized by relatively large land holdings, many with surface and mineral rights owned by the federal government.

⁹ Oil companies submitted most of the studies to show the added productivity from unitization versus continued rule of capture production.

While fewer records of large-scale waste exist for the Northern Plains, cases of over-drilling and depletion of reservoir energy can be found, and clearly the problem was recognized in all three states.

Organization of the Thesis

The thesis is organized to introduce the nature and history of oil and the oil production problem, develop an economic model to provide a foundation for hypotheses and predictions, and finally present empirical analysis of the key propositions of the thesis. Chapter 2 examines the physical properties of oil, its origins, and the techniques involved with its production. The chapter explains the variables petroleum engineers use to evaluate the quality of an oil reserve as well as the natural processes affecting oil extraction. This overview of engineering principles is important because many of the variables described alter benefits and costs to the producer and are, therefore, integral to an understanding of rule of capture production and the development of the well-choice models in Chapter 4. A number of these variables are also included in the empirical analysis in Chapter 5 to examine the importance of reservoir mechanics on productive decisions.

Chapter 3 presents a historical overview of oil production in the Northern Plains within the context of national oil policy. Included in this discussion are the important legal conservation cases in that have altered the nature of property rights institutions in Montana, North Dakota, and Wyoming. The chapter explains the responses of federal and state government agencies to cases of waste presented by the rule of capture

production. Evidence of reservoirs with significant over-drilling is presented along with examples of reservoirs that avoided waste either through pre- or post-production contracting among landowners. Chapter 3 closes by discussing the unique circumstances specific to North Dakota. Here is an opportunity to study a state that already had well-developed conservation institutions in place before any significant production occurred. While indications of oil and gas were first reported in the 1890's, commercial oil production did not begin in North Dakota until the early 1950's with the development of the Williston Basin (Bleumle and Lewis, 1988). With the experiences of other states to guide them and almost 70 years of legal and conservation history to reference, North Dakota was able to assemble a body of rules and regulations in a timely manner without responding to conflicts on a case- by-case basis. This section of the chapter will examine the history of Williston Basin for evidence of successful unit contracting and decreased waste from rule of capture production.

Chapter 4 develops economic models, which can be used to analyze decisions for optimizing production under the regimes of sole owner, rule of capture, and unitized production. The discussion begins with the presentation of a one period profit maximization model for a single firm with access to acreage overlying an entire oil reservoir. Subsequent models relax the initial assumptions of the sole owner case by first introducing numerous owners and rule of capture production. The next variation considers the optimizing problem of a zero cost contract model. The final model examines the addition of transaction costs to the previous case, and contracting cost implications on production.

Chapter 5 presents an empirical analysis of reservoir contracting using data collected in 1998 and 1999 on 189 unitized and non-unitized reservoirs in Montana, North Dakota, and Wyoming. This section of the thesis first introduces the data set and discusses the choice of variables selected to capture effects on transaction costs of differing land ownership patterns, institutional regimes that have evolved in each state, and geological aspects of each reservoir. Next, test conditions and predictions for specific contracting cost measures are introduced. The primary implication generated by the well-choice models posits that increases in transaction costs or decreases in the value of the unitized reservoir will reduce the likelihood of a reservoir unitization. Finally, econometrics and empirical case studies are used to test the effects of contracting determinants on the likelihood of reservoir-wide unitization.

Chapter 6 summarizes the study. The chapter discusses the contributions of the study and the weaknesses in the methodology and technical analysis. Finally, the chapter concludes with an overview of future work that would support and add to the validity of the thesis.

CHAPTER 2

PETROLEUM AND RESERVOIR PROPERTIES¹⁰

This chapter surveys the nature of petroleum and important characteristics of oil reservoirs. Because reservoir features determine transaction costs, it is important to understand them in order to study their impact on the likelihood of unitization. The chapter examines the links between the technical and physical aspects of oil production and the costs of contracting.

The Formation of Oil

While the exact origin of oil is unknown, the most commonly accepted hypothesis asserts that the formation of petroleum is the result of the transformation of organic matter through heat, pressure, and bacteria into two general types of petroleum compounds, liquid oil and natural gas. According to this theory, millions of years ago in ancient seas, masses of tiny marine plants and animals were buried beneath layers of sand and silt. The sediment, carried into the oceans by prehistoric rivers, sealed the organic material, preventing its decay. As the centuries passed, layers of silt and sand continued to accumulate, burying the biomass beneath tons of sediment. The weight of this

¹⁰ The primary source of information for this chapter is Clark's Elements of Petroleum Reservoirs, 1960. Petroleum engineers today still recognize this text as one of the best works on the subject of petroleum production and reservoir properties.

sediment created heat and pressure, which in combination with the action of bacterial decomposition, transformed the plant and animal material into new compounds known as petroleum.

Molecules of petroleum are formed of hydrogen and carbon from original marine life. These molecules chemically combine in different petroleum compounds depending on the amount of compaction and bacterial activity at the time of deposition. Some compounds are chemically simple and light such as methane or propane while other compounds are more complex and heavy such as tar-like crude oil. Deposits where oil is formed typically contain a wide range of these compounds from the light gases to heavier oils. Likewise, because the conditions of oil formation are unique to each deposit, the types and amounts of petroleum compounds within a deposit may differ significantly. In the extreme case, one deposit or reservoir may be all natural gas while another may be all crude oil.

The heterogeneity of the deposit often leads to complications in determining the value of the deposit. Since conditions are not identical everywhere on the deposit, cost of extraction at alternate reservoir locations may differ significantly. This difference becomes problematic in the unitization context because landowners determine their willingness to enter a unit agreement based on the expected value of the petroleum beneath their land. If negotiations do not reach consensus on lease values, contracts can

fail or units may not include the entire deposit.¹¹ These factors in turn affect the method of extraction and value of the petroleum.

Characteristics of Oil Reservoirs

Originally, the layers of sediment and organic matter were deposited in a nearly horizontal manner at the bottom of oceans. Over time, geologic forces changed the initial structure of the beds of sediment and petroleum. The forces of shift and uplift also led to deformation of the layers of sediment causing them to bend, twist, and break. Salt water percolated into these spaces, joints, and fractures, eroding and enlarging them into substantial cavities.

These spaces became deposits for newly formed petroleum. It is not known whether oil traveled great distances to fill these cavities, or if it was dissolved in the salt water initially filling the cavities. A cavity or series of interconnected cavities, bounded on all sides by geologic structures preventing oil movement, is known as *trap* or *reservoir*. Reservoirs result from forces that change the initial structure of the sediment beds, creating spaces for the storage of petroleum. Reservoirs are often confused with fields. A *field* is simply the name attached to a well-defined geographical area containing one or more oil reservoirs.¹²

¹¹ Appendix A discusses the origin of the lease and land policy issues pertinent to this thesis.

¹² Reservoirs are named by first identifying the field in which it is located and then naming the reservoir. For example the Woodbine reservoir on the East Texas Field can be identified as East Texas-Woodbine.

Oil reservoirs have been erroneously compared to pools of fluids. The analogy is inaccurate for several reasons. Pools typically contain a single body of homogenous fluid. If a second fluid is present in the pool, it is uniformly distributed across the pool.¹³ An oil reservoir, in contrast, is not a single storage space for oil and gas, but a series of spaces connected by channels. Some reservoirs consist of small, interconnected spaces while others may have large spaces with few connections. Also unlike a pool, the reservoir is not filled with homogenous, uniformly distributed fluids. Gas may be concentrated in one small area of the reservoir, while oil is in another. While the behavior of a single homogenous body of fluids is predictable based on rules of physics, the behavior of an oil reservoir is more complex. Not only must the physics of fluids be considered, but the physical structure of the reservoir and the composition and distribution of fluids within the reservoir must also be understood in order to determine ultimate oil recovery. Several quantifiable factors may be measured which help describe these physical characteristics and allow petroleum engineers to predict oil recovery from a reservoir.

Physical Reservoir Properties

A primary factor important to the recovery of oil is the *depth* at which the oil layer is found. Because of geological shifts, the depth at which oil is found is not usually the depth at which it was formed. Nonetheless, depth does affect physical properties such as reservoir pressure and, therefore, the ultimate recovery. Depth also affects drilling costs.

¹³ An example would, of course, be a swimming pool or any other contained storage for fluids, like a pond or lake where numerous fluids are evenly distributed throughout the pool.

As the oil zone deepens, the cost of boring and time to reach the oil increase. Often, deeper oil reservoirs have pressure characteristics that require fewer wells to be drilled in order to drain the reservoir optimally. The earliest oil discoveries were, not surprisingly, very shallow. The first discovery at Titusville, Pennsylvania was just sixty-nine feet deep. By 1900 at Spindletop, Texas technology had improved so that wells were drilled 880 feet before oil was discovered (Yergin, 1992). Today wells can be drilled economically to depths of thirteen thousand feet and more.

A second important factor, which helps in determining the productivity of a reservoir, is the rock *porosity* (Clark, p.18-27). Porosity measures the interconnected spaces within the reservoir. Quantified as a percent of the total rock volume, effective porosity relates the proportion of total volume of the rock structure that holds recoverable fluids. Porosity is used by engineers to measure the amount of space within the rock available for the accumulation of oil and gas. The measure is used in the calculation of the *original-oil-in-place* (OOIP), which gives an estimate of the total amount of oil present in the reservoir based only on physical characteristics. Petroleum engineers use calculated measures of OOIP to determine the amount of potentially recoverable oil. The largest reservoir in the United States measured by OOIP is the Prudhoe Bay-Saddlerock reservoir in Alaska with 22 billion barrels of estimated original-oil-in-place. The huge East Texas-Woodbine reservoir has an OOIP estimated at almost 8 billion barrels of oil.

In the Northern Plains, the largest reservoir determined by OOIP is the Salt Creek Second Wall Creek reservoir in central Wyoming with an estimated 800 million barrels of oil.¹⁴

Another important factor in reservoir productivity measures the ability of oil to move within the reservoir. Frequently, channels connect spaces within a reservoir so that oil, gas and water can move between the spaces. This characteristic of rock is known as *permeability* (Clark, p. 21-30). Holding other oil characteristics constant, larger channels lead to greater flow and higher permeability. Permeability of rock, measured in units called millidarcies, is the volume of oil at a constant viscosity or thickness, which will flow through an area of sand when subjected to a one-atmosphere drop in pressure. Variations in permeability often have effects on the amount of oil recovered from the reservoir. Thus, reservoir values are linked to measures of permeability. For instance, the East Texas-Woodbine reservoir has a permeability measure of 1050 millidarcies while the Cutbank-Cutbank reservoir measures an average of 38 millidarcies. Holding other reservoir properties equal, the measures indicate that oil flows more easily through the East Texas-Woodbine sand than the Cutbank-Cutbank formation, making oil recovery more effective. As a result, holding other reservoir variables constant, rule of capture drainage is more wasteful, since drilling additional wells allows greater flow to the low pressure bore hole. But the relationship between permeability and recovery is not always so straightforward and can be complicated by other reservoir characteristics

¹⁴ Data for these OOIP statistics are collected from the National Institute for Petroleum and Energy Research database of oil reservoirs with OOIP greater 50 million barrels.

Natural Drive Mechanisms

An important factor affecting the permeability/recovery relationship is the natural drive of the reservoir. The natural drive is energy stored within the reservoir as highly pressurized fluids. All reservoirs have an inherent energy or natural drive that originated with the deposition of layers of sediment and marine life and grew with the formation of oil within the deposit. The weight of the seas above the deposited layers created pressure in the pore spaces of the deposits, which was preserved even as the waters receded. The pressure varies with depth so that deeper reservoirs generally have greater pressure. But after eons of uplift and faulting, reservoir pressure is not always correlated with depth. While reservoir pressures may vary, they are always greater than atmospheric pressure due to underwater conditions at the time of the reservoir formation. The differential between reservoir and atmospheric pressure pushes petroleum to the surface when a hole is drilled into the reservoir. As long as there is a dis-equilibrium between surface and subsurface pressures, energy will continue to be released in the higher-pressure fluid, driving it to the area of lower pressure at the surface. The image of oil gushing out of the ground and spraying above the well rigging hundreds of feet into the air is an example of the great pressures preserved in the reservoir and the energy released when a well is drilled. The natural drive mechanism of the reservoir utilizes the natural pressure held within the reservoir to produce oil. Petroleum engineers recognize three general drive mechanisms: gas cap, dissolved gas, and water drive.

The *gas cap* drive uses the expansion of free gas to move oil. With a *dissolved gas* drive, oil is held in solution in the oil layer. When a well is drilled, the oil is driven

up through the well bore as the gas expands and dissolves out of the oil. A *water drive* operates in a similar fashion to the gas cap. Water underneath the oil layer expands and forces oil up towards the area of lower pressure around the well bore. While each mechanism provides for the release of reservoir energy and movement of oil, the recovery characteristics of each is different.

The gas cap reservoir is formed with a layer of gaseous hydrocarbon above the oil deposit. The cap forms if temperature and pressure are not sufficient to keep the lighter hydrocarbons in liquid solution with the heavier crude oils. The less dense gas then rises to the top of the trap where it forms a cap over the oil. The gas is held in a compressed state so that when a well is drilled into the oil layer, the gas can expand, releasing energy and forcing oil to the surface. Pressure in a gas cap reservoir typically falls at a constant and slow rate as the cap uniformly expands throughout the trap. Operators must be careful with a gas cap reservoir not to place a well over the cap. If this occurs, gas is released and energy is prematurely lost. Likewise, as the gas expands and pushes oil in front of it, wells close to the gas-oil boundary will measure an increasing gas-oil-ratio (GOR).¹⁵ These wells are often shut-in (prevented from further production) in order to preserve reservoir energy. As gas begins to infiltrate the pore spaces, it acts as a block, preventing the movement of oil and reducing the permeability of the reservoir rock.

Water production is uncharacteristic with gas cap oil production because the trap typically contains little water. Gas caps tend to flow longer than dissolved gas reservoirs

¹⁵ The GOR is a measure proportion of volume of gas to oil. It is typically scaled as cubic feet of gas to barrels of oil. So a GOR of 700 implies seven hundred cubic feet of gas produced for every barrel of oil.

because of uniform expansion. The recovery rate again depends on pressure in the reservoir and rates of production as well as the size of the gas cap. Recovery often averages 20–40 percent of the original oil in place. Of the sampled reservoirs in this study, 12 percent are gas cap drives.

The dissolved gas drive results from a reservoir without a gas cap or water layer. Hydrocarbons lighter than oil are held in solution in liquid form. When oil production begins, the lighter hydrocarbons are liberated from solution and expand into a gas phase, releasing energy that drives oil to the surface. As production continues, energy is released, and reservoir pressure falls as more gas dissolves out of the gas-oil solution. Eventually, this gas migrates to the well bore and begins to be produced along with oil. Operators note a rising GOR. This ratio rises dramatically because the lighter gas, dissolving out of the oil, flows more easily to the well bore. Permeability relative to oil again decreases as gas fills the pore spaces in the rock structure (Clark, p.30). As pressures continue to decrease, less gas is liberated and the GOR may stabilize or fall slightly. Because the reservoir is a closed structure without water, no water is produced. Initial pressure, initial gas-oil ratio, and the rate of production on the reservoir all affect the ultimate primary recovery rate. Recovery with dissolved gas drives via natural reservoir energy is often very low, only 5-30 percent of the original oil in the reservoir. Sixty-four percent of the reservoirs sampled for this thesis are dissolved gas drive reservoirs.

Finally, the water drive mechanism provides the greatest amount of natural energy for oil production. Water is usually thought of as a non-compressible fluid, but when

great quantities are involved in deep underground reservoirs, the weight of overlying structures does compress the fluid. Because quantities of water are large, the energy contained in the compressed fluid is large. When a well is drilled on a water drive reservoir, the pressure differential causes water to flow toward the low pressure, pushing the oil in front of it. This action occurs because water, being heavier than oil, forms in a layer below the oil zone. Pressure decreases at a very slow rate with water drives because the total energy within the reservoir is dispersed evenly throughout the large amounts of water within the deposit. Since the pressure remains high, GOR and permeability remain constant throughout the productive life of the reservoir. The gas held at constant pressure cannot dissolve out of solution. Water is eventually produced first at the wells producing from the deepest part of the reservoir. A much larger portion, 35–75 percent, of the oil originally in place is produced with a water drive. Many of the world's important reservoirs are water drives, including the huge East Texas oil field. For the sampled reservoirs used in this thesis, 24 percent are water drives. Table 1 summarizes the important features in the discussion of natural reservoir drives.

Table 1: Reservoir Drive Mechanism Characteristics

CHARACTERISTIC	DESCRIPTION		
	GAS CAP	DISSOLVED GAS	WATER DRIVE
PRIMARY PRODUCTION RESERVOIR PRESSURE	Declines slowly and continuously	Declines rapidly and continuously	Remains high
GAS TO OIL RATIO	Rises continuously	First low, then rises to a maximum, then drops	Remains low
EXPECTED OIL RECOVERY	5-30% of OOIP	20-40% of OOIP	35-75% of OOIP
EXAMPLES:			
United States	Prudhoe Bay,	Long Beach,	East Texas
Current Study	Alaska Salt Creek, Wyoming	California Cutbank, Montana	Cat Creek, Montana

Source: Clark, *Elements of Petroleum Reservoirs*

Stages of Production

As long as reservoir pressure remains higher than atmospheric pressure, petroleum will continue to move toward the borehole. Ultimately, however, depending on depth of the hole, permeability, and other factors, the difference in pressures will not be enough to drive oil all the way to the surface. In order to continue production, active extraction methods are required. Operators may first try to pump oil from the reservoir. This technique holds down marginal production costs, but energy within the reservoir continues to decrease. Again, a critical pressure is reached when pumping is no longer cost effective. If reservoir pressure prematurely reaches this critical level, oil may be permanently lost to recovery given the available technology and costs of extraction. Due to structural features, porosity, and permeability, pockets of oil in the reservoir may not

be recoverable. Operators constantly monitor reservoir production parameters to prevent damage to reservoir drive energy, which can reduce ultimate recovery.

The types of production described using only the natural drive mechanism of the reservoir or in combination with pumping are referred to as *primary production* techniques. To extend production, operators can act to re-pressurize the reservoir. These active methods of prolonging reservoir life are known as *secondary* or *enhanced recovery* operations. Secondary recovery involves the injection of gas or water into the reservoir to move the remaining oil to the well bore where it may be pumped to the surface. These projects involve significant investment of capital to construct injection wells and facilities to store or process the injecting fluid. Important to the success of secondary recovery is the method of production in the primary stage. If initial production rates are high, causing damage to the reservoir, injection projects may not lead to substantial secondary recovery. Of the reservoirs sampled for this study, thirty percent are in the primary stage of production, while fifty-nine percent are in the secondary stage. The remaining eleven percent of reservoirs are exploratory reservoirs, indicating that oil has been located but field boundaries are not completely defined and commercial production has not yet commenced.

Rule of Capture and the Rate of Production

The rate of oil production is important to the study of rule of capture and unitization because the rate at which oil is produced has impacts on the value of the oil reservoir and the gains from unitization. When production rates are excessive, the natural

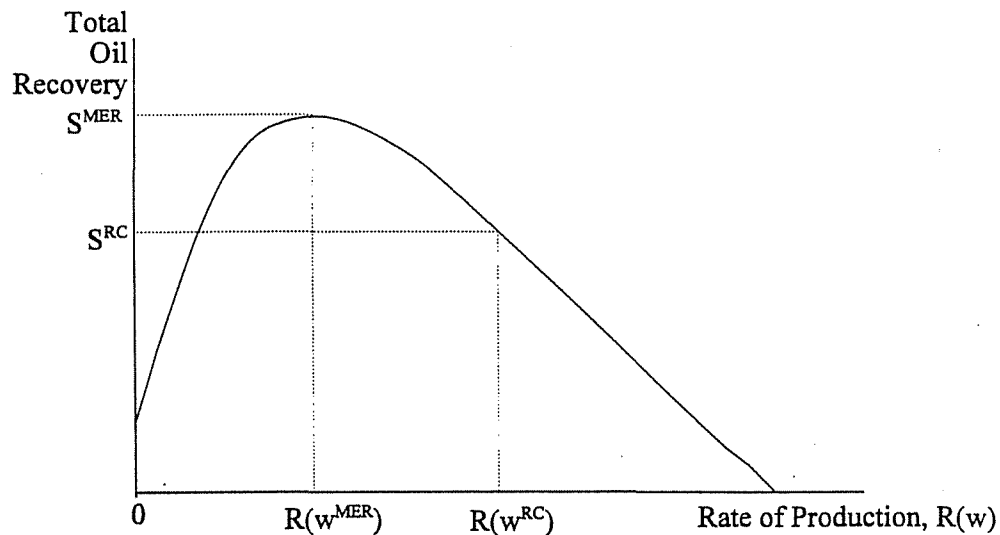
drive mechanism of the reservoir can be permanently damaged, reducing total oil recovery. Often under rule of capture, over-drilling results in excessive rate of production that reduce total oil recovery and the value of the reservoir. For the same reservoir if optimal well choice decisions occur, as with a unitized reservoir, production rates do not damage the reservoir. As a result, the value of reservoir production is greater than under rule of capture production when over-drilling occurs.

The *rate of production* for an oil reservoir is the amount of oil in barrels recovered from the reservoir in a specified time period. Often production rates are described as a measure of barrels per day. The rate depends on the number of wells drilled on the reservoir and the rate of flow for each well.¹⁶ Petroleum engineers recognize that the rate of flow clearly affects the overall recovery of oil from the reservoir (Buckley, 1951; Clark, 1960; McKie and McDonald, 1961). For a reservoir with a given set of reservoir characteristics including permeability, porosity, and natural drive type, increases in the rate of production increase the overall recovery of oil. But the rate of production can only be increased to a point after which further increases will lead to increasing loss of ultimate recovery. This loss can be attributed to rapid decline of natural reservoir pressure, release of dissolved gas, dissipation of gas and water, and by-passing large deposits of oil. Petroleum engineers and economists refer to this point as the "maximum efficient rate" (MER) of production.

¹⁶ For this thesis the rate is assumed to be constant and equal for all wells so that the rate of production only depends on the number of wells drilled.

For a given reservoir and period of time, the MER specifies the optimal rate of production at which a reservoir can be produced so that oil recovery is maximized. Since conditions vary across the reservoir, the MER figure is not a single reservoir-wide figure, but falls into a range of rates across the reservoir. Figure 1 provides a graphical interpretation of the relationship between the rate of production and recovery of oil, where $R(w)$ is the rate of production and w equals the number of wells drilled on the reservoir. I assume that with fixed rate of flow, for a given reservoir, an increase in wells, w , increases the rate of production, $R(w)$ (McKie and McDonald, p. 105). Total oil recovery in barrels is denoted by S .

Figure 1. The Effect of Production Rate on Oil Recovery



The graph suggests that the $R(w^{MER})$ leads to the maximum total recovery. Rates of production greater than the MER reduce overall recovery so that potential oil is lost. If

under rule of capture production the rate of production is $R(w^{RC})$, then the implied recovery S^{RC} is less than the maximum recovery, S^{MER} .¹⁷ Because rates of flow for individual wells are held constant for this study, the lost oil production, $S^{MER} - S^{RC}$, implies over-drilling of the reservoir.

Important to reservoirs is the relationship between rate of production and pressure. Increases in the rate of production beyond the MER have a damaging impact on each of the three natural drive mechanisms described previously. High production rates on a dissolved gas drive reservoir can lead to rapidly decreasing pressures which may increase rule of capture losses from decreased oil recovery. In gas cap drive reservoirs, high rates of production will affect the uniformity of gas cap expansion and again reduce ultimate recovery. Rule of capture losses on a water drive reservoir may not be as severe. Reservoir-wide pressure loss from high rates of production can be corrected on water drive reservoirs by slowing production and allowing pressure to increase. In contrast, gas cap and dissolved gas drive reservoirs do not have the ability to regenerate natural pressure. As a result, overproduction can permanently damage reservoir drive and reduce ultimate oil recovery.

Oil reservoirs have many important physical properties that affect and determine the amount of recoverable oil. These properties vary from reservoir to reservoir and across any single reservoir, affecting the costs of contracting for reservoir unitization. Reservoir properties also affect the potential losses from rule of capture over-drilling.

¹⁷ In the MER context, $w^{MER} = w^*$, the optimal well choice giving a set of reservoir and economic parameters. Also, it is generally the case, as will be shown in Chapter 4, that $w^* < w^{RC}$.

When reservoir properties suggest that rule of capture production imposes significant costs on producers, a contract to unitize the reservoir can benefit all firms. The testable implications based on physical reservoir properties pertain to increasing costs and benefits of forming unit contracts. While much of this data is proprietary and difficult to collect, it is clear that reservoir properties such as depth, drive type, and stage of production are important to the contracting process.

CHAPTER 3

HISTORY OF OIL PRODUCTION IN THE UNITED STATES AND ON THE NORTHERN PLAINS

This chapter focuses on the significant events in the evolution of the oil industry, that have led to the present day choices of individual producers on the reservoir. Participation in a contract to unitize an entire reservoir is an option, but other production choices exist. A presentation of the history of oil production in the United States reveals the origins of these choices and provides an initial understanding of the costs and benefits of each.

1880-1900: The Early Years of U.S. Oil Production

In August of 1859, after fifteen months of drilling outside Titusville, Pennsylvania, "Colonel" Edmund Drake struck oil for the first time in the United States. Oil seeps had been recognized for years throughout the United States, but uses for oil were limited. With improvements in refining technology that allowed oil to be burned in lanterns, demand increased, making the search for oil worthwhile. The discovery and development at Titusville marked the beginning of a process of redefining property rights that would last more than one hundred years. Yergin (1991) described events that

immediately raised questions as to the traditional understanding of ownership, questions that would be repeatedly asked as new reservoirs were discovered in the years to follow.

Within days of the discovery, the oil rush commenced. Newcomers looking for oil overwhelmed Titusville. Land prices soared in areas surrounding the discovery, and investors spent hundreds of thousands of dollars leasing land and buying farms in order to gain access to underground oil. In 1860, the common law rule of capture determined ownership of oil. Under this rule, property rights to oil were only assigned upon extraction. Combined with the migratory nature of oil and small surface holdings, the rule of capture provided a strong incentive for each operator to drill and drain before others did the same. As a result, production increased dramatically. Within the first one and a half years, seventy-five new wells were successfully drilled and many others came up dry. This increased production caused the price of oil to fall from \$10 a barrel to a low of \$0.50 a barrel by 1861.

The race to drill wells and claim as much oil as possible resulted in economic losses to firms at Titusville for three important reasons. First, costly above ground oil storage systems often failed, resulting in the waste of thousands of barrels of oil. Because the rule of capture required actual possession to determine ownership, oil was produced regardless of demand. As excess production continued, the need for above ground storage grew. Safe storage was difficult with few options available. Drake and other producers filled whiskey barrels and vats. This method of storage was not entirely satisfactory.

Ironically, it was not uncommon for a spark from a kerosene lamp to ignite entire storage areas causing thousands of barrels of oil to be wasted.¹⁸

A second cause of waste resulted from the excessive number of wells drilled at Titusville. In 1859, producers had no knowledge of over-drilling. Optimal spacing of wells would not be introduced until reservoir dynamics were better understood in the mid-1900's. As a result, many more wells were drilled than were needed to sufficiently drain the reservoir. Economic losses were incurred from overcapitalization in drilling equipment and expenditures on labor. An analysis of Titusville is difficult, but other studies suggest this type of waste was significant (Emery, 1930; Zorichak, 1932; and Libecap, 1989).

Finally, over-drilling resulted in the premature loss of reservoir pressure, which markedly reduced the amount of oil recovered in primary production. After the discovery at Titusville, Oil Creek was quickly developed with wells operating at flush production levels.¹⁹ With all wells producing at capacity, the internal pressures of the reservoir were prematurely dissipated. Well production decreased and eventually came to an end, leaving large quantities of oil trapped in the reservoir.²⁰ Wells were abandoned with oil

¹⁸ Later, oil was stored in open ponds near producing wells. This method was just as dangerous and wasteful with oil subject to fire, surface evaporation, overflow, and leakage. (McDonald, 1971, Libecap, 1989).

¹⁹ Flush production is a term used in the oil industry to refer to wells producing at their highest possible rates. In the primary stage of production, the wellheads on these wells were completely open allowing all possible oil to flow to the surface.

²⁰ As well as loss in pressure, venting also wasted millions of cubic feet of natural gas. A study of Signal Hill in California by R.D. Rush in The Oil Weekly, September 28, 1928 indicated an annual loss of over \$5 million as a result of gas flaring, an amount of natural gas currently worth \$141 million.

still remaining in the reservoir. The shallow producing sand, which became known as the Drake sand, was driven by a water mechanism (Pees, 1999), which in combination with shallow depth may have resulted in primary losses of up to 65 percent of the original oil in place. Rapid overproduction damaged the producing capabilities of the reservoir, so that only a fraction of the potentially recoverable oil was actually produced.

Perhaps as important as the initial discovery of oil by Drake was the establishment of the common law definition of ownership as the prevailing property rights institution. For reservoirs with numerous surface holdings, the absence of regulatory control and rapid entrance into the oil production business often led to competition for oil and widespread waste as firms rushed to claim oil. At this time, the only solution to rule of capture waste was private contracting for coordinated or unitized production. With the discovery of large reservoirs underlying the tracts of multiple surface owners, questions of ownership became more common. Conflicts among landowners occurred because the fluid nature of petroleum allows the possibility that oil beneath the land of one owner may be drained by a well on the property of an adjoining landowner.

Questions of possession of oil were problematic for the courts because they were dealing with an entirely new resource.²¹ The first recorded cases over possession began with an 1861 ruling that compared oil to percolating waters.²² While the cases asked for determinations of possession, the origins of these conflicts can be traced to the adverse

²¹ Previously mineral resources, such as coal, were claimed unambiguously through the common law *ad coelum* doctrine that stated the owner of a piece of land owned all within the property boundaries, from the center of the earth to the sky.

