on bay shrimpers during the spring brown shrimp season. Daily limits of 300 pounds per vessel have been assigned in the bays in the spring, but no catch restrictions are imposed for fall bay white shrimp season or the fall and winter brown shrimp season in the Gulf. Taxes and other internal effort controls have received little political support from shrimpers and have not been adopted.

SUMMARY

The apparent inability of fishermen to biologically overfish the shrimp fishery, even though catch per unit of effort has fallen, has prevented conditions from deteriorating to a level that would lead to political agreements among shrimpers, regulators, and politicians in Texas on more restrictive controls on individual effort to reduce common pool losses. Instead as suggested under “The Gains from Contracting and Bargaining Problems,” the regulations that have received support are those that are designed to increase aggregate catch with little or no impact on shares, such as seasons and related equipment restrictions. Shrimpers also have been able to agree on regulations that are designed to limit the fishing of rivals as indicated in the conflict between bay and Gulf shrimpers. So long as the stock of shrimp is maintained through annual recruitment, reducing the pressure for stricter regulation of access and of individual catch in the Texas shrimp fishery, a suboptimal political equilibrium may persist, whereby incomes remain low for a large number of shrimpers and rents are dissipated through excessive labor and capital investment.

This discussion of fisheries emphasizes the importance of the details of contracting for property rights for determining how a society responds to common pool losses. For many fisheries the institutional solutions have been very incomplete and serious rent dissipation has continued. Understanding the chronic nature of problems such as these requires further analysis of the distributional conflicts that hinder the adoption of more complete property rights. Chapter 6 continues this investigation of contracting for property rights to reduce the losses of the common pool by examining competitive crude oil extraction.

CONTRACTING FOR THE UNITIZATION OF OIL FIELDS

INTRODUCTION

This chapter examines the contracting problems encountered in efforts to unitize the production of crude oil in the United States. Since the first discovery of petroleum in the United States in 1859, oil production has been plagued by serious common pool losses. These losses arise as numerous firms compete for migratory oil lodged in subsurface reservoirs. Under the common law rule of capture, private property rights to oil are assigned only upon extraction. This follows similar practices in allocating property rights to other naturally occurring resources, such as fish, wildlife, and even frontier federal land. For each of the firms on a reservoir, a strategy of dense-well drilling and rapid production allows it to drain oil from its neighbors and to take advantage of the low extraction costs that exist early in field development. In new, flush oil fields, subsurface pressures are sufficient to expel the oil without costly pumping or injection of water or natural gas into the reservoir to drive oil to the surface.

Under these conditions, when there are multiple firms on a reservoir, each firm has incentive to drill competitively and drain to increase its share of oil field rents, even though these individual actions lead to aggregate common pool losses. Rents are dissipated as capital costs are driven up with the drilling of excessive numbers of wells (more than geologic conditions require or price and interest rate projections warrant) and with the construction of surface storage, where the oil can be held safe from drainage by other firms. Unfortunately, once in surface storage, oil is vulnerable to fire, evaporation, and spilling. Rapid extraction also increases production costs as subsurface pressures are vented prematurely, forcing the early adoption of pumps and injection wells. Total oil recovery falls as pressures decline because oil becomes trapped in surrounding formations, retrievable only at very high extraction costs.
Contracting for Property Rights

Finally, rents are dissipated as production patterns diverge from those that would maximize the value of output over time.

There never has been much disagreement over either the nature of the common pool problem or the general solution to it. Early discussions of restrained oil production in the United States emphasized extraordinary wastes. In 1910, oil losses from fire and evaporation from surface storage (wooden tanks or behind earthen dams) in California, a major producing state, ranged from 4 to 8 million barrels, or 5 to 11 percent of the state's production. In 1914, the director of the Bureau of Mines estimated losses from excessive drilling at $50 million, when the value of U.S. production was $214 million (in 1926, pp. 91, 141; American Petroleum Institute, 1951, p. 166). In 1926, the Federal Oil Conservation Board (1926, p. 30; 1929, p. 10) estimated oil recovery rates of only 20 to 25 percent with competitive extraction, whereas recovery rates of 85 to 90 percent were thought possible with controlled withdrawal.

In 1928, competitive drilling on the Hendrick field of West Texas led to one well per ten acres at a cost of $57,000 per well, where porous geologic conditions suggested that only one well per eighty acres would have been sufficient to rapidly drain the reservoir. The associated loss in underground pressure forced premature oil pumping at a marginal cost of $1.10 per barrel. Moderate withdrawal would have maintained pressure and allowed oil to flow without pumping until late in the field's life (Oil Weekly, March 23, 1928; April 13, 1928). Moreover, storage capacity was driven up by the competition for oil. During the first five months of 1928, storage capacity on the Hendrick field rose from 2,511,000 to 10,987,000 barrels at a cost of $3,842,300. By contrast, on the neighboring and similarly sized Yates field, where private controls limited production, storage was only 736,000 barrels at a cost of $274,000 (Oil Weekly, February 24, 1928; March 23, 1928; May 25, 1928). In 1937, the American Petroleum Institute estimated that unnecessary wells on the East Texas field cost over $200 million (American Bar Association, 1958, p. 256). In 1980, intensive drilling under prevailing ownership and regulatory practices in the United States left the United States with 88 percent of the world's oil wells and only 14 percent of the world's production (International Petroleum Encyclopedia, 1982, pp. 334-35).\(^1\)

