The Structure and Contributions of Relational Contracts: Theory and Evidence from Oil and Gas Unit Operating Agreements

By

Gary D. Libecap
University of Arizona
National Bureau of Economic Research

and

James L. Smith
Southern Methodist University

August 18, 1997

Prepared for the Inaugural Conference of the International Society for New Institutional Economics, September 19-21, 1997, St. Louis, Missouri.

I. Introduction.

A major objective of transactions-costs economics is to extend micro-economic analysis to complex economic relationships and institutions that traditionally have been neglected in standard neo-classical investigations. Indeed, much of the emphasis of the transactions-costs literature has been to show how certain observed arrangements facilitate beneficial investment and exchange that otherwise might not be possible. As detailed by Williamson (1979, pp. 238-45, 1985, pp. 20-21), there are many transactions in a modern economy that deviate significantly from strict neo-classical assumptions: they are not discrete; they involve a limited number of parties over a long period of time; there is considerable uncertainty about future events, costs, and asset values so that contingencies cannot be spelled out clearly in advance; the parties have limited cognitive abilities to evaluate and respond to new market information (bounded rationality); investments often are specific to the transaction with low salvage values (asset specificity); and given these conditions, opportunism among the parties is a threat. These situations potentially could block or seriously limit socially-valuable economic relationships. Because the gains from addressing them often are so large, economic agents devote considerable resources to devising institutions that mitigate transactions costs and facilitate long-term exchange.[1]

Relational contracts are examples of such institutions. They are long-term agreements among parties to promote cooperative behavior and achievement of collective goals. They are written when there is too little information *ex ante* to specifically describe performance parameters over the life of the contract, to identify future contingencies that would require

[1] The transactions-cost literature is a large one, with major debts to Coase (1960, 1992), North (1990, 1981), Williamson (1975), Demsetz (1988), and others. For summaries of the literature, see Furubotn and Richter (1991), and Eggertsson (1990).

parameter adjustments, and to spell out the nature of those adjustments. Hence, relational contracts are much less precise or mechanistic than are formal contingent contracts. They are written around the most extreme cases of limited information and uncertainty about future economic events. Yet, they provide mechanisms to distribute quasi rents and align incentives among the contracting parties as events unfold over time to help assure contractual compliance, reduce opportunism, avoid costly re contracting, and minimize the need to resort to outside arbitration. Relational contracts necessarily leave details unspecified and instead rely on broad incentive provisions to encourage cooperation. Although the intuition about these important institutions is straightforward, empirical investigations of the relational characteristics of actual contracts has been relatively limited.[2] Until more empirical investigations are completed, it remains unclear as to the specific mechanisms that successfully enjoin parties to cooperate over the long term, given all of the opportunities for coordination to break down. Further, empirical investigation of relational contracts can reveal more precisely how they differ from contingent contracts.

This paper provides new theoretical clarification and empirical evidence about relational contracts written for the exploitation of oil and gas reservoirs in the United States and Canada. To mitigate common pool losses, oil fields often are developed under unit operating agreements. These agreements are classical relational contracts: They are long term (often 20 years or more), include many parties (typically ten or more firms), involve considerable uncertainty about geological and economic conditions, address site-specific investments, and align the incentives of the oil-producing firms over the life of the contract to maximize the economic value of the reservoir without repeated re contracting. The paper presents a theoretical framework describing

[2] We cite many of the exceptions to tins claim below. For instance, an analysis of price-adjustment mechanisms in long-term natural gas contracts is provided in Crocker and Masten (1991).

the essential elements necessary for unit operating agreements to be successful as relational contracts. It examines 60 unit operating agreements to determine whether the theoretical provisions are found empirically.

We find the predicted provisions in most of the unit operating agreements. Further, we find that unit operating agreements operate in a routine manner with little apparent critical discord among the parties and rare reliance on the court system to arbitrate disputes, despite the long-term nature of the contracts, the uncertainties involved, and the amount of money at stake. Finally, the paper analyzes an important exception, the unit operating agreement for the Prudhoe Bay Unit in Alaska, which covers the largest oil and gas field in North America. We show why that contract is not relational, examine the discord that has resulted among the parties as they engage in opportunism, and illustrate some of the rent dissipation that has resulted.

Our investigation of the experience of the Prudhoe Bay Unit also reveals that a series of contingent contracts, written as alternatives to a long-term relational contract, is unlikely to be a good substitute for achieving collective action. Although it is costly to complete unitization contracts because of differences of opinion over the sharing formula, once agreed to, the sharing formula for costs and returns provides the relational mechanism that unites the contracting parties over time as unforeseen events unfold.[3] By contrast, shorter-term contingent contracts may be easier to complete because they leave contentious sharing issues for later resolution. But the differential incentives for behavior among the parties that arise due to the failure to initially resolve allocation issues create path dependencies that make subsequent resolution and agreement for beneficial collective action even more costly.

[3] See Wiggins and Libecap (1985) for discussion of the problems of reaching unit agreeements. Smith (1987) shows how the relative bargaining strength of parties to the agreement affects the sharing formula.

II. Relational Contracts.

The parties interested in undertaking complex, long-term transactions face a number of formidable challenges in writing and administering contracts for collective action that will be to their mutual advantage. They have to devise mechanisms to line up incentives for cooperation over the life of the contract, divide up the potential rents, provide for dispute resolution, and outline overall governance structures. Once the contract is written, the parties have to administer the agreement, allocate the returns, monitor compliance, address unanticipated events that may require adjustment in contract provisions, and resort to outside arbitration should internal dispute resolution mechanisms break down. What is included when the contract is drafted is important for its subsequent performance. Indeed, devising *ex ante* provisions to maximize rents and to minimize *ex post* costs is the central issue with most long-term contractual relationships.

All contracts, however, suffer from potential reneging, opportunism by some parties to increase their individual profits or to reduce their individual costs.[4] Opportunism arises because of the small numbers of parties that are tied together in a long-term relationship, asset specificity through investments specialized to the contract, and information asymmetries that allow some parties to distort information to their advantage. When future events can be predicted well enough or when they can be identified at a later date through objective measures that do not involve serious disagreement, then contingent contracts can be written to spell out performance guidelines and other benchmarks for adjusting contract provisions. Contingent contracts are written for a variety of economic phenomena, including employment contracts with profit-sharing and retirement provisions as well as price-adjustments in raw material supply contracts, such as those for coal, coke, and natural gas as described by Goldberg (1985), Goldberg and Erickson (1987), Joskow (1985, 1987, and 1988), Masten and Crocker (1985), and Mulherin (1986).[5]

[4] Opportunism is defined in Williamson (1975, p. 26).

[5] For related discussions, see Goldberg (1976), Polinsky (1987), Crocker and Masten (1988), and Williamson (1994). As Crocker and Masten (1991) point out, however, there is no sharp distinction between relational and

Relational contracts are used when it is not possible to predict or to particularize when or how a contract should be adjusted as new events unfold and/or when there is likely to be disagreement on the parameters for doing so. Hence a complete contingent contract is not possible.[6] Goetz and Scott (1981, p. 1091), for example describe relational contracts as long-term agreements completed when "the parties are incapable of reducing important terms of the arrangement to well-defined obligations." Negotiating parties understand these problems and instead, attempt to craft provisions that align incentives *ex ante* through the division rule for rewards and punishments and provide guidelines for that flexible and smooth responses to changing circumstances to maintain the relationship for the benefit of all. Because performance standards are likely to be hard to describe in advance because of unknown contingencies and desired responses, they are left imprecise.[7]

Accordingly, relational contracts are simpler and more flexible than are contingent contracts. Relational contracts, however, may be open to compliance problems (Crocker and Masten, 1991, pp. 71-73). As a result, relational contracts may require more creative control mechanisms than do conventional contingent contracts because they spell out less and allow more discretion within broad contract guidelines or governance structures. They must rely instead on incentive systems to create bonding and to limit opportunism.[8] Because the incentive system within the relational contract is used to reduce enforcement costs it must be drafted with care. If successfully completed, however, relational contracts may better align incentives for long-term collective action than do a series of shorter-term contingent contracts that do not have incentive-compatible provisions.

contingent contracts. The differences are matters of the degree of precision and specificity of update conditions and parameters. Some long-term contracts may have elements of both.

[6] Williamson (1975, pp. 30, 65-94) discusses incentive issues and relational contracts, which he argues cannot be contingent-claims contracts.

[7] Goetz and Scott (1981, p. 1092).

[8] Goetz and Scott (1981, p.1100). See also Goetz and Scott (1983) for additional discussion. Macneil (1978, p. 886) describes relational contracts.

These arrangements, of course, are difficult to formulate, and there must be important motivation to do so. If no agreement can be reached, the contract is not completed. If it is written in a faulty manner, then a breakdown in cooperative behavior is likely, dissipating the rents created by the contract. The task facing negotiators is to reach agreement and to draft contracts when many attributes of the relationship necessarily are left undefined. The contracting parties have a mutual interest in forging an exchange relationship in which all have confidence, where each party's profits are dependent on the quantity and quality of the other party's efforts. To achieve these objectives they attempt to identify incentive-compatible provisions that will encourage long-term relationships and provide the benefits of long-term exchange.[9]

HI. Relational Contracts as Solutions to the Common Pool: Unit Operating Agreements.