²² *Frazier v. Brown*, 12 Ohio St. 294 (1861). See Moses, 1943.

drainage problem. With adverse drainage, a landowner's well could interfere with and reduce the production of an adjoining landowner's well by causing oil to drain to his well. Subsequent cases in 1866 and 1875 likened the behavior of oil to *ferae naturae*, or wild animals²³ With little knowledge of oil to guide them, courts sent down rulings on possession consistent with other more familiar resources. The "rule of capture," which historically applied to the taking of wildlife,²⁴ was now applied to the ownership of oil. The rule as applied to oil states that, "the owner of a tract of land acquires title to the oil or gas that he produces from his own wells despite the fact that the oil may have migrated from adjoining tracts."²⁵ The rule was even more clearly stated in *Kelly v. Ohio Oil Company*, where the court declared, "Whatever gets into the well belongs to the owner of the well, no matter where it came from."²⁶ For the landowner subject to drainage losses, the famous solution as stated in the comments of *Barnard v. Monogahela Natural Gas Company*²⁷ in 1907 was,

"What then can the neighbor do? Nothing, only go and do likewise. He must protect his own oil and gas. He knows it is wild and will run away...and it is his business to keep it at home."

²³ In *Funk v. Haldeman*, 53 Pa. St. 229,236 (1866) Oil " is a moveable, wandering fugitive thing in the bowels of the earth. The judgement in *Brown v. Vandergrift* 80 Pa. St. 142, 147 (1875) refers to the uncertainty of the " fugitive and wandering existence [of oil and gas] within the limits of a particular tract. (Moses, 1943).

²⁴ See the famous *Pierson v. Post*, 3 Cai R. 175 (N.Y. Supr Ct., 1805) ruling on the possession of the hunted fox which is based in the British common law.

²⁵ This ruling is attributed to *Westmoreland & Cambria Gas v. DeWitt*, 130 Pa. 235, 18 Atl. 724 (1889).

²⁶ 57 Ohio St. 317,327,49, N.E. 399, 401 (1897).

²⁷ 216 St. Pa. 362, 65 Atl. 801 (1907)

The Barnard case defined what came to be known as the offset drilling rule. The rule reinforces the concept of protecting one's property right to oil and gas and is an extension of the rule of capture phrased specifically to recognize the right of a tract owner to defend himself from adverse drainage. The rule states that the owner of a tract which is being drained by operating wells on adjoining tracts cannot enjoin the operation of those wells or recover damages from the owner of those wells. He can protect his oil by drilling offset wells on his own land to prevent further drainage. Offset wells are wells drilled often on the boundaries of tracts that act to prevent oil from migrating across boundary lines. Offset wells act like underground fences except that the oil is not just contained; it is produced.

Under the rule of capture production continued in what Robert Hardwicke (1961) termed a "disorganized and haphazard fashion". As the century drew to a close, surface property rights, which had in the past clearly defined ownership to certain minerals, now led to ambiguity of ownership with respect to oil and encouraged a system of exploration and development that led to waste of natural and financial resources.

Northern Plains: Pre Commercial Oil Developments

In the early years of U.S. development, oil activity in the Northern Plains was limited primarily to exploration. There was little need for legislative and judicial action.²⁸ The absence of commercial production prevented major property rights conflicts and

²⁸ The first statute dealing with the conservation of oil and gas would not be passed until 1901 in Wyoming. (Murpy, 1949).

statutes to prevent waste were not necessary. Numerous reports of oil seeps in both Montana and Wyoming can be found as far back as 1864 (Douma, 1953 and Murphy, 1949). By the mid-1880's, fourteen producing wells were bored in Wyoming, and in 1895, oil was discovered at Salt Creek, west of Casper, Wyoming. Salt Creek would become the focal point of early oil development in the Northern Plains and would prove to be a giant oilfield of national proportions.²⁹ In North Dakota, gas was discovered in 1907, but the first petroleum explorers did not strike oil until 1928 (Friedrich and Garrison, 1948).

While commercial production did not begin until after 1900, the Northern Plains did experience its first oil rush in 1899 in Northwestern Montana. At Kintla Lake, just south of the Canadian border, and along the North Fork of the Flathead River, the discovery of high-grade crude led to intense land leasing reminiscent of Titusville. Claims rose in price from \$5.00 each to \$100.00 in just a year (Douma, 1953). Drilling began in 1901, but amounted to little. Even with the higher prices commanded by this quality oil, commercial production was not profitable. Not for another seven years, with the discovery of Salt Creek, would the Northern Plains sustain commercial production.

²⁹ While oil was known to exist by the 1890's on Salt Creek, the first major production and subsequent development did not begin until 1908.

1900-1930: The Age of Waste and the Beginning of Regulation

The industrial revolution brought with it rotary technology which eased the drilling process by rendering obsolete the costly hammer drill.³⁰ A new source of demand brought drastic changes to the oil industry and the United States. The invention and development of the internal combustion engine increased the need for oil and transformed petroleum into a highly valued commodity, able to affect the welfare of the nation. By 1930, annual production would approach 900 million barrels and represent almost 1.5 percent of U.S. gross national product (Murphy, 1949).

Between 1860 and 1930, major new discoveries were made in Indiana, Ohio, Louisiana, California, Kansas, Oklahoma, and Texas, shifting the focus of oil production from the northeast to the central United States and California. Development of oil fields in these regions continued with great intensity, bringing with it numerous examples of waste (Marcosson, 1924; Stocking, 1925; Lindstedt, 1991; and Yergin, 1991). Of the new finds, two Texas reservoirs discovered at the beginning and end of this period epitomized the rapid development resulting from the predominance of the rule of capture.

Spindletop, Texas is well known for introducing the term "gusher" into the oil production jargon. In 1901 when the drillers first struck oil, so much pressure was immediately released from the reservoir that drilling pipe, rock, mud, gas, and oil were shot one hundred feet into the air. Oil continued to rush forth at the rate of 75,000 barrels

³⁰The rotary drill allowed a bit to spin, much like today's hand drills, as opposed to the hammer drill, which pounded its way to the oil zone. The rotary drill improved drilling efficiency and also improved the process of removing material from the borehole, making oil exploration less costly than with hammer technology.

a day.³¹ Speculators drove the price of land around Spindletop up to as much as \$900,000 an acre. The nearby Texas town of Beaumont grew from 10,000 to 50,000 citizens in a few months, and wells were drilled on leased sights just large enough to fit an oil derrick (Yergin, 1991). By the middle of 1901, over 214 wells were producing at Spindletop; within a year, five hundred derricks covered only 140 acres (Marcosson, 1924.). The price of oil fell from \$1.88 to \$0.03 a barrel, and still wells continued flush production (Carleton, 1998). By the middle of 1902, after only 18 months of production, the natural pressure within the reservoir was exhausted and production came to a halt.

The huge East Texas reservoir tapped in 1930 quickly became the largest producing pool in the United States and exemplified the excesses of unrestricted competitive production and the need for coordinated development of oil reservoirs.³² Libecap and Wiggins (1987) note that within nine months of development, oil produced from this pool alone represented 50 percent of Texas' oil output and 20 percent of U.S. production. Over 3,000 firms, more than all those operating in Oklahoma, rushed to lease land and drill wells on a reservoir estimated at 275,000 producing acres (Carleton, 1998). Wells were flowing flush at maximum rates and drilling of new wells continued at a frenzied pace as producers raced each other to extract oil. By 1938, almost 26,000 wells were producing oil on East Texas. On average, one well was drilled every 5 acres but numerous one acre tracts could be found with 5 to 10 wells in production. Libecap and Wiggins (1984) cite a report indicating that as few as 3,000 wells would have sufficiently

³¹ Drakes well in Titusville produced approximately 50 barrels a day. (Yergin, 1991).

³² Carleton (1998) gives an excellent detailed account of the discovery and oil rush at East Texas.

drained the reservoir. At a cost of \$26,000 a well, excess drilling had cost producers almost \$600 million.³³

To combat the massive waste, efforts were made by state governments and private individuals to reduce losses from competitive production. Beginning in the mid-1900's, private solutions to rule of capture waste that avoided the need for state intervention began to appear. With advances in technology leading to the regular use of magnetic and seismic methods of exploration by 1920 (IOCC, 1964), operators were able to better estimate the location of oil before drilling. Using this technology, a single producer could lease numerous high probability tracts of land before drilling and prevent the losses incurred from rule of capture. An early 1915 case is recorded in Knowles (1985) on the Augusta Field in Kansas where the operator, Cities Services, consolidated numerous leases before drilling its first well. A similar account is cited for the development of the Powell Field in Texas in 1923 (Marcosson, 1925). The operator, Humble Oil, leased thirty percent of the field before any production began, thus, preventing to some extent the chaotic rush to claim leases. Finally, Marcosson provided an early example of voluntary cooperation among landowners dating back to the 1920's. He described the development of a portion of the Breckenridge Field in Texas by operators who pooled their lease interests to drill a common well with the revenues of that production distributed among them. This pooling process prevented the drilling of unnecessary wells and eliminated the waste from over-development.

³³ This cost calculation is based on the lowest reported oil price in 1930 of \$0.18 a barrel.

In 1929 on the Van Field in Texas, the pooling method used on Breckenridge was applied to an entire reservoir. In this first recorded case of reservoir-wide unitization, the Pure Oil Company was able to negotiate a contract with all owners and operators for the cooperative management of the reservoir as a single unit with costs and revenues divided among the participants (Bradley, 1996). As petroleum engineers learned more about reservoir dynamics, they began to understand that unitized operation was an important contractual form allowing significant reduction of waste. While the costs of unitizing could be significant as well, if a unit could be formed, the benefits were clear. By managing the reservoir as a single unit, decisions could be made that maximized the net present value of the reservoir. The three types of over-drilling losses under rule of capture were all reduced with reservoir-wide units. First, oil could be held in the reservoir with no threat of drainage. Second, wells were only placed where they were needed to efficiently drain the reservoir. The number of wells and, therefore, drilling costs were minimized. Third, with wells only placed in ideal locations and production occurring at an optimal rate, pressure could be maintained so as to maximize the amount of oil that could be recovered in primary production.

Unfortunately, voluntary units on large reservoirs with numerous owners involved significant costs to reach contractual agreement, making them difficult to create (Hardwicke, 1961, Libecap and Wiggins, 1984, 1985, Weaver, 1986). Even with the growing understanding of the gains from unitization, operators struggled to reach consensus on plans of reservoir management. Because net unit returns are shared among participating firms, all firms must agree on an allocation schedule of returns before

unitized production can begin. Often the share of returns allocated to firms in unit agreements differed from their expected return. The resulting costly negotiations required to reach agreement on each firm's allocation often prevented unit formation.

Beginning in 1924, with Henry Doherty's appeals to President Calvin Coolidge, campaigns for federal and state compulsory unit laws began. A federal compulsory unit law, as envisioned by Doherty and others, would empower a federal regulating body to force unitization to prevent wasteful rule of capture production. To investigate Doherty's case and other conservation concerns, Coolidge organized the Federal Oil Conservation Board (FOCB). The FOCB conducted extensive research into the nature of oil production and largely sided with Doherty on the benefits to be gained through unitization. The FOCB presented its results to Coolidge, but neither took direct regulatory action. Rather, the findings were made available to state governments along with a federal commitment to support state conservation initiatives. Opposition to the compulsory unit laws proposed by Doherty was widespread (Hardwicke, 1961). Independent producers disliked the idea of more regulation of oil reservoirs, believing that existing regulations already infringed on their right to produce from privately owned tracts.³⁴ With persistent lobbying in state legislatures, they managed to prohibit the introduction of any compulsory unit law until 1940 when Louisiana passed a regulation to coordinate producers and force them to invest in technology to re-inject excess produced gas back into reservoirs.³⁵

³⁴ Independent producers are only associated with the production of oil, in contrast to major producers such as Exxon or Mobil, who produce, refine, and market petroleum products.

³⁵ In 1935, Congress did pass a statute giving the Secretary of the Interior the authority to compel unitized development on reservoirs in the federal domain. (Hardwicke, 1961).

The main vehicle of state control was the enacting of laws and statutes governing operations at the wellhead.³⁶ These laws appeared as early as 1878 when Pennsylvania passed a measure regulating the casing and plugging of wells to prevent the pollution of water and the loss of oil into other subsurface layers (Bradley, 1996). Oil producing states continued to enact legislation to control for poor drilling techniques, waste of gas through flaring, and other wasteful production practices. The first well spacing regulation was introduced by Kansas in 1905 and prevented wells from being drilled within 100 feet of a railroad right-of-way. The Texas Railroad Commission passed the first statewide spacing regulation pertaining to relative well placement in 1919. This rule forbade wells from being drilled within 300 feet of each other and 150 feet of a property line (Bradley, 1996). To aid the enforcement of new rules and regulations, states began creating independent regulatory agencies with the purpose of monitoring statewide oil production. By 1930, governments of all oil producing states were aware of problems associated with rule of capture production and had passed court confirmed conservation statutes.

Northern Plains: The Origins of Commercial Oil Production

The invention of the automobile which powered the demand for mid-continent and West Coast oil also brought the age of commercial production to the Northern Plains. By 1930, Wyoming was the seventh largest producing state in the country with 17.8 million barrels of oil annual production. Montana production grew to almost 3.5 million

³⁶ State and federal courts largely upheld these laws and early on confirmed the state's role in oil conservation. In 1900, the Supreme Court of the United States upheld the right of states to pass and enforce conservation legislation in *Ohio Oil v. Indiana* 177 US 190 (1900).

barrels of oil annually. This output was still minor compared with other states such as, Texas which produced 290 million barrels of oil in 1930 and California with 227 million barrels of oil produced in 1930. With the growth in production came problems of waste, although much less severe than Texas and California. Several reasons can explain why the waste problem was less important on the Northern Plains compared to other regions. First, the local demand for petroleum products was less in the Northern Plains due to its lack of population and distance from major cities. Murphy (1949) states lack of demand was "sufficient in a limited way to effectuate some conservation, for the reason that fields had to be shut-in at frequent intervals because of lack of a market." Second, transportation of oil from remote locations to refining plants often made production uneconomical (Douma, 1953). Oil pipelines were inaccessible to most new reservoirs and rail freight rates were often too expensive for regular use. Finally, land holding sizes in Montana and Wyoming were larger than other oil producing states such as Texas and Oklahoma. For instance in 1930, according to the U.S. Census of agriculture, average farm sizes in Montana and Wyoming were 940 and 1469 acres, respectively. In Texas, average farm size was only 250 acres, and in Oklahoma, average farm size was only 165 acres. As a result, relatively fewer firms could access reservoirs and drill wells in the Northern Plains reducing rule of capture waste.

The concern over losses from rule of capture production, whether from direct experience or from observing developments in Pennsylvania, Texas, and California, led to legislative action in both Montana and Wyoming. By 1911, each state enacted its first conservation law regarding waste and formed an independent oil regulatory agency

comprised of appointed officials to monitor petroleum production. Initial Wyoming laws were upheld in State and U.S. Supreme Courts, while the laws of Montana went unchallenged.³⁷

The oil discoveries that were made in both Montana and Wyoming during this period were some of the most important reservoirs ever to be discovered in either state. Five of Montana's top eleven cumulative producing oil reservoirs were discovered in the early and mid-1900's.³⁸ The discoveries at Cat Creek and Kevin-Sunburst quickly brought attention to Montana oil. In Wyoming, new strikes included Salt Creek and twelve other major fields that would account for 45 percent of all cumulative production in Wyoming as of 1997.³⁹

The most important discovery in this period and maybe in the history of production in the Northern Plains was made at Salt Creek, just west of Casper, Wyoming in 1908. Even though the reservoir underlay 20,000 surface acres, it was one of the first examples of successful coordinated operations in the Northern Plains.⁴⁰ Commercial production began at Salt Creek in 1911. By 1921, the number of producing wells on the

³⁷ *Wall v. Midland Carbon Company*, 254 U.S. 300 (1920) upheld Wyoming's legislative act authorizing the control of waste. *MacDougall v. Board of Land Commissioners*, 48 Wy. 493, 49 Pac. 2nd 663 (1935) confirmed the authority of the Commissioner of Public Lands to enforce conservation legislation.

³⁸ In order of discovery Elk Basin, Cat Creek, Kevin-Sunburst, Pondera, and Cutbank were all discovered between 1915 and 1930.

³⁹ Salt Creek would be the second major discovery in Wyoming and be its largest cumulative producing reservoir with 653 million barrels, representing ten percent of Wyoming total cumulative production. For comparison, the East Texas field has produced over 5 billion barrels of oil since 1930.

⁴⁰ The Salt Creek field would grow to consist of twelve distinct reservoirs by 1930. At the time of the production agreement, however, only three reservoirs, the Upper Shale and the First and Second Wall Creeks, had been discovered. The Wall Creek reservoirs are by far the largest on the field and by 1957 accounted for 85 percent of the cumulative field production.

Salt Creek field had risen to 705 and annual production reached 12.3 million barrels when an initial agreement to prorate production was completed. The reason for the initial agreement appears to be a lack of a market for produced oil. The solution to overproduction was to form a conservation committee, representing all operators, with the authority to restrict drilling and prorate production. From 1921 to the end of 1923, the committee only approved permits needed to satisfy lease obligations. Production allowables were calculated as a percent of the flush potential of each well and varied weekly from 30 to 75 percent (Emery, 1930). By 1924, market conditions improved, allowing proration quotas to be removed and reservoir production returned to 100 percent. When the conservation committee was disbanded, rule of capture again predominated, and the drilling rush began. The number of wells on Salt Creek almost tripled, from 685 to 1600, in only three years, and production at then end of 1924 was over 30 million barrels. Only four years after the abandonment of the production agreement layer, the same reservoirs produced just over 10 million barrels of oil, a 66 percent drop in production accompanied by a 130 percent increase in wells. The development of Salt Creek reveals the gains and losses confronting producers. With constraints on rule of capture production, excessive wells can be prevented and productive life can likely be extended. When those constraints are removed as in this example, the losses from over-drilling become apparent.

The discovery of oil on the Cat Creek field in central Montana provides an interesting example of rapid development and attempts to avoid waste from overproduction. After initial geological exploration in the region showed favorable signs

of oil, the Frantz Oil Corporation leased contiguous tracts over what it thought to be the entire surface acreage of the reservoir before drilling its first well in an attempt to prevent the race for leases (Tonnsen, 1985). In 1920, the discovery well struck oil in the shallow Cat Creek sand at approximately 1000 feet. Despite its attempts to consolidate the productive area under one lease, Frantz underestimated the size of the reservoir. Within a year, over sixty oil rigs were producing on the reservoir. By 1925, 186 wells produced 1.2 million barrels of oil. With a productive surface area of 1400 acres, Cat Creek was drilled at a density of one well every four acres. Production reached an annual maximum in 1921 when 2.1 million barrels of oil were produced. By 1927, annual production declined by 61 percent to 775,000 barrels and continued to fall through the life of the reservoir. The recovery rate of the reservoir supports the case for waste. Cat Creek produces oil naturally through a water drive mechanism where primary recovery from a properly managed reservoir averages 55 percent of the original oil in place. By 1996, Cat Creek's cumulative primary recovery rate was just 25 percent of the original oil in place, well below expected recovery for a properly managed water drive reservoir.⁴¹

Northwest Montana experienced a similar oil rush at the same time with seemingly different results. In 1921, Gordon Campbell discovered the Kevin-Sunburst reservoir near Glacier National Park. This reservoir shifted attention to the northern part of the state for the remainder of the 1920's. Development again was extremely rapid with production from 658 wells peaking at 6.4 million barrels a year by 1926. While the well

⁴¹ Zorichak (1932) lends support to this argument by pointing out that the addition of wells after 1921 did not add to production. He concludes the reservoir could have been sufficiently drained with one well every ten acres, rather than one every four acres.

count increased to 860 in 1927, annual production declined through the decade. An assessment of the Kevin-Sunburst reservoir is more difficult because of the lack of available information on the reservoir, but the indicators of over-drilling present on Cat Creek are not found here. While 860 wells were producing in 1927, the producing surface acreage of Kevin-Sunburst was over 40,000 acres. Well density was one well every forty-five acres.⁴² The huge 1926 surge in production can be attributed to a Canadian request for producers to extract oil at maximum rates to satisfy refinery demand in Alberta (Douma, 1953). Previously, Canadian oil refiners relied completely on Canadian petroleum to supply their plants. In the mid-1920's, Canadian production decreased, allowing Montana oil to find a ready market. With the beginning of the Depression in the early 1930's, Canadian refinery demand decreased, and with it, production from Kevin-Sunburst. The estimated rate of primary recovery was approximately 22 percent, a relatively high expected recovery rate from a dissolved gas drive reservoir. Despite the size and rapid development of this reservoir, Murphy's conclusion (1949) that the lack of stable regional markets may act to reduce waste appears to hold.

1930-Present: Modern Regulation and Production

By 1930, the oil business in the United States had grown from the fifty barrel-a-day discoveries at Titusville to the 800,000 barrel-a-day reservoirs like East Texas. Annual production in the United States (all in Pennsylvania) was 450,000 barrels in 1850,

⁴² The current statewide well-spacing law for this type of reservoir is one well every forty acres. Montana Rule 36.22.702

but in 1930, the United States was producing over 900 million barrels of oil. Rule of capture predominated during the pre-depression era, but as the waste became more problematic, conservation initiatives became more numerous. By 1980, institutional arrangements in the industry would be drastically different, with every major oil producing state having in place a set of legal institutions addressing wellhead production rules, spacing regulations and compulsory unit laws.⁴³

The problems at East Texas, described earlier, climaxed in 1930 when the governor of Texas declared martial law to prevent violence over proration rules and ordered all production halted. Proration rules set field-wide or wellhead quotas on daily production. Known as production allowables, the rules, upheld in state courts, were often used to limit reservoir production (McDonald, 1971). The Texas order again confirmed the state's role in assuming primary responsibility for petroleum conservation in the United States.⁴⁴ States continued to take steps to curb rule of capture waste as they acquired more technical knowledge of reservoirs. Legislatures added new regulations based on engineering principles to limit gas flaring, control the disposal of salt water produced with oil, specify methods for plugging wells, set minimum distances for well placement, and encourage unitization (IOCC, 1964). In 1945, Oklahoma passed the first

⁴³ The exception is Texas, which still has no compulsory unit law. Weaver (1986) provides a complete story of legislation in Texas and the role of independent producers in preventing passage of a compulsory unit law.

⁴⁴ The statutory power of the state to determine reasonable waste confirmed by the Supreme Court in 1931. *Bandini Petroleum Company v. Superior Court* 284 U.S. 8 (1931). *Champlin Refining Co. v. Corporate Commission* 286 U.S. 10 (1932) explicitly confirmed the police power of the state to prevent unnecessary loss of oil.

compulsory unit law pertaining to oil and gas on public and private land. The law required that 85 percent of the owners agree to a plan of development and distribution of costs and revenues for the entire reservoir (Murphy, 1949). After seven years of appeals in the state and federal courts, the law was finally confirmed and declared constitutional in 1952 by the United States Supreme Court.⁴⁵

The federal government assumed a supportive role, helping enforce state rules, providing national production statistics, and subjecting operations on federal land to rules consistent with the rules of the involved states (McDonald, 1971). The federal government was instrumental in conservation through the creation of several agencies, beginning with the Federal Oil Conservation Board (FOCB) founded in 1924. From 1926 to 1932, the FOCB published the first in depth series of reports based on technical research that recognized the losses due to rule of capture and endorsed unit operations as a means to prevent waste. By 1930, with the nation in the midst of a depression, the board shifted focus to stabilizing markets through proration orders to control supply. The agency later evolved into the Interstate Oil Compact Commission (IOCC). The 1935 act of Congress authorizing the IOCC gave the Commission no specific authority to make rules; that power remained with the states. Instead, the main role of the IOCC has been the dissemination of information regarding conservation techniques and the promotion of conservation by providing model form conservation statutes and general rules and regulations to facilitate the conservation efforts of oil producing states. Since the

⁴⁵ *Palmer Oil Corp. v. Amerada Petroleum Corp.*, 343, U.S. 390 (1952).

Depression, the federal government has intervened in the production process only to ensure national security. For instance during World War II, the Petroleum Administration for War regulated supply through proration quotas to maintain a fuel supply for the war effort.

As the oil industry matured after World War II and discoveries of new fields became less frequent, the industry began to turn its attention to improvements in drilling and geophysical technology.⁴⁶ In the post-legislation era, new discoveries occurred primarily in Alaska, on the Outer Continental Shelf of Texas, Louisiana, and California, and in the Williston Basin of Montana and North Dakota. While primary production from these reservoirs was important, production from secondary injection techniques contributed significantly to overall oil output. Statistics presented in the Fifth Biennial Report of the IOCC Subcommittee on Secondary Recovery reveals the significance of enhanced recovery techniques. In 1940, only fifteen percent (210 million barrels) of produced oil was recovered by secondary production. By 1960, thirty percent (almost 800 million barrels) of recovery resulted from enhanced recovery methods.⁴⁷ According to the report, the possibilities for future recovery appear bright as well. In 1962, the estimated original oil in place of all known reservoirs was 346 billion barrels. The rate of recovery for primary reserves on these reservoirs was 28.5 percent, or 99 billion barrels of oil. The

⁴⁶ Halbouty (1970, 1979, and 1989) documents discoveries of giant oil fields worldwide for the American Association of Petroleum Geologists. His studies clearly indicate a declining trend in significant discoveries in the continental U.S.

⁴⁷ Lovejoy and Homan (1967) discuss and dispute the exact statistics reported by the IOCC, but confirm the fact that large amounts of oil are available for enhanced recovery as well as from use of the techniques to improve the process of development on new reservoirs.

rate of recovery rises dramatically to 45 percent when oil recoverable by "all known methods" is included. This additional production represents an additional 56 billion barrels of oil available by enhanced recovery techniques (IOCC, 1964).

Technical advancements continued rapidly through the 1980's and into the 1990's. Improvements in seismic and computer imaging increased the likelihood of locating new reservoirs before drilling.⁴⁸ New enhancement methods involving carbon dioxide injection and chemical scrubbing procedures increased recovery ratios. Operations on oil reservoirs today have changed tremendously in the century of commercial production. From massive rule of capture waste and hammer drilling, the industry now has developed a set of institutions that more clearly define property rights to oil and the technology to drill not only vertically, but also horizontally.

Federal regulations also improved the environment for exploration. Amendments to the Mineral Leasing Act of 1920 led to increased exploration on federal land through the post war era. The formation of Federal Exploratory Units became more common as a result of these changes. These units are formed before any drilling has occurred on the potential reservoir and are often more easily formed because no producer has a strategic information advantage (Libecap and Wiggins, 1985). These units provide the operator with numerous advantages including lease extensions, exceptions to maximum lease-holdings on federal land, and an orderly transition from primary to secondary production. Because operations are on a reservoir-wide basis from the outset, rule of capture waste is

⁴⁸ Anderson (1996) discusses the uses and legal implications of the newest 3D seismic techniques for production and exploration.

entirely eliminated over the life of the reservoir. By 1979, twenty percent of all federal units were exploratory in nature (Laughlin, 1983).

Northern Plains: The Development of Regulations
and Discovery of the Williston Basin

With the end of federal control of oil production in the late 1940's, Montana and Wyoming resumed regulatory authority of oil production. The depression and war experience showed operators that regulations not only helped stabilize markets in difficult times but also led to better oil reservoir management and increased profit. Much of the opposition to legislation diminished, and by the mid-1950's, Montana, North Dakota, and Wyoming added to existing conservation law. In North Dakota, commercial production did not begin until 1951, but by 1941, a complete set of conservation provisions was established including the creation of the North Dakota Industrial Commission to regulate the industry. The commission created a comprehensive set of conservation rules and regulations based on provisions of other oil producing states that allowed the orderly development of the Williston Basin.

Legislative activity continued in the Northern Plains with the addition of statewide spacing statutes in 1951 for Wyoming, and 1953 for Montana and North Dakota. The Wyoming law is the least restrictive, stipulating only 40 acres between wells. Montana and North Dakota have regulations which vary spacing according to depth, so that in Montana spacing is 40 acres for wells less than 6000 feet, 160 acres for wells between 6000 and 11,000 feet, and 320 acres for wells over 11,000 feet deep. In

North Dakota, a similar depth/spacing rule prevails.⁴⁹ All states give regulatory agencies the explicit or implicit authority to grant exceptions to spacing rules to prevent waste or to protect correlative rights, the rights of landowners to have a fair chance to produce oil from beneath their tracts.⁵⁰

The adoption and implementation of compulsory unit laws in the Northern Plains has been a fairly recent occurrence. With the rise in wellhead conservation (regulation of gas-oil ratios, gas flaring, water disposal), use of daily allowables, and well-spacing, many thought unitization laws were unnecessary (e.g., Hardwicke, 1961). In the Northern Plains, North Dakota was the first state to adopt such a regulation in 1965; Montana followed in 1969. Wyoming remained one of the three major oil producing states, along with New Mexico and Texas, without compulsory unit laws until the state legislature approved a law in 1971.

With the passage of compulsory unit laws in the Northern Plains, the legal and statutory institutions in Montana, North Dakota, and Wyoming were essentially complete. Table 2 summarizes some of the important dates and details of state conservation regulations. Refinements continued as courts further defined correlative rights and supported the authority of regulatory agencies to shut in production to prevent waste and

⁴⁹ The concept of varying spacing by depth derives from the ability of deeper wells to drain larger areas as well as from present value calculations of an oil value that includes the increasing cost of drilling deeper wells. See McDonald, 1971.

⁵⁰ See Wilson, 1990 for an elaboration of state authority over oil conservation. Montana does not specifically identify the protection of correlative rights in its rules, but the Montana Supreme Court has expressly upheld the right of the Oil and Gas Conservation Commission to do so (*Pattie v. Oil and Gas Conservation Commission of Montana* 145 Mont. St. 531, 435 P2d 596(1965)).

induce unitization.⁵¹ The conservation institutions of each state, while similar, are not identical. Differences can be seen in the details of regulatory laws and definitions of waste adopted by each state.

For instance, compulsory unitization laws differ across states. In Wyoming and Montana, 80 percent of the cost bearing interest and 80 percent of the cost-free royalty and overriding royalty interests must ratify a plan of unitization before it can be approved by the state regulatory agency.⁵² In North Dakota, approval by only 70 percent of cost bearing and cost free interest is required, but overriding royalty interests are not included in the ratification process. The division of consent into cost and cost free interests recognizes two different types of ownership on each tract. The royalty owner is considered to have a cost free interest because his percentage interest is based on gross production. The working interest is the leasing firm that actually produces oil from the tract. The working interest share is based on profit or the value of production minus the costs of production. In order to successfully form a unit the state stipulated percentage of each of these interests must agree to unitize.