There also are pecuniary losses associated with competitive common pool extraction, because oil cannot be held in the reservoir in response to price and interest rate forecasts. With rapid competitive production, oil is dumped onto the market by firms, depressing prices. For example, be-
Contracting for Property Rights

volved in common pool crude oil production, complete fieldwide unitization has not been widespread. Bain (1947, p. 29) noted: "It is difficult to understand why in the United States, even admitting all obstacles of law and tradition, not more than a dozen pools are 100 percent unitized (out of some 3,000) and only 185 have even partial unitization." Similarly, Libecap and Wiggins (1985) reported that as late as 1975 only 38 percent of Oklahoma production and 20 percent of Texas production came from fieldwide units.

Just why this is so is the subject of this chapter. The key issue in blocking agreement on the voluntary unitization of oil fields is conflict over a share formula to divide the net proceeds of unit production among the various parties. An early student of unitization, Williams (1952, pp. 1173-74), commented:

"The principal obstacle to full, voluntary agreement is the problem of dividing the proceeds of production. If development of the area sought to be unitized is incomplete, there is a certain amount of gamblers' instinct to overcome; some lessors and leasees may be inclined to rely on the possibility that their interests lie in the most favorable part of the producing structure and to take their chances that the entire production from their land will be more valuable than an undivided interest in production from a much larger unitized tract. If development of the pool is relatively complete, there is frequently acrimony as to the respective shares of production to be given owners with interests in favorable parts of the structure and owners of interests in less favorable areas.

This chapter examines the source of these distributional conflicts over unit shares. Uncertainties and information asymmetries regarding the valuation of individual firm oil leases, which are the basis for unit shares, are important contributors to the disagreements that block unitization, even in the presence of large and uncontroversial aggregate gains from unit formation. More than for any of the other cases examined in this volume, sufficient information is available for unitization to analyze the details of private contracting and the problems encountered in attempting to reach agreement. The discussion draws from Libecap and Wiggins (1985) and Wiggins and Libecap (1985).

The Contracting Environment

Oil reservoirs are commonly found below numerous independently owned surface tracts. The surface landowners initially hold the mineral rights, but transfer them to firms through mineral leases. By this process, multiple firms gain access to the pool, and the lease, rather than the field, becomes the unit of production. Many firms, particularly major produc-
Contracting for Property Rights

completed. This is because changes in reservoir dynamics after unitization make it impossible to link unit production to particular leases, which would be necessary for adjusting shares. Before unitization, extraction occurs from each productive lease; but after unitization, the production pattern is fundamentally altered. The field, not the lease, is the producing unit, and wells are placed to maximize aggregate field returns. Many existing wells are plugged or used solely for injection of water, natural gas, or other substances to drive the oil to the unit's producing wells. These policies change the flow of oil migration in the reservoir, and the lease as a producing unit loses its significance. Postunitization production, then, cannot be used to infer relative lease values.

A second problem in unitization contracting is general uncertainty and asymmetrical information regarding relative preunitization lease values, which determine unit shares. These problems block agreement on lease value estimates and proposed shares in unit rents. The level of information available to the contracting parties depends upon the stage of production in which unitizing occurs. In exploration, little is known regarding the location of oil and its commercial extraction possibilities. At that time, all leases are relatively homogeneous, and unitization agreements are comparatively easy to reach, using simple allocation formulas, often based on surface acreage. Since no party knows whether the formula is to its particular advantage or disadvantage, negotiators can focus on the aggregate gains from unitization.

Information problems and distributional concerns, however, arise with development, as oil reserves are proved and expanded. With the initial discovery well and the drilling of subsequent wells, lease heterogeneities emerge. Because reservoirs are not uniform, the information released from a well is descriptive of only the immediate vicinity. Hence, through drilling their individual leases, firms gain knowledge of their portion of the reservoir; the full extent of the deposit and the productive potential of other areas of the reservoir will be revealed only through the drilling activities of other firms.

The production potential and commercial value of a lease are functions of both public and private data. Public data include objectively measured and noncontroversial variables, such as the number of wells on the lease, its surface acreage, and the record of current and past production. These data are available to all of the contracting parties. Private data on lease parameters involve more subjective geological variables, which tend to be assessed and valued by individual company engineers. They include the amount of oil below lease lines—gross acre-feet of pay (volume of the producing formation), net acre-feet of pay (nonporous and non-oil-bearing rock is subtracted from gross acre-feet), remaining reserves (original oil in place less cumulative production), net oil migra-

Contracting for the Unitization of Oil Fields

tion, oil viscosity, permeability of the surrounding medium, and bottom hole pressure. These latter variables, which are important for assessing lease values, are a major source of contracting problems.

Information about them and their significance for lease value estimations are drawn from well logs and production histories. They require highly subjective interpretation by company engineers and geologists; estimations regarding them and their impact on unit shares, therefore, become very controversial. For an example of the disputes that can arise over the interpretation of these data, it was noted during negotiations in the Western RKM unit in Texas that "the Engineering Committee could not agree upon oil reserves for a large number of tracts in the unit area because of the poor quality and interpretive nature of the available basic data" (letter, March 13, 1963; Western RKM Unit File, company records).