A. The Common Pool Problem.

The production of crude oil and natural gas potentially involves serious common-pool losses that arise when firms compete for migratory oil and gas lodged in subsurface reservoirs. Under the common-law rule of capture, private property rights to the hydrocarbons are assigned only upon extraction. Production rights are granted to firms through leases from those who hold the mineral rights, often surface land owners. Each of the producing firms has an incentive to maximize the economic value of its leases, rather than that of the reservoir as a whole. Firms competitively drill and drain, including the oil of their neighbors, to increase their private returns, even though these actions reduce aggregate rents. Rents are dissipated as capital costs rise through excessive investment in wells, pipelines, and surface storage, and as production costs increase with too-rapid extraction. Rapid production of oil results in the early venting of natural gas and/or water, which otherwise help drive the oil to the surface. As natural gas and

[9] Other discussions of the conditions underlying relational contracts include Llewellyn (1931), Macneil (1978), Posner (1979), and Williamson (1985, pp. 164-203). Franchise arrangements in part are a type of relational contract. See Rubin (1978).

water are voided from the reservoir, costly pressure maintenance or secondary recovery actions must be implemented with additional pumps and injection wells. Total oil recovery falls as pressures decline and oil becomes trapped in surrounding formations, retrievable only at very high extraction costs. Finally, rents are dissipated as production patterns diverge from those that would maximize the economic value of the reservoir over time.[10]

The costs of competitive common-pool production on oil and gas reservoirs long have been recognized, and they can be huge. For example, in addressing early unitization efforts on gas-solution fields, the Oil Weekly (April 13, 1942; May 3, 1943) estimated that recovery would be increased from two to five times that of unconstrained production.[11] Similarly, on the Fairway field in Texas, the Oil and Gas Journal (December 7, 1964) predicted that unitization would raise oil recovery by 130 million barrels valued at over $200 million.[12] With so much at stake, oil firms have had incentives to find solutions to the common-pool problem.

B. Unitization as a Solution to the Common-Pool Problem.

The most complete solution to the common-pool problem in oil and gas reservoirs is unitization. With unitization, typically a single firm is designated as the unit operator to develop the field as a whole. The other firms share in the net returns with the unit operator based on negotiated formulas, and the individual firm lease loses its production significance. Wells and other equipment are placed to minimize costs, and production is controlled to maintain subsurface pressures and to increase overall recovery.[13] The unit operator and other lease

[10] There is a considerable literature on the common-pool problem in oil and gas production and efforts to counter it. See, for example McDonald (1971), Libecap and Wiggins (1984), Weaver (1986), Smith (1987), and Libecap (forthcoming).

[11] A gas-solution field is one where natural gas is the primary driving force in expelling the oil from the reservoir. Other major drives to flush oil to wells are gas-cap drives and water drives.

[12] Manthy (1978, p. 111).

[13] See McDonald (1971, pp. 24-5, 237). The benefits of unitization by increasing the ultimately recoverable unitized substances and by preventing waste is emphasized in unit documents. For example, see Anshutz East, Wyoming Unit Agreement, December 1982, on file with the authors.

holders (who otherwise would be competitively producing on the field) are residual profit claimants with joint incentives to develop the reservoir in a manner that maximizes its economic value over time. With unitized development firms do not compete for subsurface hydrocarbons in production and the reservoir, not a lease, is the operating unit. Under these circumstances production can occur so that no difference exists between the privately supplied oil and gas and the socially-optimal amount.

C. Unit Operating Agreements as Relational Contracts.

Unit contracts generally involve two documents. One is the Unit Agreement that is between the firms (lessees) that plan to unitize the reservoir and the property or royalty owners (lessors) that lays out the general agreement for the formation of the unit. Unit agreements generally describe the unit area and covered formations and substances, the effective date of the unit, the location of the tracts and leases included, the identity of the royalty interests and the working interest owners (WIOs) who are the lessees.[14] A typical unit agreement is that for the Brady (Deep) Unit of Sweetwater County, Wyoming, dated August 10, 1972. It a), sets out the objectives of the agreement "to conserve natural resources, prevent waste, and secure other benefits obtainable through development and operation of the area subject to this agreement...," b). identifies the relevant enabling legislation and regulations, c). provides maps of the unit area and the identity of the tracts and leases included on a geological formation (often in what are called participating areas), d). describes the royalty allocations among the royalty owners, e). outlines provisions for additions to or contractions from the unit, f). defines diligent production requirements, g). names the unit operator and describes general responsibilities and provisions for unit operator's term, resignation, removal, or replacement, h). outlines general accounting provisions, i). calls for the combination of separate participating areas if they are found to have hydrocarbons that communicate with one another and hence, have interdependent costs (the

[14] For example, see the Model Form of Unit Agreement provided by the American Petroleum Institute, third edition, January 1970.

common pool problem), and j). outlines other conditions affecting both the royalty owners and the working interests.[15]

The other document is the Unit Operating Agreement, which is the more detailed contract among the working interests or WIOs in forming and operating the unit. The unit operating agreement is the relational contract. It also includes a), designation of the location and limits of the reservoir or formation to be unitized and the procedures to expand the unit as necessary, b). definition of key terms such as development wells, injection wells, and test wells, c). the identity of the unit operator and procedures for removal of the unit operator, d). the start date of the agreement, and e). the identity of the working interests, including their holdings (leases) on the field.

Unit operating agreements have additional provisions that define the operating relationships among the working interests including a), outlining governance mechanisms such as voting rules, notification requirements, grievance and arbitration procedures, unit operator reporting and accounting practices, and establishment of a supervisory committee, b). describing compensation for private capital equipment (typically, wells, pipelines, and possibly injection plants) taken over by the unit, and c). defining the sharing formula by which revenues, capital, and operating costs are distributed among the working interests. Achieving agreement on the sharing formula is very contentious, often requiring long-term negotiations with many votes, and discord can delay unitization for years or make the unit incomplete.[16]

Unit operating agreements also define the phases of production as primary, when natural, subsurface pressures or drives flush the oil to the surface and secondary, when various injection procedures are used. All parties understand the life-cycle of an oil field with primary and secondary production phases. Based on engineering reports agreed to at the time the unit is

[15] Brady (Deep) Unit Agreement, Wyoming, August 10, 1972.

[16] For discussion on the contracting problems involved in reaching agreement on the sharing formula, see Wiggins and Libecap (1985), Libecap and Wiggins (1985), Smith (1987), and Libecap (1989). An incomplete unit is one whereby some parties decide that they can obtain more profits by dropping out of unit negotiations so that the unit covers only part of the formation. This, of course, entails additional costs to the unit and makes it less effective.

established, the negotiating parties also have a sense of how the various leases or tracts will fare in each of the phases, so that different sharing or ownership percentages are defined for each phase. What is not known is exactly when each phase will begin, so general benchmarks are specified, such as a particular gas/oil ratio or production level. These benchmarks typically are not controversial.[17]

Finally, unit operating agreements describe the mechanism by which parties are added or dropped from the unit. If the unit agreement is written during exploration or early development when the full extent and nature of the subsurface formation are unknown, parties may be included in the unit who subsequently are found to have barren leases or other parties may be left out who should be in the unit. Unit operating agreements include provisions for drilling test wells to confirm participation in the unit. With these adjustments, the new (or remaining) parties participate in the revenues and costs according to the sharing formula. These provisions define the working structure of the unit, they are spelled out *ex ante,* and once operations begin under the unit operating agreement they may last for 20, 30, or more years, depending on the extent of the hydrocarbon formation, the nature of technological change, production costs, and market prices.[18]

What ties all of the working interests in the unit in a relational sense are the provisions for participating areas and sharing formulas. These provisions must have *specific* characteristics to maximize the economic value of the reservoir and to maintain the viability of the unit over the long haul as we show below. The parties to the unit operating agreement need a flexible contractual structure that provides incentives for the unit operator to respond quickly in a unit-profit-maximizing way to new events, such as changes in subsurface dynamics, introduction of

[17] There may be multiple secondary phases and the type of injection-water, natural gas, carbon dioxide, depends upon the nature of the reservoir.

[18] Examples of unit operating agreements include the Model Unit Operating Agreement for Statutory Unitization provided by the American Petroleum Institute, first edition, March 1974 and the Unit Operating Agreement for the Brady (Deep) Unit of Wyoming, August 10, 1972.

new recovery technologies, and changes in relative prices, and for the other parties to cooperate with and assent to those actions.

Accordingly, unit operating agreements, in part, are hybrids of both contingent and relational contracts. Certain contingencies are laid out, primarily the sharing formula under different production phases and mechanisms for adding or subtracting membership. But day-to-day operation of the unit is left unspecified in the contract, with the unit operator bound only to a "best efforts" standard of performance, a standard which would be costly to monitor without self-enforcing provisions.[19] It is not possible to define strict performance criteria for the unit operator because far too much remains unknown at the time the contract is written, particularly about future reservoir conditions, market conditions, and production technology. Under those circumstances, it is desirable to provide the unit operator with considerable latitude in reservoir development.

