# Appendix C

# Legal Aspects of Enhanced Oil Recovery

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# Introduction

The purpose of this appendix is to provide details of legal issues associated with enhanced oil recovery (EOR). The term "enhanced oil recovery" refers to any method of oil production in which gases and/or liquids are injected into the reservoir to maintain or increase the energy of the reservoir or react chemically with the oil to improve recovery. Thus, enhanced recovery encompasses the techniques referred to as pressure maintenance, secondary recovery, and tertiary recovery. The reason for the broader use of the term in this section is the fact that the legal problems are much the same for any technique of oil recovery beyond primary methods. There has been relatively little commercial application of tertiary recovery techniques, so no body of case law specifically regarding it has developed; the law in this area must draw upon experience in pressure maintenance and established methods of secondary recovery. Secondly, the regulatory schemes of most States do not distinguish among the different types of recovery beyond primary methods. Distinctions among the various techniques of enhancing recovery will be made only when necessary.

To assess fully how the law encourages, hinders, limits, or prevents employment of EOR techniques, it would be necessary to examine in detail each reservoir in which such techniques are or might be used. Such was beyond the scope of this assessment. The approach used here identifies existing or possible constraints without attempting to suggest how much more or less oil could be produced with or without particular constraints. Statutes, regulations, and rules of law affecting EOR are described in a general way without discussing their applicability to particular fields, not only because the complex interplay among various factors makes specific judgments about individual fields very difficult, but also because the law on some important points is undecided or very uncertain in most jurisdictions. The views of producers and State regulatory personnel are discussed when appropriate, as are the observations and comments of legal authorities on particular subjects.

# Unitization: Voluntary and Compulsory

## Basic Principles of Oil and Gas Law

The most efficient means of utilizing EOR techniques is generally to treat the entire oil reservoir as though it were a single producing mechanism or entity. There is no problem with this when the operator of the field owns the leasehold or mineral interest throughout the entire reservoir; in this case obtaining the consent of any other owner of an interest in the minerals in order to undertake enhanced recovery operations is unnecessary. However, where there are other owners of interests in the same field, obtaining consent may be necessary before fieldwide operations may be commenced. In order to better understand the problems that may be involved in securing this consent or cooperation, it would be useful to describe briefly the basic legal framework in which oil and gas operations take place.

The right to develop subsurface minerals in the United States belongs originally with the ownership of the surface. The different States which have fugacious minerals within their jurisdiction are divided as to whether such minerals are owned in place or whether the surface owner owns only a right to produce the minerals that may lie beneath his land. For present purposes the distinction has little significance. It is sufficient to point out that the ownership of the surface carries with it, as a normal incident of ownership, the right to develop the minerals beneath the surface.

The owner of the land may, however, sever the ownership of the surface from ownership of the minerals. He may convey away all or a part of his interest in the development of the minerals and in so doing may create a variety of estates, Thus, for example, the owner of a 640-acre tract of land (one section) may convey to another person (or company) all of the mineral under the land absolutely. Or he may convey to that person a one-half interest, or some other percentage of interest, in all of the minerals beneath the section. Or again, he may convey to another all or a part of the minerals beneath a specific 40-acre tract carved out of the section. Each of these interests would be described as a mineral interest. Unless otherwise restricted by the instrument creating it, the ownership of a mineral interest carries with it the right to explore for, develop, and produce the minerals beneath the land.

**Another** type of interest that may be created by a landowner or mineral interest owner is a leasehold interest. The owner of the minerals is normally unable to undertake the development of the minerals himself because of the great expense and risk of drilling. in order to obtain development without entirely giving up his interest in the minerals he will lease the right to explore for and produce the minerals to another. In return the lessee will pay a sum **of money as a bonus for the granting of the lease and** will promise to pay the lessor a royalty, generally one-eighth, on all oil and gas produced. Typically, the lessee will be granted the lease for a period of 1 to 5 years (the primary term), subject to an obligation to pay delay rentals if a well is not drilled in the first year, and so long thereafter as oil and gas or either of them is produced from the leased land (the secondary term). In addition to a royalty interest of one-eighth, the lessor will retain a possibility of reverter; that is, if the delay rentals are not paid on time or production is not obtained within the primary term, or if production ceases on anything other than a temporary basis in the secondary term, the interest leased reverts automatically back to the lessor.[1] When the interest reverts, the lessor may then enter into a new lease with another party or may undertake or continue development himself.

The power to grant leases is often described as the executive right, and a mineral interest may be created with the executive power being granted to another person. To illustrate, A as father of a family and owner of a tract of land may give by will to child B a one-quarter undivided interest in the minerals in the land, to child C a one-quarter undivided interest in the minerals, and to child D an undivided one-half interest in the minerals together with the executive right to lease all the minerals. This would mean that only D could execute leases for the development of the minerals. D would be under a duty to exercise the right with the utmost good faith and fair dealing. Each child would receive a share of the proceeds from the development of the land (i.e., a share of the bonus, rental, and royalties), but it would be upon the terms established by D in his dealings with the lessee in granting the lease. Under well-established principles of law, D must exercise this right in such a manner that it does not unfairly advantage him nor unfairly disadvantage the owners of the nonexecutive interests, children B and C. The duties owed by lessees to lessors and royalty owners, and the duties owed by executive right owners to nonexecutive right owners, can impact upon the unitization of mineral lands for enhanced recovery purposes. This is because the lessee or executive right owner must consider not only his own interest but the interests of those to whom he owes a duty in entering into agreements for unitized operations.

In addition to duties, the lessee has certain rights arising from a lease that have significance for EOR, These rights may be express or they may be implied. They are express if the parties to the lease or deed have specifically recognized or granted them in the conveyance. For example, the parties may explicitly provide that the lessee shall have the right to conduct certain activities such as laying pipelines on the surface of the land without being liable in damages. The rights are implied if the parties have not expressly provided for them, but the law recognizes that they exist by virtue of the nature of the transaction between or among the parties. Thus, the lessor and lessee may fail to provide expressly that the lessee has the right to come upon the leased land or to build a road for carrying equipment to a drill site. The law will imply that the lessee has the right to do this when it would not be reasonably possible to develop the minerals without undertaking such activity.

**NOTE: All references to footnotes in this appendix appear on page 230.**

Briefly stated, the law recognizes that even without express grant, the lessee has the right to use such methods and so much of the surface as may be reasonably necessary to effectuate the purposes of the lease, having due regard for the rights of the owner of the surface estate. It is well established that the lessee does have such rights.[2] However, the question may arise whether such rights are limited to those activities, either surface or subsurface, that could be contemplated at the time of the execution of the lease or deed. The same answer should be given for the more exotic methods of enhanced recovery that the courts have given for traditional waterflood operations when these were not provided for in the lease. In allowing a waterflood project to go forward, the Appellate Court of Illinois stated in a 1950 case:[3]

> The mere fact that this method of production is modern is no, reason to prevent its use by a rule of law. It is true the contract of the parties does not specifically provide for this process, but neither does it specify any other process. The contract being silent as to methods of production, it must be presumed to permit any method reasonably designed to accomplish the purpose of the lease: the recovery of the oil and the payment of royalty. The court would violate fundamental principles of conservation to insert by implication a provision that lessee is limited to production of such oil as can be obtained by old fashioned means, or by so-called "primary operations."

The same rationale would apply to more modern methods of enhanced recovery, even though these methods might involve somewhat greater use of the surface and different types of injection substances.

*A* closely related question is the extent to which the lessee or mineral grantee may use water located on the property for purposes of enhanced recovery. This has been an area of some controversy and will be taken up in a later section because it involves matters going beyond lease and deed relationships.

Finally, it should be noted that some authorities have contended that there is not only a right for the lessee to unitize or to undertake enhanced recovery activities but also a duty to do so. The implied covenant of reasonable development is well recognized in oil and gas law.[5] It is to the effect that the lessee has the duty, where the existence of oil in paying quantities is made apparent, to continue the development of the property and put down as many wells as may be reasonably necessary to secure the oil for the common advantage of both the lessor and lessee. The lessee is expected to act as a prudent operator would in the same circumstances. With increasing experience with enhanced recovery, it can be argued that a prudent operator would, when it appears profitable, undertake enhanced recovery operations. Thus, where the lessee is reluctant to do so, the lessor might be able to require the lessee to engage in such operations or give up the lease. Probably because of the difficulty or proof of profitability and feasibility for a particular reservoir there has been little litigation on the point. However, one court has noted that there is "respectable authority to the effect that there is an implied covenant in oil and gas leases that a lessee should resort to a secondary recovery method shown to be practical and presumably profitable as a means of getting additional return from the lease."[6] In another case the court similarly declared that "the Lessee not only had a right, but had a duty to waterflood the premises for the recovery of oil for the benefit of the mineral owners should it be determined by a prudent operator to be profitable. "[7] Lessors then could encourage enhanced recovery by making demands on their lessees.