Although it is difficult to achieve consensus among firms on the implications of such information for lease values, these subsurface variables are nonetheless used by each firm to form private estimates of the value of its leases. The estimation of static reservoir characteristics, such as thickness and porosity, further illustrates the information problems that can lead to divergences between lease value calculations based on public data and those based on private information. Each calculation is based on only a small number of observations at well bores. The interpolation of the reservoir's structure between wells, however, is sensitive to the specific functional forms employed by company engineers. Procedures and estimates vary across firms. For instance, in unit negotiations on the Prentice field in West Texas there were differences in porosity estimates of 60 to 100 percent.

The estimation of dynamic reservoir characteristics, such as remaining oil reserves and future lease output, involves even greater complications. Companies often have differing opinions about the correct estimation procedure, when choices may reallocate millions of dollars. There is no generally accepted standard. The result of subjective estimates and differences in procedures is that consensus often cannot be achieved among the bargaining parties on future lease output. Such an agreement, however, is necessary for successful unit share negotiations.

As a result of these problems, negotiations over the formation of oil field units must necessarily focus on a small set of objectively measurable variables, such as cumulative output or wells per acre, because of the

4 The company records are from one of the largest oil producing firms in the United States. Libeap and Wiggins were granted access to unitization files on the condition of confidentiality. These files include letters, memorandums, minutes, recorded votes, engineering committee reports and other detail documents on contracting for unitization on each of the seven fields examined in this chapter.
potential disputes over the use of subsurface parameters. These objective measures, however, may be poor indicators of lease value. The resulting asymmetry in lease value calculations based on differential information and interpretation among firms is the primary cause of breakdown in unit share negotiations.

In addition to the problems of estimating static and dynamic geological characteristics, firms have other proprietary information that contributes to conflict over lease value estimates. Lease production is influenced by firm management policies, the details of which are available only from company records. Although company records are available to the firm's engineers and geologists, they can be misrepresented easily and may not be considered reliable by other firms. For example, in efforts to organized the North Cowden unit, one large firm noted that

the validity of the selection of the pay is very interpretive, being dependent upon the individual who observed the drilling samples on that well...a disadvantage [of gross pay] is that we are basing a parameter of unitization on the skill or lack of skill in the persons observing the samples. Therefore, there is considerable question as to the consistency of the picks [estimates] between wells, and it would likely be difficult to reach an agreement between operators on such data. (letter, June 16, 1959; North Cowden Unit File, company records)

Thus, there are important differences in the data for estimating lease values and unit shares in negotiations. These differences inhibit agreement between the lease owner and other firms on the formation of a unit, even when there are large aggregate gains from such action. These conflicts over lease values and unit shares will continue until late in the life of a reservoir. With the accumulation of information released through development and production, public and private lease value estimates converge as primary production (production based on natural subsurface pressure) approaches zero. At that point a consensus on shares and the formation of the unit is possible. Without artificial injection of natural gas or other substances to supplement underground pressure and other secondary recovery techniques, lease values will approach zero. Secondary recovery generally requires coordinated actions across multiple leases and, hence, is most effective with a unit. This suggests that as with fisheries, unit agreements are more likely to be reached late in the life of the reservoir. Unfortunately, by the time secondary recovery is required, most of the common pool losses already have occurred.

In unit negotiations, each of the bargaining parties compares the expected value of its returns under the status quo or nonunitized produc-

7Regulatory arrangements in the absence of unitization are outlined in Libecap and Wiggins (1984).
Contracting for Property Rights

field acreage, these aggregate reservoir effects are largely external. Those small firms (based on limited leased acreage) have greater incentive to withhold their highly productive leases, which have high variance in value estimates. If the acreage of firms with larger, multiple leases is in contiguous leases, then in the presence of continuing disagreements over unit shares, the firm may decide to leave negotiations and form a subunit on part of the field. As shown below, however, subunits, although preferable to no unitization, involve significantly higher costs and lower returns than do complete units.

Besides the information issues that particularly affect the owners of small productive leases, these small firms have had other reasons for opposing unitization. As described later, small lease owners were given preferential drilling permits by regulatory authorities under prorating controls adopted by states in the absence of widespread unitization. Those policies allowed such leases to be more densely drilled than larger leases, and with more wells per acre, small lease owners could drain neighboring areas. In unit negotiations, small lease owners, as vested interests in prorating regulation, insist on protecting their regulation-imposed advantages in the unit allocation rule as a condition for joining. Differences in lease value estimates can block consensus on any side payments to draw potential holdouts into agreement. Under unanimity voting rules, small firms could delay or block the formation of fieldwide units.

EMPIRICAL EVIDENCE

The contracting arguments outlined in the previous section can be applied to seven Texas and New Mexico units for which information is available for detailed analysis: North Cowden, Goldsmith/Landreth, Prentice Northeast, Western RKM, Slaughter Estate, Empire Abo, and Goldsmith/San Andres. Table 6.1 summarizes the data and shows that in each of the cases, unitization contracting was a long process, requiring from four to nine years from the time negotiations began until agreements could be reached. Moreover, in five of the seven cases the acreage in the final unit was less than that involved in the early negotiations. Overviews of negotiations on three of the fields illustrates the private contracting issues encountered in attempting to form units.