⁵¹ *Pattie v. Oil and Gas Conservation Commission of Montana* 145 Mont. St. 531, 435 P2d 596(1965) defines correlative rights. *Working Interest Owners of Buck Draw v. Wyoming Oil and Gas Conservation Commission* 85-287 Wy S. Ct. 721 P.2d 1070 (1986) and *Gilmore v. Wyoming Oil and Gas Conservation Commission* 5552 Wy S Ct 642 P2d 773 (1982) authorizes shut-in of all production until ratification of a plan of unitization by working and royalty interest owners.

⁵² An overriding royalty interest is a fractional interest in gross oil production that is free of costs of production. The share is an interest carved out of the working firm's interest and is paid by the working firm in addition to usual royalty payments to the lessor of the tract (Williams and Meyers, 1976).

Table 2. Summary of Conservation Regulations

	Date of First Conservation Statute	Date of First Well Spacing Law	Date of First Compulsory Unit Law	Percent Interest Consent for Compulsory Unit		State Agency and Board Selection
				Royalty	Working	
Montana	1917	1953	1969	80	80	Montana Board of Oil and Gas Conservation, 7 Governor appointed members, approved by State Senate
North Dakota	1911	1953	1971	70	70	North Dakota Industrial Commission, 3 elected members, Governor, Attorney General, Commissioner of Agriculture
Wyoming	1901	1951	1965	80	80	Wyoming Oil and Gas Conservation Commission, 5 members: Governor, State Geologist, State Lands and Investment Officer, 2 additional governor appointed members.

* Includes over-riding royalty interests

Sources: Year of First Conservation Statute, Murphy, 1949
Remaining Data, Stat Statutory Code

Williston Basin. The most significant event of the post War era in the Northern Plains was the 1951 discovery of the Williston Basin on the Montana / North Dakota border. The Basin brought North Dakota to prominence in the oil industry and tripled Montana's oil output in the first decade of production. If the development of Salt Creek characterized Northern Plains' production in the first half of the twentieth century, the development of the Williston Basin, beginning in 1951, became the center of attention for the remainder of the century. The Basin has produced 1.3 billion barrels of oil in North Dakota and over 600 million barrels in Montana. In 1981, production from Williston Basin represented about 2 percent of all oil produced in the United States (Hough, 1982). North Dakota rose from being a non-oil producing state in 1950, to one of the top fifteen producers in the United States in less than ten years. While the Basin has been a boon to the Northern Plains oil industry, it is relatively small when compared to Prudhoe Bay in Alaska, the Permian Basin reservoirs of west Texas, and the offshore production in California, all of which exceed 3 billion barrels of cumulative production.

The Williston Basin covers 65,000 square miles in Montana, North Dakota, Canada, and a small portion of South Dakota and includes over 400 different producing reservoirs (Hough, 1982). Oil in the basin produces primarily from two stratigraphic systems: the Mississippian/Devonian layer and the Silurian/Ordovician group. The Mississippian/Devonian layer includes the Madison, Duperow, and Winnepogosis formations. These formations produce at an average depth of 10,000 feet primarily through a water drive and secondarily by dissolved gas drive. Reservoirs in the formation include some of the largest in North Dakota and Montana including Little Knife, Tioga,

Beaver Lodge, and East Poplar. The Silurian/ Ordovician group lies below the Mississippian/ Devonian system by 1000 to 2000 thousand feet and includes primarily the Red River and Interlake formations. Primary production in these formations occurs by both gas cap and dissolved gas drives. Significant reservoirs in these formations include the Pennel and Pine reservoirs in Montana and the first Williston Basin discoveries on Montana's Cedar Creek Anticline.

Development of the Basin appears to have taken place without large rule of capture losses. In the first fifteen years of development, production in the Basin grew gradually to approximately 50 millions barrels of oil annually.⁵³ In North Dakota, seven to eight new reservoirs were added each year. In Montana, development was slower with only 33 producing reservoirs by 1965. This number increased dramatically in the next thirty years. By 1996, 176 of Montana's 238 producing reservoirs were located in the Williston Basin. North Dakota saw a similar rise in exploration beginning in the late 1970's as the OPEC oil embargo and Iran / Iraq war raised oil prices to over \$50.00 a barrel in 1996 dollars. From 1977 to 1984, 447 reservoirs were discovered, increasing North Dakota production to 52 million barrels of oil in 1984. The fall in the price of oil from 1985 through the mid-1990's accompanied a fall in Williston Basin exploration, discovery, and output (Heck, 1996). In 1995, total production from Williston Basin was only 40 million barrels, down almost 50 percent from the record year in 1984. The past two years have seen improving conditions in North Dakota, while Montana production

⁵³ North Dakota produced 27 million barrels in 1965 and has historically produced more from the Williston Basin than has Montana. This production trend is attributed to a larger percentage of the reservoir being located in North Dakota.

remains stagnant. This increase in North Dakota output is largely due to the discoveries of the Eland and Stadium reservoirs near Dickinson, North Dakota.

An important consideration in the early development of the Williston Basin is the pattern of leasing as early Williston reservoirs were discovered. One method of avoiding rule of capture waste involves reducing the number of operators on the reservoir by consolidating leases in the exploratory phase.⁵⁴ Interviews conducted in the spring of 1999 with Jack Wilborn, assistant director of the North Dakota Industrial Commission, indicate that this process occurred to a substantial degree in the basin. A clear example of pre-production consolidation occurred when the firm, Amerada Hess, began leasing large portions of western North Dakota and eastern Montana in the late 1940's. Leasing began based on new seismic technology introduced by Amerada Hess that indicated the presence of large reservoirs of oil. According to Wilborn, when Clarence Iverson discovered oil in the Basin, Amerada Hess had leased close to half of the producing acreage in western North Dakota by 1951. This claim is difficult to verify due to the lack of lease records at Amerada Hess and the subsequent sale of properties by Hess. Support is offered through summary statistics from the North Dakota data sample and an interview with Amerada Hess representative Randy Pharr.⁵⁵ Of the twenty-nine unitized reservoirs in the sample, twelve were operated by Amerada Hess with an average of 84

⁵⁴ Several noteworthy failures of the unitization process in North Dakota will be discussed in the empirical section of the thesis.

⁵⁵ Randy Pharr provided all information regarding the history of Amerada Hess and acreage leasing in a telephone interview in January, 2000. As landman for Amerada Hess in North Dakota, Pharr manages all properties leased by the firm in the Williston Basin.

percent working interest. On four other units, Hess was one of the top three working interest owners with an average 20 percent working interest. Pharr suggested that this working interest ownership may have represented up to 200,000 acres and 50 percent of the producing acreage in the Williston Basin in the late 1950's before the company began selling properties.⁵⁶ These figures only provide data on unitized reservoirs in the sample and may not be accurate when applied statewide to all reservoirs, but they do give some idea of the role of a single operator in the Basin and the potential impact of that operator on overall development.

The regulated development of the Williston Basin has not been without problems.⁵⁷ The Littleknife reservoir discovered in 1977 in western North Dakota failed to reach a unit agreement despite obvious indications of severe reservoir damage resulting from over-drilling. In 1982 with decreasing reservoir pressures, the North Dakota Industrial Commission refused to shut-in production to prevent further damage even though that action had been condoned by the judicial branches of other states including Wyoming. Gulf Oil, the operator attempting to unitize the reservoir, failed to get the needed super-majority of votes due to a technical mistake in the unit contract. Despite the estimated 40 percent increase in recovery from unit operations, unit proceedings ended unsuccessfully. In 1983, Gulf sold its 65 percent interest to Chevron. Soon after, boundary wells became unproductive and were shut-in, leaving only the core wells

⁵⁶ Currently, Hess leases 88,000 acres and is the third largest producer in the state.

⁵⁷ Other examples will be discussed in the empirical section of the thesis.

producing. New reservoir simulation models run in 1997 indicated that water injection might have added another 50 percent to ultimate recovery.

CHAPTER 4

THE ECONOMICS OF OIL RESERVOIR CONTRACTING

Previous economic models of reservoir production under the rule of capture have considered the static (Libecap and Wiggins, 1984 and 1985; Wiggins and Libecap, 1985) and dynamic (Lueck and Schenewerk, 1996) effects of the absence of regulations on firm behavior. These studies have primarily modeled the firm's decision as a choice of how much oil to produce. Using a static analysis, the models in this thesis develop the economics of rule of capture and unitization by modeling the firm's choice of how many wells to drill. As chapters 2 and 3 indicated, the economic waste associated with over-drilling is directly related to the rule of capture. The well choice models reveal the importance of property rights to the method of production and the impact of contracting costs on the formation of unit agreements.

The chapter begins with a brief discussion of developments in the economics of property rights and transaction costs. These concepts provide the theoretical basis for the subsequent analysis of firm production decisions. Next, one period profit maximization models under four different reservoir property rights regimes are developed to show the implications on the firm's well choice decision. First, a single owner model is developed, generating the gains from first-best, efficient production, assuming zero transaction costs and free information. Next, the rule of capture is introduced and dissipation of rents under

conditions of firm homogeneity and heterogeneity are examined. The final models consider contracting to reduce losses from rule of capture. Contracting on oil reservoirs can occur privately when consensual agreement among all negotiating parties is achieved or through a state regulated compulsory unitization process where only a super-majority of negotiators agrees to a unit contract. When a super-majority agrees, the non-consentors are then compelled to join by the state oil conservation agency. These models alter the firm's choice from wells to share of unit revenues and include a contracting cost function. The decision of the firm to place its tract in a unit can then be analyzed.

Property Rights and the Transaction Costs Approach To Oil Unitization Agreements

Examining reservoir production under various ownership regimes utilizes the economics of property rights and transaction costs. The models used in this study rely on Coase (1960), who showed how decisions are determined by the specific property rights that govern resource use. Firms may attempt to modify property rights through legal or contractual methods if they expect to gain from the change. As Coase (1960) and Demsetz (1964) pointed out, these changes are not free because firms must spend time and effort to negotiate and enforce these modifications. While the alternative institutions may provide a comparative productive advantage, the transaction costs of making the alteration may be prohibitive. In other words, when the costs of reaching an agreement are included in the cost/benefit analysis of the two property rights regimes, the net gain may become negligible. The economic analysis of oil production in the property rights

and transaction cost framework is useful because changes in ownership institutions clearly have benefits, but are subject to costly contracting. For example, the costs imposed by rule of capture production on an open access reservoir can be reduced or eliminated by unit agreements that remove the rule of capture from the production process. Yet the costs of completing these agreements can prevent their adoption.

The economic modeling of oil production as a contracting problem began with Libecap and Wiggins (1984), but the original studies of open access examined fisheries.⁵⁸ Gordon (1954) developed a model to graphically analyze overuse as measured by fishing effort on an open access or non-exclusive fishery. Gordon asserted that fishermen will choose a level of fishing effort such that average product and average cost are equal and fishery rents are dissipated. Cheung (1970) extended Gordon's model and derived the equilibrium amount of fishing effort expended under open access. In an open access fishery, waste comes from over-investment in fishing effort (labor) and fishing equipment (capital) as well as potential loss of future catches. Over-fishing is the result of competition among numerous fishermen with equal access to the fishing ground. Each new fisherman (or additional unit of fishing effort) entering the grounds decreases the average and marginal productivity of all other fishermen (or units of effort). Because no single fisherman has an exclusive right to fish a portion of the fishery, entry continues until all rents are dissipated. The result is an equilibrium in which the average product and the average cost of fishing effort are equated. The outcome also suggests that rents

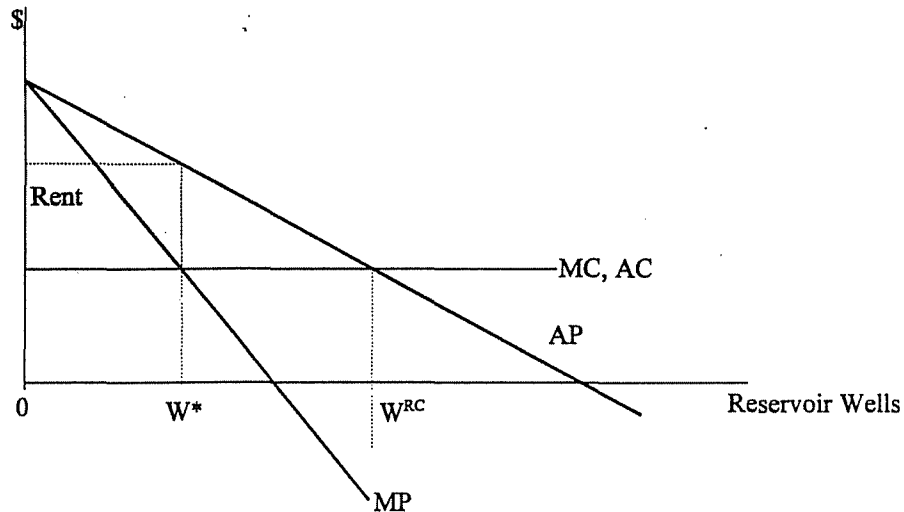
⁵⁸ McDonald (1971) and Homan and Lovejoy (1985) provide early economic analysis of oil production under rule of capture, but studies of oil reservoir contracting began with Libecap and Wiggins (1984).

are dissipated when the fishery is a non-exclusive resource as opposed to when it is privately owned. Because rent is dissipated under open access, fishermen have an incentive to restrict entry. By enacting regulations requiring licenses to fish or enforcing a type of exclusive common property through unions or private contracts, fishermen can capture rent from the fishery.

In some cases, production of oil closely resembles the fishery case examined by Gordon and Cheung. While the specific legal institutions and physical attributes differ, the economic problem of overuse of a common resource is similar. In the fishery numerous fisherman have unlimited access to a non-exclusive resource. Similarly, when numerous tracts of land overlie an oil reservoir, many individuals have access to the supply of oil by leasing mineral rights to these tracts. Figure 1 uses the Gordon-Cheung analysis to show the overuse of an oil reservoir.⁵⁹ In the figure, the horizontal axis represents the number of wells (w) on a reservoir. The productive input on oil reservoirs, number of wells, is analogous to fishing effort, the input factor on ocean fisheries described by Gordon and Cheung. Optimum production under private or sole ownership occurs at w^* , and dissipation under rule of capture occurs at w^{RC} . Inframarginal losses in the oil case result from excess wells drilled on the reservoir, $w > w^*$ in figure 1, which decreases the average and marginal productivity of all existing wells and leads to complete rent dissipation at w^{RC} . At w^{RC} , equality of the average product of wells and the average cost of wells implies all rent has been dissipated.

⁵⁹ Specific assumptions for oil production and cost functions will be discussed in the model development.

Figure 2. Reservoir Rent Dissipation Under the Rule of Capture



The Gordon - Cheung model is useful to gain a perspective on overuse for an entire oil reservoir, but they are limited in application to the oil problem. Its usefulness is limited because it does not explicitly account for effects of reduction in stock size on production decisions. Libecap and Wiggins (1984) first examined this problem with study of the impact of the number and heterogeneity of parties on contracting success. Using a one-period profit maximization model, Libecap and Wiggins derive implications on the effects of firm size and numbers on the likelihood of successful unit contracting. By constructing a model of firm production choice, not well-choice, that includes costs of both firm output and output of all other firms, Libecap and Wiggins model the inframarginal cost effects to the firm of added oil production by other firms. In their analysis, Libecap and Wiggins show that since firms do not face the full costs of extraction, production can exceed the profit maximizing level. When individual firm

dissipation is aggregated across the reservoir, the result is the significant dissipation of reservoir rents.

Wiggins and Libecap (1985) focus on the importance of information differences in the success of unit contracting. These asymmetries appear as differences in estimates of lease values by the firms on the reservoir. Wiggins and Libecap assume that each firm has better information about its own leases than other firms on the reservoir and that there is no universally accepted method of transforming raw data on reservoir qualities into value estimates. The result is firms rarely agreed on the value of leases on the reservoir and strategic bargaining ensues with incentives for firms to withhold leases for a greater share of unit revenues.⁶⁰ Using a two-period value maximization model, Libecap and Wiggins separate profit from a productive lease into pre and post-unit streams. Then they derive conditions whereby the firm elects to place its lease into a unit only if the unitized stream of revenues is greater than the stream of revenue under rule of capture. The model derivation implies that increasing bargaining costs and differences in expectations of lease values limit unit success. Libecap and Wiggins (1985) expands the empirical study to include reservoirs in Wyoming, Oklahoma, and Texas by examining the effects of regulatory regimes among the three states. This empirical paper referenced the theoretical work from Libecap and Wiggins (1984) and Wiggins and Libecap (1985) to test the effects of different state and federal regulations on private contracting by measuring the percent of state production from unitized reservoirs. An important conclusion of the paper

⁶⁰ See Smith (1987) for a thorough discussion of the bargaining strategies under rule of capture production.

is that firms are likely to hold out of unit negotiations are also likely to resist government regulations promoting unit agreements.

Economic Models of Firm Well Choice

The following models examine the costs and benefits of forming reservoir-wide unit agreements. The models I develop allow analysis of the effects of regulations and reservoir qualities on unitization as well as the study of the important heterogeneity and information asymmetry problems discussed by Libecap and Wiggins. The use of a static model allows for a cross-sectional analysis of numerous reservoirs and leads to predictions of firm well choice for a single period. The model examines the drainage problem, but does not address the dynamics of reservoir depletion.⁶¹ While dynamic modeling provides a more extensive set of predictions and allows the use of time series data, the static model of firm well choice is sufficient to examine the determinants of reservoir-wide unitization.

First Best: Production under Sole Ownership

The first case to be considered is the well choice decision when one firm controls all access to the reservoir and by assumption, can costlessly exclude new entrants. Sole ownership occurs through pre-drilling lease consolidation or complete ownership of

⁶¹ Dynamic models of reservoir production are useful because they capture the inter-temporal effects of overproduction in the current period. Oil reservoir production like the harvesting of many natural resources, including forests and wild game, is an inter-temporal problem and depends on economic variables as well as physical reservoir properties. These models lead to predictions regarding rates of extraction, depletion paths, and total oil recovery under unitization and rule of capture which cannot be studied with a static model. See Lueck and Schenewerk (1996).

surface acreage (and associated mineral rights) overlying the productive area of the reservoir. For all models, "a" represents the number of acres controlled by the firm and "A" is the total acreage overlying the reservoir. For simplicity, reservoir size will be normalized to $A = 1$. In the sole owner case, $a = A$ since one firm has exclusive access to all reservoir acreage.

The production function used in this model is the same for all models and takes the form $q = q(w, S)$, where q is the amount of oil extracted, w is the number of wells, each with constant output, and S is the stock of petroleum available for extraction from the entire reservoir. The stock of petroleum available for extraction is constrained by the amount of stock initially available and the amount of stock lost from additional wells drilled on the reservoir. In this case, $S = S_0 - L(w)$ where, S_0 is the initial stock and $L(w)$ is the stock lost from the additional wells. The loss or damage effect, $L(w)$, captures the added cost of extraction by modeling the effects of over-drilling and damage to the reservoir's natural drive mechanism. As discussed in Chapter 2, given a particular set of reservoir conditions, an optimal range of extraction rates can be determined to maximize ultimate recovery. When the number of wells increases so that production exceeds the range of MER's, then the stock of oil available for production is reduced by the amount extracted and by the amount permanently lost due to over-drilling. The loss effect, $L(w)$, captures both these decreases in potentially extractable petroleum. Based on the engineering principles of MER's, it is clear that $L_w > 0$ for $w > w^*$.⁶²

⁶² With regard to underground minerals, this effect is specific to oil and gas, where additional wells can reduce future productivity by more than the amount extracted. For instance, increasing the use of factor inputs in the mining of coal or gold does not affect the amount of stock available for future production

I assume that production is characterized by diminishing returns so that and $q_{ww} < 0$.⁶³ I also assume that $q_s > 0$ and $q_{ss} \leq 0$. I make no assumption about the cross effect of changes in the number of wells and changes in stock size on the quantity of oil produced. For example, while increases in the number of wells and increases in stock size lead to higher productivity, the relationship between increasing well numbers and decreasing stock size is unclear. Therefore, q_{ws} is ambiguous. Marginal costs remain constant because additional wells are not incrementally costly. Thus, where total costs of production are cw , $c_w = 0$.⁶⁴

Accordingly, the firm's problem is to maximize the value of the reservoir by choosing the number of wells to drill per acre according to the objective function:

$$1. \quad \max_w V = [p q(w, S) - cw]$$

$$\text{subject to } S = S_0 - L(w)$$

where p is the competitive price of oil. Substituting the constraint into the objective function gives:

$$2. \quad \max_w V = [p q(w, S_0 - L(w)) - cw]$$

except to reduce the stock by exactly the amount of ore extracted. Where w now the factor input analogous to wells, such as mining effort, $L_w = 0$.

⁶³ Clark (1960) provides support for a production curve that is increasing in the number of wells but at a decreasing rate because of changes in physical reservoir characteristics caused by each additional well. The characteristic shape of this curve is well known to and accepted by petroleum engineers

⁶⁴ This is a rather simplified assumption that necessitates certain reservoir conditions including uniform depth to the oil zone and that wells are drilled just to extract oil in primary production, not inject fluids in for enhanced recovery.

The optimal number of wells to drill per acre, w^* (p, S_0, c) can be found by solving the first order condition:

$$3. \quad pq_w = c + p[q_L L_w]$$

The term on the left side of the equation is the value of the marginal product of a well. Together, the two terms on the right hand side represent the full marginal cost of a well where the first term is the marginal cost of drilling a well and the second term represents marginal value of the oil lost to over-production. The latter term is the price of oil times is the change in the amount of oil produced for a change in the loss effect times the change in the loss effect for a change in the number of wells drilled. In other words, as the additional wells are drilled, losses in productivity accumulate from both the stock extracted and stock lost due to damage to the reservoir. Because the sole owner controls all access to the reservoir and thus all production, he faces the full marginal cost of extraction, including the explicit cost of drilling an additional well and the implicit cost of the loss effect. The optimum indicates that the sole producer solves the well choice problem by valuing both the implicit and explicit costs of extraction.

The value the reservoir under sole ownership where $a = A = 1$ is:

$$4. \quad V^* = pq(w^*, S_0 - L(w^*)) - cw^*$$

Under the assumptions of full information and zero enforcement costs, the well choice solution w^* is first-best, and reservoir value is maximized. Any other well choice results in a sub-optimal solution where reservoir value is not maximized. Thus alterations in reservoir and institutional conditions that generate the first-best outcome can lead to net benefits if the costs of the change are less than the benefits.

Rule of Capture

When numerous firms have access to the oil through leasing of lands overlying the reservoir, the rule of capture provides an incentive for drilling more wells than the optimum under sole ownership. With numerous firms controlling identical acreage, $A = \sum_{i=1}^n a_i = na_i$. Also since $a_i = a_j$ for $i \neq j$ and $i = 1, \dots, n$, $a_i = \frac{A}{n}$, where n is the total number of firms on the reservoir. For the initial case, I assume homogeneity of reservoir properties and firms: values of all surface tracts are exactly the same, and firms are of identical size, each with control of A/n acres. Any firm with access to the reservoir must solve the following maximization problem:

$$5. \quad \max_{w_i} V_i = a_i [p q(w_i, S) - cw_i]$$

$$\text{subject to } S = S_0 - \sum_{i=1}^n a_i L(w_i)$$

The constraint indicates that the loss effect is the result of all wells drilled on the reservoir, not just the wells drilled by the i^{th} firm. The firm's well choice decision must satisfy:

$$6. \quad pq_{w_i} = c + pa_i[q_L L_w],$$

where the left hand side is the value of the marginal product of an additional well and the right hand side is the full extraction cost of an additional well.

For each individual firm, the value of its access to the reservoir, given the equilibrium well choice $w_i^{RC}(a_i p, S_0, c)$, is:

$$7. \quad V_i^{RC} = a_i \left[pq[w_i^{RC}, S_0] - \sum_{i=1}^n a_i R(w) \right] - cw_i^{RC}$$

Compared to the first-best case, the firm only faces a portion, a_i , of the total loss effect from the drilling of wells. The important feature of this result is that since $a_i < A$, only a share of the costs of the loss effect are internalized. As the number of other firms with access to the reservoir approaches infinity, the firm's share of the loss effect gets infinitely small:

$$8. \quad \lim_{n \rightarrow \infty} a_i [q_L L_w] = 0, \text{ and}$$

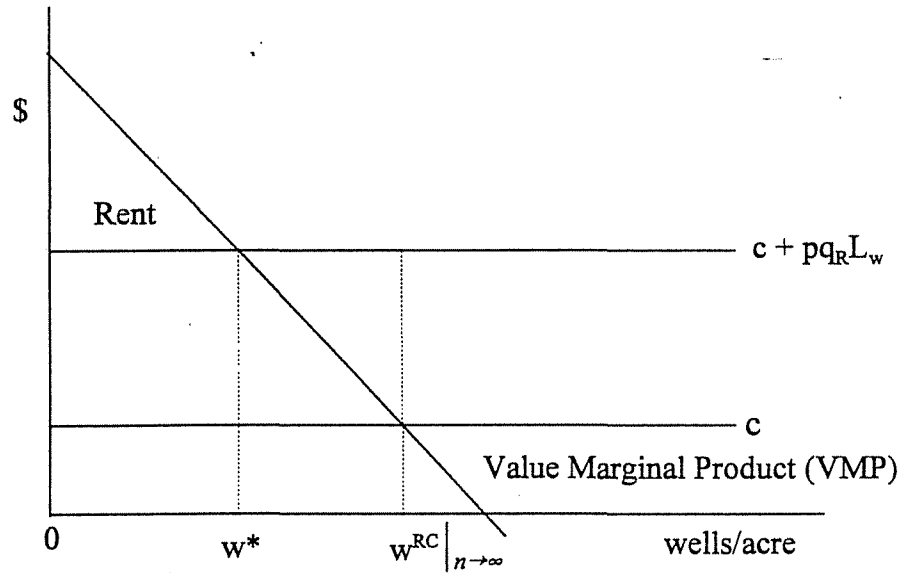
$$9. \quad pq_{w_i} = c$$

According to the homogeneity assumption, the number of wells drilled by each firm and the profit from that production is the same. The value of the reservoir like the sole owner model is the sum of the returns from current production and the value of remaining reserves.

$$10. \quad V^{RC} = \sum_{i=1}^n a_i \left[pq[w_i^{RC}, S_0] - \sum_{i=1}^n a_i R(w) \right] - cw_i^{RC}$$

Figure 3 shows the well choice decisions for the firm under the regime of sole ownership and rule of capture production.

Figure 3. Well Choice: First Best Versus Rule of Capture



In this figure, the value of marginal product curve is depicted in a linear form. The curve is drawn this way to simplify the graphical analysis of rent and dead weight losses. However, the assumption of linearity may be relaxed without fundamentally changing the well choice analysis. The well choice for the sole owner, w^* , suggests that all costs are included in the well choice decision of the firm and the value of the reservoir is maximized. Under the rule of capture as the number of firms approaches infinity, each firm faces a smaller portion of the loss effect until all of the costs are external to the firms decision, and the number of wells drilled occurs at w^{RC} , where $VMP = c$. This result is evident from equations (14) and (15) where as landholding size, a_i , decreases, an increasing portion of the loss effect cost becomes external to the firm, and it has an incentive to drill more wells than w^* . Each well drilled in addition to w^* imposes dead

weight losses because for $w > w^*$, the value of the marginal product is less than the full extraction cost. At w^{RC} , all rents have been dissipated, as indicated in figure 3 where the area of the rent triangle is the same as the area of the shaded triangle.⁶⁵

If the assumption of homogeneity of firms is relaxed, then firms control different amounts of surface acreage, and the value, productivity, and the number of wells drilled on each of each landholding is not the same. Heterogeneity on oil reservoirs is a result of the unequal distribution of surface holdings among individuals as well as variable physical qualities across the reservoir that result in advantages for some firms. In a simple case, a firm whose surface acreage is flat and open may have a cost advantage (in drilling) over a firm whose acreage is steep and forested. With regard to subsurface conditions, one firm may have relatively low cost drilling through layers of clay and sand, while a second firm may encounter a more costly stratigraphy, including rock layers. As a result, heterogeneous firms and reservoir conditions lead to different drilling incentives. For example, Libecap and Wiggins (1984) discuss the propensity of small firms (firms with access to only a small portion of a reservoir) to over-drill since they rely more heavily on drainage. This is consistent with the preceding model of rule of capture since smaller firms face smaller portion of the full opportunity cost of extracted oil.

Finally, the analysis of sole ownership and the rule of capture allows an important conclusion. The two models have been used to show that on a non-exclusive oil reservoir $w_i < w_i^{RC}$. Because production at w^* is optimal and additional wells dissipate reservoir

⁶⁵ In reality, however, the number of firms drilling on a reservoir is not infinite so that dead weight losses are not complete, allowing firms to capture some rent.

rents, the value of the reservoir calculated using w^* is maximized and must be greater than the value under rule of capture when the number of firms on the reservoir is greater than one. Thus, where V^P is the net benefit under private or sole ownership:

$$11. \quad V^P(a_i, p, S_0, c) = V^*(p, S_0, c) - V^{RC}(a_i, p, S_0, c) > 0.$$

The inequality relationship above intuitively suggests productive institutions that lead to optimal well choice, including sole ownership, private contracting, and compulsory unitization, are more likely to form when the net benefits, V^P , of the well choice, w^* , increase. Parameters that increase the difference between V^* and V^{RC} increase V^P and the benefits of unitized production.

For example, changes in a_i imply changes in V^P , the net benefits of optimal well choice. As the size of surface acreage controlled by each firm, a_i , decreases, each firm faces less of the loss effect, $L(w)$, and overdrills its landholding. Because each firm does not face the full cost of drilling, the rule of capture leads to decreasing the returns to production and reduced reservoir value. In this case, for decreasing a_i , V^{RC} decreases causing, V^P to increase. As a firm's share of reservoir access increases, the loss effect becomes more internal to that firm and it has an incentive to stop drilling before w^{RC} , thereby capturing some rent from production and increasing the value of the reservoir.⁶⁶ Thus for increasing a_i , V^{RC} increases causing, V^P to decrease.