## The Rule of Capture

One of the most important and fundamental principles of oil and gas law is the rule of capture. It stems from the fact that oil and gas are fugacious minerals; that is, they have the property of being able to move about within the reservoir in which they are found. Followed by every jurisdiction within the United States, the rule of capture is to the effect that a landowner may produce oil or gas from a well located on his land even **if the oil or gas was originally** in place under the surface of another landowner, so long as the producer does not physically trespass on the other's land. The other landowner's recourse against drainage of the petroleum under his property is the rule of capture itself: he may himself drill a well and produce the hydrocarbons and thereby prevent their migration to the property of another.

The problem with the rule of capture has been that it encouraged too rapid development of oil and gas. A landowner or his lessee must drill to recover the oil and gas beneath his property or they will be recovered by a neighbor and lost forever to the landowner. The problem became especially acute when there were many small parcels of land over a single reservoir. Overdrilling resulted from the rush to recover the oil and gas before it is produced by another, and the overdrilling caused the natural pressure of the reservoir to be depleted too rapidly, thereby leaving oil in the ground that could have been recovered with sounder engineering practices.

### Conservation Regulation: Well Spacing and Prorationing

Recognizing that the rule of capture was resulting in great loss of resources and excessive production of oil, the producing States began enacting legislation to modify it in the mid-1930's. To prevent excessive drilling the States authorized regulatory commissions to promulgate well spacing rules, limiting the number of wells that can be drilled in a given area.[8] For example, the Texas Railroad Commission in Rule 37 allows, as a general rule, only one well every 40 acres. In general, in each major producing State special spacing rules may be established for each different field and exceptions may be granted upon showing of good cause.[9]

Well spacing alone would not be enough to overcome the problem of excessive production, for a producer might continue to produce at an excessive rate in such a manner as to deplete prematurely the natural drive of the reservoir or in quantities that the market could not absorb. To overcome this, the States established well allowable; that is, they set a limit to the amount of oil or gas that could be produced in any 1 month from a field or well. This is also known as prorationing of production. Well allowable have been set in two different ways. The first is known as MER regulation: allowable are established for production at the maximum (or most) efficient rate of recovery.[10] The maximum efficient rate for a reservoir is established before a regulatory commission by expert testimony as to what would injure the reservoir and produce waste. This rate is not constant, but changes with the age of the field, and is not generally capable of exact computation. The second basic type of regulation of well allowable is known as market demand regulation: MER remains as the maximum rate of production, but the rate actually allowed may be lowered to a level which the commission believes is the maximum amount of production that the market will bear for that month. This is generally established by the commission after it has heard from producers as to the amount that they would like to produce. The commission may wish to give special incentives to certain types of activity and will establish allowable with more being allowed for one type of production than another. To encourage drilling the commission may allow new wells to produce at the reservoir's maximum efficient rate of recovery, while older fields must produce at a lower rate, so that total production from the State does not exceed the anticipated reasonable market demand. With the exception of Texas in recent months, the market-demand type States have set allowable for wells at the maximum efficient rate for every month since 1973.

## Pooling and Unitization

### Pooling

State regulation of well spacing and production can cause significant problems that must be overcome by the producers themselves or by additional regulations. If there can be only one well within a given area and there are several parcels of land with different owners, some determination must be made as to who will be able to drill a well and who will be entitled to receive proceeds from the production from the well. The integration of the various interests within the area for the purpose of creating a drilling unit for development of a well and sharing of the proceeds is known as pooling.[11] It may be voluntary if the interest owners come together and agree by contract upon the drilling and sharing of the production from the unit well. It may be compulsory if the State forces interest owners to participate on a basis established by the State regulatory commission when there is an applicant who wishes to drill and some of the interest owners are unwilling or unable to reach an agreement upon sharing of development cost and/or production. Pooling then refers to the bringing together of the different interests in a given area so as to integrate the acreage necessary for establishing a drilling unit, and it may be voluntary or compulsory. Virtually all States with production of oil or gas have compulsory pooling statutes which can apply when the parties are unable to reach an agreement for voluntary pooling.

### Unitization

**Pooling does not result in the reservoir being treated as a single entity; it does reduce the number of competitive properties within a reservoir, but there will still be competitive operations among the enlarged units to the extent permitted by law.**

The mo efficient and productive method of producing oil may be achieved only if the entire reservoir can be treated as a single producing mechanism, i.e., when the reservoir may be operated without regard to property lines. This becomes possible when one owner or lessee owns or leases the rights to the entire reservoir or when all the interest holders in the reservoir unite for a cooperative plan of development. When owners of interest do come together for such a purpose for development of most or all of a reservoir this is referred to as unitization.[12] It is much the same in principle as pooling, for it is an integration of interests, and as with pooling it may be voluntary or compulsory; but it is much more complex than pooling in attempting to reach agreement on cost and production sharing, and the statutory schemes for compulsory unitization are more difficult to comply with than for compulsory pooling. Unitization of most or all of a reservoir is usually very desirable or is required in order for there to be application of enhanced recovery techniques to a reservoir.

## Voluntary Unitization

### Time of Unitization

Ideally, unitization should take place at the first discovery of a reservoir capable of producing hydrocarbons in commercial quantities, or even during the exploration phase. However, this is not feasible for it is only through drilling a number of wells—with production from the first well and subsequent wells going on—that the parameters of the reservoir can be established. Only when the characteristics and the limits of the field are generally known will the parties with an interest in the field be willing to unitize. Prior to that time they would possibly agree to share production of petroleum from under their lands with parties who had no petroleum under theirs. It is only after extensive drilling that it is possible to make an intelligent assessment of the basis upon which participation in the production from the reservoir should be established. Because of this, unitization has generally come about after the primary drive of the reservoir has begun to decline measurably, and it has appeared to interest owners that it may be desirable to unitize in order to undertake operations to enhance recovery beyond the field's life by primary methods of recovery.

### Who May Unitize

Once it is clear to some of the parties with interest in the reservoir that unitization is desirable, there is the problem of determining who may undertake the unitization. Without express authorization, either in the lease or by separate agreement, the lessee is not able to unitize the interest of the royalty owners to whom it must pay royalty. The lessee may unitize its own interest—that is, agree to share with another the seven-eighths of production that it normally owns-but without the consent of the royalty owner(s) it may not agree with others to treat the potential production attributable to the royalty interest from the leased acreage on any basis other than the one-eighth (or other fraction) going to the royalty owners. Some leases will contain authority to the lessee to enter into fieldwide unitization agreements on behalf of the lessor, but the noted authority on unitization, Raymond M. Myers, has stated that "[d]ue to the complexity of the modern unitization agreement, a clause authorizing the unitization of the entire field, or a substantial portion thereof, has not generally appeared in oil and gas leases. Lessors have not generally been willing to grant such broad powers to lessees as such authorization would entail. "[13] Even with authorization the prudent lessee will gain the express consent of the lessor. Whether the executive right owner may unitize, or authorize the lessee to unitize, the interests of the nonexecutive interests are open to question in most jurisdictions because there has been little litigation on the point.[14] The rule in Texas is that the executive does not have this power; the rule in Louisiana is that he does. In general, it may be stated that it is desirable or necessary to get the express consent of each royalty owner in order to effectuate voluntary unitization.

Reaching agreement on unitization is a complex and drawn out undertaking often involving dozens or hundreds of parties. To understand this and to place in perspective the State's role in unitization of property for purposes of enhanced recovery, it would be useful to examine in some detail the manner in which unitization is agreed upon.

## Negotiation of Unit Agreement

The integration of separate and often divergent ownership interests necessarily requires careful negotiation which may extend over several years. The best way to describe effectively the nature of and the problems inherent in the voluntary unitization process is to relate the actual experiences of companies. The discussion of the process which follows draws in part from the case history of the McComb Field Unit in Pike County, Miss.,[15] and from the Seeligson Field Unit in Jim Wells and Kleberg Counties, Tex.[16]

In the evolution of a voluntary unit, each negotiation has its own unique problems and circumstances which affect the ability of principals to achieve fieldwide unitization in a reasonable period of time. Even though no two unit operations are alike in every respect, there appear to be four general stages in the negotiation process:

- Initiation of joint organization,
- planning period,
- Determination of participation formula, and
- Drafting and approval of agreements.