The North Cowden field was discovered in 1930, but negotiations for the unit did not begin until 1958 as the field neared depletion of primary reserves. An engineering committee was formed by the negotiating parties to collect field and lease data from the various operators to assign shares to the unit and to estimate the aggregate gains from secondary recovery under the proposed unit. Two years later in 1960, the

Committing for the Unitization of Oil Fields

Table 6.1 Unit contracting summaries for seven fields

<table>
<thead>
<tr>
<th>Field</th>
<th>Discovery date</th>
<th>Date unit negotiations began</th>
<th>Date unit formed</th>
<th>Acreage under negotiations</th>
<th>Acreage in final unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>North Cowden</td>
<td>1930</td>
<td>1958</td>
<td>1966</td>
<td>30,870</td>
<td>17,503</td>
</tr>
<tr>
<td>Goldsmith/Landreth</td>
<td>NA*</td>
<td>1961</td>
<td>1965</td>
<td>10,760</td>
<td>8,398</td>
</tr>
<tr>
<td>Prentice Northeast</td>
<td>1951</td>
<td>1954</td>
<td>1963</td>
<td>8,500</td>
<td>6,828</td>
</tr>
<tr>
<td>Western RKM</td>
<td>NA*</td>
<td>1962</td>
<td>1966</td>
<td>16,400</td>
<td>4,918</td>
</tr>
<tr>
<td>Slaughter Estate</td>
<td>NA*</td>
<td>1958</td>
<td>1963</td>
<td>5,528</td>
<td>5,280</td>
</tr>
<tr>
<td>Empire Abo</td>
<td>1957</td>
<td>1965</td>
<td>1971</td>
<td>11,323</td>
<td>11,323</td>
</tr>
<tr>
<td>Goldsmith/San Andres</td>
<td>NA*</td>
<td>1959</td>
<td>1963</td>
<td>7,199</td>
<td>6,103</td>
</tr>
</tbody>
</table>

*Note: NA, not available
*Note: Separate reservoirs.

Source: Adapted from Wiggins and Libecap (1985).

committee produced estimates that oil recovery would increase by 100 million barrels with unitization, a gain of $285 million in 1960 prices (minutes, July 28, 1960; North Cowden Unit File, company records). Despite these prospective aggregate gains, nineteen of the thirty-one firms on the field eventually withdrew part or all of their leased acreage from the proposed unit, and a smaller unit was not formed until 1966, eight years after negotiations began.

Contracting for the Goldsmith/Landreth unit began in 1961, but conflict over unit boundaries delayed work by the engineering committee until 1963. With the assembled field and lease data, unit revenues and firm shares were estimated and presented for discussion. In the ensuing negotiations four of the ten firms bargaining for the unit withdrew their leases in disagreement over the proposed allocation rules. Additionally, after a share formula was finally agreed upon, another firm withdrew eight more leases due to a dispute over unit secondary recovery plans. The final smaller unit was not formed until October 1965.

The Prentice field was discovered in 1951, and unit negotiations began in 1954. Despite predictions that early unitization would substantially increase oil recovery, negotiations faltered and were abandoned between 1956 and 1959. In 1959, the largest firm on the field attempted to reopen negotiations, but by 1963, it was clear that fieldwide unitization was not possible. In late 1963, three subunits were formed, nearly ten years after initial negotiations because "a common formula
Contracting for Property Rights

could not be negotiated" (minutes, Operators' Meeting, February 7, 1963; Prentice Northeast Unit File, company records).

There is clear evidence that the very productive leases were systematically withheld from early unitization efforts on the seven fields, even though there were large and generally undisputed aggregate gains from fieldwide unitization. On the North Cowden field, firms with very productive leases voiced opposition to the proposed unit in early negotiations, with one firm asserting that "none of the proposed parameters give justice to those leases because of the abnormal producing capabilities" (letters, January 20, 1959; March 30, 1961; North Cowden Unit File, company records). Eight of the firms that eventually withdrew acreage from the proposed unit had ten of the most productive leases on the field. During the first six months of 1960, output from those leases averaged 133 barrels per acre, while the average for all other leases on the field was 79 barrels per acre (engineering report, December 1, 1960; North Cowden Unit File, company records). In negotiations one of the unit proponents reported: "It is extremely difficult to arrive at a single factor which can be said to represent an equitable minimum, since the field is currently under active development and current production relationships are changing with each month's data" (letter, February 3, 1960; North Cowden Unit File, company records).

In unit discussions, firms with small productive leases repeatedly demanded changes in the proposed unit allocation formulas. For example, on the Goldsmith/Landreth field, three firms with unusually productive leases requested that acreage be deleted from any allocation rule. Those three firms had leases with average output per acre three times that for other leases on the field and would have been disadvantaged by any share formula that considered surface acreage as an allocation parameter.