Importantly, many potential long-term contracting problems are not addressed explicitly in unit operating agreements. For example, procedures to address potential extortion by some parties of the value of fixed, capital assets (non-moveable wells, injection plants, and pipelines) typically are not described. This is a potential problem. Hypothetically, any working interest could engage in opportunism and extort the unit for the value of those assets by threatening to withdraw from the agreement or otherwise hinder unit operation unless certain extortion demands were met.[20] Also, absent are discussions of how to deal with threats by some strategically-located parties to withdraw from the unit. Because of the nature of hydrocarbon deposits and changes in their flow with unit production, certain lease holders can be essential for viable unit operation because of their position on the formation. Theoretically, a small number of strategically-positioned parties could force a re negotiation of the unit once it was put into

[19] For discussion of similar general contract conditions and the problems involved, see Goetz and Scott (1981, p. 1115), Goldberg (1985), and Muris (1981).

[20] The problem of asset specificity arises because significant investments will be made in the unit that have value or most value only under an operational unit. Hence, those parties who make the investment are vulnerable to holdups by the other parties to capture some of the rents.

place and became profitable. Unit production may involve the positioning of injection wells to push oil to particular parts of the field and hence to particular leases. These lease owners are then advantageously positioned to hold up the unit.

In addition, there is the bounded rationality problem because the unit parties will not know how to react to future events at the time they are drafting the agreement, and subsequent discord is possible when these events later unfold. Finally, there is the problem of asymmetric information, because each lease owner knows the geology of his section of the reservoir better than does anyone else, and there are often sharp disagreements among engineers about the interpretation of subsurface information and hence on proper field development.[21]

Any of these conditions could lead to opportunistic behavior and a breakdown in the unit operating agreement. But if the bargaining problems are resolved during initial unit negotiations and a sharing formula is agreed to with the particular characteristics described below and if it covers all hydrocarbon deposits that communicate with one another, then the unit operating agreement can be silent on the issues of asset specificity, bounded rationality, small numbers bargaining, and opportunism. Through the defined sharing formula, each party becomes a residual claimant in the effective operation of the unit, and this formula provides for self-enforcing cooperative behavior. *The relational aspects of the sharing formula solve the contract compliance problem.*

The self-enforcing, incentive-binding provisions of the unit operating agreement are a), the designation of a single participating area that unites all the working interests whose leases cover oil and gas deposits that communicate with interdependent production levels and costs, and b). the delegation of unit operating expenses and investment costs across the working interests (including the unit operator) according to their shares of unit revenues as defined in the sharing formula. That is, the cost allocation is proportionate to the revenue allocation or unit

See Wiggins and Libecap (1985) for discussion of some information issues.

participation: "Unit expense shall be apportioned among and assessed against the Tracts in proportion to their respective Tract Participations."[22]

With these provisions all tracts or leases with oil and gas in the same deposit are in a single participating area with a sharing or participation formula that makes each working interest a residual claimant in net unit-wide profits.[23] Under these conditions, each working interest has an incentive to support a production plan that maximizes the economic value of the total unit regardless of where or when production takes place from the hydrocarbon reservoir.

Additionally, unit participation defines each party's voting interest in the unit for selecting the unit operator and for making governance decisions regarding the operation of the unit. The weight of each working interest in deciding group-wide production issues is determined by its share of unit-wide net profits.[24] Those with the most at stake have the greatest role to play in production and investment decisions. Finally, the allocation of all pre-unit investment expenses that are assumed by the unit upon its formation are paid for with charges to each working interest according to the participation formula.[25] Again, the parties pay for investments according to their share of the net benefits that result from those investments. Hence, the designation of a single participating area to cover all communicating oil and gas resources within the reservoir and a corresponding sharing formula that defines the proportionate allocation of revenues and costs among the interests are the *essential, relational aspects of unit operating agreements.* They align incentives for profit-maximizing behavior over the life of the contract.

[22] Plan of Unitization, East Binger (Marchand) Unit, Caddo County, Oklahoma, Article 17. See also, Article 11.1 of the American Petroleum Institute, Model Forms for Voluntary and Statutory Unit Operating Agreements, fourth and second editions, respectively, June 1, 1993.

[23] Units could have separate participating areas for separate geological formations and separate sharing formulas for each. If the areas are truly separate, then production costs and revenues are not interdependent across the areas. In other words, there is no common pool problem across the distinct participating areas.

[24] For example, see Article IV of the Big Stone Gas Unit, No. 1, Alberta, Canada. More generally, see API Model Forms, Article 4.3.1.

[25] See Articles 10.3 and 10.5, API Model Forms.

IV. Incentive Provisions within Unit Operating Agreements as Relational Contracts: Theory and Predictions.

This section demonstrates why a single participating area for all interdependent oil and gas deposits and a corresponding proportionate allocation of costs and revenues among the working interests in the participating area are necessary for a relational unit operating agreement. Absent these provisions, the unit operating agreement will not be successful in encouraging optimal production practices. Disagreements over capital investment, production schedules, and development strategies that are designed to advance one interest at the expense of others will lead to the dissipation of oil field rents.

An oil field consists of one or more reservoirs in proximity, with mineral rights defined by a surface grid that overlies the deposits. For simplicity, we focus on the case where a single reservoir is present. The grid consists of N sectors, with associated mineral rights each held by a separate lease owner.[26] The rule of capture (regulated or competitive, common-pool production) applies unless the owners adopt a plan of unitized operations that would allocate production streams and costs on some other basis.

The planning horizon over which the field is to be exploited extends through T periods, and T may be made arbitrarily large to accommodate whatever is expected to be the full economic life of the reservoir. The volume of oil extracted from the nth sector during the tth period is denoted q_{nt}, $n=1,\ldots,N$; $t=1,\ldots,T$. Total expenditures (capital outlays plus operating costs) incurred in the nth sector during the tth period are denoted c_{nt}. Sectoral production flows and cost expenditures are related to each other via the cost function: $c_{nt} = c_{nt}(Q)$, where $Q =$

[26] Individual owners may hold several individual leases, in which case those leases are to be viewed collectively as comprising one "sector."

$\{q_{11},\ldots,q_{1T}; q_{21},\ldots,q_{2T}; \ldots; q_{N1},\ldots q_{NT}\}$, and where $c_{nt}(Q)$ represents the cost incurred in sector n during period t under the most efficient (least cost) program for achieving the field-wide production program described by Q. The cost function reflects implicitly the physical constraints that limit oil extraction, conditional on the volume, distribution, and characteristics of the original oil deposits. Certain production programs, Q, may be prohibitively (infinitely) expensive to achieve. The physical constraint on total reserves is thus incorporated into the cost function.

The initial period of the analysis ($t=1$) may be regarded as coincident with initial field development. Alternatively, the analytical framework can be applied to examine the remaining life of a previously developed field, in which case the cost function would be interpreted as consisting only of those incremental costs necessary to extract the remaining resources according to the schedule described by Q.

We denote by R the set of sectors that are associated with the reservoir. Sectors that are associated with a common reservoir are those sectors that overlie portions of the field that are in communication via interrelated pressure gradients and resource migration paths. This notion is operationalized by specifying that any two sectors (m and n) are not associated with the same reservoir if:

$$\frac{\partial c_{nt}}{\partial q_{mt'}} = 0 \qquad \text{for } n \neq m \text{ and for all } t \in \{1,\ldots,T\} \text{ and } t' \in \{1,\ldots,T\}.$$

Thus, extraction from sector m would not affect in any way the costs of extraction from sector n if the two sectors are not associated with the same reservoir. It follows that, if sectors n and m are associated with the same reservoir, then

$$\frac{\partial c_{nt}}{\partial q_{mt'}} \neq 0 \qquad \text{for } n \neq m \text{ and some } t \in \{1,\ldots,T\} \text{ and } t' \in \{1,\ldots,T\}.$$

By this criterion based on cost externalities, the set of all sectors associated with the reservoir can be identified and denoted R.

The economic value of the oil field can be represented as:

$$\Pi = \sum_{n \in R} \sum_{t=1}^{T} \left[p_t q_{nt} - c_{nt}(Q)\right] d_t$$

where p_t is the expected price of oil in period t and d_t is the appropriate discount factor: $d_t = 1/(1+r)^t$. The set of first-order (necessary) conditions for optimal development is then given by:

$$\text{(i)} \qquad \frac{\partial \Pi}{\partial q_{\nu\tau}} = p_\tau d_\tau - \sum_{n \in R} \sum_{t=1}^{T} \frac{\partial c_{nt}(Q) d_t}{\partial q_{\nu\tau}} \equiv 0; \text{ for all } \nu \in \{1,\ldots,N\} \text{ and } \tau \in \{1,\ldots,T\}.$$

This result relies on the fact that $\partial c_{nt}(Q)/\partial q_{\nu\tau} = 0$ for all $n \notin R$.

Proper unitization causes all parties to agree on this optimal program, as follows. A plan of unitized operation allocates to each sector a certain share of production drawn from the field, and a certain share of expenditures incurred in the field. The interest of the jth sector under such a plan can be represented by the following terms:

α^j_{nt} = the share of production extracted from the nth sector during period t that is allocated to the jth sector; and

β^j_{nt} = the share of expenditures incurred in the nth sector during period t that is allocated to the jth sector.