The remainder of this appendix is concerned with the discussion of these four stages and their integration during the formation of a voluntary unit operation.

*Initiation of Joint Organization.—The* first stage in the unitization process involves the initiation of a joint organization of operating interests who recognize the necessity for a fieldwide unit in order to increase the ultimate recovery of oil and gas. A major operator or leaseowner will usually initiate the process by informing other ownership interests that a unit operation may be desirable for undertaking a particular fieldwide project for enhanced recovery.

For example, shortly after primary production was undertaken in the McComb Field, the coowner of the discovery well and major leaseowner (Sun Oil Co.) began accumulating additional technical information and data with respect to the parameters of the reservoir. The data revealed an alarming condition in the reservoir-a rapid decline in reservoir pressure which could bring premature abandonment with a tremendous loss in recoverable oil reserves. It was apparent that a fieldwide gas- or water-pressure maintenance project was needed to arrest the deterioration of the reservoir and increase ultimate recovery. This pressure maintenance project required fieldwide unitization which, in turn, required full-field participation. A meeting was held in February 1960, at the urging of the Sun Oil Co., and the preliminary evidence was presented to 70 operating interests.

The initial stage of the Seeligson Field Unit negotiation involved a different set of circumstances. Numerous tracts in the field contained gas, oil, or both. A gas-unit operation had existed since 1948, and the current problem was to unitize both oil and gas under one set of agreements. In particular, the proposed new unit operation was primarily concerned with the increased oil production that would result both from the transfer of allowable and from a pressure maintenance program. Thus, operators having had previous negotiation experience could facilitate matters with the negotiation of a new unit agreement. A meeting was called in February 1952, to discuss just such a possibility.

In specific terms, the initiation of a joint organization entails three primary steps. First, after a discussion of the preliminary technical information and data, operators reach a general agreement on the "problem" giving rise to the necessity for a unit operation. Once the problem is identified and clearly defined, then possible solutions for consideration can be enumerated.

During this initial step and the steps that follow, obstacles or delays may be encountered when the joint organization involves a large number of participants. If an inordinate number of operators have had little or no first-hand unitization experience or technical knowledge of the proposed solution projects, or where misunderstandings or suspicions develop, then unnecessary delays may occur in the formation of a joint organization.

The next step encompasses the acceptance of the articles of organization which establish the organizational framework and procedural rules for the initial operating committee (Unitization Committee) and ancillary subcommittees. The Unitization Committee is a temporary body charged with supervising the collection of extensive information and data germane to the formation of the unit as well as presiding over the general negotiations prior to the approval of the unitization agreements. The composition of the Unitization Committee and the various subcommittees requires an acceptable representation of major and independent leaseowners. This will provide a major step in spreading the responsibilities for unit formation among all parties interested in the fieldwide operation and also to minimize the potential misconceptions and mistrust which may develop among operating interests.

The final step in the initiation of the joint organization involves financing of the temporary organizational structure. Rather than the major leaseowner bearing the full costs, financial responsibility is generally shared according to some acceptable method of cost allocation. In the McComb Field, expenses were shared jointly on a well basis.

Generally, the initial stage in the negotiation process does not require more than a few meetings to finalize the temporary procedures for the joint organization. Given sufficient preliminary evidence, most operators recognize the necessity for careful planning and thorough investigation in the development of a fieldwide unitization operation.

*Planning Period.*—The second stage in the negotiation process centers around the planning period, which culminates in the unitization agreements. This stage involves the activities of various subcommittees who are responsible for collecting extensive data and information and for developing the details for the unit operation. In general, there are four main areas of concern: technical, legal, land, and accounting.

*Technical.* The gathering of technical data and information is the joint responsibility of a Geologic Subcommittee and an Engineering Subcommittee.

The Geologic Subcommittee prepares the various geological maps and accumulates field data necessary for study by the joint organization. In particular, their duties center around ascertaining the extent of the reservoir in terms of its size, shape, and geological limits. Aside from the extent of the reservoir, this subcommittee is concerned with mapping the thickness, structural position, and extent of the "productive" pay of the reservoir. information gathered by the Geologic Subcommittee is made available to the Engineering Subcommittee for the evaluation of the various projects under consideration and to operators for determining oil recovery factors under various operating conditions. This is an important phase in the negotiation process, due primarily to the fact that the technical feasibility and economic profitability of various projects are evaluated and recommendations submitted to the Unitization Committee for consideration by the joint organization.

The task of this subcommittee is best illustrated by the Engineering Subcommittee of the McComb Field Unit. As the reservoir data were assembled, oil recovery factors were derived under five operating conditions:

1. Primary recovery (18 percent recovery factor);
2. Injection of produced gas (increase ultimate recovery to 23 percent);
3. Gas pressure maintenance (increase ultimate recovery to 30 percent);
4. Water pressure maintenance (increase ultimate recovery to 39 percent); and
5. High-pressure miscible gas injection (increase ultimate recovery to 54 percent).

Based on these oil recovery factors the water pressure maintenance and high--pressure miscible gas injection projects were selected for further feasibility analysis, where the advantages and disadvantages of each project were then evaluated.

While the miscible gas injection project offered the highest oil recovery factor, its disadvantages were extremely critical: the supply of extraneous gas was available but at prohibitive costs; the process was relatively unproven in terms of general industry-wide use; there existed possible corrosion problems as well as contamination of reservoir gas; the project would require a long period of time to implement and would require expensive plant expansion; and, finally, there was a greater risk of failure. Furthermore, the rate of return for the capital investment was calculated to be 31 percent per year.

The advantages of the waterflood project were numerous: ample supply of salt water in the reservoir; relatively lower initial investment expenditure; proven method of recovery with a low risk of failure; minimum time required to implement the project; and undertaking the waterflood project did not preclude the adoption of miscible injection at a later date. In addition, the capital investment **was** calculated to earn a 72-percent annual rate of return. Finally, the primary disadvantage of waterflooding was the relatively lower oil recovery factor.

After careful consideration of the economic feasibility and advantages and disadvantages of each project, the technical subcommittees recommended the selection of the water pressure maintenance project for the McComb Field Unit Operation. Aside from the higher rate of return on capital investment, the major factors which led to the waterflood selection involved the minimum risk of failure and the short implementation time associated with the project. These factors were extremely crucial, given the rapidly declining pressure in the reservoir.

Once the extensive geologic data and engineering information are accumulated and project recommendations set forth, the final task of the technical subcommittees involves a preliminary determination of the participation formula whereby lessors and lessees share in unit production. The relevant aspects of the participation formula will be considered later in this appendix, but it should be noted that the time frame for the work of the technical subcommittees can vary considerably. For the Seeligson Field Unit, the Unitization Committee appointed working interest representatives to the technical subcommittees in February 1952, and the Engineering Subcommittee offered recommendations (with respect to the most feasible project and the tentative participation formula) to a meeting of operators in January 1955. Hence, nearly 3 years had elapsed during which time the major technical groundwork for the unit operation was completed. For the McComb Field Unit, the work of the technical subcommittees was initiated in February 1960 and recommendations and findings were presented approximately 9 months later,

Therefore, the time required for collecting and evaluating detailed technical information and the subsequent recommendations which follow can consume from several months to a few years during the unitization process, In general, a number of factors such as the geological complexity of the reservoir, the number of development wells necessary for assessing the characteristics of the reservoir, the nature of the unitization projects under consideration, and whether the field is in the development phase or production phase may all contribute to the length of time required for the planning period.

Legal. During the planning of a fieldwide unit, the Legal Subcommittee handles the legal aspects associated with the unitization process and the subsequent negotiation and drafting of agreements. This charge necessarily requires an understanding of the desired goal of the unit operation and the manner in which this goal impacts on land titles, overriding royalties, operating leases, and other factors. In particular, the Legal Subcommittee determines whether there are any legal restrictions or problems related to property rights and the achievement of the desired goal of the unit. It is incumbent upon the Legal Subcommittee to advise lessees that they continue their lease obligations to lessors. The Legal Subcommittee must ensure that the implied as well as expressed obligations of lessees are satisfied during the negotiation and execution of a unitization agreement.

The Legai Subcommittee is also responsible for submitting to the appropriate State regulatory agency all requisite documents and instruments which pertain to the unit operation. Such procedures will be discussed in a subsequent section.