Similar cases can be made for p , S_0 , c . For increases in p and S_0 , the value marginal product also increases (VMP in Figure 3 shifts out). Under the rule of capture,

⁶⁶ As firm shares increase in this example, it is assumed that the number of firms must decrease, since total acreage is fixed.

increases in these parameters lead to increases in the equilibrium number of wells drilled on the reservoir. Any additional rents are also dissipated because the equilibrium well choice still occurs where average product equals average cost. Under private ownership, the number of wells also increases, but well choice remains at the marginal optimum so that firms capture additional rents. Likewise, as c decreases (both cost lines in Figure 3 shift down), more wells are drilled under both rule of capture and private ownership.

Again, the rule of capture equilibrium occurs where average product equals average cost so that rents are dissipated. The private owner optimum, on the other hand, occurs where marginal product equals marginal cost allowing additional rents to be captured. In all three cases, parameter changes increase V^* by more than V^{RC} so that the net value of the reservoir under private ownership, V^P , increases⁶⁷.

Contracting Models of Production

Unitization is a contractual method of reducing or eliminating waste from rule of capture production by establishing property rights to an underground reservoir. Unit agreements stipulate that firms share net benefits of reservoir production and empower a single operator to make well choice decisions for the entire reservoir. The unit contract alters the original property rights by excluding all firms, except the operator, from well-

⁶⁷ The previous discussion assumes that the number of firms producing on the reservoir approaches infinity so that rule of capture production occurs where average product equals average cost and rents are dissipated. While this assumption is unrealistic, the predictive result is likely the same with a finite number of firms. While rents are not completely dissipated under rule of capture with finite firms, they are likely less than rents under optimal production. Parameter changes that result in increased reservoir value under rule of capture do not increase the reservoir value by as great an amount as under first-best because at least some of these rents are dissipated by over-drilling. As a result even with finite firms, V^P still increases for changes in p , S_0 , c .

choice decisions.⁶⁸ As a result, unitization completely internalizes the costs of drilling because the operator, acting alone, has an incentive to maximize reservoir value, not individual well rents, in order to claim a larger amount of net returns. The model begins with the case of private, or voluntary, contracting under the assumptions of homogenous reservoir properties and equal acreage landholdings by all firms. The Operator well choice mimics the sole owner case and maximizes reservoir value. The optimal allocation of unit returns also makes all firms better off than under rule of capture. Next, the model examines the implications of differences in firm access, reservoir properties, and the addition of negotiating costs. Finally, a model of compulsory unit regulations introduces the role of state agencies in the contracting process.

Private Contracting with Zero and Positive Transaction Costs. The contracting model depicts the firm's problem in a two-stage process. The first stage models the objective function of the unit operator, which is solved for the optimal number of wells to drill on the reservoir. In the second stage, the group of firms in the unit uses the maximized reservoir value to derive an optimal set of shares of unit returns to allocate to the firms.

The main problem for each firm is negotiating with all other producers on the reservoir to select a set of optimal production shares for all firms that maximizes the total

⁶⁸ For the purposes of this study, the operator is considered to be a single firm. Often on unitized reservoirs, a committee of firms with ownership interest oversees unit operators. These firms act together to monitor the well choice decision of the operating firm.

value of the reservoir.⁶⁹ Each firm negotiates its share, k_i , of the net returns, such that $0 < k_i < 1$ for all $i = 0, 1, \dots, n$ and $\sum_{i=1}^n k_i = 1$.⁷⁰ Because each share k_i is a fraction of the total reservoir returns, all k_i 's must sum to one. The group of firms chooses shares subject to the operator's well choice decision. In all cases, successful contracting requires that the net return to the unit be positive, and all firms must be better off joining the unit than continuing rule of capture production.

The unit operator performs two unique roles in the unit process. First, the operator organizes the unit by gathering the producing firms, determining unit boundaries and facilitating unit negotiations.⁷¹ During this stage of the unit contracting process, firms negotiate the allocation of shares of reservoir rents based on implicit operator well choice decision that maximizes the value of the reservoir. Based on his allocated share of reservoir rents, the unit operator, then, makes the well-choice decision for the entire reservoir. This induction method of solution allows the optimal firm shares to be determined before the well choice decision has been made. The operator makes the well choice decision by solving the following maximization problem given his share of net returns, k_o :

$$12. \quad \underset{w_o}{\text{Max}} V_o = k_o[pq(w_o, S) - cw_o]$$

$$\text{subject to } S = S_o - L(w)$$

⁶⁹ Smith (1987) discusses in detail the bargaining problem and negotiating solutions using Nash conditions to determine the share allocations between two firms.

⁷⁰ The operators share in this problem is represented by k_o .

⁷¹ For the purposes of this study, these inputs are considered to be without cost so that the unit operator does not need to be compensated for these tasks.

The constraint shows that the operator faces the full cost of the loss effect, not a share equivalent to his share of reservoir returns as under the rule of capture. This is the case because the operator is the only firm making well choice decisions on the reservoir. All costs of production are then completely internalized. The optimal well choice can then be found by solving the first order condition:

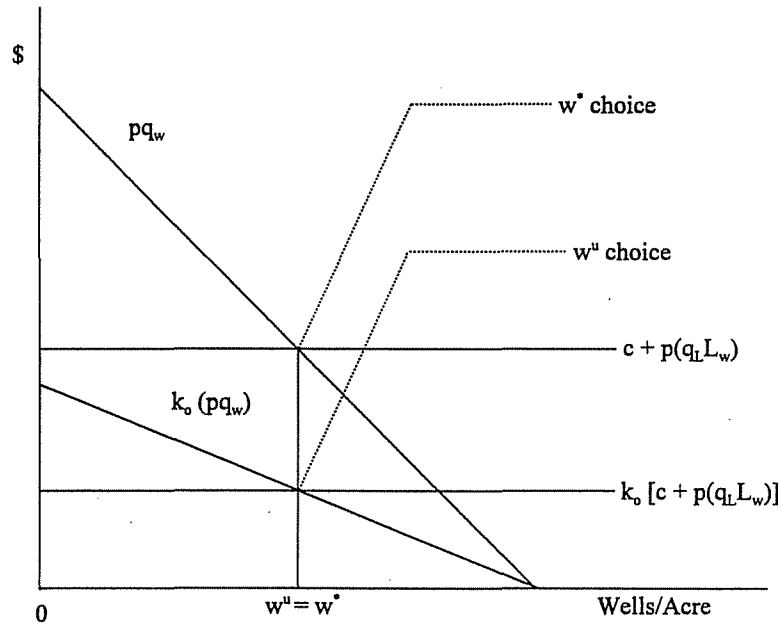
$$13. \quad k_o[pq]_{w_o} = k_o[c + p(q_L L_{w_o})]$$

The well choice solution for the unit, w^U , is the same as for the sole owner case derived in equation (3) and shown in Figure 3 so that $w^* = w^U$. Even though the operator makes his decision based only on his share of reservoir returns, k_o , he still internalizes all of the costs of production including the marginal cost and the loss effect of drilling a well.⁷² Thus, the well choice decision made by the operator is the same as that of the sole owner. Figure 4 shows the well choice decision for the operator.

⁷²

Notice that the actual size of k_o is arbitrary and does not change the well choice decision of the operating firm.

Figure 4. The Well Choice Solution for the Unit Operator



Because the well choice decision is the same for the unit and the sole owner, the value of the reservoir, V^* , is the same as well, and can be calculated using equation (4). Also, because the well choice decision is the same, the net benefit of sole ownership, V^P , as determined by equation (11) is the same as the net benefit under unit production, using the well choice w^* :

$$14. \quad V^P = V^* - V^{RC} > 0, \text{ where } V^* \text{ is now the value of the unitized reservoir.}$$

With the well choice decision made, firms now confront the first stage of the unit contracting problem, determining of individual shares, k_i . Optimal allocation of the returns of unitization requires that for each firm, $i = 0, 1, \dots, n$:

$$15. \quad k_i V^P > a_i V^{RC}$$

For the case of homogenous firms with equal surface acreage access to the reservoir, the optimal k_i can be found by dividing the net returns of unitized production equally among the n firms, including the operator:

$$16. \quad k_i = k^* = 1/n \text{ for } i = 0, 1, \dots, n.^{73}$$

Because $V^P > 0$, the net returns to the unit are positive and every firm is better off than under rule of capture. This condition allows consensual agreement on the unit contract allowing for unitized production.⁷⁴

If firms do not have equal access to the homogenous reservoir, the solution changes because k_i for each firm depends on the portion of the reservoir accessed by the firm. The solution to the first stage of the problem remains the same. The operator still makes the optimal well choice based on his share net of returns, k_0 . The problem now is to allocate V^P among firms with different size landholdings. If for each firm, a_i is the surface acreage accessed by the firm and A is the total acreage of the reservoir, then the allocation of returns can be optimally divided based on the portion of the reservoir accessed by the firm. Now,

$$17. \quad k_i = k_i^* = a_i / A \text{ for } i = 0, 1, \dots, n \text{ and } \sum_{i=1}^n k_i = 1.$$

These surface acreage allocation formulas are commonly found as practical solutions for sharing returns of unitized production. Most often they occur with older

⁷³ While the distribution of k_i^* 's is sufficient for an optimal distribution of reservoir rents required to reach a successful agreement, this distribution may not be unique. Other distributions may exist which would allow all firms to be better off.

⁷⁴ Libecap and Johnson (1982) discuss this result for a fishery where contractual agreement can be easily reached when firms are identical and no information asymmetries exist.

units where lack of reservoir data prevented the calculation of complex allocation formulas based on reservoir properties common today. Surface acreage allocation formulas are also frequently used on exploratory units when no information is available regarding actual reservoir properties.

Contracting Positive Transaction Costs and Statutory Remedy. Transaction costs further complicate the unit-contracting problem. Modeling a transaction costs function is difficult because the relationship between these costs and specific contracting determinants is unclear. The properties of the transaction function can only be proposed and the implications tested. For this study, the transaction costs depend on *firm numbers*, *heterogeneity*, *regulations*, and *reservoir productivity*:

Increasing the number of negotiating firms or decreasing firm access to the reservoir, a_i , can increase the transaction costs. This result is not clear and confirms the difficulty in specifying a transaction costs function. If firms are relatively homogenous in terms of size and access to the reservoir, the number of firms may not add significant negotiating costs. But if additional firms are not homogenous, transaction costs may become significant when a_i decreases. Increases in firm heterogeneity, then, increase transaction costs. *Heterogeneity* can be measured by firm and reservoir characteristics, including reservoir surface acreage, land ownership patterns, reservoir porosity, and permeability. When differences among firms are significant whether due to the amount of access each has to a reservoir or due to variability in reservoir properties, negotiations can be costly.

Regulations that reduce the costs of negotiations reduce transaction costs of unitization. For example, compulsory unitization laws forego the need for consensus by requiring only a pre-determined percentage of agreement to force non-consenting firms to join the unit. These laws in essence decrease the number of negotiating parties on the reservoir and likely reduce some degree of heterogeneity. As a result, they also decrease the transaction costs of unitization.

Finally reservoir *productivity* can also affect transaction costs through the determination of lease values. In order to join a unit, the firm must determine that its share of returns, k_i , provide a net gain when compared to rule of capture production. In order to make this determination, the firm must estimate the value of its lease. At the same time, all other firms also form an estimate of the value of that lease. The firms then negotiate to find an agreeable share that provides positive unit returns for the leaseholder. This process occurs for each lease on the reservoir. The negotiations become increasingly costly with highly productive leases where agreement over estimated values are difficult to reach (Libecap and Wiggins, 1985). Because reservoir properties vary between leases and within large leases, firm differences in information which lead to very different value estimates can significantly complicate negotiations.

The contracting cost analysis begins with the original assumption of reservoir and surface acreage homogeneity. Because the transaction cost function is an added fixed cost, the unit operator's well choice solution remains w^* according to the marginal conditions in equation (13) and the value of the reservoir with this optimal well choice is still V^* . Letting θ equal transaction costs, the net benefits from unitization are,

$$18. \quad V^u = V^P - \theta$$

To join the unit, each firm ($i = 0, 1, \dots, n$) must determine that its return from joining the unit is greater than the return it would get from rule of capture production:

$$19. \quad k_i V^u > a_i V^{RC}$$

Allowing for differences in physical properties across the reservoir further complicates the model because firm shares can no longer be calculated by a simple surface-acreage allocation formula. Instead, each firm negotiates its share based on its valuation of oil beneath its lease.⁷⁵ Finding shares, k_i , for all firms can become a lengthy and costly process. The formula depends on estimating numerous physical and economic parameters that affect the value of oil beneath the tract of each potential participant in the unit. Because physical attributes differ across the reservoir and some degree of uncertainty as to the actual character of the reservoir exists, tract values are often difficult to quantify. The values of each tract are controversial and seldom fully agreed upon because of differences in proprietary and public information on individual leases. Wiggins and Libecap (1985) and Smith (1987) discuss the bargaining and holdout implications of differences in tract value between the firm and the other participants. Under the assumptions of heterogeneity, information differences, and positive transaction costs, each firm must negotiate k_i so that:

$$20. \quad E(k_i V^u) > E(a_i V^{RC}) \text{ for } i = 0, 1, \dots, n.$$

⁷⁵ This discussion pertains to reservoirs in primary production. Exploratory units are often easier to form because of the lack of strategic advantage by any one firm (Libecap and Wiggins, 1984). Unitization in the secondary stage of production is often more straightforward as well because the gains from rule of capture have been exhausted and again bargaining advantages are eliminated.

If the expected value of unitized production including does not exceed the expected value under rule of capture for all firms, then reservoir-wide unitization will not occur. This result is similar to the outcome reached by Wiggins and Libecap (1985) and allows for predictions regarding information asymmetries and bargaining strategies resulting from expectation models.

Contracting With Compulsory Unit Laws. Compulsory unit laws amend the need to reach one hundred percent agreement in order to achieve a successful unit contract by stipulating that only a super-majority of firms or firm interests agree to the contract.⁷⁶ Once the percentage of agreement has been achieved, the state regulatory agency can compel the dissenting firms to join the unit or be penalized for withholding. These laws reduce the transaction costs of reaching agreement by allowing the agency to force a certain percentage of firms that withhold their acreage from the agreement to join the unit. A successful unit agreement subject to a compulsory unit regulation requires:

$$21. \quad k_i V^u > a_i V^{RC}$$

for all $i = 0, 1, \dots, pn$, where $p \in (0, 1)$ and is the fraction of firms required to agree to unitize under the state compulsory unit law.

Model Summary Predictions and Other Contracting Issues

Using property rights and transaction cost approaches, models of well-choice are developed to compare the gains from sole ownership, rule of capture, and unitized

⁷⁶ Currently, Montana and Wyoming require 80 percent owner agreement and North Dakota requires 70 percent.

production. The models show that optimal production occurs under exclusive property rights whether through sole ownership or unit operation. In the absence of transaction costs, the value of the reservoir will be greater under these regimes than under rule of capture production. When the net gains from unit production exceed the gains from the rule of capture, a firm will join the unit. If all firms agree, a voluntary unit is formed. If the state-regulated super-majority agrees, then a unit is formed by agency intervention.

Predictions. The discussion yields the following theoretical predictions regarding the probability of unit formation.

Prediction 1a. *The probability of unitization decreases as reservoir surface acreage increases.*

This prediction stems from the notion that given an average landholding size, as the total productive acreage overlying a reservoir increases, the number of landowners and firms with access to the reservoir increases. The negotiating parties increase transaction costs and reduce V^u , the net benefit of unitization from equation (18). However as the number of firms with access to the reservoir increases, rent dissipation also increases, so that V^p in equation (14) increases as well. The prediction then depends on transaction costs increasing more than V^p so that overall, V^u decreases and with it the likelihood of unitization.

Prediction 1b. *The probability of unitization decreases with an increase in firm heterogeneity as measured by decreasing firm size and increasing firm numbers (Libecap and Wiggins, 1984).*

The discussion of the transaction costs function indicates that transaction costs increase with differences among firms. As a result, the net benefits of unitization, V^u , decrease as well. Decreases in the net benefits of unitization suggest a decrease in the likelihood of unitization. But also as heterogeneity increases, rule-of-capture dissipation increases as firms with less reservoir access over-drill their leases. The increases in dissipation increase and V^p , the benefits of optimal well choice, suggesting an increase in the likelihood of unitization. The prediction then depends on the transaction cost effect having a greater impact on unitization than the decrease in rule of capture returns. Increasing heterogeneity implies increased transaction costs and a decrease in both the net benefits of unitization and the likelihood of unitization.

Prediction 2. *The probability of unitization increases for older reservoirs (Wiggins and Libecap, 1985).*

This prediction stems from the reduction in transaction costs as more information becomes publicly available on reservoir production. The availability of information allows firms to agree on unit allocation formulas in a less costly manner. On the other hand, as reservoirs age and stock size decrease, the benefits of optimal well choice, V^P , likely decrease as well. This prediction again depends on the impact of transaction costs being more significant than the change in reservoir value between rule of capture and first-best. If the decrease in transaction costs is greater than the decrease in reservoir value, then the net benefit of unitization, V^u , increases as does the likelihood of unitization.

Prediction 3. *The probability of unitization decreases when reservoirs operate in primary production stage and increases when reservoir produce by enhanced recovery techniques.*

In primary production, rule of capture dissipation is likely most dramatic, thus V^P increases. But also during primary production, the transaction costs of forming a unit are also significant, as the problems of firm size, numbers, and heterogeneity are most apparent. The prediction then implies that the increase in transaction costs is greater than the increase in reservoir value from optimal well choice, so that V^u and the likelihood of reservoir unitization decrease. Enhanced recovery is necessary to extract additional oil when primary production ends. With the implementation of these techniques the value of the reservoir, V^P , increases significantly. Also transaction costs are lower than under primary recovery because differences in information among firms is reduced by primary production comes to an end and the productivity of all leases becomes known. Thus, V^u and the likelihood of unitization increases because of reduced transaction costs and increased reservoir value.

Prediction 4. *The probability of unitization increases with changes in physical reservoir properties that increase reservoir value without additional transaction costs.*

Factors such as the gas cap drive mechanism, which are associated with significant rule of capture losses, increase V^u and also increase the likelihood of unitization. These losses are primarily associated with the loss effect in the rule of capture model. A reservoir more sensitive to over-drilling has reduced total recovery resulting from damage to the reservoirs drive mechanism. Thus the net benefit of optimal production, V^P , increases as does the net value of the unit, V^u .

Prediction 5. *Increases in reservoir productivity or the productive potential of the reservoir increase likelihood of unitization.*

Increases in stock size, S_0 , increase the value of the reservoir when well choice is optimal because more oil is available for production from larger reservoirs. Increases in stock size then increase the net benefits of unitization and the likelihood of unitization.

Prediction 6a. *Compulsory unit laws lower the costs of reaching contractual agreement and increase the likelihood of unit formation.*⁷⁷

Compulsory unit laws lower transaction costs by reducing the percentage of agreement required for unitization. Thus, V^u and the likelihood of unitization increase.

Other Considerations.

The models developed to this point derive conditions for the formation of a unit agreement. Implications of the model allow an examination of the role of ownership regimes, property rights, producing firm characteristics, physical reservoir properties, and regulatory institutions on the unit process. The model does not examine all forms of reservoir production and does not provide explanations for several determinants that may also impact the formation of units. Among these productive organizations and determinants, partial units, enhanced recovery units, well-spacing regulations, and the different incentives of royalty and working interest owners are particularly noteworthy.

Partial Unit Formation. The contracting model does not consider the formation of partial units. With partial reservoir unitization, a subset of producing firms organizes to form an agreement for coordinated production. Typically, these producers have access to contiguous acreage so that all acreage within the partial unit boundary is unitized

⁷⁷ A corollary to Prediction 6 implies also that as the state regulated percentage of owner agreement required for compulsory unitization decreases, the probability of unitization increases.

(Wiggins and Libecap, 1985). These units form if the participating firms determine that the unit generates positive net returns and makes each firm better off despite the lack of reservoir-wide coordination. Since these units do not occur on the entire reservoir, the net gains are only a percentage of the expected gains from reservoir-wide unitization. Partial units are likely to form when numerous small firms have access to a reservoir with highly variable physical properties. Uncertainty and differences in information among a large number of contracting parties can be so prevalent that unit negotiations do not even commence. Instead, one or more partial units can form on a reservoir.

Enhanced Recovery Units. Enhanced recovery operations are used on reservoirs after the natural drive mechanism has been so depleted that the remaining pressure in the reservoir is insufficient to force oil to the surface. In order to continue production, reservoir pressure must be actively increased through the injection of gas, water, or other fluids to occupy the space left by the extracted oil and gas. Injecting fluids is a capital intensive project requiring the shutting-in of some previously productive wells as well as the drilling of injection wells to re-introduce fluids to the reservoir. Enhanced recovery increases the incentive to unitize for three important reasons. First, unitization of the reservoir allows that investment costs be shared among all firms on the reservoir, making investment in expensive projects possible and not giving a cost advantage to non-paying firms. The investment costs are usually divided according to the allocation formula specified by the unit contract, so that the firm still maximizes its return as a share of net returns from the unit as in primary recovery. Second, enhanced recovery requires an

optimal pattern of injection and extraction well placement, so that if contractual agreement allowing this pattern cannot be reached, production will be reduced. Finally, unitization ensures that losses from drainage will be eliminated from production. With high investment costs, operators will be unwilling to initiate enhanced recovery if the threat of significant drainage by holdout firms exists. Ironically, rule of capture production then results in underdevelopment of the reservoir when enhanced recovery is necessary.

Well Spacing Regulations. This chapter has focused on the development of models under the rule of capture and unitization, but well-spacing regulations can also be modeled in the contracting framework. The regulations are of interest and depending on their application they do likely have an affect on unitization. Spacing regulations specify the pattern of well placement by defining the distances between wells and distances from lease boundaries. These density rules allow a maximum number of wells per acre. As a result, they reduce the effects of rule of capture by setting a limit on the number of wells that can be drilled on a reservoir. Spacing rules do create a problem for the small landholder. Because spacing regulations set the number of wells drilled per acre, the small landowner with less than the specified acreage cannot drill a well on his property. To remedy this problem, state agencies passed forced pooling regulations so that these small tracts could be joined with adjacent tracts to form a combined acreage large enough to permit the drilling of a well. Alternatively, small landowners also were pooled into tracts with already existing wells, and revenues were shared among all the interest

owners. Through forced pooling, spacing rules in effect reduced the number and heterogeneity of landowners by aligning the incentives of tract owners within a pooled group of leases.⁷⁸ The transaction costs model suggests that this reduction in heterogeneity increases the likelihood of successful unit contracting. On the other hand, because well spacing regulations limit drilling and reduce rule of capture losses, the net gains from unitization may be negligible, decreasing the likelihood of unit formation. The result is that no consistent prediction regarding spacing rules is forthcoming.

Differential Incentives: Working and Royalty Interests. Compulsory unit laws can be especially advantageous when tract interests are divided among numerous costbearing working interest operators, and non-costbearing royalty interest landowners.⁷⁹ The division originates with the lease agreement. Because landowners are seldom familiar with petroleum production, they lease the right to drill to an experienced producer. The lease agreement used most commonly on oil reservoirs allows a producing firm to lease mineral rights from the land owner in exchange for a royalty percentage, typically 12.5 percent, of the production revenues.⁸⁰ This type of lease agreement results in conflicting incentives for the lessee and the lessor. As has been discussed previously, the firm, or

⁷⁸ Unit formation exempts a reservoir from state spacing laws, eliminating the need for forced pooling.

⁷⁹ To this point, the "firm" represents all cost-bearing interests in a producing tract. Typically the firm makes day to day operation decisions regarding production, well choice, and so on. But in contract negotiations, non-cost bearing or royalty interests also have voting rights equivalent to their royalty percentage. Voluntary unit formation then requires the unanimous consent of all firms and royalty interests.

⁸⁰ An interesting question beyond the scope of this thesis is why do producers not negotiate lease agreements that allocate royalty interests a percent of the profits as opposed to revenue? Historical precedent, cost of negotiations, and reputation of the working interest may all contribute to the current lease form.

working interest, solves the problem of maximizing net returns. The royalty interest owner, however, is interested in a well choice that maximizes revenues.

As a result, in the case of multiple working and royalty interests, negotiations may be more costly because each interest group has a different maximization problem. The absence of costs for the royalty interest provides an incentive for these owners to place more wells on the lease than would be chosen by the working interest. As a result of the different maximizing problems for the same lease, costly problems are already built into the contracting process. With unit negotiations, if royalty and working interest cannot agree on the value of the tract or the allocation share, k_i , the tract may be withheld from the unit. Libecap and Wiggins (1984, 1985) comment on this problem and on the infrequency of unit formation in the absence of compulsory unit laws. By reducing the percentage of agreement to a state mandated percentage, a portion of the negotiating costs can be avoided, leading more successful contracting.

CHAPTER 5

EMPIRICAL ANALYSIS: ECONOMETRICS AND CASE STUDIES

This chapter examines and tests the predictions derived in Chapter 4. First, reservoir data is summarized and described. Second, probit regressions estimate the effects of specific economic variables on the likelihood of unitization for all sample reservoirs and for reservoirs in the Williston Basin. Third and finally, case studies are used to further examine contracting determinants by examining five examples of successful and unsuccessful attempts at reservoir-wide unit formation.

Reservoir Data Summary

Observations for use in the empirical study include 62 reservoirs in Montana, 62 in North Dakota, and 65 in Wyoming. Figures 4, 5, 6, and 7 show well locations on a regional scale and state by state. Table 3 provides a reference guide to figures 5, 6, and 7. The reservoir numbers on the maps refer to identification numbers (ID) in Table 3. The ID numbers reference reservoir names and basic data for each observation in the sample.