Ownership interests in the field are completely defined by this set of participation factors: $F = \{\alpha^j_{nt}, \beta^j_{nt}; j=1,\ldots,N; n=1,\ldots,N; t=1,\ldots,T\}$. Given F, the owner of the jth sector would therefore seek to arrange production (and expenditures) to maximize:

$$\Pi^j = \sum_{n \in R} \sum_{t=1}^{T} \left[\alpha^j_{nt} p_t q_{nt} - \beta^j_{nt} c_{nt}(Q)\right] d_t,$$

where Π^j measures the profit accruing to the jth sector. The set of first-order (necessary) conditions pursued by the jth owner is therefore given by:

$$\text{(ii)} \qquad \frac{\partial \Pi^j}{\partial q_{v\tau}} = \alpha^j_{n\tau} p_\tau d_\tau - \sum_{n \in R} \sum_{t=1}^{T} \beta^j_{nt} \frac{\partial c_{nt}(Q) d_t}{\partial q_{v\tau}} = 0;$$

for all $v \in \{1,...,N\}$ and $\tau \in \{1,...,T\}$. This result again relies on the fact that $\partial c_{nt}(Q)/\partial q_{v\tau} = 0$ for all $n \notin R$.

Competitive, common-pool production that would occur in the absence of unitization can be defined as the special case wherein all production and expenditures are allocated to the sector within which they occur; that is:

$$\begin{aligned} \alpha^j_{nt} &= 1, && \text{for } j = n, \\ &= 0, && \text{otherwise, and:} \\ \beta^j_{nt} &= 1, && \text{for } j = n, \\ &= 0, && \text{otherwise.} \end{aligned}$$

Given this set of non-unitized participating interests in the field, the set of first-order (necessary) conditions pursued by the owner of the jth sector reduces to (cf. (ii)):[27]

$$\text{(iii)} \quad p_\tau d_\tau - \sum_{t=1}^{T} \frac{\partial c_{jt}(Q) d_t}{\partial q_{j\tau}} = 0, \qquad \text{for all } \tau \in (1,..,T).$$

Under unitized development with $\alpha^j_{nt} = \beta^j_{nt} = f^j$, for each $n \in R$, and for all $j \in (1,...,N)$ and $t \in (1,...,T)$, condition (ii) is sufficient to ensure (i). That is, if each sector is allocated a (time-invariant) share of production from the reservoir with which it is associated that

[27] We are comparing unitized production with non-unitized, common-pool production. Of course, there are state regulatory controls on production which attempt to minimize common-pool losses in the absence of unitization. See Libecap and Wiggins (1984) and Weaver (1986) for discussion of state regulations.

matches that sector's allocated share of expenditures in that reservoir, then all separate owners are motivated by pursuit of private interests to pursue the socially optimal plan of development, which maximizes the economic value of the field. The non-unitized, common-pool production characterized by (iii) would not, in contrast, generally satisfy the necessary conditions that characterize the optimal program, and would therefore not maximize the value of the oil field. Note the (iii) ensures (i) if and only if:

$$\sum_{n \in R} \sum_{t=1}^{T} \frac{\partial c_{nt}(Q) d_t}{\partial q_{\nu\tau}} = \sum_{t=1}^{T} \frac{\partial c_{\nu t}(Q) d_t}{\partial q_{\nu\tau}}, \qquad \text{for all } \tau \in (1,\ldots,T) \text{ and } \nu \in (1,\ldots,N).$$

That is, incentive-compatibility under non-unitized operations requires:

$$\sum_{t=1}^{T} \left[\sum_{n \in R} \frac{\partial c_{nt}(Q)}{\partial q_{\nu\tau}} - \frac{\partial c_{\nu t}(Q)}{\partial q_{\nu\tau}} \right] d_t = 0, \qquad \text{for all } \tau \in (1,\ldots,T) \text{ and } \nu \in (1,\ldots,N).$$

In general, this condition will be satisfied if and only if:

$$\frac{\partial c_{nt}(Q)}{\partial q_{\nu\tau}} = 0, \qquad \text{for each } \nu \in (1,\ldots,N) \text{ and each } n \neq \nu.$$

This last condition implies that the entire reservoir is associated with just a single sector; meaning that the common pool problem does not exist. This condition, of course, does not characterize most oil fields where there generally are multiple firms with leases on the formation. Several observations can be drawn from this framework. First, the sharing or participation formula is the key relational aspect of the unit operating agreement. When the cost share assigned to each sector equals the production share assigned to that sector, then the firms owning those sectors are residual claimants to the *net* economic profits from *unit-wide* production.[28] No party has an incentive to adjust production away from that which maximizes the economic value of the reservoir.

[28] Operating firms typically lease the mineral rights from surface land owners, and they often have multiple sectors.

This essential provision, then, is the self-enforcing, incentive-compatible element of the unit operating agreement. When cost and revenue shares are allocated equally, then all parties in the unit will agree on a common plan of development. Hence, implementation and execution of that plan can safely be left in the charge of a single unit operator without detailed performance provisions or enforcement guidelines defined at the initiation of the contract. Any firm with a lease interest in the field and the technical competence to develop it would provide incentive-compatible management.[29] Beyond this, reliance on a single unit operator reduces transaction and coordination costs and further enhances the overall net value of the field.

Within such a unit, a super-majority voting rule (which essentially gives veto power to minority interests) could be adopted for approval of major expenditures and development decisions without thwarting maximization of overall field value. In fact, the role played by such voting rules would be to provide insurance against non-optimal development, since if the unit has been successfully structured to meet condition (i), no aspect of the optimal development plan would be opposed by minority interests. Because any minority dissent sends a warning signal regarding the possible misalignment of interests, a provision for super-majority rule in unit agreements plays a special role in validating the structure of the contract and ensuring efficient operations.

Procedures to enlarge or expand the unit membership based on new information regarding the configuration, geographical extent, and/or communication of reservoirs is essential to efficient development. Our initial period "$t=1$" can be regarded as coincident with any milestone that has been reached during the life of a field. To ensure optimal expenditures and extraction from that point forward, the structure of participating interests (F) must reflect the geographic extent and configuration of the underground formation. Changes in the parties' knowledge of the reservoir can therefore cause the unit to expand or contract over time. In contrast, the structure of participation, F, is robust against unexpected changes in oil prices,

[29] Technical competence and understanding of the overall geological formation generally implies that the firm with the largest lease holdings will be selected as unit operator. This prediction is empirically verified.

costs, or recovery methods, because incentives remain aligned with the common good even as these features of the project are unpredictably altered. This aspect illustrates the strong connection of the unit operating agreement to the purpose of relational contracts.

Importantly, the requirement that revenues and costs be allocated proportionately among the contracting parties reduces the information necessary for agreement. If the relational aspects are assembled, the contract can be left relatively simple, since new information will be incorporated by consensus over the life of the unit in a manner that maximizes its value and the returns to the parties.

This discussion suggests the following implications for unit operating agreements.

a). Unit revenues and costs will be allocated among the parties in proportion to one another (cost allocation will equal revenue participation).

b). There will be a single unit operator.

c). Voting weights will be based on unit participation, and may include veto power through the use of super majority voting rules.

d). There will be a single participating area at any point in time. That participating area will include those sectors where the hydrocarbon resources are in communication with one another and hence have cost and production interdependencies. Ideally, the participating area will include all sectors associated with a single reservoir.

e). Where costs and revenues are not allocated proportionately, incentives will not be aligned and evidence of discord among the operating interests and rent dissipation will be observed.

V. Empirical Evidence from 60 Unit Operating Agreements.

Our empirical investigation begins with an examination of 60 unit operating agreements from oil and gas fields in Alaska, Alberta, Illinois, Louisiana, Oklahoma, New Mexico, Texas, and Wyoming. Unit operating agreements often are placed on file with the state regulatory agency, such as with the Oklahoma Corporation Commission. Other files were made available

to us from company records. These operating agreements include many important fields in the United States and Canada, and the fields represented range from strictly oil or gas to both oil and gas and from relatively simple geological formations to more complex ones. Moreover, there is considerable variation in the number of parties involved in the units, from two working interests in the Cole Creek, Wyoming Unit to 113 working interest owners in the Empire Abo, New Mexico Unit.[30] Additionally, the unit operating agreements span a wide time range, including the July 3, 1934 Fourbear, Wyoming Unit and more recent units, such as the May 1, 1992 Rocky Ford Upper Mannville F Pool Oil Unit, Alberta. Hence, we believe that the empirical record from this sample of operating agreements is reflective of the general pattern of unitization contracting.

Table 1 summarizes four key aspects of the unit operating agreements: cost and revenue sharing, number of participating areas, voting based on unit participation, and number of unit operators. As shown in the table, overwhelmingly, unit operating agreements include provisions to allocate costs and revenues in proportion to one another among the participating working interests in the unit. 80 percent (48 of the 60) of the unit operating agreements contain such a provision. This finding underscores the importance of equating cost and revenue shares among the parties to link their interests in the maintenance of a production plan that maximizes the value of the reservoir over the life of the contract. Moreover, 56 of the 60, or more than 93 percent of the unit operating agreements, have a single unit operator, which reduces coordination problems within the unit. Additionally, to effectively address the common pool problem it is necessary to include in the unit all leases or working interests that draw on the same oil and gas deposit. By sharing migratory hydrocarbons and subsurface pressures, these leases have interdependent costs and production.