Land. The Land Subcommittee is generally comprised of land agents whose function it is to identify royalty owners and leaseholders for the purpose of communicating information to the various interest owners and facilitating the acceptance of the unitization agreements. While operating interests may be readily identifiable, a widespread distribution of royalty interests can make the task of the Land Subcommittee difficult and time consuming. Frequently, overriding royalties, various types of working-interest arrangements, and royalty interests involving estates or trusts may add both time and expense to the complexity of forming a unit.

Once the majority, if not all, of the interested parties are identified, the land agents are responsible for conveying to the ownership interests, information with regard to the nature of the unit operation (in terms of the project to be instituted as well as each owner's share **in unit production).** The work of the Land Subcommittee begins in the planning stage of the unitization process and ends with the obtaining of signatures for the unit agreements.

*Accounting.* The initial concern of the Accounting Subcommittee involves the accounting for expenses incurred prior to the unit agreement. The work performed by the technical subcommittees and, to a lesser extent, the other subcommittees operating during the planning period generates expenditures which must be underwritten by the operating interests. Accounts are maintained by the Accounting Subcommittee and subsequent billings to operators on a predetermined share basis are made for purchases of supplies and field equipment as well as the overhead costs of the temporary joint organization.

The primary charge of the Accounting Subcommittee, however, is to prepare the joint operation accounting procedures which establish the method of accounting and the allocational rules to be used in the unit operation. The accounting procedures appear as an exhibit to the proposed unit agreement and specify the items to be charged to the joint account, the disposition of lease equipment and material, the treatment of inventories, and the method of allocating joint costs and revenues among unit participants.

An important role of the Accounting Subcommittee entails the explanation and, in some cases, the determination of specific tax considerations which impact on ownership interests as well as the general fieldwide operation. For example, tax legislation and tax court interpretations with respect to **EOR projects are ever-changing, and the application of future tax law to EOR projects is in a state of uncertainty. Therefore, the tax treatment applied to** EOR projects might affect the incentive among participants of a proposed unit operation to engage in a particular EOR project or it could affect the incentive of an individual ownership interest to commit its property rights to the unit operation.

An example where a possible disincentive exists for joining a unit operation can be seen in the Income Tax Reduction Act of 1975, which eliminated the percentage oil-depletion allowance for major companies. However, an exemption to this is provided for independent producers and royalty owners where an independent producer is defined as one whose total retail sales is less than 5 percent of its total sales. When this exemption is applied, the independent producer can apply the. 22-percent oil-depletion allowance to the market value of a maximum 1,800 barrels per day (for 1976, and declines to 1,000 barrels per day by 1980).[17] When confronted with a choice of joining a unit operation which would enhance the producer's recovery of oil above the limit of 1,800 barrels per day and thus lose the exemption, the independent producer would necessarily be concerned with its participation factor in the unitization agreement. If the independent's share of unit production did not compensate for the exemption loss or ensure at least a comparable return for joining the unit, then the negotiations of the unit operation could face an obstacle to the attainment of full field participation. This situation might create costly delays in the unitization process.

Another example can be seen in the questions arising with respect to the tax treatment of costs associated with EOR projects, where costs relevant to the discussion include intangible drilling and development costs (IDC), cost of physical facilities required in the EOR project, and the cost of injected material .18 According to the internal Revenue Code enacted in 1954, an IDC refers to costs (i.e., labor, fuel, transportation, supplies, and other items having no salvage value) associated with installing equipment "incident to and necessary for the drilling of wells and the preparation of wells for production of oil and gas."[19] Hence, the cost of installing injection wells, production wells, water source wells (in the case of waterflooding), and converting production wells to input wells are treated as IDC and subject to the tax option of either expensing these cost items or capitalizing them. The generally accepted accounting practice is to expense IDC, which allows them to be written off in the year that they occur.

The cost of physical facilities (i.e., storage tanks, pipelines and valves, waste-water treatment equipment, etc.) must, by law, be capitalized and depreciated over the expected useful life of the equipment. However, the method of depreciation may impact on the incentive to undertake a particular EOR project. A straight-line method of depreciation (20 percent per year for 5 years) would provide a "quick" writeoff and enable the full cost of the investment expenditure to be recovered in the first 5 years of the equipment's useful life. With the sum-of-year's digits method (over an 11-year period), only 68 percent of the full cost of the equipment would be recovered during the first 5 years. The allowable depreciation is greater for the straight-line method, and use of this method could improve the economic incentive of the EOR program. 20 Furthermore, the tax treatment advice of the Accounting Subcommittee would be extremely valuable at this point in evaluating the feasibility of projects under consideration by the joint organization.

The cost of the injected material may also be a relevant tax consideration. When high-cost materials are injected into a reservoir and a portion of the injected material cannot be recovered from the reservoir, then the total cost of the unrecoverable material can be expensed during the year in which it was injected, or it can be capitalized and depreciated (using the straight-line method) over the life of the reservoir. In addition, "if it can be demonstrated, in any year, that a particular injection project is a failure (i.e., the injection of this material did not benefit production), a loss may be claimed for the undepreciated cost of the injected material. "[21] At the margin, these tax options may be an important consideration when choosing among EOR projects which require the use of high-cost injected material.

*Determination of Participation Forrnula.*-The "participation formula" (share of unit production accruing to the separate ownership interests) is the heart of the unitization agreement. As such, it represents the principal point of contention among the parties negotiating the voluntary formation of a unit operation. According to the noted authority Raymond Myers, "The ideal is that each operator's share of production from the unit shall be in exact proportion to the contribution which he makes to the unit. "[22] However, the determination of the "exact proportion" contributed by each operator to unit production is difficult to determine and has led to long and labored negotiations.

In the early days of unitization, participation was based solely on surface area. The criteria was found to be wanting since, as Myers observes, it assumed "uniform qua!ity and thickness throughout the [reservoir] with each tract having beneath it the same amount of reserves per acre. This rarely, if ever, happened."[23] More recently, shares are often determined in direct proportion to the amount of productive acre-feet of pay zone which lies beneath the surface of each tract. However, this determination may be derived only after a series of development wells have ascertained the parameters of the reservoir. The effective procedure which is frequently utilized is to initially establish participation factors on the basis of surface area and preliminary acre-feet of pay zone criteria, then after the commencement of unit production (usually 6 months), the participation factors are adjusted in accordance with more reliable or updated pay zone values.

Based on geologic studies of the McComb Field, it was determined that the average pay zone thickness was approximately 15 feet per acre for each 40-acre tract. This value provided the basis for allocating unit production among the various ownership interests during the initial production phase in which approximately 18 percent oil recovery would occur. In the second phase of the formula, secondary oil reserves were allocated among the unitized interests on the basis of 75-percent credit for net acre-feet of oil zone plus 25-percent credit for the participation factor used in the first phase. This second phase adjustment of participation factors was designed to take into consideration more technical aspects **(actual pay zone) and thereby give some tracts additional credit for their relatively larger contribution to unit production.**

**There are a number of obstacles, delays, or disincentives which tend to affect the acceptance of the participation formula** as well as the subsequent negotiations in drafting and approving the unitization agreements. A few of these have been previously discussed and others are worth a brief mention.

Some of the ownership interests may be of the opinion that they should have a "fair advantage" with respect to their participation factor. In particular, some parties may contribute more surface acreage to the fieldwide operation or a portion of the unit's plant and equipment (such as injection wells, storage facilities, and the like) may be located on their property. Hence, by virtue of the large surface acreage contribution or operations taking place on their property, these ownership interests may argue for preferential treatment and the adjustment of their proposed participation factor to reflect this "fair advantage. " The debate over this issue may create delays in the determination of an acceptable participation formula and, if left unresolved, could have a detrimental effect on the ability of all parties to form a voluntary unit operation.

Pride of property ownership and/or control over individual operations may affect the willingness of an individual ownership interest (royalty as well as operating) to join a unit and commit their property and operational control to joint decisions. When such strong feelings are held (and they may surface with participation factor dissatisfaction), acceptance of the participation formula or general approval of the unitization agreements may be difficult to achieve.

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A final consideration, which might well impact on the incentive for accepting the participation formula and entering a unit operation, involves the effect of FEA regulations. The domestic price of crude oil is controlled at specific levels by FEA. However, the anticipation of future price deregulation might prompt some producers to leave oil in place until the price of oil increases. This could be particularly critical when the producer feels that its return (based on the participation factor) from the joint operation is marginal, at best.

In **general, the acceptance** of the participation formula by operators and royalty owners reflects their satisfaction with the unit operation and its ability to ultimately increase profits while safeguarding property rights. Fieldwide unitization is initiated in order to increase the ultimate recovery of oil and gas while reducing the riskiness and costs associated with individual operations. Through a joint effort, higher rates of return can thus be realized with the retention of ownership interests in the recovery of oil and gas.