Figure 5.
Northern Plains Map and Distribution of Sample Reservoirs

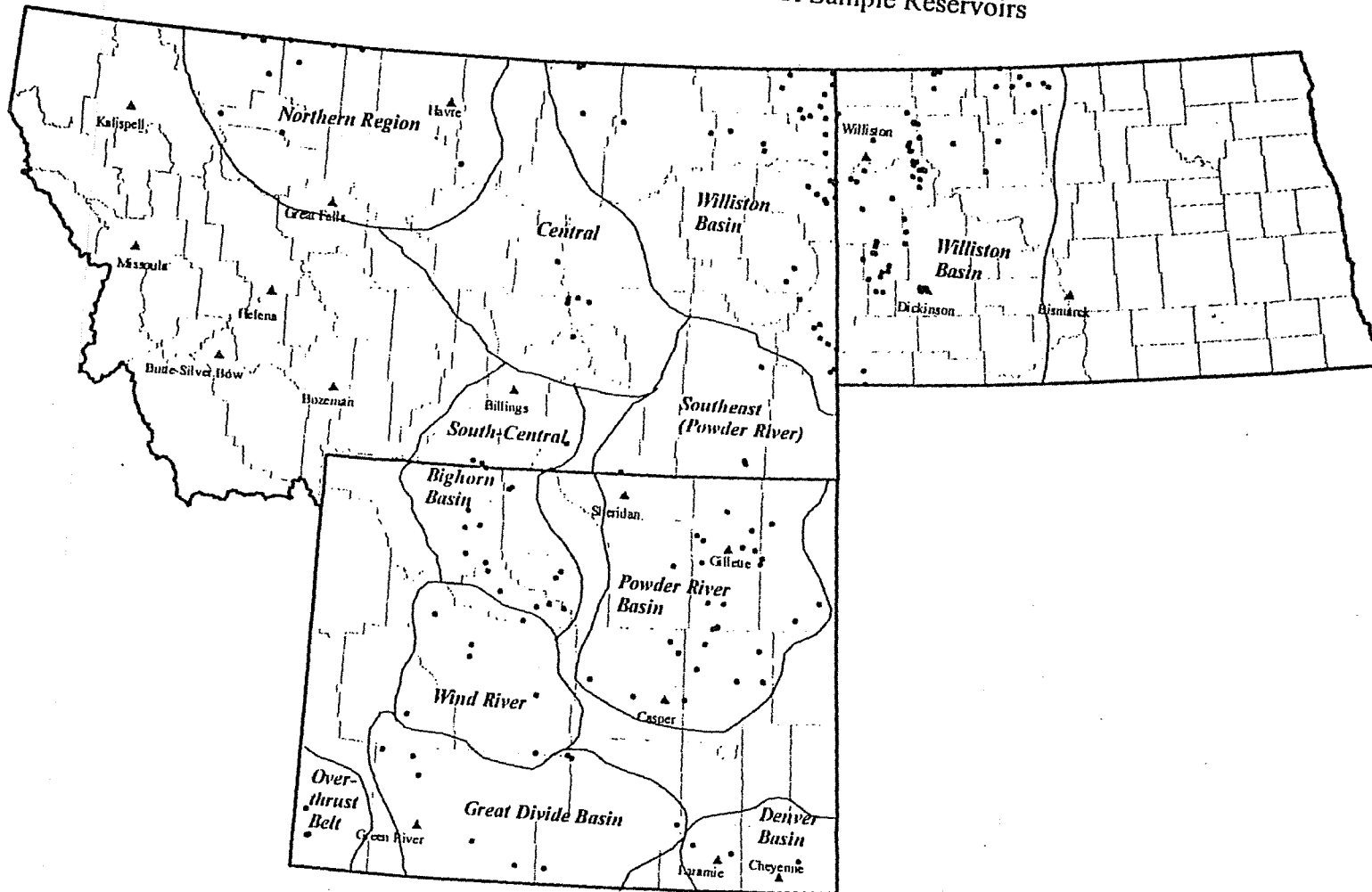


Figure 6.
Distribution of Wyoming Reservoirs

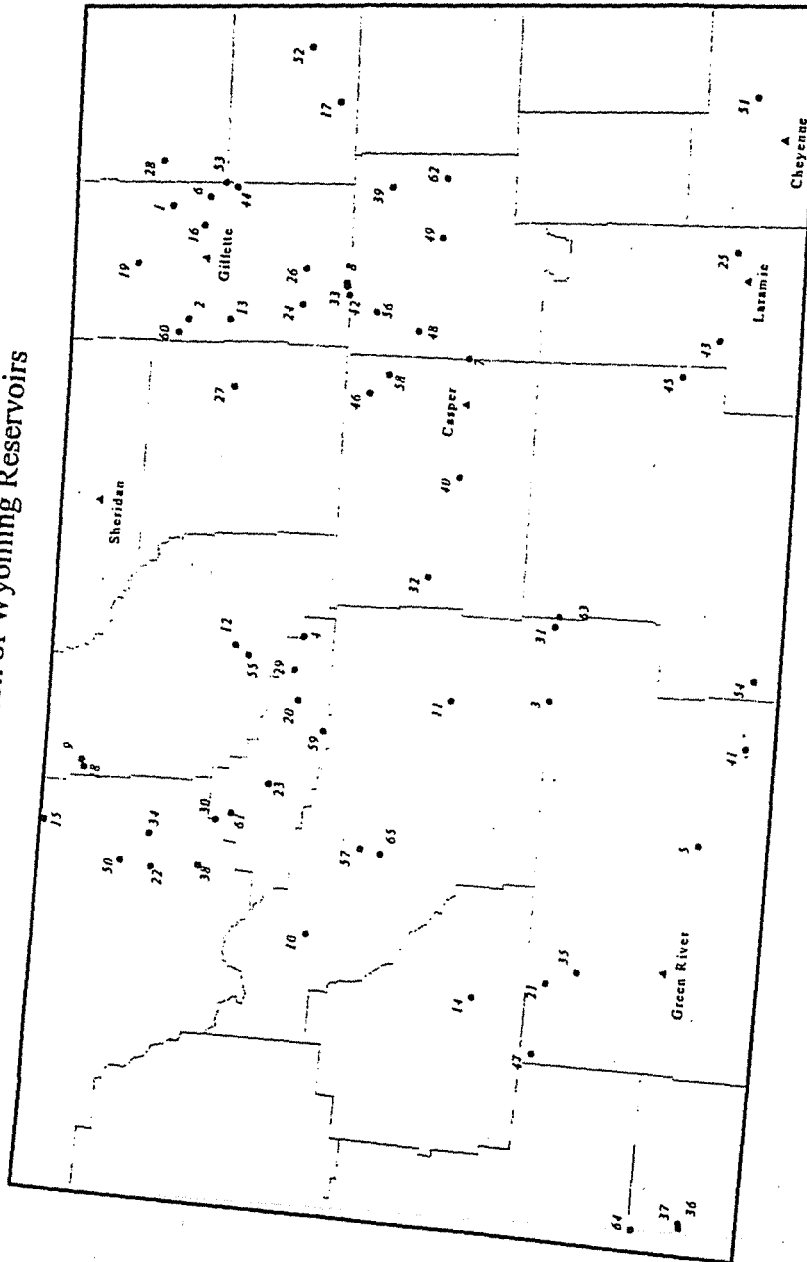


Figure 7.
Distribution of Montana Reservoirs

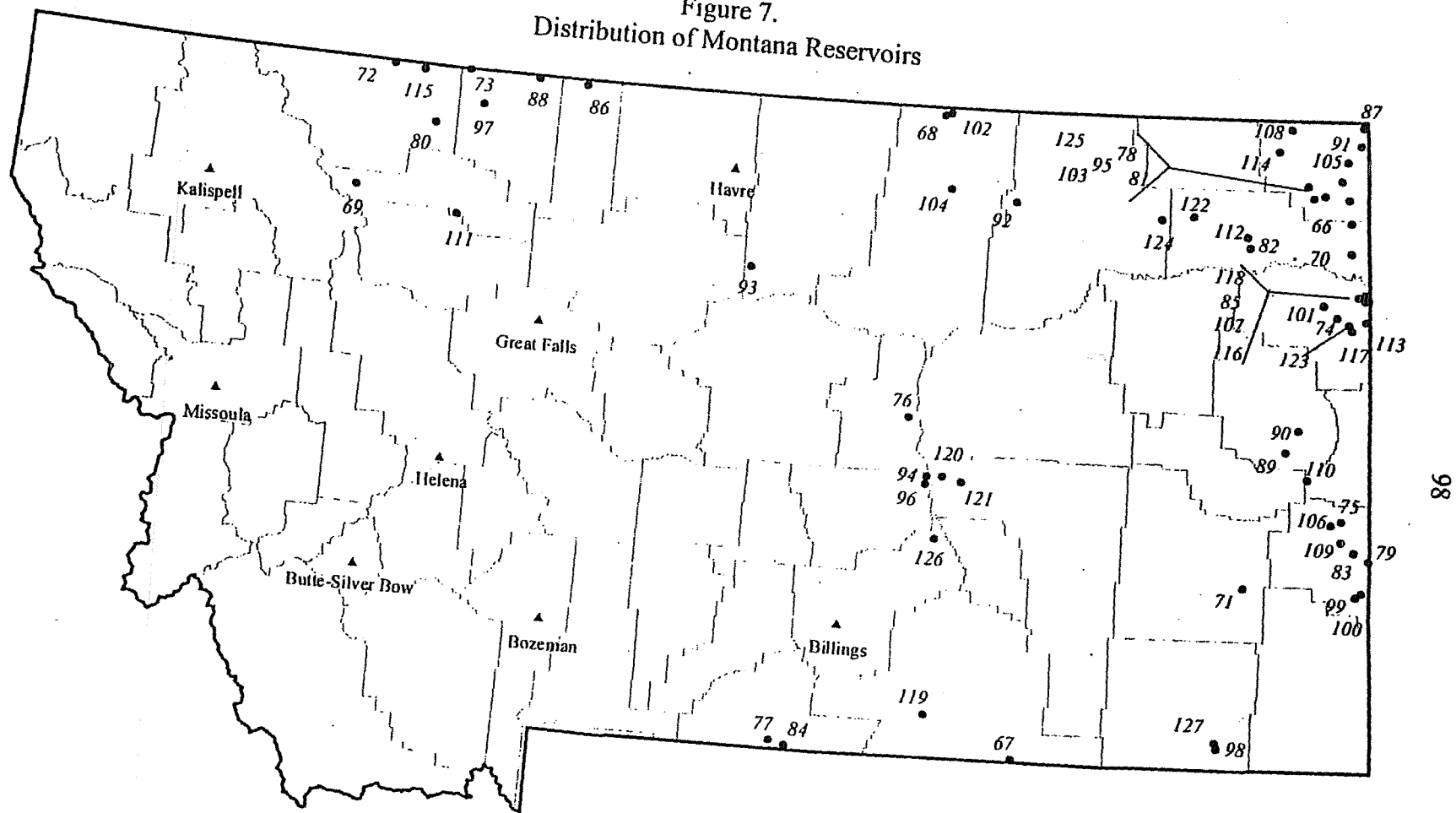
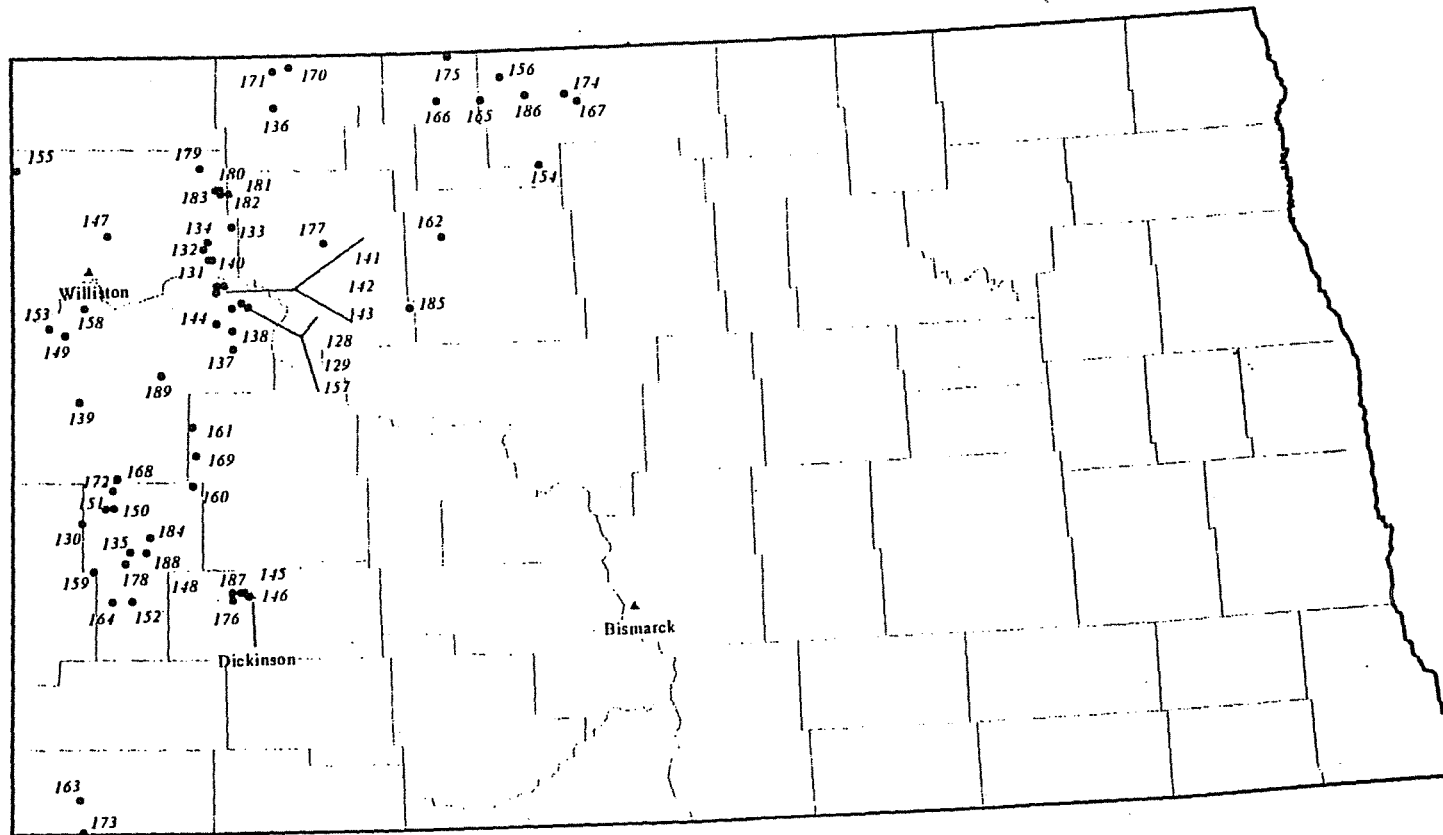


Figure 8.
Distribution of North Dakota Reservoirs



Reservoir level data for each state was collected from unit agreements, surface ownership land status maps printed by the Bureau of Land Management, annual reservoir production statistics published by the regulatory agencies of each state, and a proprietary database provided by P.I. Dwight's in Richardson, Texas. The data set organized for this thesis is notable for the large number of reservoirs included. No previous works have used such a large and varied sample of reservoirs. For example, Libecap and Wiggins (1984) analyze just five major oil fields in Texas and Oklahoma. Wiggins and Libecap (1985) included empirical tests using only seven fields in Texas and New Mexico.⁸¹ The thesis takes a broader approach, analyzing a large number of reservoirs discovered throughout the history of each state's oil development and chosen to represent a diversity of physical reservoir conditions. The sample includes an approximately equal number of reservoirs from each of the three states so that analysis to provide a diverse state by state sample.⁸²

The reservoir data collected can be sorted into the following types of variables: 1) surface ownership variables, 2) reservoir variables, and 3) regulatory variables. Tables 4 and 5 describe variables collected for each category and summarize sample statistics for reservoirs in the entire sample, in the Williston Basin, and state by state.

⁸¹ While Libecap and Wiggins are unclear as to the actual geological structures they are studying, this thesis clearly selects a single reservoir within a field as the observation to be analyzed.

⁸² Appendix B includes more information on the process of collecting data and summary statistics for sample reservoirs.

Table 3. Sample Reservoirs

ID	Field Name- Reservoir Name	Basin	Discovery Date	Unitized (Date)
1	Adon Road- Minnelusa B	Powder River, WY	1962	YES (1990)
2	Amos Draw- Muddy	Powder River, WY	1982	NO (NA)
3	Biselo- Wasatch	Wind River, WY	EXPL	YES (1995)
4	Black Moutain- Tensleep	Big Horn, WY	1924	YES (1946)
5	Brady- Muddy	Great Divide, WY	1973	NO (NA)
6	Brennan- Minnelusa	Powder River, WY	1980	YES (1984)
7	Brooks Ranch- 2nd Frontier Sand	Powder River, WY	1957	YES (1966)
8	Buck Creek- Dakota	Powder River, WY	1952	YES (1986)
9	Byron- Pretensleep	Big Horn, WY	1918	YES (1955)
10	Circle Ridge- Madison	Wind River, WY	1923	NO (NA)
11	Conant Creek- Lance	Wind River, WY	EXPL	YES (1961)
12	Cottonwood Creek- Dakota	Big Horn, WY	1953	YES (1953)
13	Dead Horse Creek-Parkman	Powder River, WY	1957	YES (1963)
14	El Nino- Lance	Wind River, WY	EXPL	YES (1998)
15	Elk Basin -Embar Tensleep	Big Horn, WY	1915	YES (1946)
16	FD- Minnelusa	Powder River, WY	1980	NO (NA)
17	Finn Shurley- Muddy	Powder River, WY	1965	NO (NA)
18	Garland- Madison	Big Horn, WY	1906	YES (1936)
19	Gas Draw- Muddy	Powder River, WY	1968	YES (1972)
20	Grass Creek- Pretensleep	Big Horn, WY	1914	YES (1957)
21	Gunsmoke-Exploratory	Great Divide, WY	EXPL	YES (1997)
22	Half Moon- Phosphoria	Big Horn, WY	1944	NO (NA)
23	Hamilton Dome- Phosphoria/Tensleep	Big Horn, WY	1918	YES (1996)
24	Hartzog Draw- Shannon	Powder River, WY	1976	YES (1980)
25	Horse Creek Muddy	Denver, WY	1942	YES (1943)
26	House Creek- Sussex	Powder River, WY	1968	YES (1987)
27	Indian Creek- Minnelusa	Powder River, WY	1974	YES (1983)
28	Kiehl- Minnelusa B	Powder River, WY	1972	YES (1984)
29	Kirby Creek- Phosphoria	Big Horn, WY	1918	YES (1968)
30	Little Buffalo- Embar Tensleep	Big Horn, WY	1914	YES (1943)
31	Lost Soldier- Tensleep	Great Divide, WY	1916	YES (1962)
32	Maverick Butte-Exploratory	Powder River, WY	EXPL	YES (1990)
33	North Buck Draw- Dakota	Powder River, WY	1983	YES (1968)
34	Oregon Basin- Embar Tensleep	Big Horn, WY	1912	YES (1948)
35	Outlaw-Exploratory	Great Divide, WY	EXPL	YES (1998)
36	Painter Reservoir- Nugget	Overthrust Belt, WY	1977	YES (1977)
37	E. Painter Reservoir - Nugget	Overthrust Belt, WY	1977	YES (1981)
38	Pitchfork- Tensleep	Big Horn, WY	1930	YES (1932)
39	Poison Draw- Teckla	Powder River, WY	1972	YES (1976)
40	Poison Spider- Sundance	Powder River, WY	1917	YES (1947)
41	Polar Bar-Exploratory	Great Divide, WY,	EXPL	YES (1992)
42	Powell - Frontier	Powder River, WY	1954	YES (1983)
43	Quealy Dome- Muddy	Denver, WY	1934	YES (1971)
44	Raven Creek- Minnelusa B	Powder River, WY	1960	NO (NA)
45	Rock River- Dakota	Great Divide, WY	1918	YES (1977)
46	Salt Creek- Wall Creek	Powder River, WY	1908	YES (1939)
47	Sand Castle-Exploratory	Great Divide, WY	EXPL	YES (1996)
48	Sand Dunes- Muddy	Powder River, WY	1982	YES (1996)
49	Scott- Parkman	Powder River, WY	1979	NO (NA)
50	Shoshone- Phosphoria/ Tensleep	Big Horn, WY	1929	YES (1988)
51	Silo- Niobrara	Denver, WY	1981	NO (NA)
52	Skull Creek- Newcastle	Powder River, WY	1946	YES (1965)
53	Slattery- Minnelusa	Powder River, WY	1957	YES (1991)
54	Snowbank-Exploratory	Great Divide, WY	EXPL	YES (1994)
55	South Fork- Embar	Big Horn, WY	1947	YES (1947)
56	Spearhead Ranch- Frontier	Powder River, WY	1973	YES (1974)
57	Steamboat Butte- Tensleep	Wind River, WY	1943	NO (NA)
58	Teapot- Shannon	Powder River, WY	1922	NO (NA)
59	Ten Mile Creek-Exploratory	Wind River, WY	EXPL	YES (1994)
60	Terrace- Minnelusa	Powder River, WY	1986	NO (NA)
61	Walker Dome- Torchlight	Big Horn, WY	1930	YES (1965)
62	Well Draw- Teapot	Powder River, WY	1973	NO (NA)

ID	Field Name- Reservoir Name	Basin	Discovery Date	Unitized (Date)
63	Wertz- Tensleep	Great Divide, WY	1920	YES (1937)
64	Whitney /Carter- Madison	Overthrust Belt, WY	1977	NO (NA)
65	Winkelman Dome- Phosphoria	Wind River, WY	1917	YES (1962)
66	Anvil- Red River	Williston, MT	1978	NO (NA)
67	Ash Creek- Shannon	South Central, MT	1952	YES (1964)
68	Ashfield- Bowdoin	Williston, MT	EXPL	YES (1973)
69	Badger- Exploratory	Northern, MT	EXPL	YES (1986)
70	N. Bainville- Red River	Williston, MT	1979	NO (NA)
71	Bell Creek- Muddy	South East, MT	1967	YES (1992)
72	Blackleaf- Madison	Northern, MT	EXPL	YES (1980)
73	Border- Cutbank	Northern, MT	1954	YES (1973)
74	Brorson- Madison	Williston, MT	1954	NO (NA)
75	Cabin Creek- Silurian	Williston, MT	1953	YES (1953)
76	Cat Creek- 1st Cat Creek	Central, MT	1920	YES (1959)
77	N. Clarks Fork- Greybull	South Central, MT	1954	NO (NA)
78	Clear Lake- Red River	Williston, MT	1977	NO (NA)
79	Coral Creek- Madison	Williston, MT	1962	YES (1962)
80	Cutbank- Cutbank	Northern, MT	1932	YES (1963)
81	Dwyer- Charles	Williston, MT	1960	YES (1968)
82	E. Poplar- Madison	Williston, MT	1951	YES (1951)
83	E. Lookout Butte- Red River	Williston, MT	1984	YES (1995)
84	Elk Basin- Frontier	South Central, MT	1915	YES (1946)
85	Fairview- Red River	Williston, MT	1981	NO (NA)
86	Flat Coulee- Swift	Northern, MT	1933	YES (1970)
87	Flat Lake- Ratcliffe	Williston, MT	1964	YES (1972)
88	Fred and George- Sunburst	Northern, MT	1963	YES (1970)
89	Gas City- Red River	Williston, MT	1955	YES (1955)
90	Glendive- Silurian	Williston, MT	1952	NO (NA)
91	Goose Lake- Ratcliffe	Williston, MT	1962	NO (NA)
92	Hinsdale- Exploratory	Williston, MT	1957	YES (1957)
93	Huebschwerlen- Exploratory	Northern, MT	1977	YES (1977)
94	Ivanhoe- Morrison	Central, MT	1960	NO (NA)
95	N. Katy Lake- Red River	Williston, MT	1981	NO (NA)
96	Keg Coulee- Tyler	Central, MT	1960	YES (1969)
97	Kevin Sunburst- Madison	Northern, MT	1922	NO (NA)
98	Leary- Muddy	South East, MT	1969	NO (NA)
99	Little Beaver -Red River	Williston, MT	1952	YES (ND)
100	E. Little Beaver- Red River	Williston, MT	1954	YES (ND)
101	Lone Tree- Red River	Williston, MT	1970	NO (NA)
102	Loring- Exploratory	Williston, MT	1977	YES (1977)
103	Medicine Lake-Devonian	Williston, MT	1980	NO (NA)
104	Milk River- Exploratory	Williston, MT	1997	YES (1997)
105	Mon Dak- Madison	Williston, MT	1979	NO (NA)
106	Monarch -Silurian	Williston, MT	1958	YES (1973)
107	Nohly- Red River	Williston, MT	1983	NO (NA)
108	Outlook- Nisku	Williston, MT	1958	NO (NA)
109	Pennel- Silurian	Williston, MT	1955	YES (1986)
110	Pine- Red River	Williston, MT	1951	YES (1951)
111	Pondera- Madison	Northern, MT	1927	NO (NA)
112	N.W. Poplar- Madison	Williston, MT	1952	NO (NA)
113	Putnam- Red River	Williston, MT	1969	NO (NA)
114	Raymond-Nisku	Williston, MT	1972	YES (1982)
115	Reagan - Madison	Northern, MT	1947	NO (NA)
116	Ridgelawn- Madison	Williston, MT	1984	YES (1990)
117	Sidney- Madison	Williston, MT	1976	NO (NA)
118	Sioux Pass- Siluro	Williston, MT	1973	NO (NA)
119	Soap Creek- Tensleep	South Central, MT	1952	NO (NA)
120	Stensvad-Tyler	Central, MT	1958	YES (1963)
121	W.Sumatra- Tyler	Central, MT	1949	YES (1967)
122	Tule Creek- Nisku	Williston, MT	1960	NO (NA)
123	Vaux - Red River	Williston, MT	1977	NO (NA)
124	Volt- Nisku	Williston, MT	1964	NO (NA)
125	Wakea- Red River	Williston, MT	1983	NO (NA)
126	Wolf Springs- Amsden	Central, MT	1984	YES (1992)
127	Wright- Muddy	South East, MT	1969	NO (NA)
128	Antelope-Devonian	Williston, ND	1960	YES (1966)

ID	Field Name- Reservoir Name	Basin	Discovery Date	Unitized (Date)
129	Antelope Silurian	Williston, ND	1960	NO (NA)
130	Beaver Creek- Red River	Williston, ND	1979	NO (NA)
131	Beaverlodge-Devonian	Williston, ND	1957	YES (1962)
132	Beaver Lodge-Madison	Williston, ND	1952	YES (1958)
133	Beaver Lodge- Ordovician	Williston, ND	1957	YES (1962)
134	Beaver Lodge- Silurian	Williston, ND	1951	YES (1962)
135	Big Stick-Madison	Williston, ND	1980	YES (1998)
136	Black Slough- Madison	Williston, ND	1959	NO (NA)
137	Blue Buttes- Madison	Williston, ND	1955	YES (1967)
138	Blue Buttes- Silurian	Williston, ND	1980	NO (NA)
139	Boxcar Butte-Red River	Williston, ND	1975	NO (NA)
140	Capa- Madison	Williston, ND	1953	YES (1960)
141	Charlson- Devonian	Williston, ND	1960	NO (NA)
142	Charlson- Madison	Williston, ND	1952	YES (1967)
143	Charlson- Silurian	Williston, ND	1977	NO (NA)
144	Clear Creek- Madison	Williston, ND	1958	YES (1962)
145	Dickinson- Heath	Williston, ND	1958	YES (1972)
146	Dickinson-Lodgepole	Williston, ND	1993	YES (1994)
147	East Fork- Madison	Williston, ND	1984	NO (NA)
148	Eland-Lodgepole	Williston, ND	1995	YES (1996)
149	Elk- Madison	Williston, ND	1980	NO (NA)
150	Elkhorn Ranch- Bakken	Williston, ND	1961	NO (NA)
151	Elkhorn Ranch- Madison	Williston, ND	1974	NO (NA)
152	Fryburg- Heath	Williston, ND	1954	YES (1973)
153	Glass Bluff-Madison	Williston, ND	1982	NO (NA)
154	Glenburn- Madison	Williston, ND	1958	NO (NA)
155	Grenora - Madison	Williston, ND	1961	NO (NA)
156	Haas- Madison	Williston, ND	1956	YES (1996)
157	Hawkeye- Madison	Williston, ND	1955	YES (1964)
158	Indian Hill- Madison	Williston, ND	1982	NO (NA)
159	Knutsen-Madison	Williston, ND	1983	NO (NA)
160	Little Knife-Madison	Williston, ND	1977	NO (NA)
161	Lone Butte- Madison	Williston, ND	1981	NO (NA)
162	Lone Tree- Madison	Williston, ND	1967	NO (NA)
163	Medicine Pole- Red River	Williston, ND	1967	YES (1985)
164	Medora- Madison	Williston, ND	1964	YES (1969)
165	Mohall- Madison	Williston, ND	1963	NO (NA)
166	Mouse River-Madison	Williston, ND	1964	NO (NA)
167	Newburg- Spearfish/Charles	Williston, ND	1955	YES (1966)
168	N. Elkhorn Ranch- Madison	Williston, ND	1981	YES (1987)
169	N. Little Knife-Madison	Williston, ND	1981	YES (1994)
170	Portal- Madison	Williston, ND	1957	NO (NA)
171	Rival- Madison	Williston, ND	1957	YES (1960)
172	Rough Rider-Madison	Williston, ND	1959	NO (NA)
173	S. Horse Creek- Red River	Williston, ND	1975	NO (NA)
174	S. Westhope-Spearfish	Williston, ND	1956	YES (1993)
175	Sherwood-Madison	Williston, ND	1958	NO (NA)
176	Stadium-Lodgepole	Williston, ND	1996	YES (1998)
177	Stanley- Madison	Williston, ND	1977	NO (NA)
178	T.R.- Madison	Williston, ND	1978	NO (NA)
179	Temple-S. Winnepogosis	Williston, ND	1982	YES (1997)
180	Tioga- Devonian	Williston, ND	1967	NO (NA)
181	Tioga- Madison	Williston, ND	1952	YES (1958)
182	Tioga- Ordovician	Williston, ND	1967	NO (NA)
183	Tioga Silurian	Williston, ND	1968	NO (NA)
184	Tree Top- Madison	Williston, ND	1979	NO (NA)
185	Wabek- Madison	Williston, ND	1982	YES (1994)
186	Wayne- Madison	Williston, ND	1957	NO (NA)
187	W. Dickinson-Lodgepole	Williston, ND	1995	YES (1997)
188	Whiskey Joe- Madison	Williston, ND	1979	NO (NA)
189	Zenith- Bell Heath	Williston, ND	1968	YES (1991)

* EXPL indicates exploratory reservoir. ND indicates no data available on unit data. NA indicates unit date not applicable for non-unitized reservoir.

Table 4. Reservoir Variable Definitions, Predicted Signs and Summary Statistics

DEPENDENT VARIABLE	DEFINITIONS	ALL RESERVOIRS					WILLISTON BASIN RESERVOIRS				
		N	MIN	MAX	MEAN	STD	N	MIN	MAX	MEAN	STD
UNIT	1 if reservoir is unitized; 0 if non-unit	189	0.00	1.00	0.60	0.49	100	0	1.00	0.46	0.50
<u>INDEPENDENT VARIABLES</u>											
<u>Surface Ownership Variables</u>											
TOTAL ACRES	Total reservoir surface acres	186	160	77,260	12,497	15,109	100	640	72,165	13,243	14,398
% PRIVATE ACREAGE	Private acres as a percent of total reservoir acres	186	0.00	1.00	0.58	0.36	100	0.00	1.00	0.74	0.29
% FEDERAL ACREAGE	Federal acres as a percent of total reservoir acres	186	0.00	1.00	0.31	0.34	100	0.00	1.00	0.16	0.25
<u>Reservoir Variables</u>											
YEAR OF DISCOVERY	Date discovery well found oil	176	1906	1997	1960	20.71	99	1951	1997	1968	12.48
GAS CAP DRIVE	1 if reservoir drive is a gas cap; 0 if otherwise	163	0.00	1.00	0.13	0.34	93	0.00	1.00	0.10	0.31
DISSOLVED GAS DRIVE	1 if reservoir drive dissolved gas; 0 if otherwise	163	0.00	1.00	0.65	0.48	93	0.00	1.00	0.72	0.45
WATER DRIVE	1 if reservoir drive water drive; 0 if otherwise	163	0.00	1.00	0.23	0.42	93	0.00	1.00	0.18	0.38
PRIMARY PRODUCER	1 if reservoir in primary production; 0 if otherwise	189	0.00	1.00	0.35	0.48	100	0.00	1.00	0.54	0.50
SECONDARY PRODUCER	1 if reservoir in secondary production; 0 if otherwise	189	0.00	1.00	0.55	0.50	100	0.00	1.00	0.41	0.49
DEPTH	Average depth of wells to oil pay zone (in feet)	143	934	13,466	6,980	3,195	72	3,317	13,466	8,824	2,522
RESERVOIR VOLUME	Reservoir volume (in thousands of acre-feet)	71	1.2	2,850	200	404	37	1.6	2,850	249	514
OOIP	Original oil in place (stock tank barrels)	99	5.59E+5	1.62E+9	1.29E+8	2.20E+8	47	2.74E+5	4.80E+8	6.97E+7	9.65E+7
<u>Regulatory Variables</u>											
UNIT LAW	1 if unit law in place at discovery; 0 if other wise	189	0.00	1.00	0.43	0.50	100	0.00	1.00	0.50	0.50
SPACING LAW	1 if spacing law in place at discovery; 0 if otherwise	189	0.00	1.00	0.75	0.44	100	0.00	1.00	0.89	0.31

Table 5. State Reservoir Summary Statistics

	N	MIN	MONTANA			N	MIN	NORTH DAKOTA			N	MIN	WYOMING		
			MAX	MEAN	STD			MAX	MEAN	STD			MAX	MEAN	STD
<u>DEPENDENT VAR.</u>															
UNIT	62	0.00	1.00	0.55	0.50	62	0.00	1.00	0.47	0.50	65	0.00	1.00	0.78	0.41
<u>INDEPENDENT VAR.</u>															
<u>Surface Ownership Variables</u>															
TOTAL ACRES	59	640.00	72,165	12,187	16,545	62	950	48,920	12,709	10,742	65	160	77,260	12,576	17,368
% PRIVATE ACREAGE	59	0.00	1.00	0.65	0.32	62	0.00	1.00	0.78	0.27	65	0.00	0.93	0.32	0.31
% FEDERAL ACREAGE	59	0.00	1.00	0.24	0.29	62	0.00	0.85	0.15	0.24	65	0.00	1.00	0.54	0.34
<u>Reservoir Variables</u>															
YEAR OF DISCOVERY	59	1915	1997	1961	17.22	62	1951	1996	1968	12.60	55	1906	1986	1948	25.95
GAS CAP DRIVE	52	0.00	1.00	0.13	0.34	61	0.00	1.00	0.10	0.30	50	0.00	1.00	0.16	0.37
DISSOLVED GAS	52	0.00	1.00	0.62	0.49	61	0.00	1.00	0.80	0.40	50	0.00	1.00	0.50	0.51
DRIVE															
WATER DRIVE	52	0.00	1.00	0.25	0.45	61	0.00	1.00	0.10	0.30	50	0.00	1.00	0.34	0.48
PRIMARY PRODUCER	62	0.00	1.00	0.39	0.49	62	0.00	1.00	0.56	0.50	65	0.00	1.00	0.12	0.33
SECONDARY PRODUCER	62	0.00	1.00	0.48	0.50	62	0.00	1.00	0.44	0.50	65	0.00	1.00	0.72	0.45
DEPTH	54	1,500	12,900	7,506	3,399	39	3,317	13,466	8,224	2,691	50	934	13,000	5,443	2,744
OOIP	47	5.59E+5	6.12E+8	8.65E+7	1.27E+8	16	4.00E+6	3.35E+8	6.87E+7	8.64E+7	36	3.10E+6	1.62E+9	2.11E+8	3.16E+8
RESERVOIR VOLUME	11	1.2	275	83	85	31	1.6	285	275	558	29	2.0	905	164	242
<u>Regulatory Variables</u>															
UNIT LAW	62	0.00	1.00	0.37	0.49	62	0.00	1.00	0.52	0.50	65	0.00	1.00	0.42	0.50
SPACING LAW	62	0.00	1.00	0.74	0.44	62	0.00	1.00	0.92	0.27	65	0.00	1.00	0.58	0.50

Four general points emerge from the summary data in Tables 4 and 5. First, the mean reservoir size as measured by total producing surface acreage is slightly larger in the Williston Basin, 13,243 acres, than for all reservoirs in the sample, 12,497 acres. Surface acreage is smaller in Montana, 12,187 acres, than in North Dakota, 12,709 acres, and Wyoming, 12,576 acres. But standard deviation of reservoir size is large for all three states, indicating large average variations for all states.⁸³

Second, the average year of discovery in the Williston Basin is 1968 while the average year of discovery for all sampled reservoirs is 1960. Reservoirs in Wyoming were generally discovered earlier than those in Montana and North Dakota. The average reservoir in Wyoming, with a mean discovery date of 1948, is thirteen years older than the average Montana reservoir which was discovered in 1961, and twenty years older than the average North Dakota reservoir which was discovered in 1968.