Cole Creek Unit Operating Agreement, January 30, 1953; Empire Abo Unit Operating Agreement, October 1, 1972.

The previous section shows that the working interests on these leases must be united in the unit through a single participating area and participation formula at any point in time.[31] Multiple participating areas and sharing formulas over related or communicating deposits create differential incentives for unit operation. Costly discord and resource rent dissipation are the likely outcomes. In Table 1, 54 of the 60, or 90 percent of the units, have a single participating area at any time for coordinating the working interests on the field. Most of the units identify the formation included, such as the Grass Creek *Pre-Tensleep* and Grass Creek *Curtis* units of Hot Springs County, Wyoming that cover different, non-communicating hydrocarbon formations within the same field.[32] Finally, 48 of the 57 unit operating agreements that address governance procedures (84 percent) have supervisory voting provisions that assign weights according to unit revenue participation.

With regard to voting, we also argued that super majority voting rules could be adopted for major decisions to insure efficient operations. An example of such provisions is provided in the Anschutz Ranch East Unit of Summit County, Wyoming and Uinta County, Utah, December 1, 1982. The Unit Operating Agreement (Article 4.4) describes voting procedures. Major issues, such as the expansion or contraction of the unit area, termed "Category A Matters," require unanimity. Failure to achieve such support forces the matter to arbitration within 10 days. Other voting issues, termed "Category B, C, and D Matters," have different requirements (all super majorities) that vary according to the significance of the issue at stake. For instance, 97.5 percent of the voting interests must approve the selection of the Arbitration Coordinator, who resolves disputes within the unit; 90 percent must agree to the completion of an Exploratory Well that might change the boundaries of the unit; 80 percent must approve the revision of the Plan of

[31] There often are different participating formulas and participating areas for different stages of production, such as primary production when the unit relies upon subsurface pressures to expel the oil and secondary recover)' when injection of water or other substances is necessary to drive the oil to the surface. But at any point in time, a single participating area exists.

[32] Grass Creek Curtis Unit Operating Agreement, November 20, 1958; Grass Creek Pre-Tensleep Unit Operating Agreement, August 22, 1957.

Depletion for the unit; and 65 percent must approve the amount of insurance to be carried or grant expenditures beyond the limits provided in the unit operating agreement.[33] 0ther unit operating agreements also have super majority voting requirements.[34]

All in all, the empirical regularities of a proportional allocation of unit revenues and costs, a single participating area where those allocation formulas apply, governance voting based on those formulas, and a single unit operator in the participating area support the predictions of the theory of what is necessary to successfully align incentives over time. Oil producing firms (the working interests) write unitization contracts to define long-term working relationships that can result in valuable returns through avoiding common pool losses, increasing oil and gas recovery, and reducing costs. For instance the preamble of the Goldsmith Landreth Deep Unit Agreement (Ector County, Texas, August 1, 1964) outlines the collective objective of the parties to the agreement: "WHEREAS, In the interest of the public welfare and to promote conservation and increase the ultimate recovery of oil, gas, and associated minerals from the Goldsmith Field...it is deemed necessary and desirable to enter into this agreement..."

The unit operating agreements are long-term relational contracts that depend upon key provisions to align incentives. The essential ingredient of these contracts is the proportional allocation of unit revenues and costs among all working interests on the same (communicating) hydrocarbon formation. This relational requirement is most effectively implemented with a single participating area that includes all the relevant working interests, unit governance voting based on the allocation formula, and a single unit operator to develop the field. The uniformity of these provisions across units formed in different areas, completed at different times, involving variation in the number of firms involved, and covering differences in geological formations indicates that the parties recognize the *essential* ingredients of a relational contract.

[33] Anschutz Ranch East Unit Operating Agreement, December 1,1982.

[34] Other examples include the Collums Muddy Sand Unit Operating Agreement, Campbell County, Wyoming, June 15, 1970, Article 4.3.2 which calls for 80 percent voting rules, and the Brady Deep Unit Operating Agreement, Sweetwater Comity, Wyoming, August 10, 1972, Article 14 which calls for 65 percent voting rules.

In Table 1, 12 of the 60 unit operating agreements appear not to have a proportional allocation of costs and revenues among the working interests, involve multiple participating areas, have multiple unit operators, and include voting procedures that are not based on a single participation formula for the entire unit. Most extreme are the Bonnie Glenn D-3 A Oil and Gas Units, Alberta, the Minnehik Buck Lake Ostracod Unit #2, Alberta, and the Prudhoe Bay Unit, Alaska. For example, the Bonnie Glen units are separate units for oil and gas deposits that are in communication with one another (the gas is in a "gas cap' above the oil) with distinct sharing formulas, unit operators, and governance procedures.[35]

The units whose operating agreements have the relational characteristics should have comparatively routine, non-controversial production histories. And indeed the empirical record appears to support this claim. Tests of the hypothesis that relational unit operating agreements more effectively align incentives and involve less costly conflict than do unit operating agreements that do not have key relational characteristics is difficult because of the limited data available. Disputes within private unit operating agreements generally are resolved through mediation with no public record. Only the most hotly contested unit operating agreements will involve litigation and/or appeals to state regulatory agencies.

Our search of court cases involving the units included in Table 1 shows no detailed court record for any of the units, except the Prudhoe Bay Unit in Alaska. Similarly, examination of regulatory records at the Texas Railroad Commission and the Oklahoma Corporation Commission provides no indication of protracted conflict among the working interests within units in these two states.[36] By contrast, the records of the Alaska Oil and Gas Conservation Commission (AOGCC) clearly show that the Prudhoe Bay Unit Operating Agreement has a history of intense and costly disputes among the working interests. This finding is predictable

[35] Bonnie Glen D-3A Gas Cap Unit, Bonnie Glenn D-3 A Oil Unit #1, Alberta, January 1, 1975.

[36] We are not claiming that we have undertaken an exhaustive search of the legal record of conflict for all 60 units. For example, we have not searched Canadian court cases or the Alberta regulatory agency records. Our search of available evidence, however, makes it quite clear that Prudhoe Bay stands out from the other units in its history of conflict among the working interests on die unit.

from the theoretical discussion in the preceding section: the Prudhoe Bay Unit Operating Agreement has none of the **key** relational characteristics that we have identified: it has multiple participating areas covering communicating hydrocarbon deposits with separate allocation formulas for costs and revenues within each participating area; it has separate governance voting for each participating area; and it has two distinct operators that share responsibility for overall field management. In many ways it appears to be two, competing units on the same formation. We now turn to the evidence regarding the Prudhoe Bay Unit.[37]

VI. Rent Dissipation When Incentives Are Not Aligned in Relational Contracts: The Case of the Prudhoe Bay Unit.

The Prudhoe Bay field was discovered in early 1968 by Exxon and Arco. British Petroleum (BP) conducted further testing on an adjacent lease in 1969 that confirmed the massive size of the discovery. The field is located on the north slope of the Brooks Range, adjacent to the Arctic Ocean on Alaska's coastal plain. When first production came on stream in July of 1977, Prudhoe Bay became the largest producing oil field in North America, eighteenth largest in the world. The total resources trapped in that single geological formation amounted to some 22 billion barrels of oil and 46 trillion cubic feet of natural gas. To date, more than $22 billion has been spent to develop these resources.[38]

Most of the leases covering the Prudhoe Bay field were owned either by Arco, Exxon, or BP, and these companies quickly appointed teams to negotiate a unit operating agreement that would facilitate joint development and production of the field. The importance of structuring that agreement to perforin as a relational contract was dictated by the many aspects of field

[37] The unit operating agreements shown in Table 1 that do not comply generally involved units on complex geological formations where the parties could not agree to an "optimal" contract.

[38] A useful description of the Prudhoe Bay field is found in D. J. Szabo and K. O. Meyers, "Prudhoe Bay: Development History and Future Potential," Society of Petroleum Engineers Paper No. 26053, 1993.

design and performance that could not be anticipated by the parties at the time of initial negotiations, and the many expenditures that could not be timed, budgeted, or even described with specificity prior to the beginning of operations.[39] For example, initial estimates of total oil recovery from the field were put at 9.6 billion barrels, but more complete reservoir information and intervening technological innovation have lifted that number above 13 billion barrels. The estimated cost of drilling has fallen from $7 million to $1.5 million per well over the years, while the total number of wells required to complete the development plan has increased from 200 to 1,300 in total.[40]

As in all unit negotiations, the owners' deliberations were hampered by these geological and technical uncertainties. However, the difficulty of reaching agreement was magnified in this instance by the prospective engineering and economic challenge of simply getting the resources to market. The gas resources were particularly problematic, since it was not clear whether a gas transportation system would ever become economically viable. If not, then the main value of the gas would be to maintain the pressure that is needed within the reservoir to force oil up and out of the wells. That is, the gas might always remain nothing more than a factor that would assist in the production of oil.