*Drafting and Approval of Agreements.—The* fourth stage in the voluntary unitization process involves the drafting and approval of agreements by participants engaged in a fieldwide operation. This stage represents the culmination of the efforts and responsibilities undertaken by the various subcommittees with the supervision of the Unitization Committee.

The Legal Subcommittee assumes the task of drafting the unitization agreements for the approval of the ownership interests. The unitization agreements are the legal instruments for the unit operation, and there are generally two types of documents: the Operating Agreement for the operators or working-interest owners, and the Royalty Owners Agreement for the royalty interests. It is customary to distinguish between the two ownership interests in order to facilitate the approval of the unit operation. While operating interests share in the proceeds and costs of the unit operation, royalty owners share only in the proceeds from unit production and do not share in the obligations incurred by the operators. Therefore, separate documents are desirable since the Royalty Owners Agreement contains material only of interest to the royalty owner.

The Operating Agreement contains a legal statement of matters containing the participation formula and adjustments thereof, provisions for enlarging the unit operation, cost allocation, operational procedures, and matters pertaining to titles, easements, and term. Furthermore, the selection of the Unit Operation is specified in this document where the Unit Operator is usually the largest leaseholder in the unit and is responsible for the general supervision of the unit operation. The execution of the Operating Agreement occurs when the signature of the operators have been obtained. This generally requires approximately 6 to 8 months, as in the cases of both the McComb and Seeligson Field Units.

As previously stated, the Royalty Owners Agreement consists of material germane only to royalty interests; as such, this instrument is considerably shorter and less difficult than the Operating Agreement. The Royalty Owners Agreement must be presented to all the owners of mineral interests in the unit area including unleased lands, royalties, overriding royalties, gas payments, and oil payments. The agreement must be acceptable to the various royalty owners before the unit operation becomes effective. Naturally, the primary concern among royalty owners involves their share of the proceeds from unit production and, to a lesser extent, their participation in plant products (gas, condensates, and others) and questions dealing with easements. Therefore, in order to allay any apprehensions or misconceptions, great care has to be exercised by operators in drafting the Royalty Owners Agreement and conveying to royalty interests the nature of the unit operation and how royalty owners would benefit from unitization while retaining their ownership rights. Myers observes that “the interests of the lessee and lessor are for the most part identical, and this fact is of course considered by the royalty owner in accepting the decisions of his lessee.”[24]

In order to achieve the maximum objectives of voluntary unitization, it is necessary that all parties having an interest in the unit area become subject to the unit agreements. However, in the absence of compulsory unitization, this may be impossible to obtain when some lessors or lessees refuse to participate in the unit. Even when non joining parties cannot complain about financial losses incident to the unit operation, the land of a non joining lessor or lessee may not be used to achieve the maximum effectiveness of the unitization program.

As a final note, the first four stages in the negotiation and execution of a voluntary unit operation demand much effort and planning on the part of interested parties. The time that is necessary to effect the fieldwide operation varies in accordance with the complexity and frequency of the problems involved. Smaller units which involve fewer ownership interests will generally establish unitization in a relatively shorter time than larger units with numerous and diverse ownership interests. The larger the number of interested parties, the more difficult it is to coordinate and reconcile individual interests with the objectives of the joint organization.

Based on the case histories of the McComb and Seeligson Field Units, the time necessary for voluntary unitization can be quite variable. When the McComb Field agreement was submitted for regulatory approval, signatures of ownership interests had been secured for approximately 68 percent of the royalty owners and nearly 84 percent of the operators. The time required for the completion of the first four stages involved less than 1 l/z years-a relatively short period for a unit operation encompassing over 300 tracts and thousands of ownership interests. On the other hand, the Seeligson Field Unit initiated negotiations in February 1952; by November 1955, signatures of working-interest owners were obtained for the Operating Agreement. In the spring of 1956, the Royalty Owners Agreement became effective and, after nearly 4 years of negotiation, the unit operation for the Seeligson Field became a reality.

## Compulsory Unitization

Compulsory unitization begins with voluntary unitization of a majority of the interests within the field. It differs from voluntary unitization in that all States with petroleum allow unitization when most or all of the interested parties agree to it, but not all States will force unwilling parties to have their interests included in the unit operations. Most States, however, do authorize the State commission to enter an order compelling all interests in a field to participate in the unit once there has been voluntary agreement among a specified percentage of interests in the field.[25] This required percentage varies from 60 percent in New York and 63 percent in Oklahoma to a high of 85 percent in Mississippi. Texas is the most significant State without a compulsory unitization statute, but it should also be pointed out that the effect of the statutes in California is so limited in application that they are rather ineffective: the California Subsidence statute provides for compulsory unitization only in areas in which subsidence is injuring or imperiling commerce or safety, while the California Townsite statute applies only to fields over 75 percent of which lie within incorporated areas and which have been producing for more than 20 years.

Without unitization of all interests, unit operators may be liable to nonunitized interests for non-negligent operations, and will have to account to nonunitized interests as though there were no unit. If a lessee in a unit has a royalty interest to which it must account for production, and that royalty interest is not joined in the unit, the lessee will have to account to the royalty owner on the basis of the production from the leased land, not on the basis of the production attributable to the leased land under the unit operations plan. The lessee may have to engage in additional drilling in order to maintain the validity of the lease against non joining reversionary interest owners; such drilling may be completely unnecessary for maximum recovery from the reservoir and, indeed, may be harmful to that maximum recovery. Lack of compulsory unitization or the requirement of a high percentage of voluntary participation could be a significant restraint on unit operations, which in turn could have a significant impact on enhanced recovery.

In response to questionnaires sent to regulators and producers, several State commissions and a significant number of producers identified the inability of getting joinder of the necessary parties in a field for unitization as inhibiting or preventing the initiation of enhanced recovery projects. It was indicated that there probably are several hundred projects in the State of Texas that cannot be undertaken because of the inability to join the necessary interests in the unit.

Four small producers and four larger ones stated that lack of joinder of parties was inhibiting projects in Texas. Producers in 10 States indicated that enhanced recovery projects would be encouraged by compulsory unitization or a lowered voluntary percentage required to invoke compulsory unitization. For example, a Louisiana independent declared "1 think 75-percent royalty owner approval in Louisiana too high. A good project that benefits operator must necessarily benefit royalty owner."

There appears to be little or no difficulty in requiring unitization and enhanced recovery activities on Federal lands. The major pieces of Federal legislation for mineral development on Federal land provide ample authority to the Secretary of the Interior to make such requirements. The Outer Continental Shelf Lands Act, for example, provides that for Federal leases the "Secretary may at any time prescribe and amend such rules and regulations as he determines to be necessary and proper in order to provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf (OCS). . . .Without limiting the generality of the foregoing provisions of this section, the rules and regulations prescribed by the **Secretary thereunder may provide** for. . .unitization. . . ."[26] Pursuant to this authority, the U.S. Geological Survey in establishing operating orders for the OCS, Gulf of Mexico area, has provided that "Development and production operations in a competitive reservoir [having more than one lessee] may be required to be conducted under either pooling and drilling agreements or unitization agreements when the Conservation Manager determines. . that such agreements are practicable and necessary or advisable and in the interest of conservation."[27] The same OCS order requires that operators "timely initiate enhanced oil and gas recovery operations for all competitive and noncompetitive reservoirs where such operations would result in an increased ultimate recovery of oil or gas under sound engineering and economic principles."[28] While Interior's authority does not appear to be quite so 'extensive under the Mineral Leasing Act of 1920, the difficulties for unitization and enhanced recovery on Federal land onshore nevertheless appear minimal when compared with development on private lands.

## Procedure for Fieldwide Unitization

The procedure for obtaining commission approval for unitization or for compelling joinder of parties in the unit is similar in most States, although by no means identical. Common elements found in almost all States include the need for application or petition by an interested party (normally the prospective operator), notice to other parties, a hearing, proof of matters required by the pertinent State statute, and entry of an order by the commission defining the unit, and the terms of the unitization. The entire procedure usually takes only a matter of weeks, although there may be a delay or denial of the permit because of inequities in the participation formula. The description of the general procedure involved is intended to be suggestive only, with detailed explanation of the procedure in several of the more important States with enhanced recovery activities. For other treatments, and specific requirements for each State, reference should be made to the work cited[29] and to table c-1 .