On the Goldsmith/San Andres field, in votes on various share formulas none of the firms consistently voting no had over 9 percent of productive field acreage. On the other hand, the three largest firms with 26, 16, and 15 percent of total acreage, respectively, voted yes on all of the allocation rules submitted for consideration. The small firms on the field repeatedly called for adjustments in the weights placed on specific parameters to reflect their individual advantages. One firm with 5 percent of field acreage, but only 1 percent of cumulative output, called for less weight to be placed on cumulative output, while another with 4 percent of acreage, but only 2.8 percent of current output, wanted current production removed or discounted in share formula calculation (minutes, January 10, 12, 1962; February 7, 1962; Goldsmith/San Andres Unit File, company records).

Contracting for the Unitization of Oil Fields

Available evidence also supports the notion that firms with large holdings on a given field will be the agents of institutional change. The motivation of large firms to promote fieldwide unitization is reflected in the following statement regarding a feared increase in unit costs due to the withdrawal of some leases from the proposed unit: "Although our reserves in the area from which all eleven tracts are eliminated are indicated to be greater . . . , our costs will undoubtedly be greater due to the requirement of additional injection wells . . ." (letter, October 12, 1964; Goldsmith/Landreth Unit File, company records).

To promote agreement, firms with large acreage in proposed units tended to be more flexible in negotiations over allocation rules. For example, on Goldsmith/San Andres field, the larger operators with 72.23 percent of current output, agreed to a smaller aggregate share of 71.09 percent of remaining primary production under the unit and 67.80 percent of secondary recovery output (letter, October 27, 1961; Goldsmith/San Andres Unit File, company records).

On the other hand, if negotiations reached an impasse, those firms with large blocks of contiguous acreage could withdraw and form their own subunits, even though the gains were less than from fieldwide units. During the lengthy North Cowden unitization discussions, three firms with large tracts of contiguous acreage finally withdrew to form separate subunits, avoiding the need to reach a share agreement among all of the firms on the field. Similarly, in negotiations for the formation of a 26,000-acre RKM unit on the Slaughter field in Texas, conflicts over proposed sharing formulas led to the exit of many of the contracting firms. The second largest firm with 26 percent of field acreage concentrated in the eastern part of the field, withdrew to form a separate subunit, arguing that the parameters considered for share assignment "considerably under-estimated" its lease values (letter, May 20, 1964; Western RKM Unit File, company records). The final Western RKM subunit was only 4,918 acres in size.

The failure to agree to fieldwide units and the formation of subunits brought significant losses. The Oil and Gas Journal, June 17, 1957, estimated 44 percent recovery of original oil in place for fully unitized fields, but only a 39 percent recovery for partially unitized fields. On smaller subunits, secondary recovery methods are less effective than when the whole reservoir is involved. Besides lower overall recovery, partial unitization leads to increased capital costs. For instance, after the unsuccessful efforts to completely unitize the 71,000-acre Slaughter field in West Texas, ultimately 28 separate subunits were established; these ranged from 80 to 4,918 acres. To prevent migration of oil across subunit boundaries, some 427 offsetting water injection wells were sunk.
Contracting for Property Rights

along each subunit boundary, at a cost per well of approximately $360,000 for a total of $156 million. These wells and related expenses were not needed for production and could have been avoided with a fieldwide unit. Such practices have been routine, particularly in Texas where multiple units are common (Oil and Gas Journal, July 9, 1956; March 1, 1965).

It was argued earlier that the range of share parameters for allocating unit rents will be limited because they must be based upon publically available information. This limits contracting flexibility because of the small number of available variables and the highly tenuous and controversial nature of even modest extrapolations from them to estimate individual lease values. For example, early in unit negotiations the engineering committee on North Cowden reported that data were too sketchy to calculate “a fair and equitable” gross or net pay under each lease. The committee had wells cores for only 20 of the 733 wells on the field, and it stressed the “meager data and poor quality of available records” (memo, April 7, 1959, North Cowden Unit File, company records). As a result, during the eight years of negotiations for the North Cowden unit, nearly all of the numerous share formulas considered were combinations of current and cumulative output, which were available and reliable for all leases. Attempts to incorporate more sophisticated parameters met with objection from the bargaining parties due to their subjective nature, given the lack of available data. Further, remaining oil reserves for the various leases could not be estimated in ways acceptable to all the firms. The major unit proponent had access to reservoir data and could have estimated the parameter, but its estimations would have been controversial. Instead, the firm chose to release the data to the engineering committee for parameter calculation. One small firm, however, hired an outside consultant to calculate its net reserves and received estimates that were double those calculated by the engineering committee (letters, January 9, 1962; March 8, 1963; North Cowden Unit File, company records).

On the Prentice Northeast field, the final accepted share formula for the unit included only one variable, current production. Estimates of another possible parameter, primary oil recovery for the leases, were made using a variety of techniques, but “relatively poor agreement between various methods were obtained in many instances. Primary reason for inconsistencies [was] due to a severe lack of control in much of

Increased well costs on the Slaughter field of Texas due to the failure to agree on a fieldwide unit were calculated by counting the otherwise unnecessary injection wells along subunit boundaries as shown on Slaughter field maps (August 22, 1967, Western RKM Unit File, company records). Costs per well are from Slaughter Estate Unit File, company records.