Third, surface acreage ownership patterns indicate that reservoirs are on average controlled more by private landowners in the Williston Basin than for all sample reservoirs. In the Basin, the mean private surface acreage for a reservoir is 75 percent of the entire reservoir, while for all reservoirs the average private surface acreage is 58 percent. For the three states, ownership patterns are somewhat variable. In Montana, the federal government controls 24 percent of surface acreage with 65 percent held privately. In North Dakota, only 15 percent of surface holdings are federally controlled while 78

⁸³ The large standard deviation may in part result from the difficulty in clearly determining reservoir boundaries for non-unitized reservoirs. Because little data is available for these reservoirs, total surface acreage was estimated by determining boundaries based on well locations on the given reservoir. Also state oil and gas agencies provided maps with rough estimates of reservoir boundaries.

percent are privately owned. In Wyoming, the federal government controls 55 percent of all sampled reservoir surface acreage; 32 percent of reservoir acreage is privately owned.

Finally, for all the reservoirs in the sample, 75 percent were discovered after a spacing law had been enacted, but in the Williston Basin, 89 percent of reservoirs were discovered after spacing regulations were initiated. In Montana, 74 percent reservoirs were discovered after a spacing regulation had been enacted. In North Dakota 92 percent of reservoirs were discovered under statewide spacing regulations. But, in Wyoming only 58 percent of reservoirs were discovered with an active spacing law.

Tables 6 and 7 present correlation coefficients for the variables used in the econometric analysis for all sample reservoirs and reservoirs in the Williston Basin. Pearson correlation coefficients indicate some correlation among certain variables being tested. In both samples, the PRIMARY PRODUCER variable is negatively correlated with the dependent variable UNIT1 (Pearson Coefficient of -0.710 for all reservoirs and -0.879 for Williston Reservoirs). Also, COMPULSORY LAW is positively correlated with YEAR OF DISCOVERY in both samples (Pearson Coefficient of 0.741 for all reservoirs and 0.881 for Williston Reservoirs). For the sample of all reservoirs, SPACING LAW is positively correlated to both YEAR OF DISCOVERY (0.793) and COMPULSORY LAW (0.510). For the Williston reservoirs, COMPULSORY LAW is positively correlated to DEPTH (0.508).

Table 6. Correlation Matrix: Pearson Correlation Coefficients: All Reservoirs

	UNIT	TOTAL ACRES	% FEDERAL ACRES	YEAR OF DISCOVERY	PRIMARY PRODUCER	GAS CAP DRIVE	DEPTH	RESERVOIR VOLUME	COMPUL-SORY LAW	SPACING LAW
UNIT	1.00									
Surface Ownership Variables										
TOTAL ACRES	-0.106	1.00								
% FEDERAL ACRES	0.351	0.096	1.00							
Reservoir Variables										
YEAR OF DISCOVERY	-0.323	0.233	-0.302	1.00						
PRIMARY PRODUCER	-0.710	-0.011	-0.266	0.298	1.00					
GAS CAP DRIVE	0.111	-0.055	-0.004	-0.054	0.001	1.00				
DEPTH	-0.269	0.010	-0.302	0.366	0.364	0.025	1.00			
RESERVOIR VOLUME	0.204	0.207	-0.044	-0.062	-0.157	0.406	0.148	1.00		
Regulatory Variables										
COMPULSORY LAW	-0.206	0.245	0.038	0.741	0.177	0.010	0.237	0.001	1.00	
SPACING LAW	-0.249	0.166	-0.126	0.793	0.229	0.037	0.203	-0.131	0.510	1.00

Table 7. Correlation Matrix: Pearson Correlation Coefficients: Williston Reservoirs

	UNIT	TOTAL ACRES	% FEDERAL ACRES	YEAR OF DISCOVERY	PRIMARY PRODUCER	GAS CAP DRIVE	DEPTH	RESERVOIR VOLUME	COMPUL-SORY LAW	SPACIN G LAW
UNIT	1.00									
Surface Ownership Variables										
TOTAL ACRES	0.116	1.00								
% FEDERAL ACRES	0.123	0.460	1.00							
Reservoir Variables										
YEAR OF DISCOVERY	-0.228	-0.092	0.093	1.00						
PRIMARY PRODUCER	-0.879	-0.088	-0.125	0.125	1.00					
GAS CAP DRIVE	0.111	-0.101	-0.148	-0.077	0.028	1.00				
DEPTH	-0.334	0.003	-0.034	0.431	0.302	0.101	1.00			
RESERVOIR VOLUME	0.274	0.256	-0.001	-0.179	-0.280	0.317	0.158	1.00		
Regulatory Variables										
COMPULSORY LAW	-0.280	-0.016	0.094	0.881	0.200	0.011	0.508	-0.039	1.00	
SPACING LAW	-0.252	-0.158	0.084	0.460	0.124	0.019	0.060	-0.257	0.351	1.00

Estimating the Probability of Unit Formation

Using probit regression techniques, I estimate the effects of contracting determinants on the likelihood that a reservoir will be unitized. The probit model can be specified according to the following general equation:

$$1. \quad P[\text{Unit}]_i = f(\text{Field Variables}_i, \text{Regulatory Variables}_i, \text{Surface Ownership Variables}_i, \text{Reservoir Variables}_i, \text{Production Variables}_i)$$

The dependent variable, UNIT, is an observed binary choice variable for reservoir i , which is equal to one when a reservoir is unitized and equal to 0 when it is not. The independent variable categories include variables that measure specific characteristics of reservoir i .

Explanatory Variables and Predictions

As Tables 4 and 5 indicate, within each category, several variables can be used to measure the impact of contracting costs on the likelihood of unitization. Table 8 summarizes the predicted sign for the coefficient of each variable and the relevant prediction from Chapter 4 for the choice variables in the analysis.

Table 8. Summary of Coefficient Predictions

Independent Variable	Relevant Prediction	Predicted Effect on Probability of Unitization
Surface Ownership Variables		
TOTAL ACRES	Prediction 1a	-
% FEDERAL ACRES	Prediction 1b	+
Reservoir Variables		
YEAR OF DISCOVERY	Prediction 2	-
PRIMARY PRODUCER	Prediction 3	-
GAS CAP DRIVE	Prediction 4	+
DEPTH	Prediction 4	?
RESERVOIR VOLUME	Prediction 5	-
OOIP		
Regulatory Variables		
COMPULSORY LAW	Prediction 6	+
SPACING LAW	No Prediction	?

Surface Ownership Variables. Surface ownership variables are used to test Predictions 1a and 1b and include important measurements of contracting costs that are not captured by other categories of the general model specification. The variables, TOTAL ACRES and % FEDERAL ACRES, measure costs associated with reservoir size and firm heterogeneity. Increases in total producing reservoir surface acreage, TOTAL ACRES, are predicted to decrease the probability of unitization. If average farm size is used as a measure of firm access to the reservoir, then for $a_i = A/n$, as A increases (with a_i held constant at average farm size), n also increases. As a result, contracting among

increasingly numerous firms and landowners becomes more costly and decreases the net returns to unitization. While additional firms may increase reservoir dissipation and, therefore, the value of the unitized reservoir, the decreases in value from added costs is predicted to be greater than the increase in value from unitizing.

Firm heterogeneity is measured as the percent of federal surface acreage, % FEDERAL ACRES, overlying a reservoir.⁸⁴ Increases in % FEDERAL ACRES suggest fewer owners leasing tracts and decreasing heterogeneity as fewer firms have access to the reservoir. This variable is an accurate measure of heterogeneity because increases in federal reservoir acreage, as managed strictly by the Bureau of Land Management, do suggest more reservoir control by a single firm. Therefore, increases in % FEDERAL ACRES are predicted to increase the likelihood of unit formation. These variables test the prediction by Libecap and Wiggins (1984) that increases in firm concentration as measured by fewer and larger firms leads to more rapid contracting agreements.

⁸⁴ Reservoir acreage also consists of private, state, tribal, and tribal allotted lands. However, variables that representing the percent surface acreage of each of these land types have measurement complications that make their economic application to transaction cost analysis difficult. The variable for the percent private acreage does not accurately measure heterogeneity costs because firm level information is not captured by the surface ownership data. For instance, if a reservoir is 100 percent privately owned, it might be the case that it is solely owned. On the other hand there may be hundreds or thousands of owners. Without the additional information, the percentage of private acreage does not capture the heterogeneity problem. Similarly, the variable for the percentage of state acreage is problematic because of the different management agencies controlling state lands. Some lands are reserved to generate school revenues while others are state forests or game refuges. As a result, state lands are not controlled by a single party, but numerous agencies, each with different management objectives. Finally, the measure of tribal acreage is also problematic. Because Indian lands consist of both *tribal* and *allotted* lands, contradictory predictions are indicated based on the number of surface owners for each land type. *Tribal* acreage is generally characterized by sole ownership and reduced heterogeneity, while *allotted* lands typically have numerous owners and greater heterogeneity. Data for Indian lands overlying reservoirs were not separated into these two distinct types in the collection process, preventing testing of these surface variables.

Reservoir Variables. Libecap and Wiggins (1985) predict that as the productive age of the reservoir increases, more information on leases becomes available, and lease value uncertainty decreases. The variable, YEAR OF DISCOVERY, measures the number of years a reservoir has been in productivity. Older reservoirs with longer production histories are predicted to have more lease-value information publicly available, thus reducing value uncertainty and contracting costs of determining allocation formulas. A decrease in contracting costs, then, increases net benefits and the likelihood of unitization. Another interpretation of the predicted effect of YEAR OF DISCOVERY on the likelihood of unitization is that as the years in primary productivity increase, the natural reservoir drive is depleted, and production can only continue through investment in costly enhanced recovery projects. Because of the significant investment in capital, these projects require unit agreement to eliminate the costs imposed on the unit by rule of capture drainage.

Predictions 3 and 4 from Chapter 4 are tested by changes in variables measuring reservoir qualities. The dummy variable PRIMARY PRODUCER is used to test Prediction 3. The dummy variable, GAS CAP, and the measurement variable, DEPTH, test Prediction 4.

Prediction 3 suggests that primary production decreases the likelihood of unitization. During primary production, and especially soon after reservoir discovery, uncertainty under rule of capture is significant. Limited information is publicly or privately available as producers add wells, attempt to define reservoir boundaries, and determine physical reservoir characteristics. Lease valuations are difficult to calculate due

to the lack of information and differences in information among producers. Contracting during primary production can be costly as a result. Other things equal, the costs of unitizing increase and net returns to unitization decrease in the primary stage, as opposed to secondary or exploratory, because lease values are not publicly available and differences in information allow for strategic bargaining.⁸⁵ This suggests that reservoirs producing in the primary stage decrease the likelihood of unitization.

Predictions regarding natural reservoir drive mechanisms involve the measurement of waste associated with each drive. As the rule of capture model indicates, increased drilling creates waste, reduces reservoir rents, and increases the net returns of unitization, holding other things constant. Drive mechanisms associated with significant waste are then expected to have an increased likelihood of unitization. Gas cap reservoirs are known among petroleum engineers to be associated with the greatest rule of capture waste. These drives produce a low percentage of original-oil-in-place in the primary stage and can be permanently damaged by over-drilling (Clark, 1960). Water and dissolved gas drive reservoirs are less sensitive to over-drilling and permanent damage from rule of capture production. These latter reservoirs also can produce a higher percentage of original-oil -in-place during primary production. The returns from unitization are greater with gas caps than with dissolved gas drives and water drives. Thus, GAS CAP reservoirs decrease the likelihood of unitization compared to the other two reservoir drive types.

⁸⁵In secondary production, lease valuations are easily determined because the history of all primary production is available and can be used in allocation formulas. In the exploratory phase, no information is initially available so again, no firm has an information advantage.

Changes in reservoir depth result in no clear prediction regarding the likelihood of unitization. As the depth to the oil layer increases, the cost of drilling each well increases, and the number of wells drilled decreases regardless of the predominant production regime. Because the number of wells drilled under first-best and rule of capture both decrease, it is unclear how the amount of dissipation and dead weight losses change.

A second component of the DEPTH variable also prevents a definite prediction. Holding other factors constant, deeper reservoirs often require fewer wells for optimal drainage. Because pressures are often higher for deeper reservoirs, fewer wells are required to optimally drain the reservoir. However, increased costs already imply fewer wells will be drilled. The economic models in Chapter 4 do not develop predictions for the effect of depth related rate changes on rule of capture losses. Also, the interactive effect of changing production rates and higher drilling costs on rule of capture dissipation and transaction costs is not clear. Consequently, the effect of DEPTH on the change in the likelihood of unitization is ambiguous.

The variables RESERVOIR VOLUME and OOIP are used to test Prediction 5. These variables represent two ways of measuring the productive potential of a reservoir: 1) the holding capacity of the reservoir (RESERVOIR VOLUME) and 2) the amount of oil available for recovery (OOIP). The economic models suggest that as the productive potential increases, the net benefit of reservoir unitization increases. Therefore, as RESERVOIR VOLUME and OOIP increase, so too does the likelihood of unitization.

Wiggins and Libecap (1985) use productivity measures at the lease level to predict that as uncertainty and differences in information increase, the likelihood of

unitization decreases. They measure uncertainty by assessing productivity of leases on the reservoir. As lease productivity increases for a firm, uncertainty over the value of *in situ* oil beneath that lease also increases. Wiggins and Libecap (1985) predict that highly productive leases will be withheld from units because uncertainty and differences in information result in unsuccessful attempts to determine shares of unitized production for the lease.

The Wiggins and Libecap prediction appeals to the transaction cost approach, but lease level productivity data is unavailable. Because the variables OOIP and RESERVOIR VOLUME only measure overall reservoir productivity and do not capture production variability across leases, these measures do not capture the intended effect of the Wiggins and Libecap prediction. The relevant prediction then implies that as productivity, as measured by RESERVOIR VOLUME or OOIP, increases the likelihood of unitization increases.

Regulatory Variables. The regulatory variables are used to test Prediction 6 in Chapter 4. The COMPULSORY LAW dummy variable equals 1 when a compulsory unit law is in place at the time of reservoir discovery, and equals 0 otherwise. Similarly, SPACING LAW equals 1 when reservoir discovery occurs with spacing regulations in place, and equals 0 otherwise. COMPULSORY LAW is expected to have a positive effect on unitization, while no prediction is forthcoming for SPACING LAW. The unit-contracting model predicts that compulsory unit laws lower transaction costs of reaching unit agreements by eliminating the need for consensus agreement on a unit contract. As a

result, these laws increase the net returns to unitization and the likelihood of a unit agreement.

The coefficient for the spacing dummy, SPACING LAW, provides no definitive prediction. Spacing rules reduce rule of capture losses because limits are placed on the number of wells that can be placed on the reservoir. The rule of capture model indicates that gains from unitization subsequently decrease, as does the likelihood of successful unitization. But, the rules, in association with forced pooling laws, also reduce contracting costs by reducing firm heterogeneity, making the returns from unitization and the likelihood of unit formation greater. According to the unit contracting model, decreasing firm heterogeneity increases net reservoir returns under unitization and therefore increases the likelihood of unit formation

Comparison of Mean Values For Unitized and Non-unitized Reservoirs

Table 9 shows mean values of important measurement variables for unitized and non-unitized reservoirs. Mean values are calculated for the entire sample and for reservoirs in the Williston Basin. The results of the means test give initial support to predictions for several key variables. For each variable, the table shows the mean values for unitized and non-unitized reservoirs and the t-statistic for the null hypothesis that there is no difference between the mean values. For example in the first cell in Table 9, the mean total acreage of unitized reservoirs is 11,197 acres, while non-unitized mean is 14,464 acres.

Table 9. Means Tests for Economic and Reservoir Variables

VARIABLE NAME	ALL RESERVOIRS RESERVOIR UNITIZED			WILLISTON BASIN RESERVOIR RESERVOIR UNITIZED		
	YES (#)	NO (#)	t-VALUE	YES (#)	NO (#)	t-VALUE
<u>Surface Ownership Variables</u>						
TOTAL ACRES	11,197 (112)	14,464 (74)	1.41*	15,232 (46)	11,881 (54)	-1.16e
PERCENT FEDERAL ACRES	0.410 (112)	0.168 (74)	-5.43**	0.196 (46)	0.134 (54)	-1.22e
<u>Reservoir Variables</u>						
YEAR OF DISCOVERY	1954 (101)	1967 (75)	4.81e**	1964 (45)	1970 (54)	2.30e**
PRIMARY PRODUCER	0.078 (114)	0.773 (75)	13.79e**	0.065 (46)	0.944 (54)	18.15**
GAS CAP DRIVE	0.161 (93)	0.085 (70)	-1.48*	0.146 (41)	0.076 (52)	-1.03
DEPTH TO OIL ZONE (ft)	6,282 (86)	8,034 (57)	3.20**	7,912 (33)	9,595 (39)	3.04**
RESERVOIR VOLUME (in 000's acre-feet)	258 (47)	85 (24)	-2.32e**	370 (21)	90 (16)	-1.68**
ORIGINAL OIL IN PLACE (mill bbl)	151.8 (68)	78.2 (31)	-1.55e*	89.5 (27)	43 (20)	-1.66e*
<u>Regulatory Variables</u>						
COMP. UNIT LAW	0.350 (114)	0.560 (75)	2.86**	0.347 (46)	0.629 (54)	2.90 **
SPACING LAW	0.658 (114)	0.880 (75)	3.52e**	0.804 (46)	0.962 (54)	2.58e**

"Yes" refers to unitized reservoirs in the sample. "No" refers to non-unitized reservoirs.

"e" indicates the t-value is calculated under the assumption of equal variances across the two sample populations.

* indicates significant at .10 level, ** indicates significant at .05 level.

The t-statistic for the difference in mean TOTAL ACRES of all sampled reservoirs is 1.41 and significant at the 0.10 level. This significant difference in means indicates that unitized reservoir are on average smaller than non-unitized reservoirs. This result is consistent with the model prediction that as TOTAL ACRES increases, the likelihood of unitization decreases. Results of means test on the entire reservoir sample provide positive support for the model predictions. In the ALL RESERVOIRS column, the mean values have the expected and significant relationship for 7 of 8 variables. For the reservoirs in the Williston Basin, the expected mean value relationship occurs 6 of 8 times.

Three other key variables with mean values as expected are discussed. The mean values of the federal surface ownership variable results in the expected relationship in both cases. These values support predictions of reduced firm heterogeneity for reservoirs with larger shares of federally owned lands. The mean values in Table 9 indicate that %FEDERAL ACRES for unitized reservoirs is larger than for non-unitized reservoirs for all reservoirs and Williston reservoirs. The mean discovery date for all unitized reservoirs is 1954 while the average discovery date for non-unitized reservoirs is 1967. The t-statistic 4.81 is significant at the 0.05 level. A similar mean value relationship exists for Williston Basin reservoirs although the difference in mean values is not statistically significant.

The mean values for YEAR OF DISCOVERY suggest unitization is more common with older reservoirs. For example, within the sample of all reservoirs, the average year of discovery for a unitized reservoir is 1954 while the average discovery

date for a non-unitized reservoir is 1967. The t-statistic of 4.81 is significant at the 0.05 level. Similar results occur for reservoirs in the Williston Basin, providing initial support for the prediction that older reservoirs have decreased contracting costs as more information on lease values becomes publicly available.

The RESERVOIR VOLUME values for unitized and non-unitized reservoirs suggest that unitization is more prevalent on more productive reservoirs in all cases. For the entire sample of reservoirs, the average reservoir volume for unitized reservoirs is 258,000 acre- feet, while the reservoir volume for non-unitized reservoirs is 85,000 acre-feet. The t-statistic of -2.32 is significant at the 0.05 level.

Probit Estimates

I test Chapter 4 model predictions using coefficient estimates for several probit regressions on two different data samples. First, I use all reservoirs in the sample. Second, only Williston Basin reservoirs are analyzed as a separate sample. This sample is selected to control for the effects of changes in reservoir properties due to different geographical locations of sample reservoirs.

All Reservoirs. Table 10 presents the coefficient estimates for six probit specifications using the sample of all reservoirs. The specifications are chosen to examine various combinations of transaction cost variables on the likelihood of unitization. Specification 1 estimates the impacts of only the surface transaction cost variables and the descriptive reservoir variable YEAR OF DISCOVERY. These variables are also included in all subsequent specifications because reservoir access, firm numbers, and firm

and reservoir heterogeneity are clearly and directly linked to the economic models of well choice developed in Chapter 4. While other transaction cost variables are predicted to impact the likelihood of unitization, their effects are only implicitly linked through the transaction costs discussion. Specifications 2 – 5 estimate the joint effects of the original variables with reservoir variables (Specification 2), regulatory variables (Specification 3), and productivity variables (Specification 4). Specification 5 estimates the impact of all variables except production variables, and the final specification is the least restricted variation with the effects of all variables on the likelihood of unitization estimated.

Sample sizes vary across the specifications because data for some variables is not available. For example, the variable RESERVOIR VOLUME is available for only 71 reservoirs.⁸⁶ Information on reservoir properties is particularly difficult to collect because the data is often proprietary and not freely disclosed. Also, because characteristics such as porosity and permeability differ across the reservoir, the calculated measures of reservoir volume and OOIP that use these measures also differ across the reservoir. Only when reservoir information becomes publicly available do the measures of reservoir volume and OOIP converge to single estimate. The information on reservoir volume and OOIP in this study is provided by P.I Dwight's, a reservoir data collection organization. According to the company, RESERVOIR VOLUME and OOIP are based on public information, or are an average of various estimates of volume and OOIP available to the firm.

⁸⁶ The same problem occurs with the other productivity measure in the study, OOIP, where even less data is available.

Table 10. Probit Coefficient Estimates of Unitization: All Reservoirs

Dependent Variable=1 if reservoir unitized; =0 if not unitized							
Independent Variable	Predicted Sign	Specification 1	Specification 2	Specification 3	Specification 4	Specification 5	Specification 6
INTERCEPT		36.01** (3.06)	39.04** (1.74)	-6.74 (0.27)	16.79 (0.74)	-28.56 (0.80)	-42.11 (0.64)
Surface Ownership Variables							
TOTAL ACRES	-	-1.1E-5** (1.52)	-7.60E-6 (0.61)	-1.17E-5** (1.57)	-5.56E-5** (2.40)	-9.62E-6 (0.84)	-4.93E-5* (1.33)
%FEDERAL ACRES	+	1.19** (3.21)	0.68 (1.01)	1.33** (3.50)	1.06** (1.81)	1.07** (1.86)	0.22 (0.26)
Reservoir Variables							
YEAR OF DISCOVERY	-	-0.02** (3.06)	-0.02** (1.71)	3.79E-3 (0.31)	-8.4E-3 (0.72)	1.53E-2 (0.84)	0.02 (0.65)
PRIMARY PRODUCER	-		-2.37** (5.51)			-2.29** (6.55)	-2.38** (4.06)
GAS CAP DRIVE	+		0.34 (0.61)			0.93** (1.87)	-0.01 (0.02)
DEPTH	?		6.02E-5 (0.86)				1.12E-4 (0.56)
RESERVOIR VOLUME	+				3.37E-6** (2.38)		1.35E-6 (0.74)
Regulatory Variables							
COMPULSORY LAW	+			-0.53** (1.56)		-0.69* (1.34)	-1.25* (1.40)
SPACING LAW	?			-0.64** (1.59)		-0.72 (1.22)	-1.05 (0.83)
χ^2 (df)		182.46 (169)	172.66 (118)	177.86 (168)	80.66 (66)	199.61 (151)	57.70 (51)
lnL		-102.48	-42.49	-101.82	-35.13	-53.57	-18.45
Number of Observations (Y=1)		173 (99)	125 (72)	173 (99)	71 (47)	159 (90)	61 (40)

t-statistic in parentheses

* significant at 10% level with one-tailed test; **significant at 5% with one-tailed test.

The estimates in Table 10 generally support the transaction cost approach, confirming that increases in contracting costs or reduction in the net value of the unitized reservoir decrease the likelihood of unitization. The coefficient estimates on TOTAL ACRES are negative and statistically significant in four of six specifications. The estimates are consistent with Prediction 1a and imply that increases in reservoir size increase the costs of forming a unit. The coefficient estimate for %FEDERAL ACRES is positive and also significant in four of the six equations. The estimates are as expected according to Prediction 1b and imply that an increase in the percentage of federal acreage on a reservoir reduces heterogeneity and transaction costs and increases the likelihood of unitization. The coefficient estimate on YEAR OF DISCOVERY is of the correct sign and significant in only the first two specifications, providing only partial support to Prediction 2 that differences in information regarding reservoir properties decrease as reservoirs age. The predicted impact of increasingly available information does not appear significantly affect the likelihood of unitization.

The coefficient estimates for the reservoir measures, PRIMARY PRODUCER, GAS CAP, and DEPTH provide conflicting support for the predictions. The coefficient on the PRIMARY PRODUCER dummy supports Prediction 3 in all cases. The coefficient on GAS CAP is of the predicted sign and statistically significant only in Specification 5, while the estimate on DEPTH is statistically insignificant in all tests. Both WATER DRIVE and DISSOLVED GAS were substituted into the specifications without but did not provide statistically significant coefficient estimates. The estimates support Prediction 3 and indicate that rule of capture losses are likely most significant

during primary production. However, the estimates fail to support Prediction 4 indicating that reservoir properties such as drive mechanism and depth do not significantly impact unitization.

The estimated coefficient for the production variable RESERVOIR VOLUME provides some support for Prediction 5, implying that as expected reservoir recovery increases, so too does the likelihood of unitization. OOIP was alternately used in the specifications with no improvement in results. To further test the productivity prediction, I constructed the variable $VOLUME / ACRE$.⁸⁷ This measure allows for a different relative comparison of productivity where absolute volume is not as important as per acre volume. For specifications using this variable, I eliminated the individual measures of TOTAL ACRES and RESERVOIR VOLUME. According to Prediction 5, as $VOLUME / ACRE$ increases, the likelihood of unitization increases. The coefficient estimates for this measure were as expected and significant in all test cases, indicating that the per acre measure of reservoir volume has a more significant impact on unitization than simple absolute volume. Curiously, when the same measure is constructed using OOIP instead of RESERVOIR VOLUME, the results are insignificant in all cases.

The coefficient estimates for COMPULSORY LAW refute Prediction 6. In all three equations, the estimated effect of COMPULSORY LAW on unitization is negative and statistically significant, opposite of the expected effect. While the coefficient prediction for the SPACING DUMMY was ambiguous, the estimates imply that spacing

⁸⁷ For each reservoir, I divided RESERVOIR VOLUME by TOTAL ACRES to arrive at a measure to productivity on an acreage basis.

laws decrease the likelihood of unitization. The estimates suggest that the primary impact of spacing regulations is the reduction in the net value of unitization because of lower well densities that prevent over-drilling.

Williston Basin Reservoirs.⁸⁸ The well-choice model suggests that changes in physical reservoir properties affect the likelihood of unitization. For instance, different drive mechanisms have different implications for the likelihood of unitization. To control for variation in reservoir mechanics, reservoirs with similar geology were selected for analysis. The most straightforward method of selecting relatively homogenous reservoirs is choosing reservoirs from the same geologic region. Unfortunately, most of the regions in this study are represented by thirty or fewer reservoirs leading to small sample problems caused by limited degrees of freedom in the econometric specifications. The sample of reservoirs in the Williston Basin was selected for analysis because it allowed the use of 100 reservoirs. All North Dakota reservoirs and 39 Montana reservoirs are located in the Williston Basin. The predominate drive mechanism in the Williston Basin is the dissolved gas drive with 75 percent of the sampled reservoirs producing by this mechanism. Another 20 percent are pressurized by a natural water drive, and the remaining are gas cap drives. Depth to the oil zone averages 8,761 feet in Williston Basin with a standard deviation of 2,554 feet. The coefficient estimates for probit specifications using the Williston Basin reservoir sample are presented in Table 11. The specifications

⁸⁸ I selected the Williston Basin to analyze because of the relatively large number of reservoirs in the sample. The Williston Basin in Montana and North Dakota includes 100 reservoirs dispersed throughout northeastern Montana and western North Dakota (See Figure 5).

used in this analysis are the same as used for 'all reservoirs' except that Specifications 3 and 5 are not included.⁸⁹

⁸⁹The results fail to confirm predictions regarding compulsory unit laws and other results for other variables are not significantly different from estimates presented in Table 11.