Most of the gas within the field was concentrated in a pocket at the top of the formation, called the "gas cap," and Arco and Exxon's leases were clustered in that part of the field. Most of the oil was located in a zone below the gas cap, in a region referred to as the "oil rim," where BP's leases were concentrated. Since the economic value of the gas resources was highly speculative, the parties sought in vain for a formula that would allocate to each party a fixed

[39] Alaska Oil and Gas Conservation Commission (AOGCC), Public Hearing Re: Prudhoe Bay Unit—Liquid/Miscible Natural Gas Injectant, April 12, 1996, page 240. (Hereafter referred to as "AOGCC Hearings.")

share of all hydrocarbons produced from the field. BP, in particular, was reluctant to see any of its oil rim resources allocated to Exxon or Arco in exchange for a reciprocal share of the gas cap resources, which after all might never be produced.[41]

This difference of opinion regarding the value of gas resources complicated unit negotiations, which the parties have characterized as being "frenetic" and "a Herculean effort."[42] What emerged after eight years of bargaining and compromise was an agreement among the owners that designated two separate participating areas within the reservoir: each owner was allocated a fixed share of Oil Rim production and Oil Rim costs, but a separate and numerically different share of Gas Cap production and Gas Cap costs. BP, for example, was allocated 51 percent of production from the Oil Rim, but only 14 percent of production from the Gas Cap.[43]

Any disparity in allocations between the two participating areas violates the basic proportionality condition of unitized operations and undermines the relational aspect of the contract. As we have demonstrated, to create a permanent alignment of interests among all owners *it is necessary that each owner shall receive the same fixed share of production, no matter where it is taken from the field.* It is clear, for example, that if BP had been allocated none of the Gas Cap production, but all of the Oil Rim production, the company would tend to oppose gas sales because the gas would be worth more (to BP) if left in the reservoir to push out more oil. Exxon and Arco, in contrast, would favor only gas sales, because gas left in (or returned to) the reservoir would have no value for them. Although less extreme than this

[40] AOGCC Conservation Order No. 360 (Prudhoe Bay Oil Field, Prudhoe Oil Pool), August 9, 1995 (Revised November 3, 1995), paragraph 85. (Hereafter referred to as "AOGCC Order 360")

[41] AOGCC Hearings, pp. 238, 289, and 951-956.

[42] Szabo and Meyers, op. cit., page 1; and AOGCC Hearings, page 16.

[43] Costs incurred in each participating area were allocated among owners on the same basis as production.

example, the disproportionality that was created by the formation of dual participating areas within the Prudhoe Bay field ultimately led to conflicts of interest, opportunistic behavior, and an intense battle over how the field would be developed.

The working interest owners, Arco, Exxon, and BP, have struggled continuously with major conflicts surrounding each stage of development of the Prudhoe Bay field. Many of these conflicts have been dealt with privately or in closed court proceedings, with few outward signs of any difficulty. Recently, however, the dissension among owners has boiled over into public view, and cast a brighter light on the entire history of the field.

At the heart of most of the conflicts is the inevitable competition that exists, by virtue of the dual participating areas, between the interests of Arco and Exxon (as majority owners of the Gas Cap), and BP (as majority owner of the Oil Rim). From the outset, the owners have been aware that the sale and removal of gas from the field would impair ultimate recovery of oil, because of the consequent loss of reservoir pressure. That is a cost that falls disproportionately on BP. On the other hand, any gas reinjection program designed to maintain reservoir pressure or otherwise enhance the recovery of oil has the potential to divert marketable gas that could perhaps be sold elsewhere, to the disadvantage of Arco and Exxon.

To maximize the economic value of the field as a whole, it is necessary to balance these two competing interests. As part of the initial negotiations to create the Prudhoe Bay Unit, the owners attempted to negotiate certain contingent agreements that would govern development decisions and commit all parties to a course that would strike a proper balance between these competing interests and promote the common good.

The contingent agreements, however, have not worked out as planned. Once experience with the field accumulated to the point where specific projects to enhance recovery could be

outlined and evaluated, the owners often found themselves on different sides of the coin; alternately championing or blocking proposals that would fail to reach consensus, and arguing over the question of who should pay for what share of the cost. Representatives of Arco have acknowledged that because of differences in the way production and costs were allocated across the field, the economics of a project look different to an individual company than to the Unit as a whole. Thus, whenever the companies would consider a new project, they would look at if from both a Unit perspective as well as from an individual company perspective.[44] Representatives of BP and Phillips Petroleum (a minority owner of the Oil Rim resources) concur that these misaligned interests and competitive tensions have hampered projects intended to increase the capacity of surface gas handling facilities.[45]

Providing facilities to handle gas has been a dominant development issue at Prudhoe Bay throughout the 1980s because the production of oil from the field is constrained by the need to dispose of gas that is produced in association with the oil. Indeed, it was not the depletion of remaining resources that set Prudhoe oil production into eventual decline in 1988—that turning point in the life of the field was caused by the lack of facilities to handle the growing fraction of gas that was produced in association with oil as the field matured.[46]

At one point in the hearings that transpired in 1996 before the Alaska Oil and Gas Conservation Commission (AOGCC), Arco's own lawyer explained the history of disputes among the owners as a series of very distressing instances where one owner would seek its own

Testimony of Jan Dana Dayton before the A O G C C Hearings, pp. 467-468.

[45] Testimony of Anthony Meggs before the A O G C C Hearings, page 730; and testimony of Jerry Lee Meronek before the A O G C C Hearings, page 1069.

[46] Szabo and Myers, op. cit, page 4.

self-interest at the expense of the Unit, and described the situation as a "knock-down, drag-out battle" that is still ongoing.[47]

For many years, the owners attempted to navigate their way through these disputes via a succession of private negotiations and voluntary amendments to the original Unit Operating Agreement. These amendments invariably modified or supplemented the contingent agreements that had been previously adopted regarding the allocation of costs and production flows among owners. This series of contract renegotiations and amendments includes the Natural Gas Liquids/Enhanced Oil Recovery (NGL/EOR) Operating Procedures (adopted in 1983), the Fuel Gas Supply Option arbitration (settled in 1983), the first and second Gas Handling Expansion Agreements, GHX-1 and GHX-2, (adopted in 1987 and 1990, respectively), the Issues Resolution Agreement (adopted in 1990), and the Amended and Restated NGL/EOR Operating Procedures (adopted in 1992).

Negotiating each of these amendments to the original contract was an arduous and time consuming task. Formal deliberations over the Issues Resolution Agreement, for example, continued for two years.[48] More recently, and at the urging of the AOGCC, the owners have set large numbers of people at work yet again to identify and resolve areas of field development and operations where the individual incentives of the owners' are misaligned. BP, for example, reportedly had 100 people working on their alignment team during 1995 and 1996.[49]

Although each of these contract amendments offered inducements that brought the two sides back together, nothing was done to eliminate the root cause of conflict. The dual participating areas remain in place and continue to frustrate the owners' attempts to view and

[47] AOGCC Hearings, pp. 188, 194, and 1120.

[48] AOGCC Hearings, page 68.

manage the field as one unified resource pool. As each separate issue was settled, it seemed that a new area of dispute would arise. In reviewing the history of the field and its management, the AOGCC found that development and operation of the Unit had not been able to proceed without this series of voluntary amendments to the original contract, but that even with the benefit of the several amendments, the revised contractual arrangements were still inadequate to prevent, and might actually promote, physical waste within the field.[50]

In 1992, following the string of previous contractual amendments, the owners renewed their efforts to voluntarily (and privately) overcome remaining barriers that blocked consensus on how the field should be managed.[51] That effort failed conspicuously. The issue that brought matters to a head was again related to the processing and disposition of produced gas. Arco and Exxon favored processing this gas to extract as much natural gas liquids (NGL) as could be blended with oil for shipment and sale down the Trans-Alaska Pipeline. BP, facing different incentives, favored processing the gas to produce miscible injectant (MI), which could be reinjected into the field to enhance the recovery of remaining oil.[52]

This conflict of interests derived, as usual, directly from the disproportionate allocations associated with the dual participating areas. BP, for example, would be credited with only 14 percent of any additional NGL that would be shipped down the pipeline, as opposed to receiving a 51 percent share of any additional crude oil that would be recovered via the injection of MI. In contrast, Arco and Exxon would be credited with only 22 percent (each) of any enhanced

[49] AOGCC Hearings, page 81.

[50] AOGCC, Order 360, paragraph 12.

[51] Szabo and Myers, op. cit., page 8.