POLICY DIFFERENCES REGARDING UNITIZATION AND THEIR IMPACT

In the circumstances of large and continuing common pool losses in oil production and the industry’s inability to privately complete unitization agreements early in the development of a reservoir, political pressures mounted for government intervention to promote unitization. Differences among large and small firms regarding their incentive to support unitization limited the effectiveness of the oil industry as a cohesive lobby group. Moreover, the policies adopted varied dramatically across political jurisdictions, due to political opposition from smaller firms, who resisted government-enforced unitization. This section examines unitization policies and politics on federal lands in Wyoming and on private lands in Oklahoma and Texas.

Of the three, federal policy is the most effective in promoting unitization because it encourages agreement during exploration, rather than after field development. The stage of oil production in which bargaining
Contracting for Property Rights

occurs is critical for contracting success. During exploration, there is little asymmetric information across bargaining parties regarding relative lease values to block agreement. On the other hand with field development, differential information about lease productivity emerges, and disputes arise over lease value and unit shares.

This point is important for Oklahoma and Texas, because, in contrast to the federal government, those states allow for unitization only after oil fields have been discovered and fully developed. In Oklahoma, these problems are mitigated by regulations that permit 63 percent of the parties to coerce other firms to join the unit. In Texas, however, unanimous agreement is required.

Federal and state policies

All private oil production rights on federal lands are assigned through the Mineral Leasing Act of 1920, as amended (30 U.S.C. sections 181–287). Firms can obtain leases for up to twenty years under the Mineral Leasing Act, but the aggregate leased acreage held by a firm cannot exceed 246,000 acres in any state. If firms agree to unitize their leases, however, the leases are automatically extended for the life of the unit, and they are exempt from the statutory acreage limit (30 U.S.C. section 226). Unit plans are approved and actively monitored by the Bureau of Land Management. These provisions provide incentives for firms to unitize on federal lands.

On federal lands unitization typically occurs once a potentially productive geological formation is identified by a prospecting firm. Other firms with leases in the area are identified, and the overlying acreage is unitized for exploration. The cost and revenue-sharing formula among the firms is based on surface acreage, because subsurface characteristics and production potentials are not yet known. Once a unit agreement is reached, prospecting is performed by only one firm, which is selected by a majority vote. As oil is discovered, proven productive areas are segregated from unproven areas by the Bureau of Land Management. Leases in proven areas, called participating areas, continue to share in the returns from the unit on the previously determined allocation formula. No firm shares in the unit revenues until its leases are shown to be productive.

Because federal policy encourages early exploratory units before commercial petroleum deposits have been found, it allows for large potential gains from unitization. Early units can restrict the total number of wells drilled and control the pace of production to conserve subsurface pressure and increase total oil recovery. In addition, production can be adjusted in response to price and interest rate forecasts. As noted earlier, on federal lands the allocation arrangements are preset early in field development before information uncertainties and asymmetries appear regarding the interpretation of particular lease characteristics. During exploration very little is known regarding subsurface conditions, so that individual bargaining positions can be relatively homogeneous with little discord. Because reservoir information is limited, firms do not have any ex ante expected advantages from natural geological conditions associated with their leases. Hence, a simple sharing rule based on surface acreage is possible. This is the key policy that separates federal regulation from practices in Oklahoma and Texas.

The federal government has incentive to encourage unitization. As the principal land owner in areas where its regulations apply, the federal government captures a significant share of the increased field rents that result from efficient development. The federal government receives both cash bonuses and royalties from the private firms that develop its leased acreage.

In Oklahoma, compulsory unitization on order of the Oklahoma Corporation Commission has been possible since 1947 if a majority of the lease owners, weighted by acreage, vote for unitization (1945 Oklahoma Session Laws at 162; 1951 Oklahoma Session Laws at 136). In Texas, on the other hand, ‘unanimous’ agreement for the formation of a unit is required before it will be approved by the Texas Railroad Commission. Further, unlike the federal government, both states require that the field be fully developed before a unit can be approved. Such requirements rule out the use of exploratory units as is possible on federal lands and the use of simple allocation rules. Because conflicts over lease value increase with development, the Oklahoma and Texas requirements for full development prior to unitization make agreements more difficult. Given these policy differences, one would expect variation in the extent of unitization on federal lands and in Oklahoma and Texas.

Impact of policy differences

Table 6.2 summarizes the patterns of unitization in Oklahoma, Texas, and Wyoming, which are largely on federal lands, for selected years from 1948 to 1975. The data indicate sharp differences in the amount of unitized production across the three states, with Wyoming having 50

Data on federal policy are based on interviews conducted by Libecap and Wiggins with the Bureau of Land Management, North Central Region, Casper, Wyoming. May 1982.

7For most federal units, unitization dates precede field discovery dates. Only on very old fields do discovery dates precede unitization.
percent of its production from field-wide units as early as 1948, whereas the Oklahoma share was 9 percent and Texas had no production from fully unitized fields in that year. Those differences persisted through 1975.