Table 11. Probit Coefficient Estimates of Unitization: Williston Basin Reservoirs

Dependent Variable =1 if reservoir unitized; =0 if not unitized					
Independent Variable	Predicted Sign	Specification 1	Specification 2	Specification 4	Specification 6
INTERCEPT		46.96** (2.31)	127.35** (2.09)	249.05** (2.48)	545.55 (0.01)
Surface Ownership Variables					
TOTAL ACRES	-	6.61E-7 (0.06)	-1.03E-5 (0.33)	-1.25E-4** (2.67)	-2.03E-4** (2.19)
%FEDERAL ACRES	+	0.63 (1.06)	1.67 (0.98)	3.36** (1.68)	5.44* (1.54)
Reservoir Variables					
YEAR OF DISCOVERY	-	-0.02** (2.32)	-0.06** (2.16)	-0.12** (2.48)	-0.27** (2.11)
PRIMARY PRODUCER	-		-3.57** (4.99)		
GAS CAP DRIVE	+		1.44* (1.56)		1.41* (1.56)
DEPTH	?		-6.12E-5 (0.48)		2.02E-4 (1.13)
RESERVOIR VOLUME	+			7.65E-6** (2.30)	1.27E-5** (1.95)
Regulatory Variables					
COMPULSORY LAW	+				1.57 (1.01)
SPACING LAW	?				-5.36 (1.62E-6)
χ^2 (df)		101.30 (95)	32.53 (64)	33.03 (32)	19.64 (27)
lnL		-64.92	-12.03	-14.24	-10.96
Number of Observations (Y=1)		99 (45)	71 (33)	37 (21)	36 (21)

t-statistic in parentheses

* significant at 10% level with one-tailed test; **significant at 5% with one-tailed test.

The estimated coefficient on TOTAL ACRES has the expected and statistically significant sign in two of four specifications. These results lend support to Prediction 1a that total surface acreage increases on reservoirs in the Basin increase transaction costs and negatively affect the likelihood of unitization. Prediction 1b is also generally supported by the coefficient estimates on %FEDERAL ACRES. In all specifications the sign is as expected but again is only statistically significant in the final two specifications, suggesting that for these specifications, decreasing firm heterogeneity as measured by increasing federal control of the reservoir, increases the likelihood of unitization.

The reservoir variables used in the specifications provide strong support for the transaction cost predictions. Prediction 2 is strongly supported by the Williston Basin estimates. In all specifications, the YEAR OF DISCOVERY has the expected effect on the likelihood of unitization. These results indicate that reservoirs with earlier discovery dates are more likely to be unitized. With more information available on reservoir properties, the costs of contracting are significantly reduced, allowing firms to reach agreement. The coefficient estimate for PRIMARY PRODUCER is negative as expected from Prediction 3. Substituting SECONDARY also results in the expected positive coefficient estimate lending additional support to the differences in contracting in the primary and secondary stages of production. Prediction 4 is also supported by the coefficient estimates on GAS CAP. The econometric results suggest that because significant rent dissipation can be linked to gas cap drive reservoirs when rule of capture predominates, the value of the reservoir can be increased by a measurable amount when the reservoir is unitized. The coefficient estimate on DEPTH is not statistically significant

in either specification implying that changes in the distance to the oil zone has little effect on the likelihood of unitization. Finally, RESERVOIR VOLUME is positive and statistically significant in both of the specifications in which it is included. Increases in stock size and potentially extractable petroleum increases the likelihood of unitization as expected according to Prediction 5. Substituting OOIP for RESERVOIR VOLUME provides less convincing results. In both cases, sample size is less than forty because of the lack of information available for RESERVOIR VOLUME and OOIP.

The predictions regarding the regulatory regime are not supported for reservoirs in the Williston Basin. The coefficient estimate on COMPULSORY LAW in the final specification is of the expected sign but is insignificant, indicating that compulsory laws have little effect on the likelihood of unitization in the Williston Basin. Other specifications not presented, using COMPULSORY LAW, resulted in similarly insignificant coefficient estimates.

The coefficient estimate on SPACING LAW and the intercept term indicate the potential multicollinearity problems in the final specification. For both terms standard errors are high but no correlation problems are evident among the dependent variables. When the SPACING LAW dummy is omitted from the specification, the results are largely the same except that the standard error on the intercept term decreases dramatically and the positive estimate for the intercept is significant. The coefficient signs on all other variable estimates are the same and have the same level of significance.

Discussion of Probit Estimates

The econometric analysis provides general support for the transaction cost theory of oil reservoir contracting. The results provide positive results for all the predictions except Prediction 6 in at least half of the specifications used for both reservoir samples. In these cases, the effects of TOTAL ACRES, % FEDERAL ACRES, YEAR OF DISCOVERY, PRIMARY PRODUCER, GAS CAP DRIVE, and RESERVOIR VOLUME while not always statistically significant are usually the sign predicted by the model. The coefficients on TOTAL ACRES and % FEDERAL ACRES also support the predictions.

The coefficient estimate for YEAR OF DISCOVERY suggests, according to Wiggins and Libecap (1985), that as information becomes more available with increasing years of production reservoir unitization is more likely. The coefficient estimates for PRIMARY PRODUCER and SECONDARY PRODUCER also suggest that contracting costs significantly decrease the likelihood of unitization when the reservoir is in the primary stage of production, but that increases in reservoir value from enhanced recovery projects increase the likelihood of unit contracting. The coefficient estimates for GAS CAP DRIVE indicates the natural drive of a reservoir has significant implications on the value of the reservoir and the likelihood of unitization. Finally, the results support the prediction that increases in reservoir size particularly as measured by RESERVOIR VOLUME, increase the expected value of the reservoir when it is unitized and thus increase the likelihood of unitization.

The econometric results provide little support for Prediction 6. The expected positive impact of the COMPULSORY LAW on the likelihood of unitization is not revealed by the probit analysis.

An important problem with the econometric analysis is the omission of relevant data. In some cases, data could not be completely collected for some variables. For example, information on RESERVOIR VOLUME and OOIP is available for less than half of the reservoirs in the sample. In other cases, data could not be collected at all. For example, data on firm numbers and firm size is left completely unexamined by the data. Only information on total reservoir surface acreage and surface acreage ownership patterns is available. Because this omitted data is likely correlated with the independent variables, some degree of bias is likely present with the coefficient estimates (Pindyck and Rubinfeld, 1998). But if the expected correlation is known, the direction of bias can be predicted. For example, % FEDERAL ACRES is likely negatively correlated with the number of firms with access to the reservoir. This suggests a negative direction of bias and regression results that underestimate the impact % FEDERAL ACRES.⁹⁰

Case Studies

Although probit estimates provide support for the contracting cost predictions, they also suggest that the estimated specifications do not completely capture all of the

⁹⁰ This can be shown by $E(\hat{\beta}_2^*) = \beta_2 + \beta_3 \frac{\text{Cov}(x_2, x_3)}{\text{Var}(x_2)}$, where x_2 is %FEDERAL ACRES and x_3 is the omitted measure of firm numbers and $E(\hat{\beta}_2^*)$ is the expected coefficient from the regression. When $\text{Cov}(x_2, x_3)$ is less than zero, $E(\hat{\beta}_2^*)$ is less than β_2 , the true estimate of %FEDERAL ACRES (Pindyck and Rubinfeld, 1998).

important economic factors that determine unitization. The addition of case studies to the econometric analysis allows insights to the contracting problem that may not be captured by regression tests. A limitation to statistically testing predictions generated by the economic models is completely and accurately detailing econometric specifications. The transaction cost determinants require the construction of contracting measurement variables that can be represented quantitatively. This process can be problematic for several reasons. First, finding variables to represent certain transaction costs can be difficult. For instance, heterogeneity can be measured by the percentage of land overlying a reservoir owned by federal and state governments, private individuals or firms, and Indian tribes. But the lack of data on individual leases for each of these ownership types may lead to an inaccurate conclusion regarding the degree of heterogeneity and consequent negotiating costs.⁹¹ Second, once variables are selected, the specification process can be complicated by multicollinearity of the independent variables and omitted variables problems.⁹² Finally, the lack of data available for some reservoirs in the study, especially non-unitized reservoirs, allows testing of only limited variables on the entire reservoir sample. In this section, case studies are examined to further explain the determinants of successful unit contracting. Figure 5 shows the locations of the reservoirs under consideration, and Table 12 reports summary data on these reservoirs. Three cases of successful contracting are first discussed and then two cases where reservoir-wide

⁹¹ For example, a private lease with thirty royalty interest owners may imply greater heterogeneity than the same lease with one royalty owner.

⁹² Kennedy (1996) notes that probit models are sensitive to misspecifications and that estimators will be inconsistent if an explanatory variable is omitted.

unitization was unsuccessful. For each group of cases, the analysis begins with an overview of reservoir characteristics, productive history, regulatory conditions, and land-ownership status. The analysis concludes with a summary discussion of attempts at unitization of each reservoir and evidence supporting or refuting the predictions of the well-choice model.

Three Reservoirs with Unit Agreements

Circle Ridge, Wyoming. The Circle Ridge Tensleep oil reservoir is located on the Wind River Indian Reservation north of Lander, Wyoming. The Tensleep reservoir produces oil from wells drilled at an average depth of 4,900 feet. The reservoir is relatively small with only 1,680 producing surface acres, yet it was the twentieth largest producing reservoir in Wyoming in 1997. Discovered in 1923, Circle Ridge has a cumulative production of almost 32 million barrels of oil, relatively insignificant compared to the substantial production of 650 million barrels at Salt Creek and 450 million barrels at Elk Basin. Yet, its development provides insight into the difficulty of analyzing the formation of unit agreements. The reservoir was originally dissolved gas driven but now produces oil through water injection that began in 1986. Surface ownership is held completely by the Shoshone Indians and managed by its tribal council. These lands, unlike tribal allotted lands, do not have divided royalty interest problems because the tribal council holds the single right to negotiate for all tribal members on the use of the land.

Figure 9.
Locations of Case Study Reservoirs

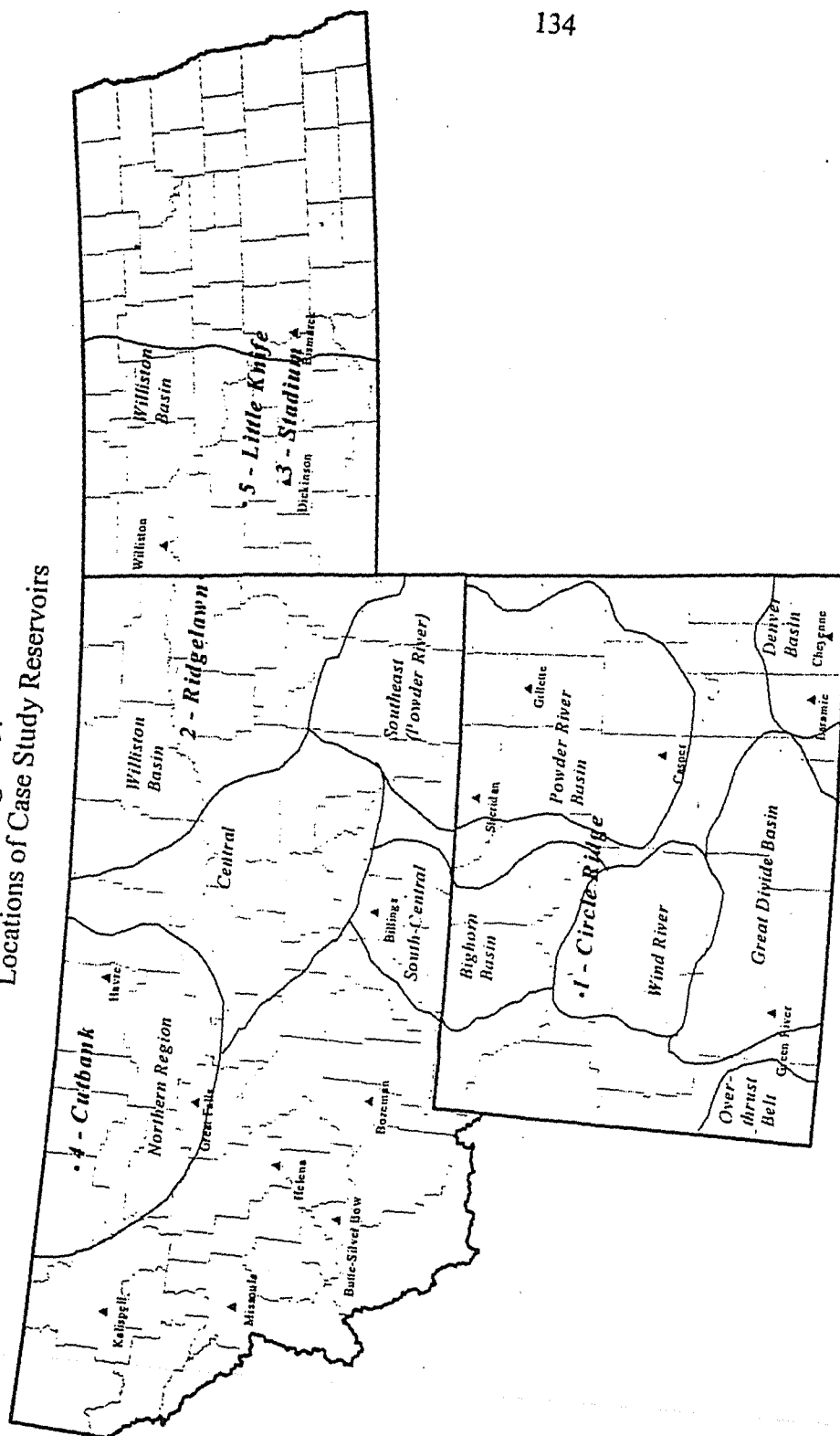


Table 12. SUMMARY DATA FOR CASE STUDIES

RESERVOIR NAME FIELD NAME	UNITIZED RESERVOIRS			NON-UNITIZED RESERVOIRS	
	MADISON CIRCLE RIDGE, WY	MADISON RIDGELAWN, MT	LODGEPOLE STADIUM, ND	CUTBANK CUTBANK, MT	MADISON LITTLEKNIFE, ND
DISCOVERY	1923	1984	1996	1932	1977
UNIT (DATE)	NOT KNOWN	1990	1998	NA	NA
YEAR OF FIRST STATE COMPULSORY UNIT LAW	1971	1969	1965	1969	1965
YEAR OF SPACING LAW	1951	1953	1953	1953	1953
DRIVE MECH	DISSOLVED GAS	DISSOLVED GAS	DISSOLVED GAS	DISSOLVED GAS	DISSOLVED GAS
OOIP (bbls)	ND	16,757,000	ND	612,000,000	160,000,000
DEPTH TO PAY ZONE	4,900	8,900	9,800	2,900	9,278
TOTAL SURFACE ACRES	1,680	3,219	1,521	49,000	26,720
PERCENT FEDERAL	0	0	5	2.25	3
NUMBER OF WORKING INTERESTS	1	41	187	30	12
UNIT OPERATOR	CONOCO	CONOCO (PHILIPS)	DUNCAN OIL	NA	NA
NUMBER ROYALTY INTEREST	1	143	1,850	ND	200+
CUMULATIVE PRODUCTION (bbls)	ND	889,000	1,064,256	167,128,000	66,049,754
NUMBER OF ACRES / WELL (1997)	16.00	804.75	304.20	123.42	133.60
AVG. COUNTY FARM SIZE AT DISCOVERY (ACRES)	1,277	1,927	1,068	3,083	2,576

ND= No data available, NA= Not Applicable

*Average farm size data was collected from U. S. Department of Commerce's Census of Agriculture volumes published in 1925, 1981, 1987, and 1994.

Because no explicit unit agreement exists, a complete leasing history is not clear. However, by the time enhanced recovery operations began in 1986, Conoco Oil Company was the sole operator on the field. Also, a lack of evidence prevents conclusions of significant rule of capture waste. The productive history of the reservoir does indicate rapidly declining productivity between 1980, when the reservoir was most productive with 1.7 million barrels of annual production, and 1985 when the reservoir only produced 550, 000 barrels. In any case, the declining reservoir drive as indicated by declining productivity led to the initiation of a water injection project by Conoco which increased annual production to 605,000 barrels of oil produced in 1987 and 666,000 barrels by 1997.

Ridgelawn, Montana. The Ridgelawn Madison/Duperow is small reservoir located in the Montana's Williston Basin. Discovered in 1984, the reservoir is located on the eastern border of the state near Sidney, Montana. Ninety-five percent of the 3,200 producing acres are privately held, while the remaining acreage is owned by the state. Individual holdings are divided among numerous royalty interests (one tract recorded forty-five royalty shares), but no single lease is smaller than 160 acres. In contrast, only forty working owners maintained operating interest on Ridgelawn. The reservoir is dissolved gas driven and original-oil-in-place is estimated at only seventeen million barrels. Ridgelawn Madison/Duperow has produced close to 900,000 barrels of oil as of 1997.

The productive history of the Ridgelawn Madison/Duperow reservoir is well recorded in Unit files maintained by the Montana Board of Oil and Gas Conservation. After four years of primary production, the natural reservoir drive began to show signs of weakening so that in the autumn of 1989, a technical committee formed by representatives of Conoco, Pennzoil, and other operators submitted a proposal for the unitization of the Ridgelawn Madison/ Duperow reservoir. The report noted the rapid decrease in reservoir energy from 1988 through April of 1989. At that time, the Montana Board of Oil and Gas shut-in the reservoir to prevent waste of gas.

Until 1988, production was limited by the ability of operators to process gas produced during production. Then, a new processing system was brought online by one of the producing firms, allowing wells to operate at flush rates. Within four months, indications of significant decreases in reservoir pressure from excessive gas production were noted. By early 1989, oil production rates were rapidly declining, and the reservoir was shut-in by Board order. At the end of 1989, the technical committee submitted its report on the benefits of unitized production which included a projected 300 percent increase in ultimate production from enhanced recovery and a 59 percent return on invested capital. By March of 1990, a unit agreement was submitted to and approved by working interest and royalty owners. The Montana Board of Oil and Gas quickly approved the project, allowing injection to begin in July. A voting record is unavailable, so the percent agreement by royalty and operating interests is unknown, and the impact of the state's compulsory unit law is, likewise, unclear. That said, the top five working interest firms agreed to a plan of unitization based on the results of the technical report.

These firms accounted for 79 percent of the total working interest on the reservoir, only one percentage point less than the statutory minimum required to force unitization. While 80 percent royalty interest approval was still required, the fact that the reservoir was shut-in combined with the well-researched benefits from unitization allowed rapid agreement on contracting terms.

Stadium, North Dakota. The Stadium reservoir on the western edge of the small town of Dickinson, North Dakota was unitized only two years after its discovery in 1996. Oil on the 1,500 acre reservoir is found in the Lodgepole formation at a depth of 9,800 feet. The surface ownership characteristics reveal a high concentration of private ownership divided into many small town lot size tracts so that almost 2,000 individuals have some royalty interest in reservoir production. Leasing of these tracts is also very diversified with over 185 firms maintaining a working interest. The reservoir is dissolved gas driven with a high sensitivity to over-drilling.

The Stadium Lodgepole was unitized without much recorded controversy only two years after its discovery. Currently the reservoir has produced only one million barrels of oil, but its annual average output per acre of 350 barrels is the highest of any reservoir included in the case studies.

Two Reservoir without Unit Agreements

Cutbank, Montana. Cutbank was first discovered in 1932 and quickly grew to close to 13,000 productive acres by the end of 1933. The reservoir produces from the Cutbank sand at 2900 feet. Exploration continued in the area, which lies just north of

Cutbank, Montana until the Montana Board of Oil and Gas was reporting over 59,000 productive acres at the end of 1960. The reservoir lay below hundreds of surface holdings. These small private interests represented over ninety two percent of the land owned on the reservoir.⁹³ Data from unit agreements of two partial units formed on the reservoir, South Central Cutbank Unit and Northeast Cutbank Unit, indicate numerous private tracts of less than forty acres, many with divided ownership shares involving twenty or more individuals. The fractionalization of ownership resulted in thousands of royalty interests claiming shares of production revenues.⁹⁴ The problem of divided interests was compounded by a similar fractionalization of working interests. The two partial units had over one hundred working interest firms competing for production in the early 1960's. The productive potential of the dissolved gas drive reservoir was huge by Northern Plain's standards with over 700 million barrels of original oil in place. Cumulative production to 1997 from the Cutbank reservoir is 167 million barrels of oil.

The history of the reservoir is not well known, but rule of capture production did lead to the extraction of seven million barrels of oil within the first five years of discovery. Montana Power Company and Texaco then acquired huge contiguous leases of up to 100,000 acres (Douma, 1953) by 1934 and likely reduced some rule of capture waste. The suspicion cannot be easily confirmed, though, because records of shut-in wells and reduced well production rates are not available. By 1962, Cutbank had a cumulative

⁹³ The federal government owned two percent of the overlying surface acreage, and the state of Montana owned the remaining five percent.

⁹⁴ Unit agreements on the Cutbank reservoir note some shares as small as 0.347 percent of tract revenues for a tract that was allocated only 0.50 of a percent of unit net returns.

primary production of ninety-one million barrels of oil, approximately fourteen percent of OOIP. Reaching a conclusion of significant waste is difficult based on this percentage, yet by 1962, enhanced recovery through waterflooding was necessary to continue production in some parts of the reservoir. Reservoir-wide unitization was not achieved. Instead smaller sub-units formed, some as large as 12,000 acres, throughout the reservoir. Between 1962 and 1967, six different waterflood projects were begun by at least three different operators: Montana Power, Texaco, and Union Oil of California. By 1993, the Montana Board of Oil and Gas permitted the operation of thirteen enhanced recovery projects. Sub-unit contracting allowed the realization of a portion of the benefits of reservoir-wide unitization, but costs drainage between sub-units and drainage losses from leases withheld from units prevented optimal economic gains.

Littleknife, North Dakota. The Littleknife reservoir provides an interesting study of a failed attempt at unitization and contrasts well with the successful unitization of the Stadium Lodgepole reservoir. The two reservoirs have similar physical and ownership parameters that would indicate similar probabilities of unitization. The differences between the two reservoirs actually lead to the conclusion that the Stadium reservoir would have a greater probability of contractual failure. Yet the Littleknife Madison reservoir was embroiled in controversy from its discovery and after six years, attempts at unitization were still unsuccessful. The Stadium Lodgepole reservoir, as noted above, was fully unitized after only two years of production.

The Littleknife Madison reservoir was discovered in 1977 when oil was struck at almost 9,500 feet deep.⁹⁵ The reservoir is located in the Williston Basin almost 50 miles north of Dickinson. Field boundaries on the large 26,000-acre reservoir were completed in 1979, and spacing was set at 160 acres in accordance with statewide regulations. Gulf, the major operator on the reservoir, acquired working interest control over 64 percent of the reservoir's productive acreage. Amoco, the next largest working interest owner, controlled another 24 percent. Surface ownership was highly concentrated in the private sector with over 95 percent of the reservoir located above fee land and over two hundred of royalty interest owners sharing in oil production revenues. Estimates of original-oil-in-place quickly indicated that the Madison formation was a major discovery with estimated reserves of over 160 million barrels of oil. Engineering studies and oil sampling revealed that the reservoir was dissolved gas driven, a very common feature for North Dakota reservoirs producing from the Madison formation.

Soon after the discovery of the Littleknife reservoir, wellhead gas-oil ratios began to rise. As reservoir pressures approached the critically low levels in the late 1970's, Gulf appealed to the North Dakota Industrial Commission for limits on production, including the shutting-in of high gas-oil ratio wells. Other working interest owners put up little resistance to Gulf's proposals, but non-working interest loudly opposed Gulf's attempts to regulate the reservoir. Organized as the Littleknife Producing Royalty Owners

⁹⁵ The information for this case study was taken from interviews conducted in the spring and autumn of 1999 with Jack Wilborn, Assistant Director of the North Dakota Industrial Commission, and Jim Legerski, Petroleum Engineer on the Commission. Data was also obtained from hearing records on file at the Industrial Commission.

Association, the group argued that Gulf was essentially asking for the reservoir to be unitized, but avoiding the compulsory unitization procedure which required 70 percent agreement of royalty interest owners.⁹⁶ After a lengthy hearing process, the Industrial Commission finally reached a compromise with Gulf and the Royalty Owners Association setting a mutually agreeable gas-oil ratio, that required shutting in an unknown number of wells to conserve pressure and extend primary production.

Despite these field rules, pressure continued to fall. Gulf began studying the benefits of enhanced recovery and attempting to legally unitize the reservoir. At the time unitization proceedings began, primary production represented less than 15 percent of estimated reserves. By the middle of 1983, Gulf was collecting signatures for the approval of its unit plan. The required working interest approval rate for compulsory unitization was easily achieved, but again the royalty interests opposed Gulf's actions, ultimately preventing any agreement from being reached.

Analysis of Unitized Reservoirs

The analysis of these three unitized reservoirs provides insight into the difficulty of examining the determinants of unitization. The Circle Ridge reservoir is essentially the sole owner case. While identifying the reservoir as a unit from state agency records is impossible, development suggests that the lack of competition among producers and royalty owners allowed optimal reservoir development. The unitization of Ridgelawn Madison/Duperow suggests the effects of negotiating costs with heterogeneous firms as

⁹⁶ The number of royalty owners in the Association is not known.

well as the impact of state agency orders in the unitization process. Rapid, successful unitization of the Stadium Lodgepole reservoir defies most of the predictions of the well-choice model. The reservoir is characterized by a high degree of royalty interest and firm heterogeneity, and high output acreage suggests high uncertainty over lease values. Yet the reservoir unitized in only two years.

The development of Circle Ridge by the Shoshone Tribal Council and Conoco Oil is a clear example of privately unitized production without agency support or authorization. The case of Circle Ridge is indeed the sole owner case and provides support for the prediction that as firm heterogeneity decreases, the likelihood of unitization increases. The leasing of all surface acreage by one landowner to one producing firm, eliminated rule of capture from the production process allowing wells to be placed according to the first best model of the sole owner. Because these private agreements pre-empt the regulatory process of application and approval, they are not recorded as unit agreements by state regulatory agencies.⁹⁷ In studies of unitization, these reservoirs are difficult to identify explicitly as unitized, but evidence from reservoirs such as Circle Ridge suggests that this categorization is incorrect.

Cases such as Circle Ridge and others suggest that agreements among a few owners and operators may be prevalent in the Northern Plains.⁹⁸ Enhanced recovery

⁹⁷ This situation is unique to Indian reservations where state regulatory approval is not required for enhanced recovery.

⁹⁸ The same development history occurred on the Steamboat Butte Madison reservoir where the Tribal Council controlled all surface acreage and Chevron was the sole lessor on the reservoir. Several other sampled reservoirs may be private units although details are unavailable.

projects on non-unitized reservoirs certainly indicate the formation of private agreements. Primary producing reservoirs with similar owner and operator characteristics also have likely reached productive agreements to reduce open access dissipation. However, data limitations make this hypothesis difficult to confirm. Econometrically, underestimating the number of unitized reservoirs in the sample would lead to biased estimates of the determinants of unitization. These biases are difficult to correct, but are revealed through the case study approach.

The successful unitization of the Ridgelawn Madison/Duperow reservoir appears to the result of the Montana Board of Oil and Gas order issued to cease production until a plan of unitization could be agreed upon. The number of royalty and working interests on the reservoir do not suggest significant heterogeneity, yet attempts to reach a unit agreement were unsuccessful until production was shut-in. The state's unitization law appears to have been an insignificant factor in the unitization as was the need for enhanced recovery.

The unitization of the Stadium Lodgepole reservoir is not well explained by the well-choice model. First, the reservoir is characterized by significant fractionalization of both working and royalty interest owners. Duncan Oil, the unit operator, ultimately had to obtain agreement from 70 percent of 1,850 royalty interest owners, and 70 percent of the 187 working interest owners. Secondly, on a per acre basis, productivity is relatively high suggesting high uncertainty over lease values. Finally, differences in information appear significant with only one year of data on which to base decisions for a unit allocation formula.

Yet with little opposition, Duncan reached an agreement after only two years. The ease of contractual success is not easy to determine, but a few explanations can be found. Despite the significant number of royalty and working interests, no organized opposition emerged to dispute Duncan's plan of unitization. The lack of opposition may be the result of apathy on the part of royalty owners or a better understanding of the expected benefits of unitization. Duncan Oil presented a well-conceived plan, which showed the dramatic gains possible from enhanced recovery under unitization versus continued primary production. With unitization, the productive life of the reservoir could be extended, and the incremental gains from unitization were expected to be extensive. The Stadium Unit was also located within ten miles of seven other reservoirs that had been successfully unitized. While the economic model allows no prediction for distances between reservoirs, successful nearby units may reduce the uncertainty of royalty interest landowners as to the expected gains from the unit. Finally, the fact that Duncan Oil was not a major oil producer may have given it more credibility and a negotiating advantage with royalty interest owners who often look upon major producers with suspicion.⁹⁹

⁹⁹ According to Jack Wilburn, the contract attorney at Stadium also took part in the failed unitization attempt at Littleknife (to be discussed below). Wilburn indicated that the lawyer's experience with that reservoir might have helped with both the writing and presentation of a unit plan to the owners on the Stadium reservoir.

Analysis of Non-unitized Reservoirs

The organization of production into sub-units on the Cutbank reservoir satisfies the prediction of Libecap and Wiggins (1985) that firms with large amounts of contiguous acreage will withdraw from unit negotiations and attempt to form their own distinct units. The history also suggests that the high level heterogeneity among working and royalty interest owners imposed too great a cost on the unit process. Without the help of compulsory unit laws, both Montana Power and Texaco, with huge contiguous tracts, formed sub-units on the Cutbank reservoir.¹⁰⁰ The leasing of large contiguous tracts also allowed secondary recovery to occur. Even though reservoir-wide unitization was unsuccessful, the formation of partial units mitigated some rule of capture losses.

The lack of unitization at Littleknife is due to the united opposition of a group of royalty owners, a determinant that is not accounted for in the well-choice model. The state's compulsory unit law provided no assistance, and the state regulatory agency refused to shut-in production as occurred at Ridgelawn, just across the Montana border. Measures of heterogeneity suggest a decreased likelihood of unitization as indicated by the high percentage of private ownership on the reservoir and relatively large number of working interest firms. But the true problem was the group of royalty interests.