[52] AOGCC, Order 360, paragraphs 73-74.

recovery of oil, but receive 42 percent (each) of whatever volumes of NGL the Unit was able to ship down the pipeline.[53]

After remaining an unresolved source of public contention among the owners for several years, the question of "sale versus use" of NGLs was finally brought before the AOGCC in late 1994.[54] Even while waiting for the AOGCC to rule on the matter, however, on February 9, 1995 Arco (acting as operator of facilities in the eastern region of the field) unilaterally increased the production of NGLs for shipment down the pipeline. To offset Arco's initiative, BP (acting as operator of facilities in the western region of the field) unilaterally restricted the volume of NGLs that it blended with the stream of crude oil entering the pipeline, thereby leaving the total shipment of NGLs from the Unit unchanged. In retaliation, Arco then increased its own blending of NGLs into the crude oil stream, but BP again took offsetting action. In addition, BP filed a claim in the Alaska Superior Court that would permit the company to take its share of field production in kind, thereby preventing Arco from using that oil as a vehicle for increased blending of NGLs. BP also filed a request with the Alaska Public Utilities Commission for permission to construct a new pipeline within the field to segregate and convey its share of the oil for shipment off the Unit, prior to any further blending of NGLs. Within weeks, Arco and Exxon filed a counterclaim with the Court, accusing BP of "unreasonable interference with Unit gas."[55]

During hearings that ensued before the AOGCC, Arco described BP's actions as the "repudiation of contractual obligations motivated by its (BP's) economic interests,"[36] and argued

[53] AOGCC, Order 360, paragraphs 73-74, and 153.

[54] Petroleum News Alaska, vol. 1, no. 6, pp. 18, 27; vol. 1, no. 7, pp. 2, 25-27; and vol. 1, no. 8, pp. 1, 6, and 17.

[55] AOGCC, Order 360, paragraphs 135-136.

[56] AOGCC, Order 360, paragraph 142.

that the sole function of the proposed BP pipeline was to "transfer money from Arco and Exxon's pockets to BP's pockets."[57] For its part, BP admitted that the proposal to segregate its crude oil stream was "vastly inefficient" from the perspective of the Unit, but still necessary to protect the company's correlative rights.[58] The Chairman of the AOGCC was alarmed to find the signatories to a unit agreement nevertheless accusing each other of causing waste, violating correlative rights, and impairing ultimate recovery from the field.[59] Observers who knew the companies well said that watching this dispute unfold in public was "like seeing dear friends go through a bitter divorce."[60] All parties to the dispute have agreed that the events which transpired during the MI/NGL dispute did not reflect "good oil field practice." The AOGCC ruled that the dispute ultimately lead to inefficient operations at Prudhoe Bay and contributed to a reduction in the quantity of oil that can be recovered from the field.[61]

Although the parties have disagreed publicly about the ultimate impact of the contested plan to sell rather than reinject the produced NGL, the potential impact is apparently significant. By BP's estimate, maximum reinjection of the gas would boost ultimate recovery of liquid hydrocarbons by some 150-200 million barrels. In BP's view, Arco's proposal to divert a portion of the injected gas for sale as NGL would decrease ultimate recovery by 60-80 million barrels.[62] To put these numbers in perspective, consider that any single oilfield with as much as

Petroleum News Alaska, vol. 1, no. 6, p. 18.

AOGCC, Order 360, paragraphs 130-132.

Petroleum News Alaska, vol. 1, no. 7, pp. 2, 25-27.

Petroleum News Alaska, vol. 1, no. 6, p. 27.

AOGCC, Order 360, paragraphs 67-68, and 139.

AOGCC, Order 360, paragraphs 59 and 62.

100 million barrels of recoverable reserves is considered a "giant" relative to the size distribution of all U.S. oil and gas fields.[63]

What lessons can we learn from this unfortunate episode in the history of the Prudhoe Bay field? The main lesson is that unit agreements work as relational contracts only if the interests of the owners are aligned, and remain aligned, as the issues and opportunities that require management concurrence evolve through time. Alignment of individual interests with the common good requires proportionality in the structure of the unit. Each owner must be allocated a fixed share of production and costs, and that share must not vary depending on the origin of production or the nature or purpose of the cost.

Uncertainties regarding field geology, engineering, and economics may make it difficult to reach agreement on the fixed proportions of unit activity to be allocated to each owner. These decisions are tantamount to assigning equity interests in the value of the property. It may seem easier to adopt a set of contingent commitments that achieve an initial balance of interests, at least relative to the expectations held initially by the owners, and to put off difficult issues that would have potential impacts on the equity of the owners. However, balancing interests by trading off contingent claims is not the same thing as aligning interests via proportional participation in the affairs of the unit. The proportional alignment of interests is permanent, more or less. In contrast, contingent claims will remain in balance only by luck, and once the balance is lost, the agreement becomes vulnerable to opportunism and obstructionism. To postpone the determination of who gets what share of the pie is to invite the very circumstances that could subsequently influence individual owners to pursue their own agendas, even at the risk of reducing the overall size of the pie.

[63] See pp. 13-15 of Richard Nehring (1981).

This lesson should be apparent to the working interests of the Prudhoe Bay Unit, who have complained that, as time progressed and circumstances changed, some owners were simply not willing to abide by the original provisions, electing instead to abrogate agreements on the basis of individual incentives that some found impossible to resist.[64] This unfortunate situation was essentially created by provisions within the contract itself, not by differing views of reservoir behavior or engineering. All parties who have reviewed these matters, including Arco, BP, the Alaska Department of Natural Resources, and the AOGCC, have agreed that, but for the competing incentives created by the formation of the two participating areas, the owners would never have been entangled in such a dispute before the AOGCC.[65]

Arco's proposed solution for the opportunism and obstructionism that ails the Prudhoe Bay Unit is simply to bring stronger enforcement:

> It is not a failure of the agreements. The agreements are in place. If the agreements had been adhered to, there would not have been any problem. ... Any time you consider the potential unitization of something, all you are really doing is binding everyone to commit themselves to act as a single prudent owner. That is really the key commitment. What is done in terms of the structure behind that isn't that important. It's like you have a rule that says you must act as a single prudent owner and once people in a voluntary unit commit to that, then they are bound by it. Then the problem simply becomes one of enforcing compliance with that.[66]

This reading of the history of the Prudhoe Bay Unit, however, misses the most fundamental point about relational contracts in general, and unit agreements in particular. To guarantee adherence to performance standards in an environment that evolves unpredictably, the structure of the agreement must create a durable alignment of interests that automatically

[64] AOGCC Hearings, page 196.

[65] AOGCC, Hearings, pp. 108-109, and Order 360, paragraphs 122, 148-149, and 158.

[66] This excerpt is from the argument of Arco's counsel at the AOGCC Hearings, pp. 195, 208.

provides permanent incentives for self-enforcement of the common good. The alternative is to imagine that a system of contingent contracts can be designed to create a balance between competing interests that is more reliable and durable than the probability estimates that the parties are willing to assign to the various contingencies, and more complete than the limited set of eventualities that can be addressed explicitly within the document that embodies the agreement. The experience of the Prudhoe Bay Unit is a case history showing why that second alternative is not a good bet.

V II. Concluding Remarks.

In this paper we have examined an important set of relational contracts, unit operating agreements. These contracts are designed to unite otherwise competing parties on oil and gas fields in exploiting hydrocarbon deposits over long periods of time. The parties in effect become share or equity holders with a claim on the net profits of the unit, and a single firm develops the field with the goal of maximizing its economic value. All of the classic problems of contracting are encountered—small numbers bargaining, asset specificity, asymmetric information, uncertainties regarding field geology, engineering, and market conditions, and related opportunism. Nevertheless, the gains from unitizing oil and gas fields provide incentives for the parties to negotiate to form units, and these negotiations often are protracted. Even so, common characteristics emerge in by far the majority of cases to insure that the contracts are relational.

We have identified the essential elements of these contracts that make them relational, that tie or align incentives across time, despite the classic pitfalls of uncertainties, asymmetric information, asset specificity, and small numbers bargaining. These characteristics are a single cost and revenue sharing formula that covers all communicating hydrocarbon deposits (the entire "common pool"). In the industry this grouping is referred to as a single participating area.

Moreover, costs and revenues must be shared in proportion to one another so that the parties receive the net returns from unit operations and have no private incentive to individually vary production or investment patterns in their behalf that harms the other interests on the unit. The empirical uniformity for these characteristics described in Table 1 despite the spread of these units across time and location underscores their importance and general recognition.

The bargaining necessary to write such relation contracts is difficult, often taking five to ten years or more. But once the relational contracts are completed, the record indicates that the units operate routinely with little costly discord. As noted in the previous section, although it may seem easier and faster to adopt a set of contingent commitments that achieve an initial, short-term balance of interests in order to begin unit operations, by postponing more difficult issues to a later date, the potential for subsequent, costly conflict becomes great. Contingent contracts do not fully align interests over the long term, and the costs of uniting those interests to successfully operate a unit *ex post* appear to be very high. The historical record of contention among the working interests on the Prudhoe Bay Unit indicates that the failure to provide for a fixed, proportional allocation of revenues and costs has encouraged opportunism that is reducing the overall returns from the field.

Our examination of long-term contracts for the development of oil and gas fields makes clear what is necessary to make them "relational." Moreover, the analysis reveals the critical role played by such agreements in facilitating mutually-beneficial relationships in the face of serious uncertainties. These relational contracts automatically provide permanent incentives for self-enforcement to achieve the common good. Finally, the analysis reveals that relational contracts provide for economic exchanges that would not likely be possible through a system of contingent contracts. Within contingent contracts path dependencies emerge, created by the differential incentives of the parties that alter the stream of benefits and costs from subsequent agreements. As individual private benefits and costs become more divergent, the likelihood of future, beneficial exchange is reduced and along with it, the economic value of the asset over which contracting is taking place. Relational contracts, such as unit operating agreements, can

be viewed as ingenious institutional innovations that allow for transactions that could not be possible under other contractual arrangements.