### Application

The application form and the information required to be contained in it vary from State to State, but five common requirements are present in whole or in part in most statutes. These are that the following should appear:

1) description of the area to be included,
2) description of the operations contemplated,
3) a statement of the unit control and composition,
4) the expense and production allocation formula, and
5) the duration of the unit.

Some States require prior notice to be given to the affected parties and several require that the applicant furnish the regulatory commission with a list of the names and addresses of affected parties.

Who may initiate the regulatory process also varies from State to State. In many States any interested party may submit a petition for unitization, while in others only a working interest owner may start the process. In a number of States the commission may initiate the procedure on its own motion, but this generally is not used except with application by a party. Usually, it is the unit operator who has been selected by the participants in the unit who initiates the process.

As described earlier, the expense and production allocation formula is tediously and carefully negotiated by the parties to the unitization agreement. Agreement with this information will normally be submitted to the commission with the petition or application. When compulsory joinder of other parties is sought, there will be a statement that such parties have been offered the opportunity to join the unit on the same basis as all others. The application will generally also cover the matters which are required by the statute to be found before the commission may enter an order, as discussed under "Proof of Findings Required. "

### Notice

**Both voluntary and compulsory unitization statutes generally require that notice and an opportunity for a hearing** be given prior to the entry of an order establishing or approving the unit. Louisiana, for example, provides that whenever any application shall be made to the commissioner of conservation for the creation, revision, or modification of any unit: the applicant shall be required to file two copies of a map of the unit with the application; the applicant shall be required to give at least 30 days notice of the hearing to be held on the unit in the manner prescribed by the commissioner; and a copy of the plat shall remain on file in the office of the commissioner in Baton Rouge and in the office of the district manager of the conservation district in which the property is located, and be open for public inspection at least 30 days prior to such hearing. JO Other States typically require a shorter time period for notice, but also require that it be given by personal notice and/or by publication in the State register or in a newspaper. Failure to comply with a statutory notice provision may result in the order being declared invalid as to parties who were not given notice.[31]

### Hearing

Opportunity for hearing is required in all States prior to the entry of an order for unitization, but in some States, such as Alaska, no formal hearing need be held if no party objects to the unitization proposal after the notice is given.[32] Hearings are generally conducted without rigid formality and are usually governed by the rules of civil procedure of the State and/or such rules as may be promulgated by the State commission pursuant to its delegated authority. Decisions are based on the record evidence and a general right to rehearing and/or appeal is accorded.[33]

### Proof of Findings Required

**Prior to approval of any unit plan or entry of an order requiring unitization** in most States, the State commission must make certain findings. These generally are that unit operations are necessary to increase ultimate recovery from the reservoir or prevent waste, that correlative rights of interest owners are protected, and that the additional cost involved does not exceed the additional recovery anticipated. The Texas statute, for example, provides that unit agreements shall not become lawful or effective until the Texas Railroad Commission finds that:[34]

1) such agreement is necessary to accomplish [secondary recovery operations] or [conservation and utilization of gas] or both; that it is in the interest of the public welfare as being reasonably necessary to prevent waste, and to promote the conservation of oil or gas or both; and that the rights of the owners of all the interests in the field, whether signers of the unit agreement or not, would be protected under its operation;

2) the estimated additional cost, if any, of conducting such operations will not exceed the value of additional oil and gas so recovered by or on behalf of the several persons affected, including royalty owners, owners of overriding royalties, oil and gas payments, carried interests, lien claimants, and others as well as lessees;

3) other available or existing methods or facilities for secondary recovery operations and/or for the conservation and utilization of gas in the particular area or field concerned are inadequate for such purposes; and

4) the area covered by the unit agreement contains only such part of the field as has reasonably been defined by development, and that the owners of interests in the oil and gas under each tract of land within the area reasonably defined by development are given an opportunity to enter into such unit upon the same yardstick basis as the owner of interests in the oil and gas under the other tracts in the unit.

The Louisiana statute, to cite a compulsory unitization statute, provides that an order for unit operation shall be issued only after notice and hearing and shall be based on findings that:[35]

1) the order is reasonably necessary for the prevention of waste and the drilling of unnecessary wells, and will appreciably increase the ultimate recovery of oil or gas from the affected pool or combination of two pools;

2) the proposed unit operation is economically feasible;

3) the order will provide for the allocation to each separate tract within the unit of a proportionate share of the unit production which shall insure the recovery by the owners of that tract of their just and equitable share of the recoverable oil or gas in the unitized pool or combination of two pools; and

4) at least three-fourths of the owners and three-fourths of the royalty owners,. . shall have approved the plan and terms of unit operation, such approval to be evidenced by a written contract or contracts covering the terms and operation of said unitization signed and executed by said three-fourths in interest of said owners and three-fourths in interest of the said royalty owners and filed with the commissioner on or before the day set for said hearing.

As indicated previously, different States with compulsory unitization provisions have varying requirements as to the percentage of parties voluntarily entering into the unitization prior to invoking the compulsory features.

### Entry of the Order for Unitization

**After application, notice, hearing, and presentation of evidence and findings by the commission, the commission, if approving the unitization, will enter a formal order** for the unitization which will become a matter of public record. In Oklahoma, for instance, the order of unitization issued by the Oklahoma Corporation Commission will provide for:[36] 1 ) the management or control of the unit area by an operator who is designated by vote of the lessees; 2) the allocation of production; 3) the apportionment of operational costs; 4) the manner of taking over the wells and equipment of the several lessees within the unit area and the method of compensation therefore; 5) creation of an operating committee; 6) time of the plan's effectiveness; and *7)* time and conditions of unit dissolution. Other States are similar. Unit members dissatisfied by the unitization order may appeal directly to the Oklahoma Supreme Court.[37]

Interests joined in the unit through compulsion may be allowed to choose prior to commencement of unit operations whether to participate as cotenants sharing in expenses and profits or to take a fair and reasonable bonus and royalty which is expense free. Several States including, among others, Alaska, Colorado, New Mexico, Utah, and Wyoming provide for or require financing programs for nonconsenting parties with limited cash outlay capabilities to defer unit expenses until production is obtained with reasonable risk assessments added.

The problem of determining a fair and equitable basis for allocation of production among the unit members can be an extremely difficult one, as was brought out in the discussion of the problems of negotiating voluntary agreements for unitization. Claims may be made that production should be allocated on the basis of surface acreage, productive acre feet, productive pore space, prior production history, and other grounds. The State commission may use a combination of these. For example, the Oklahoma Corporation Commission for the West Cache Creek Unit in Cotton County, Okla., used a split formula based first upon the estimated remaining net economically recoverable primary production of the unit, and secondly on the floodable acre feet of the unit. The Oklahoma Supreme Court upheld this approach against a challenge by a dissatisfied party who claimed that the formula should, in its second phase, take into account the current production from the claimant's well; the commission's order was, the court ruled, supported by substantial evidence and so the court would not overrule the commission.[38]

State commissions have set formulae on a variety of base: and have generally been upheld by the courts regardless of the formula used.[39] Statues do occasionally provide some standards, but as one authority has stated, "Viewing present statutory standards, shed of all frills, the parties must look for real protection to the integrity of the regulatory agency and of the parties presenting evidence, as well as to careful scrutiny of the information by those who expressly consent to the allocation."[40] Both the sparsity of litigation *on* the subject and statements concerning the regulatory commissions in response to OTA's questionnaires indicate that the State commissions are effectively protecting the interests of the parties to unitization proceedings.

### Amendment and Enlargement

**Under most statutes for unitization,** it is possible to enlarge the unit and/or amend the unit agreement(s) following the same procedures that were used in creating the unit in the first instance. This may occur if additional parties wish to participate in the agreement or if it is learned that the reservoir has different parameters than originally believed.

### Effect of Unitization

**Each State authorizes the establishment of voluntary fieldwide units, although formal State approval may not be required for the creation** of such a unit. There are distinct advantages to getting such approval even when it is not a requirement. First, the State will generally, by statute, immunize the participants from application of the State antitrust laws to the unit operation.[41] Second, it may serve to protect the participants from application of the Federal antitrust laws to the unit operations. The argument can be made that unitization reduces competition and can serve as a means of limiting production and controlling price. However, the general weight of authority is that, so long as there is no collusion in refining and marketing, the mere joint production of oil does not create antitrust problems.[42] Where unitization is necessary to increase total production it would appear that unitization would actually promote competition by increasing the amount of oil available to all the parties. The role of State approval in Federal antitrust considerations (if they should be raised) is that it can be argued that the approval and order of the State commission gives rise to the well-recognized *Parker v. Brown*[43] exemption from the operation of the Federal antitrust laws. That is, in the case of *Parker v. Brown,* the U.S. Supreme Court held that State approval of a raisin marketing program provided the cooperative activities of the raisin growers with immunity from the Federal antitrust laws. The same rationale would apply to unit operations approved by a State commission.[44] Only one Federal case[45] has attempted to apply the Federal antitrust statutes to unit operations, and was terminated through a carefully negotiated consent degree.