The Royalty Owner's Association resistance to unitization at Littleknife can be attributed to three factors, none of which can easily be tested empirically. First, the historical relationship between royalty owners and Gulf was poor, originating in the late

¹⁰⁰ The information available does not indicate that either of these firms even attempted to unitize the entire reservoir.

1970's with disagreements over gas-oil ratios and continuing through 1983 with conflicts over production limits. Second, the Industrial Commission had recently dissolved four units north of Littleknife, because the agency determined that the operators were not managing the reservoirs in the best interest of royalty owners.¹⁰¹ Littleknife royalty owners were aware of these actions and were wary of unitization and negotiating with a major producer. Finally, Gulf's initial agreement was flawed, at least to the Royalty Interest Owners Association, because unit boundaries did not include all the wells on the reservoir. The Association also objected to engineering data presented by Gulf and tract valuations across the reservoir, determinants that have been discussed in the thesis. By December of 1983, Gulf determined contracting complications with the original unit agreement were insurmountable, and withdrew the agreement. The company attempted unitization one more time with the same result. By 1985, Gulf sold all interest in the reservoir to Chevron.

Currently many peripheral wells have been permanently abandoned, but some primary production continues in the central portion of the reservoir. Enhanced recovery was never undertaken. Reservoir simulations performed in 1983 estimated production from enhanced recovery at 48 million barrels of oil up to 1997. Production from continued rule of capture after failed unitization in 1983 until 1997 totals 42 million barrels, a difference based on the simulation of 6 million barrels of oil. Using an average

¹⁰¹ A more thorough explanation of "best interests" is not available at this time. In my interview with Legerski, he could not clarify the details of the four cases mentioned.

price of \$22.00 over the period, the lack of unit success cost interest owners \$132 million in lost production.

These econometric results and five case studies reveal the difficulties in completely specifying the important determinants for successful unit contracts with the available data. In numerous cases, issues specific to a particular reservoir have strongly influenced the outcome. While some reservoirs follow a predicted pattern based on reservoir engineering and surface ownership, others have a history of events which are difficult to link to the transaction costs model. Uncertainty, differences in information, and heterogeneity among interest owners account for much of the negotiating difficulties, but constructing determinants to represent these characteristics is a difficult task, complicated by the unique events beyond the scope of the model.

CHAPTER 6

CONCLUSION

The objective of this thesis has been to gain a better understanding of oil reservoir unitization by examining the determinants of unit contracting among landowners and oil producing firms. The main hypothesis of the thesis is that the probability of reservoir-wide unit formation increases when transaction costs of forming an agreement decrease. The well-choice models in chapter 4 develop this general hypothesis and generate testable implications. The well-choice models are constructed to study firm behavior under three different reservoir property rights regimes: sole ownership, rule of capture, and unit contracting. When the reservoir is solely owned or unitized, the optimal well-choice decision results. In both these cases, firm rents and the reservoir value are maximized. When the rule of capture holds and numerous firms have access to an oil reservoir, firms only face a portion of the full production costs. Because firms do not include all the costs of extraction in their production decisions, they choose to drill wells in excess of the first-best optimum. Each added well beyond the optimum results in dead weight losses, reducing firm rents and decreasing the total value of the reservoir.

While unit operations result in optimal well choice and maximized reservoir value, unit agreements are costly to negotiate. The contracting model indicates that units will only be formed when for all firms, the expected net returns of the unit operation,

including contracting costs, exceed the expected net returns of rule of capture production. In addition, these gains must be distributed so that each firm is better off than under the rule of capture. Compulsory unit regulations amend the need for consensus by requiring the agreement of only a state-mandated majority of firms and royalty interests. The models generate several testable implications regarding the effects of reservoir qualities, regulatory regimes, surface ownership characteristics, and productive history on the likelihood of reservoir unitization.

To test the implications of the model, I collected data on over 150 reservoirs in the Northern Plains states of Montana, North Dakota, and Wyoming. Empirical analysis included probit regressions to estimate the effects of contracting cost variables on the probability of unit formation and the analysis of five case studies to illuminate contracting effects not captured by regression analysis.

The econometric analysis showed that decreasing contracting costs generally increase the likelihood of unitization. In particular, the estimates show that:

1. Changes in total reservoir surface that increase firm numbers and firm heterogeneity, also increase transaction costs and reduce the likelihood of unitization.
2. As the amount of federal surface ownership on reservoir increases, the likelihood of unitization increases, suggesting a decrease in firm heterogeneity and transaction costs.
3. The increasing availability of information as reservoirs age or as primary production ends, decreases negotiating costs and increases the likelihood of unitization
4. Increases in the productive potential of the reservoir, as measured by reservoir volume, increase the expected value of the unitized reservoir and the likelihood of unitization.

5. Compulsory unitization laws, unexpectedly, do not seem to reduce the costs of contracting and have little statistical impact on the likelihood of reservoir-wide unitization.

Case study analysis of three unitized and two non-unitized reservoirs in the Northern Plains provide additional information on the formation of unit agreements, and give examples of factors not accounted for in the probit analysis. The case studies show that:

1. Sole ownership implicitly indicates unitization since the owner can make optimal well-choice decisions without rule of capture competition. But these informal, private agreements are often hard to identify in the econometric study of unitization, leading to underestimates of the level of unitization.
2. State conservation agency actions to shut-in reservoirs can bring about unit agreements when contracting costs impede negotiations.
3. Unitization sometimes occurs when statistical models using available data suggest agreements are unlikely. Factors such as experience writing unit contracts and experience presenting plans of unitization may be the most important unit determinants.
4. On large reservoirs with numerous landowners and operating firms, unitization may not be attempted. Groups of firms may form sub-units if drainage can be prevented or reduced.
5. Errors by the potential unit operator and lack of trust between the operator and royalty interests may prevent the formation of units. If royalty interests do not believe the operator will act in their best interests, unit agreements are less likely to occur.

Limits of Econometric Analysis

The performance of the probit coefficient estimates can be explained by two general difficulties: data problems, and specification errors.

Data Problems

First, it was difficult collect complete information on the reservoirs selected for the study. Files maintained by state conservation agencies on unitized reservoirs were often incomplete, leaving gaps in the data set. Because the state agencies do not require ownership and lease data for non-unitized reservoirs, information on these observations is even more difficult to collect. For instance, productivity measures that provide information on oil recovery potential were very difficult to find and often when found conflicting measures were reported by different sources.

Second, several variables used in regression analysis do not always precisely measure the intended effects. Especially problematic in this regard are the surface ownership and productivity variables. The surface ownership variables only measure the percent of reservoir acreage controlled by the various ownership types. They give no indication of the number of firms or owners on the reservoirs, the size of the firms or owners, or whether the firms have leased adjacent acreage. The acreage measures give no indication of the spacing patterns for individual tracts. For instance, a reservoir overlain by classic railroad "checkerboard" of private and federal ownership likely has very different rule of capture implications than the same reservoir where all private lands and all federal lands are contiguous. The primary difficulty again resides with the problem of collecting data. While reservoir level data is readily available, although incomplete, lease level data and accurate maps of leasing patterns are very difficult to find.

Specification Problems

An important specification problem that may have effected the econometric analysis is the possible omission of relevant variables. This type of error results in biased coefficient estimates except when the omitted variable is uncorrelated with all the included independent variables. The omitted variables problem is the practical result of the difficulties with data collection. Because relevant information on non-unitized reservoirs and leases could not be collected, this data is left unexamined. It is likely that uncollected data on surface ownership qualities is correlated with available data. As a result some bias can be expected in coefficient estimates. Particularly with the surface ownership variables, the correlation between the surface acreage measures and the unmeasured lease information is likely negative, suggesting that the coefficient measures underestimate the likelihood of unitization

Further Study

Continuing with this topic requires renewed attempts at gathering data. The importance of lease level data is apparent. Also the importance of royalty interests in the unit contracting process has not been well addressed. Compulsory unit laws require consent of both working interest firms and royalty interest owners. Thus, by not having royalty interest data, part of the information needed to measure transaction costs of negotiations is missing. As mentioned at the end of Chapter 4, the different incentives of royalty and working interest likely has an important impact on the likelihood of unitization.

Another important area to be further explored is the importance of compulsory unit laws on unitization. The repeated failure to find a positive impact of compulsory unitization laws on unitization is difficult to understand. This failure may result from the specification errors discussed previously or selection bias in the data sample. However, it is worth considering that the absence of rule of capture waste on the scale of Texas, Oklahoma, and California has made compulsory laws less important in the Northern Plains. For example, in Wyoming where the federal government owns approximately 50 percent of surface acreage in the state, large landholdings (average farm size of 3,690 acres in 1997) combined with an effective statewide spacing rule may limit rule of capture waste to the extent that unitization may not generate significant returns. Montana and North Dakota also have large average farm sizes and high percentages of federal ownership of surface acreage, which likely affect rule of capture and unitization in similar manner as in Wyoming. To determine the importance of these laws, data would need to be collected to determine the extent of use of the law. In other words, for unitized reservoirs, one would need to know if unitization occurred with the aid of the compulsory law. Also voting records recording the percentage agreement of royalty and working interests would provide important information on the necessity of these laws in creating units. With this information, one could test the likelihood of unitization using percent working and royalty interest agreement as additional explanatory variables.

This thesis has shown that when unitization leads to significant increases in reservoir value, unit contracting is more likely to be successful. The study also supports the transaction costs approach by showing that property rights arrangements are likely to

change when the net returns of change are positive. Contrary to studies by Libecap and Wiggins studies, unitized reservoirs are commonly found (at least on the Northern Plains), implying that gains from reservoir unitization exceed the costs of forming units. The empirical results also indicate that private contracting continues to be an important institution despite the prevalence of modern conservation regulations. While compulsory unitization laws are economically appealing, they are not the only variables impacting the unit process. Instead, firm differences and reservoir characteristics also affect the likelihood of unitization.

Initially state agencies were thought to affect contracting primarily through regulatory controls. This thesis suggests these agencies may best aid the unitization process by reducing firm and reservoir heterogeneity. To some extent, agencies perform this function by collecting and making freely available well logs that chart physical reservoir characteristics and production records that track well extraction histories. The thesis also provides evidence that other state agency regulations such as well-spacing laws and forced pooling regulations may reduce initial rule of capture dissipation, reducing the advantages of altering property rights.

This analysis of reservoir unitization contributes to the understanding of the reservoir contracting problem in several ways. First, the models developed allow the analysis of not only firm heterogeneity characteristics important to Libecap and Wiggins' studies, but also the impacts of physical reservoir features, and regulatory institutions. Second, the econometric analysis uses a large number of reservoirs and a variety of measurement variables to provide a broad overview of contracting in the Northern Plains.

By examining a large data sample, the effects of unusual ownership patterns or reservoir qualities may not impact the statistical results as a small data sample might. For example, the studies of Libecap and Wiggins may be somewhat biased as a result of their use of sample of ten or fewer Texas and Oklahoma reservoirs characterized by numerous small surface landholdings and famous for rule of capture dissipation. Finally, the case study analysis provides new insights into the unitization problem, emphasizing the roles of royalty interests and state regulatory agencies in the contracting process.

While this thesis has focused on the production of oil, the economic theory and econometric analysis can be applied to other resource management problems where open access leads to overuse, such as water rights, fishing, pollution control, or wild game management. The models are useful because they provide insights into the affects on production of firm characteristics, qualities of the resource, and regulatory institutions. Each of these general categories can be altered to the specific parameters of the resource problem under study.

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APPENDICES

APPENDIX A

LAND POLICY AND LEASE ORIGINS

The designation "firm" has been used to identify the entity with drilling rights on a specified tract of land overlying all or a portion of an oil reservoir. Often this entity does not maintain outright ownership of the land on which it chooses to drill. Instead, the firm reaches an agreement, a lease, with the landowner to exchange a share of gross oil production for exclusive right to drill for oil and develop the tract. The origins of the oil lease are important for this thesis because leasing of private mineral rights from individuals has resulted in many rule of capture problems. In many countries, unlike the United States, the private surface landowner typically does not retain sub-surface mineral rights. In Canada for instance, the federal government originally controlled all surface and mineral rights. When the government deposed lands to private individuals or firms, it retained control of mineral rights. Beginning in the late 1800's and continuing through the early 1900's, the federal government transferred large tracts of land to provincial governments. These property rights features of these lands remained the same with mineral rights residing with the provincial government after subsequent sales to private individuals. For example, in Alberta and Saskatchewan, two provinces accounting for a large majority of Canadian oil production, the provincial government owns 80 percent of

mineral rights, but less than 20 percent of surface rights.¹⁰² With the provincial Crown's severance of mineral rights, leasing firms must negotiate with a single mineral owner who controls all access to underground resources. In the United States, when the federal government retains mineral rights to lands entirely overlying oil reservoirs, the situation is similar to that in Canada, with *one* owner controlling reservoir access. But often oil reservoirs lie beneath lands that are diversified among private, state, federal, and Indian owners. In these cases, individuals, state and federal governments, and tribal landowners all have the right to develop and exploit petroleum resources beneath their property. This right allows *numerous* owners to control access to the oil reservoir. As the number of landowners increases, more firms have the opportunity to lease tracts and drill wells. The different reservoir ownership regimes have important effects on unitization because of their different access implications. Thus, understanding the history and leasing policy of these lands contributes to a better understanding of the unitization problem. This appendix briefly surveys ownership and leasing by first explaining the establishment of the four different property classifications and then describing the leasing policies on each land type.¹⁰³

To encourage the initial settlement of the western United States, sovereign nations including Spain, France, and England granted ownership of land to individuals willing to

¹⁰² This information was acquired in a phone interview in the winter of 2000 with Ken Corbett, an oil and gas leasing specialist with Natural Resources Canada, the agency responsible for mineral rights policy on Canadian federal lands.

¹⁰³

Woodward (1983) is the primary information source for the land policy discussion in this appendix.

colonize the new territories. As these lands passed to U.S. sovereignty through the Louisiana Purchase of 1803 and the Oregon Compromise of 1846, the title of these settled lands remained with the original owners. These Foreign Land Grants were the original fee or private lands in the western United States. Individuals, corporations, schools, or any organization capable of ownership under U.S. law could own fee lands. At the time the lands passed to the United States, surface and mineral rights were unsevered. With the acquisition of huge tracts of land, the United States encouraged settlement and development by transferring land ownership to those willing to live and work in the West. The Railroad Right of Way acts transferred 131 million acres of land to the railroads by 1871 to promote the building of transcontinental railroads. The Homestead Act of 1862 and Stock-raising Homestead Act of 1916 were passed to encourage agricultural development. After a specified number of years, a patent was issued covering rights to the land. The patent under the Homestead Act applied to both mineral and surface ownership. Patents issued through the Homestead Act are the sources of title for most land in the United States. Under the Stock-raising Act, though, the federal government retained rights to all minerals. Most lands transferred to the private sector since the 1916 Act contain the stipulation that the landowner gains only surface rights to the acquired tract. Mineral rights remain with the federal government (Woodward, 1983). After the original transfer of patent, the individual was free to use the land and exploit mineral resources as allowed by law. Original tracts were often large, 160 acres, but through the years, they have been subdivided and sold or divided among heirs.

State lands originated with the Ordinance of May 2, 1785 in which Congress recognized the need for states to have land for schools and revenue raising. Under this ordinance, public lands were surveyed before any sale into rectangular townships that were further subdivided in thirty-six 640-acre sections. These sections were numbered from one to thirty-six and the state was given Section 16 of every township in the state. The Enabling Act of 1859 changed the Ordinance so that subsequent states including Montana, North Dakota and Wyoming were given Sections 16 and 36. If these sections were within a National Park or Forest, states were permitted to select an equal number of sections for ownership. States are also the owners of all navigable streams and lakes subject to federal control of navigation.

The history of ownership of Indian Lands is complex, involving wars, treaties, and acts of Congress. Title to original Indian lands was acquired by occupation or "aboriginal possession." As white colonists moved west, Indians lands were taken first by treaties and then by force as colonists pushed Indians onto lands, known as reservations. Indians resisted the reservation system and the notion that they could be confined to less desirable lands. In 1887, with the passage of the Dawes Act, each family head was given or "allotted" 160 acres to which he would gain full title after twenty-five years. This Act attempted unsuccessfully to break up tribes, dissolve reservations, and assimilate Indians into white man's civilization. Later acts conveyed unallotted reservation lands to tribes to be managed by Tribal Councils. Two distinct types of land ownership now exist on reservations: *allotted lands* that have title with individual tribal members and *tribal lands*,

which are held by the tribe as a group and managed by a central tribal government.

Transactions on both are subject to oversight by the Bureau of the Interior.

The oil lease was an institutional development that allowed the owner of a tract of land to give exclusive authorization to a specialized firm to prospect and produce oil from the tract. Leases often have terms stipulating the method of payment and duration, but the means of obtaining a lease varies with the class of land ownership (fee, state, federal, tribal, or Indian allotted). Typical leases have a fixed term with extensions granted for continued production and payment via an up front bonus plus a royalty percent based on the gross value of well production. Since the mineral owner does not pay any of the costs of production, his share is calculated as a percent oil revenues.

On fee lands leases are obtained through negotiations between the firm and the landowner over specific lease terms. The owner of a tract of land also has the right to divide his tract so that numerous leases can be issued for the tract. In the oil case, the subdivision of tract interests increases access to the oil reservoir and has implications on rule of capture production as will be discussed in Chapter 4. The division of tracts is often characteristic of oil development in a region. For instance in Texas, the permanent division of lands into small tracts was especially popular so that a landowner could lease drilling rights to numerous firms and attempt to increase his returns from his tract (Anderson and Smith, 1999). In a famous case at East Texas, 'Dad' Joiner leased more interests in his tracts than there were interests to be leased. Yergin (1992) discusses this leasing story in detail.

States lands are leased through a competitive bidding process, either sealed or oral. Terms of state leases are set by state legislatures. Typically lease stipulations include duration, bonus payments, acre rental rates, and royalty percentages.

The discussion of leasing on federal tracts is limited to onshore lands. On unexplored federal lands, firms secure oil and gas leases through a lottery system conducted by the Bureau of Land Management (BLM). With the passage of early mineral leasing laws, the BLM was given responsibility for the issuance and administering of leases on non-productive tracts. Lands lying above a known geological structure or in an area where oil has been discovered can only be secured through a sealed bid procedure administered by the U.S. Geological Survey. Leases for known producing areas are typically shorter, have higher initial bonus payments, and higher royalty payments than leases on unexplored lands. Firms are limited to leasing 246,080 of Federal lands in a state at any given time. But federal lands leased in a unit agreement are exempted from this limitation.

To secure leases on Indian lands, the firm must negotiate with individual owners of *allotted* lands or with the tribal government when *tribal* lands are at stake. For tribal lands, the interested firm submits a request to lease a tract or tracts to the Tribal council, who has the right to negotiate lease terms for the tribe. The lease sale is then advertised and the tribal council holds a sealed-bid auction. The superintendent of the particular Indian agency where the lease originates then administers the lease. This process is common for all reservations in the United States.

Acquiring leases on allotted lands occurs through a similar application and bidding process except that the superintendent of the agency now has jurisdiction instead of the tribal council. In Montana, North Dakota, and Wyoming, a second difference, significantly complicating the leasing process, is the nature of ownership on allotted lands. When lands were originally allotted to the heads of families, exclusive right of possession passed to the individual. When the allottee died, ownership was divided among his heirs. In some cases over 100 heirs were known to have a share ownership of a tract as small as forty acres. In order to complete a lease, all owners must agree to the lease terms. Anderson and Smith (1999) discuss this complication to the leasing process.

In summary, as the United States acquired sovereignty to lands in the West, it began to transfer title to private individuals, states, and Indians. For a large majority of these lands, the transfer of title included rights to use of surface acreage and subsurface minerals. Lease agreements are legal instruments developed to allow the transfer of mineral rights from a landowner unable to exploit his mineral resource to a firm with the ability to discover and produce oil. Leases are administered through private negotiation, lottery, or auction with terms negotiated by the parties involved.

The transfer of mineral rights from a single owner, the federal government, to numerous individuals, states, and tribes and the subsequent development of leasing institutions to exploit mineral resources has important impacts on oil production. The pattern of ownership among the four land types, the number of individual owners, and the size of ownership tracts, all affect rule of capture production and the probability of unitization.

APPENDIX B

DATA

This appendix provides additional information on the selection of reservoirs for the data sample. A large number of reservoirs were chosen to provide data on a diverse set of physical properties and surface ownership conditions. As chapter 4 suggests, a weakness of past studies has been the limited number of reservoirs selected for empirical analysis. Libecap and Wiggins (1984) used information on only the five of the largest oil producing fields in Texas and Oklahoma discovered between 1926 and 1935. Their next study in 1985 utilized data from only seven observations in Wyoming, Texas, and Oklahoma.

To provide a broad representation, the reservoirs collected for the sample were chosen to give a geographical and chronological distribution, to represent primary and secondary production techniques, and to include unitized and non-unitized reservoirs. For the units selected, the original unit agreement was used as the data source, not a more recent revised agreement with an enlarged or contracted participating area. Because the thesis is attempting to evaluate the determinants of unit formation, the original unit contract for a reservoir contains the pertinent information.

In order to include important reservoirs in the history of each state's oil development, top current and cumulative producing reservoirs were selected for the sample. First, the top twenty-five producing reservoirs from each state in 1997 were

selected to be included in the survey. Next, those reservoirs with significant cumulative production were chosen. While not important to current state production, these reservoirs have significant productive histories. For instance, the Muddy reservoir on the Gas Draw field in Wyoming produced only 50,660 barrels of oil in 1996, but in 1978 the reservoir produced 961,987 barrels of oil. Since its discovery in 1968, the Muddy reservoir has produced 26,883,399 barrels of oil. By comparison, the Minnelusa reservoir on the Slattery field in Wyoming was the twenty-fifth ranked annual producer in 1996 with 470,078 barrels of oil but only has a cumulative production beginning in 1957 of 10,206,989 barrels.

Reservoirs were next selected to represent the different productive regions of each state. State oil and gas agencies define regions, which are typically based on geological boundaries. For instance, the Big Horn Basin in Wyoming, as defined by the Wyoming Oil and Gas Conservation Commission, is bounded by the Yellowstone Plateau on the west, the Big Horn mountains to the east, the Owl Creek Mountains to the south and the Beartooth Mountains to the north. Wyoming has six producing regions while Montana recognizes five. North Dakota production takes place entirely in one producing region: the Williston Basin. While the basin extends into South Dakota, Montana and Canada and contains numerous fault zones, the structural geology of the region is similar, and all of North Dakota producing reservoirs lie within this basin.

Table B1. State and Regional Comparison of Production Statistics

REGION	1997 SAMPLE PRODUCTION											
	NUMBER OF RESERVOIRS SAMPLED	UNITS				NONUNITS			CUMULATIVE SAMPLE PRODUCTION (BBLs)	TYPE OF PRODUCTION**		
		NUMBER	BBLs	% OF SAM-PL	NUMBER	BBLs	% OF SAM-PL	PRIM.		SEC.	EXPL.	
MONTANA												
Central	6	5	213,776	2.45	1	4,625	0.05	81,818,000	0	6	0	
Northern	11	9	1,385,837	15.87	2	291,193	3.34	302,977,000	1	7	3	
South Central	4	2	221,632	2.54	2	36,138	0.41	64,116,763	2	2	0	
Southeast	3	1	170,910	1.96	2	8,496	0.10	133,249,442	2	1	0	
Williston	38	16	4,435,098	50.80	22	1,961,369	22.47	474,503,755	19	14	5	
Total	62	33	6,426,983	73.62	29	2,302,821	26.38	1,056,664,960	24	30	8	
NORTH DAKOTA												
Williston	62	29	11,950,410	67.66	33	5,710,921	32.33	783,118,779	27	35	0	
Total	62	29	11,950,410	67.66	33	5,710,921	32.33	783,118,779	27	35	0	
WYOMING												
Big Horn	15	14	12,819,003	41.94	1	67,173	0.22	1,032,805,000	2	13	0	
Denver	3	2	41,456	0.14	1	456,062	1.49	16,329,000	0	3	0	
Great Divide	9	8	2,303,870	7.54	1	318,016	1.04	217,629,773	0	4	5	
Overthrust	3	2	3,545,959	11.60	1	438,444	1.43	87,421,000	1	2	0	
Powder River	28	20	7,679,061	25.12	8	1,994,829	6.53	353,052,000	5	22	1	
Wind River	7	5	148,035	0.48	2	935,758	3.06	NA*	0	3	4	
Total	65	51	26,357,384	86.23	14	4,210,282	13.77	NA*	8	47	10	

*Wyoming reports cumulative production for fields only. When a field contains numerous reservoirs, determining production for each is not possible.

** PRIM= Primary Stage, SEC.= Secondary Stage, EXPL.= Exploratory Stage

Table B1 provides regional and state by state summary data on production and physical reservoir characteristics for sample reservoirs. For each state and region, except for the Denver, Great Divide, and Wind River Basins in Wyoming, average 1997 production from units in the sample exceeds that of non-units. For example, in Montana, 33 sample units accounted for an annual production of 6,426,983 barrels of oil or an average of 194,754 barrels per reservoir. Twenty-nine non-unitized reservoirs produced 2,302,821 barrels or an average of 79,379 a reservoir. The sample production totals account for over 50 percent of oil production for each state in 1997. For Montana and North Dakota, the sampled reservoirs also capture over half the cumulative oil produced in these states. Since cumulative data are only available on the field level for Wyoming reservoirs, a similar calculation cannot be made.¹⁰⁴ With the data available from reservoirs that are the sole reservoirs on the field, sample production accounts for 25 percent of the cumulative total.

The table reflects the high concentration of production into only a few regions in each state. While some regions may be over-represented in order to include important reservoirs, oil production is nonetheless, centered around three key regions. For instance, Wyoming state summary statistics for 1997 report that approximately 35 percent of Wyoming oil was produced in the Powder River Basin. Another 30 percent was

¹⁰⁴ When more than one reservoir occurs on a field, reservoir production cannot be distinguished from field production.

produced in the Big Horn Basin.¹⁰⁵ More dramatically the Montana state summary statistics indicate that the Williston Basin accounted for 79 percent of 1997 annual statewide production. In North Dakota, 100 percent of production occurs in the Williston Basin. Statistics in Table 14 confirm the concentration of production for the reservoirs in the sample, with Powder River, Bighorn, and Williston Basins showing the highest combined unitized and non-unitized productivity.

Focusing the study on these three regions alone would eliminate historically important reservoirs in Montana and Wyoming. The significance of Northern Montana oil production is apparent with the inspection of cumulative production data. Many of Montana's oldest reservoirs are located in this region and accounted for much of the early Montana production. In Wyoming, while the Green River Basin only contributes a small percentage to statewide production, it contains three of the top twenty-five 1997 producers

Table B1 also provides information on the stage of production for reservoirs in the sample. The table indicates the limited number of primary producing reservoirs in Wyoming while in Montana and North Dakota, roughly one third to one half of the sampled reservoirs are primary producers. No exploratory reservoirs from North Dakota are included. At the time of data collection, oil prices were at record lows nationwide.¹⁰⁶ As a result exploratory activity slowed considerably across the region. For instance, no

¹⁰⁵ Another measure of concentration reveals Salt Creek, Oregon Basin, and Elk Basin were responsible for almost 50 percent of Wyoming's annual production in 1997. Only three fields contributed over half of all Wyoming production.

¹⁰⁶ For several weeks in 1999, prices were so low that no wells were producing in North Dakota.

exploratory units were formed in North Dakota. Wyoming and Montana did have some exploratory activity, although exploration on these units began before oil prices fell. The eighteen exploratory reservoirs in Montana and Wyoming were all unitized before exploration began.

As well as geographical distribution, reservoirs were also chosen to be distributed across time according to their date of discovery. Table B2 shows the distribution of reservoir discoveries for each state from 1880 to the present. The table gives some indication of the oil development history in each state. In Wyoming, many discoveries occurred in the early 1900's. During this period of time Salt Creek became a major producer and several other important reservoirs were developed including Elk Basin and Oregon Basin. While important discoveries such as Cutbank and Kevin-Sunburst occurred early in Montana oil history, activity beginning in the early 1950's with the discovery of the Williston Basin had the greatest impact on oil exploration in the state. Table B2 also shows the concentration of North Dakota discoveries from 1941 to the present. This distribution results from the 1951 initiation of commercial production in North Dakota with the discovery of oil on the Beaver Lodge-Devonian reservoir east of Williston.

Discoveries from 1889 to the present are included to examine the impacts of conservation legislation on the reservoirs discovered and unitized both before and after the passage of spacing regulations and compulsory unitization laws. Table B3 provides information on the important dates when regulations were initially enacted as well as the distribution of reservoir discoveries around those dates. The table indicates that over half,

56 percent, of reservoirs in the sample were discovered when states already had spacing laws in effect but before a compulsory unit law had been passed. In fact, 75 percent of the reservoirs in the sample were discovered with spacing rules enacted. In Wyoming, 42 percent of reservoirs were discovered before a spacing law while in Montana the figure was 28 percent and in North Dakota only 8 percent. The figures give some indication of the impact of rule of capture on production. For example, the large percentage of reservoirs discovered after spacing laws were enacted suggests that significant rule of capture waste may have been reduced for a large majority of the reservoirs in the sample.

Table B2. Distribution of Sample Reservoir Discovery Dates

	WYOMING	MONTANA	NORTH DAKOTA
1880-1900	1	0	0
1901-1920	13	2	0
1921-1940	7	4	0
1941-1960	12	23	26
1961-1980	17	18	24
1981-present	5	7	12

*Discovery date refers to date of first commercial production. Exploratory units are by definition excluded

Table B3. Regulations and Sample Reservoir Discovery

	Spacing Law					Compulsory Unit Law				
	Year Spacing Law Enacted	Reservoir Discovery Pre and Post Spacing Rule		Percent of Reservoirs Discovered Pre and Post Spacing Rule		Year Unit Law Enacted	Reservoir Discovery Pre and Post Unit Rule		Percent of Reservoirs Discovered Pre and Post Unit Rule	
Montana	1953	16	46	26%	74%	1969	39	23	63%	37%
North Dakota	1953	5	57	8%	92%	1965	30	32	48%	52%
Wyoming	1951	27	38	42%	58%	1971	38	27	58%	42%