Political contracting for unitization legislation

The observed policy differences among the federal government, Oklahoma, and Texas are due to a variation in the political strength of the firms that are opposed to private unitization. In the discussion above, information problems in share negotiations particularly affected the stands taken by small lease owners with very productive acreage on a reservoir. If those firms are small producers with little or no acreage on other fields that would benefit from unitization there, then they are likely to mobilize to resist government policies to force unitization through the adoption of majority voting rules. A majority-imposed allocation rule and forced minority membership in the unit could make these small firms worse off relative to the status quo by reassigning property rights to field rents. As described below, as a legacy of past political agreements regarding property rights, small producers also had regulatory-imposed advantages that would lead them to oppose compulsory unitization. Accordingly, any government policies to promote unitization when private agreements failed depended critically on the political power of these small firms.

The federal government was able to adopt its comparatively effective unitization policies with no recorded political opposition, because there were relatively fewer small producers and leases on federal lands and they had less influence on federal policy than did the numerous small firms in Oklahoma and Texas. The federal government’s unitization policies were added to its leasing practices in 1930 in response to rapid extraction and competitive production in the North Dome Kettleman Hills field on federal lands in California (Oil and Gas Journal, July 3, 1930). The number of small producers on federal lands was limited because leases were typically large. The Mineral Leasing Act of 1920 allowed individual leases of up to 2,560 acres for prospecting and 640 acres for production. The federal government reserved the mineral rights underlying its land and issued large leases, because it did not gain from strategic drilling, which often was practiced on private land as both lessees and producers tried to encourage oil migration to their leases.

On private lands in Oklahoma and Texas, however, lease size was determined by land ownership, which was much more fragmented. Further, landowners often divided their lands into multiple leases to encourage rapid production and drainage. The result was that very small leases were common in Oklahoma and Texas. For example, on the Oklahoma City field in 1930, there were approximately 85 leases of less than 50 acres, 111 leases of 50 to 350 acres, and only 1 lease of 640 acres (Oil Weekly, September 25, 1930). The East Texas field was even more fragmented, with many leases under five acres. Moreover, the small leases often had no other holdings. Consequently in Oklahoma and Texas, there were more very small producers, which would be concerned about the valuation of their leases in unit shares or benefited from favorable prorating rules, than existed on federal lands.

The smooth adoption of unitization to reduce common pool losses on federal lands was not repeated in either Oklahoma or Texas. Small firms in those states resisted private unitization agreements and were the core of political opposition to government regulations promoting unitization. Because these producers were relatively homogeneous, numerous, and often aligned with small oil field service companies and small land owners, their lobbying efforts were successful in delaying unitization legislation in Oklahoma and Texas. In the absence of unitization, larger firms lobbied for statewide prorationing of oil production to limit total output, minimum well-spacing rules, and the forced pooling of leases to reduce drainage and general losses from dense drilling. Forced pooling allowed small leases to be consolidated into larger tracts for drilling to reduce well densities. The enactment of this legislation in Oklahoma facilitated the subsequent adoption of compulsory unitization legislation by reducing the advantages offered by current regulation for small firms.

Oklahoma adopted formal minimum well-spacing rules and commit...
Compulsory lease pooling in 1935 and 1941, respectively (American Bar Association, 1938, pp. 209–10; Myers, 1967, p. 312). Spacing and compulsory pooling resulted in more uniform drilling on new fields and narrowed the advantages of small leases to only those arising from their natural position on the reservoir. Those policies helped to reduce opposition to compulsory unitization legislation in Oklahoma, which finally passed in 1945 with lobby support by the Mid-Continent Oil and Gas Association, an organization of large firms. To make the legislation politically palatable, the law required that 85 percent of the leases on a fully developed field approve unitization before the Corporation Commission could intervene. It also exempted from compulsory unitization all older fields discovered at least twenty years prior to the enactment of the law.

Immediately after passage of the compulsory unitization law, two major Oklahoma fields, West Edmond Huntin Lime and West Cement Medrano, were unitized by the Oklahoma Corporation Commission upon petition by the lease owners. Nevertheless, resistance by some firms to forced unitization on these fields led to unsuccessful efforts to repeal the compulsory unitization law in 1947 and a subsequent Oklahoma Supreme Court test (American Bar Association, 1949, p. 400). The intensity of the repeal efforts, which resulted in floor votes in both houses of the Oklahoma legislature, underscores the opposition of small firms to unitization, even though there were clear gains for the reservoirs involved. With unit management, output from the West Cement Medrano field increased by 70,000 barrels per day by 1951 by plugging wells with high gas/oil ratios to maintain subsurface pressure and by recycling natural gas back into the reservoir instead of selling it (Oklahoma Corporation Commission, West Cement Medrano Unit Files). By 1959, opposition to the Oklahoma compulsory unitization statute was largely spent, and the original law was amended with little controversy to lower the required majority for forced units from 85 to 63 percent (1951 Oklahoma Session Laws at 136).