Another reason for getting State approval for a voluntary unit even if not required is that it may provide protection from liability for nonnegligent operations to other parties in the reservoir who have not joined in the unit. This is an important subject in itself, and is taken up in a later section. Suffice it to say at this point the element of State approval of the enhanced recovery program has been enough for some courts to establish immunity from such liability for operators. And, of course, where the requisite percentage approval is achieved in a State with a compulsory unitization statute, the entry of a commission order for a unit will result in unitizing the field and all interests in the field may be treated as members of the unit; no separate accounting or operations on a nonunit basis will be necessary.

One more point should be brought out, and that is that under the terms of an oil and gas lease in some instances and by statute in others the establishment of the unit will sever the unitized portion of the leasehold from the rest of the lease.[46] Depending on the wording of the lease clause (known generally as a "Pugh clause" because of the person purportedly creating it originally) or of the applicable statute, such as in Mississippi, Louisiana, and Wyoming, additional activity on the severed part of the leasehold may be necessary to keep the lease in force as to the portion of the lease not included in the unit. Such lease and statutory provisions can serve as a disincentive to lessees to participation in unit operations.

## Allowable and Well Spacing

In order for an enhanced recovery project to be successful, it is necessary to be able to produce the oil. The fixing of allowable in market-demand type States could discourage enhanced recovery if the production rates were set at a level below the optimum rate for the reservoir. The regulations of the State commissions generally do make provision for the setting of allowable for enhanced recovery operations. For example, Oklahoma provides that "An" approved and qualified waterflood project shall be entitled to produce an allowable of forty-five (45) barrels of oil per well per day including producing and injection wells on a project basis upon the acreage developed for waterflooding. The commission may increase the allowable for a waterflood project for good cause shown after notice and hearing. "[47] In other States, similar provision is made and/or allowable may be transferred among interest owners for the encouragement of enhanced recovery.[48] Because of special treatment and encouragement of enhanced recovery projects, it does not appear that the setting of allowable would impede enhanced recovery operations. No producer responding to OTA's questionnaires indicated that there was a problem of establishing adequate allowable for enhanced recovery. The same is true of well spacing.

## Administrative and Judicial Encouragement to Unitization

**A** number of State commissions and courts have recognized the benefits that result from undertaking unit operations to enhance recovery and accordingly have attempted to encourage unitization. They have done this in several ways.

One has been to deny to non joining parties the benefits they might have expected to obtain by their refusal to join. Production allowable have been set at a higher rate on occasion for unit members than for those who decline to enter the unit.[49] To cite another example, an agency has limited the royalty payable to a non joining royalty owner to the royalty that would have been paid had the allowable not been increased for the enhanced recovery operations.[50] Such actions have been upheld by the courts. [51]

Another method of encouraging unitization has been for agencies to use their authority over well spacing or the prevention of waste to make unitization more attractive to interest owners. Thus in one well known case,[52] the Colorado Oil and Gas Conservation Commission prohibited the production of gas from a large reservoir unless the gas was returned to the reservoir, used in lease or plant operations, or used for domestic or municipal needs in or near the field. The oil could not be produced without production of the gas, and the gas could not be reinfected without unitization of the field. Although sympathizing with the commission's goal, the Colorado Supreme Court struck down the order on the ground that it was beyond the authority of the commission. Subsequently, Colorado enacted a compulsory unitization statute. A recent effort by the Oklahoma Corporation Commission to require separate owners of interests to develop their land as a unit was struck down as being beyond the statutory authority of the commission.[53]

Finally, the courts have encouraged unitization by denying damages to a non joining interest owner who has asserted that his production has suffered by virtue of the unit operation of the party against whom the claim is brought. Such cases are taken up in a later section.

It should be observed that while agencies and courts have expressed support for enhanced recovery, they are limited to the statutory authority they possess. There is only limited opportunity for them to use their discretion for encouragement of enhanced recovery.

# Approval of Enhanced Recovery Projects

## Permit Requirements

prior to commencement of any underground injection for EOR purposes, (all enhanced recovery projects require underground injections), the party responsible must obtain approval from the proper State commission. Often this may be done at the same time that approval of unitization is sought; much the same information is required and a similar procedure is employed. The two should be treated separately, however, because they are separate legal requirements involving different considerations and because an operator must get a permit for enhanced recovery operations even when a unitization procedure is not necessary, as when the operator owns the entire area covered by the reservoir.

As with the unitization statutes, the requirements for enhanced recovery operations permits vary from State to State.[54] What is attempted here is to highlight the general features of the regulatory procedures that are similar in most States with detailed references to the regulations of the larger producing States. The procedure typically requires the filing of an application or petition by the party responsible for the project which describes the activity proposed. Depending on the jurisdiction, notice of the proposed action may have to be given to interested parties before application or it may be given subsequent to the application, either by the regulatory commission or by the operator. A hearing upon the application will be held if timely objection is made by an interested party or on the commission's own initiative.

## Application

Applications for enhanced recovery permits typically require four elements of information to be included, and these may be specified either by statute or by rule of the **regulatory agency: 1) geographic description of the area** covered by the operation; 2) identification of parties affected or who may be affected by implementation of the proposed project; 3) data concerning the formations underlying the area of operation; and 4) explanation of the recovery program.

Geographic descriptions required generally include a plat of all leases in the affected area with locations given for all present, abandoned, and proposed wells. New Mexico, for example, requires a plat showing the locations of all wells within a 2-mile radius of existing and proposed injection wells and the formation from which the wells are producing or have produced.[55]

To facilitate the giving of notice to affected parties, and to enable the States to prepare conservation plans, the States generally require the application to include one or more of the following: the names and addresses of operators within the area, the names of all operators within the unit, the names of all owners of property interests within one-half mile of injection wells, and the names of all lessees within 2 miles of injection wells.

Data concerning subsurface formations that are generally required under the statutes or regulations include full descriptions of the formations in the area and specific delineation of the reservoir to be flooded. Other such information may be required. Kansas, for example, requires not only the name, description, and depth of the formations to be flooded, but also the open-hole depths of each such formation, the elevations of the top of the oil- or gas-bearing formation in the injection well, the wells producing from the same formation within one-half mile radius of the injection well, and the log of the injection well (if a complete log does not exist, such information regarding the well as is available).[56]

The data concerning development plans that are generally required include specific description of injection methods, identification of the substance(s) to be injected, the source of the substance, and the daily amounts of the injection. information pertaining to casing and casing tests must similarly be submitted along with such log information as is available to the operator. Some States require additional data on oil to gas ratios

**and oil to water ratios on production obtained to the date of the application. Separate application requirements exist in some states** for waterflood methods, repressurization, disposal wells and the use of hydrogen sulfides'

Because it is typical of the requirements of State commissions for enhanced recovery applications, section 3-30l (b) of the General Rules and Regulations of the Oil and Gas Conservation Division of the Oklahoma Corporation Commission is set forth:

> The application for an order authorizing a pressure maintenance or secondary recovery project shall contain the following:
>
> (1) The names and addresses of the operator or operators of the project.
>
> (2) A plat showing the lease, groups of leases or unit included within the proposed project; the location of the proposed injection well or wells and the location of all oil and gas wells, including abandoned and drilling wells and dry holes; and the names of all operators offsetting the area encompassed within the project.
>
> (3) The common source of supply in which all wells are currently completed;
>
> *(4)* The name, description, and depth of each common source of supply to be affected;
>
> (5) A log of a representative well completed in the common source of supply;
>
> *(6)* A description of the existing or proposed casing program for injection wells, and the proposed method of testing casing;
>
> (7) A description of the injection medium to be used, its source and the estimated amounts to be injected daily;
>
> (8) For a project within an allocated pool, a tabulation showing recent gas-oil ratio and oil and water production tests for each of the producing oil and gas wells; and
>
> (9) The proposed plan of development of the area included within the project.