Bibliography

Coase, Ronald, 1960, "The Problem of Social Cost," Journal of Law and Economics. 3: 1-44.

_____, 1992, "The Institutional Structure of Production," American Economic Review. 82: 713-9.

Crocker, Keith J. and Scott E. Masten, 1991, "Pretia Ex Machina? Prices and Process in Long-Term Contracts," Journal of Law and Economics. 34(1) 69-99.

Demsetz, Harold, 1988, "The Theory of the Firm Revisited" Journal of Law. Economics, and Organization. 4: 141-62.

Eggertsson. Thrainn. 1990. Economic Behavior and Institutions. New York: Cambridge University Press.

Furubotn, Eirik G. and Rudolf Richter, 1991, The New Institutional Economics. College Station: Texas A & M University Press.

Goetz, Charles J. and Robert E. Scott, 1981, "Principles of Relational Contracts," Virginia Law Review. 67(6): 1089-1150.

_____,1983, "The Mitigation Principle: Toward a General Theory of Contractual Obligation," 69(6): 967-1024.

Goldberg, Victor P., 1976, "Toward an Expanded Theory of Contract," Journal of Economic Issues. 10: 45-61.

_____,1985, "Price Adjustment in Long-Term Contracts," Wisconsin Law Review. 527-543.

Goldberg, Victor P. and John R. Erickson, "Long-Term Contracts for Petroleum Coke," Journal of Law and Economics. 31: 369-98.

Joskow, Paul L., 1985, "Vertical Integration and Long Term Contracts," Journal of Law. Economics, and Organization, 33-80.

_____, 1987, "Contract Duration and Relationship Specific Investments: Empirical Evidence from Coal Markets," American Economic Review. 77: 168-85.

_____,1988, "Price Adjustment in Long-Term Contracts: The Case of Coal," Journal of Law and Economics, 31(1): 47-83.

Klein, Benjamin, 1992, "Contracts and Incentives: The Role of contract Terms in Assuring Performance," in Lars Werin and Hans Wijkander, eds., Contract Economics, Cambridge, Mass: Blackwell, 149-173.

Klein, Benjamin, Robert G. Crawford, and Armen A. Alchian, 1978, "Appropriable Rents and the Competitive Contracting Process," Journal of Law and Economics 21: 297-326.

Libecap, Gary D., 1989, Contracting for Property Rights, New York: Cambridge University Press.

_____, forthcoming, "Unitization," New Palgrave Dictionary of Law and Economics. Peter Newman, ed.

Libecap, Gary D. and Steven N. Wiggins, 1984, "Contractual Responses to the Common Pool: Prorationing of Crude Oil Production" American Economic Review. 74: 87-98.

_____,1985, "The Influence of Private Contractual Failure on Regulation: The Case of Oil Field Unitization," Journal of Political Economy, 93: 690-714.

Llewellyn, Karl N., 1931, "What Price Contract? An Essay in Perspective," Yale Law Journal, 40: 704-751.

Macneil, Ian R., 1978, " Contracts: Adjustment of Long-Term Economic Relations under Classical, Neoclassical, and Relational Contract Law," Northwestern Law Review, 72: 854-905.

Manthy, Robert S., 1978, Natural Resource Commodities—A Century of Statistics. Baltimore: Resources for the Future and Johns Hopkins University Press.

Masten, Scott E. and Keith J. Crocker, 1985, "Efficient Adaptation in Long-Term Contracts: Take-or-Pay-Provisions for Natural Gas," American Economic Review. 75: 1083-93.

McDonald, Stephen, 1971, Petroleum Conservation in the United States. Baltimore: Resources for the Future.

Mulherin, J. Harold, 1986, "Complexity in Long-Term Contracts: An Analysis of Natural Gas Contractual Provisions." Journal of Law. Economics, and Organization, 2: 105-117.

Muris, Timothy J., 1981, " Opportunistic Behavior and the Law of Contracts," Minnesota Law Review. 65: 521-590.

Nehring, Richard, 1981, The Discovery of Significant Oil and Gas Fields in the United States. Santa Monica, CA: The Rand Corporation.

North, Douglass C, 1981, Structure and Change in Economic History, New York: Norton.

_____,1990, Institutions. Institutional Change and Economic Performance. New York: Cambridge University Press.

Petroleum News Alaska, various issues, Anchorage, Alaska.

Posner, Richard A., 1979, "The Chicago School of Antitrust Analysis," University of Pennsylvania Law Review. 127: 925-948.

Rubin, Paul, 1978, "The Theory of the Firm and the Structure of the Franchise Contract," Journal of Law and Economics. 21 (1): 223-233.

Schwartz, Alan, 1992, "Legal Contract Theories and Incomplete Contracts," in Lars Werin and Hans Wijkander, eds., Contract Economics. Cambridge, Mass: Blackwell, 76-108.

Smith, James L., 1987, "The Common Pool, Bargaining, and the Rule of Capture," Economic Inquiry 25: 631-44.

State of Alaska, Oil and Gas Conservation Commission, Transcript of Public Hearings Re: Prudhoe Bay Unit—Natural Gas Liquid/Miscible Injectant, April 11-24, 1996, Anchorage.

State of Alaska, Oil and Gas Conservation Commission, Conservation Order No. 360 (Prudhoe Bay Oil Field, Prudhoe Oil Pool), August 9, 1995 (revised November 3, 1995), Anchorage.

Weaver, Jacqueline Lang, 1986, Unitization of Oil and Gas Fields in Texas: A Study of Legislative. Administrative, and Judicial Policies. Washington D.C.: Resources for the Future.

Wiggins, Steven N. and Gary D. Libecap, 1985, "Oil Field Unitization: Contractual Failure in the Presence of Imperfect Information," American Economic Review 75: 376-385.

Williamson, Oliver E., 1975, Markets and Hierarchies. New York: Free Press.

_____, 1979, "Transactions Costs: The Governance of Contractual Relations," Journal of Law and Economics. 22(2): 233-261.

_____,1985, The Economic Institutions of Capitalism: Firms. Markets. Relational Contracting. New York: Free Press.

_____, 1988, "The Logic of Economic Organization," Journal of Law. Economics. and Organization. 4: 65-93.

_____, 1993, "Calculativeness, Trust, and Economic Organization," Journal of Law and Economics, 36 (1): 453-86.

Table 1
Unit Operating Agreement Characteristics

Unit Name	Proportional Allocation of Costs and Revenues	Single Unit Operator	Single Participating Area	Voting Based on Unit Participation	Unit Name	Proportional Allocation of Costs and Revenues	Single Unit Operator	Single Participating Area	Voting Based on Unit Participation
Anshutz East	X	x	x	X	Salem Flood	x	x	x	x
Benton	X	x	x	X	Salt Creek South	x	x	x	x
Big Stone Gas	X	x	x	X	Seeligson	x	x	x	x
Birch Creek	X	x	x	X	Sharon Ridge Canyon	x	x	x	x
Brady Deep	X	x	x	X	South Swan Hills	x	x	x	x
Burke Ranch	X	x	x	X	Southwest Homer	x	x	x	x
Carpenter	X	x	x	X	Star Misner-Hunton	x	x	x	x
Collums Muddy Sand	X	x	x	X	Sycamore	x	x	x	x
County Line	X	x	x	X	West Cement Medrano	x	x	x	x
East Binger	X	x	x	X	West Edmond	x	x	x	x
East Burke Ranch	X	x	x	X	West Elmwood	x	x	x	x
East Salt Creek	X	x	x	X	Wildhorse	x	x	x	x
Edson Cardium B	X	x	x	X	Big Sand Draw	x	x	x	NA
Empire Abo	X	x	x	X	Cole Creek	x	x	x	x
Fox Deese-Springer	X	x	x	X	Forebear	x	x	x	NA
Goldsmith San Andreas	X	x	x	X	West Poison Spider	x	x	x	NA
Graham Deese	X	x	x	X	Canyon Reef	x		x	
Grass Creek Curtis	X	x	x	X	Bumpass	x	x	x	x
Green River Bend	X	x	x	X	North Thackerville		x	x	x
Hartzog Draw	X	x	x	X	Virginia Hills Belloy		x	x	x
Joffrey D-2	X	x	x	X	Alliso Canyon		x	x	
Karon	x	x	x	X	Clive D-2		x	x	
Little Buffalo Basin	x	x	x	X	Clive D-3A		x	x	
Milroy	x	x	x	X	Harmattan East		x		x
Nipisi Gilwood	x	x	x	X	Harmattan Elkton		x		x
North Twining	x	x	x	X	NAMAO Blairmore		x	x	
Painter Reservoir	x	x	x	X	Rocky Ford		x		
Pembina Ostracod	x	x	x	X	Bonnie Glen D-3A				
Ryckman Creek	x	x	x	X	Minnehik Buck Lake				

Sage Spring Creek	x	x	x	X	**Prudhoe Bay**				