In Texas, where small firms were even more numerous, successful opposition was mounted against the kinds of legislation adopted in Oklahoma, including wider well spacing, forced pooling of leases, and compulsory unitization. Available evidence suggests that in 1930 the average Texas producer was only 63 percent of the size of the average Oklahoma producer.¹⁰ The difference in the incidence of small firms was exacerbated by the late 1930 discovery of East Texas field. Within three

¹⁰This excludes the ten largest firms in both states. Data are based on production reports in Oil Weekly (March 20, 1931). Comprehensive data were not available for Oklahoma for the very small firms, those with output less than $5,000, and those firms were not used in calculations.

years there were 1,000 primarily new firms on East Texas, three times as many as were reported for all of Oklahoma in 1930. Because of the influence of small producers on East Texas, state regulations to prorate production on that field were implemented only on a per well basis, whereas other Texas fields generally had prorating quotas based on 50 percent acreage and 50 percent wells.¹¹

The benefits received by small firms on East Texas from this prorationing rule are reflected in their drilling practices. By 1933, small firms averaged one well per nine acres, whereas the twenty-four largest firms on the field averaged one well per fourteen acres. The Cole Committee of the U.S. House of Representatives, which was studying oil production practices, estimated that prorationing rules in East Texas contributed to the drilling of 23,000 unnecessary wells at a per well cost of $26,000 (U.S. House of Representatives, 1939, p. 503). Hence, existing prorationing regulation provided small East Texas operators with benefits and incentives to resist wide well spacing, lease pooling, and compulsory unitization.

Even when spacing laws were passed, widespread exemptions to spacing rules were granted by the Texas Railroad Commission to small producers, particularly on the East Texas field. The agency allowed all property owners access to the oil beneath their land in sufficient amounts to cover extraction costs. This regulatory practice promoted drainage and dense drilling. For example, a one-acre lot in Kilgore on the East Texas field had twenty-seven producing wells, and one-acre tracts with five to ten wells were common (American Bar Association, 1949, p. 493). Between 1938 and 1948, of the 100 well-spacing exemption cases heard by appellate courts in Texas, 99 concerned East Texas producers (American Bar Association, 1949, pp. 489–90). As late as 1959, the Railroad Commission did not establish well-spacing rules until eighteen months after the discovery of a new field. This delay, reflecting the political influence of small crude oil-producing firms, provided sufficient time to allow narrow well-spacing practices to become established (Oil and Gas Journal, May 1, 1959).

Both dense drilling and per well quotas provided small Texas firms with strategic advantages and a clear vested interest in prorationing regulation relative to unitization. Compulsory lease pooling was resisted by the Texas Independent Producers and Royalty Owners Association (TIPRO), an organization of small firms (TIPRO Reporter, February 1949). Compulsory pooling legislation did not pass the Texas legislature until 1965, twenty-four years after Oklahoma. Moreover TIPRO helped block changes in prorationing rules from a per well to an acreage basis

¹¹The political problems faced by proponents of prorationing and the resulting policy concessions are outlined by Libecap and Wiggins ((113,949),(864,950)
Contracting for Property Rights

(TIPRO Reporter, September/October 1950). Preferential allocations to small lease owners continued through 1962, when per well quotas were overturned by the court in Atlantic Refining Co. et al. v. Railroad Commission (357 S.W.2d, 364 1962). TIPRO lobbied against compulsory unitization legislation, which has never been enacted in Texas. Under current law, unanimity voting rules are in force and voluntary, private units can be approved only after a field is fully developed. Hence, the early cost-saving unitization practiced on federal lands is impossible in Texas.

SUMMARY

The failure of unitization to be widespread, despite significant gains from unitizing oil production, is another example of how distributional conflicts over rental shares can limit the adoption of property rights to reduce common pool losses. Prorating, as an alternative arrangement, has offered some relief from rent dissipation. Prorating could be adopted because it allowed for side payments through favorable production quotas to politically influential parties that were not possible with unitization, even though unitization offered larger aggregate returns. These issues of the adoption of seemingly incomplete property rights arrangements are summarized in Chapter 7.

Concluding remarks

This volume joins a growing literature on institutional analysis by examining how particular property rights emerge or are modified. The gains from reducing common pool losses through the structure of property rights provide important incentives for institutional change. Common pool losses span those associated with classic open access resources, where no formal property rights exist and informal arrangements pose only limited constraints on behavior, to cases where formally defined property rights already are in place, but are too incomplete to prevent wasteful production practices. Although both existing informal property rules agreed to by the relevant parties or more formal, codified rights may be sufficient to channel behavior toward socially productive use of valuable resources, these status quo equilibria can be upset by changes in relative prices. Price changes through shifts in demand or supply conditions can generate greater competitive pressures for assets and thereby reduce ownership security. Depending on its extent, greater insecurity will lower time horizons in production decisions, reduce investment, and encourage too rapid exploitation.

Although the focus of the analysis has been on the political contracting behind four efforts to devise or to change property rights to natural resources in the United States, the implications of these studies can be applied to the broader examination of property rights institutions. In each of the cases, political bargaining involved both informal negotiations among claimants to devise local rules for resource use and lobbying to influence politicians and bureaucrats in legislation, court rulings, and administrative regulations regarding property rights. Despite the fact that bargaining involved similar natural resources and took place in a legal environment in the United States, which is generally favorable toward private property rights, the institutions adopted are surprisingly different, with distinct contracting histories and records of success in addressing common pool losses. Gaining a better understanding of this diversity and drawing implications for other settings is the goal of this volume.