## Notice

Because enhanced recovery operations may affect in one way or another virtually all parties in the vicinity of the operation, the notice requirement and opportunity given for a hearing reflect a liberal attitude toward notification of nearby tract owners and operators. Service of notice must be personal, by mail, or by publication in a readily available or official publication. Generally, notice must be given by the applicant himself to the other parties, and it will have to be given some 10 to 15 days before the application or just after filing of the application. Notice commonly must be extended to owners and operators of the reservoir and all those with interests in property within one-half mile of the injection well(s). Protest against the application must be lodged within 15 days of service of notice or of the application, depending on the jurisdiction, In many jurisdictions no hearing need be held if no party objects to the application or if the commission does not order one on its own motion.

An example of the notice requirements can be given by reference to Alaska's rules[58] which require a copy of the application to be mailed or delivered by the applicant to each affected operator on or before the date the application is filed with the Oil and Gas Division of the Department of Natural Resources. Statements must be attached to the application showing the parties to whom copies have been mailed or delivered. In the absence of any objection within 15 days from the date of mailing, the division's committee may approve the application. If objection is made, the committee shall set the matter for hearing after giving additional notice to the affected parties. Other States **are** similar in their provisions.

## Hearing

**Once** a protest is made to an application or the commission on its own initiative requires one, a hearing will be held on the application. The function of the hearing will be to determine whether the injection program is reasonably necessary for the prevention of waste and to obtain greater recovery from the common source, whether the recovery costs will be less than the proceeds from recoverable oil and gas, and whether the rights of other interested parties are adequately protected. Hearings are governed by the State's rules of civil procedure and/or rules promulgated by the commission pursuant to authority delegated to it. Evidence introduced at the hearings will normally be scientific information and data brought out through the testimony of geologists and engineers under questioning by the operator's attorney or the opponent's attorney. A right to rehearing and/or a court review of a commission decision is generally provided upon timely application.

## Order

In general, an application for any type of injection program may be denied by the State commission for good cause; the commission will have considerable discretion allowed by State statute. If the application is approved, an order will be issued by the commission giving the operator authority to proceed. The order will be a matter of public record and can be rescinded for any good cause. The injection program will be subject to additional requirements while it is being implemerited. [59] The operator will normally be required to complete reports before or at the time of commencement of injection, to issue periodic reports regarding the program, and will be subject to inspection of operations by the State regulatory agency. Additional notice to other State agencies may be required after issuance of the order. The appropriate State agency will also have to be notified of the termination of the injection program.

## Injection Regulations Under the Safe Drinking Water Act

Acting under the authority of the Safe Drinking Water Act, [60] the Environmental Protection Agency (EPA) has issued proposed regulations[61] that would be applicable to underground injections for EOR purposes. While these regulations were not final at the preparation of this report, it is useful to examine them in the context of the Safe Drinking Water Act and current State control programs. Some type of regulation will be forthcoming from EPA, even if not in the precise form of the present proposals.

The Safe Drinking Water Act was passed into law as an amendment to the Public Health Service Act in 1974. Its purpose is to establish national drinking water standards and ensure minimum protection against contamination of drinking water supplies by well-injection practices. It attempts to accomplish this by having EPA issue regulations specifying minimum requirements for State programs to control underground injection of fluids that may threaten the quality of water in aquifers that are or may be used for public supply. Section 1421 (b) (1)[62] of the Act itself sets out the minimum requirements for State programs to control underground injection. They are, 1 ) only State-authorized injections may be continued after 3 years from the date of enactment; 2) the injector must satisfy the State that his operation does not endanger the drinking water; 3) the State program must have procedures for inspection, monitoring, recordkeeping, and reporting for injection operations; and 4) the regulations must apply to all persons including Federal agencies.

With specific respect to oil and natural gas production, the Safe Drinking Water Act provides further in section 1421 (b)(2)[63] that:

> Regulations of the [EPA] Administrator under this section for State underground injection control programs may not prescribe requirements which interfere with or impede—
>
> (A) the underground injection of brine or other fluids which are brought to the surface in connection with oil or natural gas production, or
>
> (B) any underground injection for the secondary or tertiary recovery of oil or natural gas, unless such requirements are essential to assure that underground sources of drinking water will not be endangered by such injection.

In promulgating regulations setting requirements for State programs, it is the interpretation of the Act by EPA that the "Administrator need not demonstrate that a particular requirement is essential unless it can be first shown that the requirement interferes with or impedes oil or gas production." [64] Thus, the burden is upon the State or the enhanced recovery operator to prove that the requirement in question does interfere with or impede production, and EPA further places the burden on the operator to show that the requirement is not essential, That is, EPA has stated that an alternative method of protection of drinking water may be approved by the State commission "if the operator clearly demonstrates that (i) the requirement would stop or substantially delay oil or natural gas production at his site; and (ii) the requirement is not necessary to assure the protection of an existing or potential source of underground drinking water." [65]

it should be observed that EPA does take note of the fact that **oil-producing States** have regulated injections for years, and does set the requirements applicable to injection wells related to oil and gas production in a subpart separate from requirements for other types of injections.

While EPA-required procedures are similar to existing State procedures for injection permit regulation, the proposed regulations would impose much more detailed requirements than do current State procedures. For example, the application requirements for new underground injection under the proposed regulations[66] set forth immediately below should be compared with the Oklahoma regulations concerning application quoted on page 218 of this appendix.

> (a) The application form for any new underground injection shall include the following:
>
> (1) Ownership and Location Data. The application shall identify the owner and operator of the proposed underground injection facility, and the location of the facility.
>
> (2) Engineering Data.
>
> (i) A detailed casing and cementing program, or a schematic showing: diameter of hole, total depth of well and ground surface elevation; surface, conductor, and long string casing size and weight, setting depth, top of cement, method used to determine top; tubing size, and setting depth, and method of completion (open hole or perforated);
>
> (ii) A map showing name and location of all producing wells, injection wells, abandoned wells, dry holes, and water wells of record within a one-half-mile radius of the proposed injection well; and
>
> (iii) A tabulation of all wells requested under (ii) penetrating the proposed injection zone, showing: operator; lease; well number; surface casing size and weight, depth and cementing data; intermediate casing size and weight, depth and cementing data; long string size and weight, depth and cementing data; and plugging data.
>
> *(3)* Operating Data.
>
> (i) Depth to top and bottom of injection zone;
>
> (ii) Anticipated daily injection volume, minimum and maximum, in barrels;
>
> (iii) Approximate injection pressure; and
>
> (iv) Type, source, and characteristics of injected fluids.
>
> *(4)* Geologic Data—Injection Zone. Appropriate geologic data on the injection zone and confining beds including such data as geologic names, thickness, and areal extent of the zone.
>
> *(5)* Underground Sources of Drinking Water Which May be Affected by the Injection. Geologic name and depth (below land surface) of aquifers above and below the injection zone containing water of **3,000** mg/l **total dissolved solids or less and aquifers containing water of 10,000** mg/l total dissolved solids or less.
>
> (6) An electric log on all new wells and on existing wells where available.

The regulations could broaden the number of persons or agencies who could challenge the application and insist upon a public hearing. New requirements would be made for record keeping at several different levels (by governmental agencies and operators); there would be a 5-year limitation on permits; new standards could be required to be met after an injection program has commenced under a properly issued permit; and the specific well requirements go beyond those of many States.

A number of parties have objected strenuously to these proposed regulations or similar prior proposals, and to the general approach taken by EPA under the Safe Drinking Water Act on the grounds that this will significantly hinder EOR operations without corresponding benefits in the protection of drinking water. A resolution of the Interstate Oil Compact Commission of June 30, 1976, for example, declared: "The State regulatory agencies estimate that if the recent draft regulations went into effect it would cause a loss of production of over 500,000 barrels of oil per day and in excess of 2.5 billion cubic feet of gas per day. All of this is from existing wells that have been producing for a number of years with virtually no adverse impact on the environment.[67] While this resolution referred specifically to the immediate predecessor of the currently proposed regulation, personnel with the Interstate Oil Compact Commission indicated in personal contact that the current regulations could still substantially interfere with or impede enhanced recovery of oil.

The Council on Wage and Price Stability recently criticized EPA's proposed regulations on the grounds that EPA may have both underestimated the costs of conducting the State regulatory programs and misjudged the health benefits to be gained by the regulations.[68] Specifically, the Council stated that "EPA's data regarding benefits and costs offered in support of the regulations are too fragmentary, subjective, and inconclusive to enable an informed decision to be made on this issue, " and urged that further evaluations be made before putting regulations into effect.[69]

Finally, both producers and State commissions identified the contemplated EPA regulations as being likely to hinder or discourage enhanced recovery operations. Of the responses from producers, four independent and six large producers stated specifically that the proposed EPA regulations would have an adverse effect on operations. An example of such responses was the following comment of one independent producer from the State of New York: "EPA-proposed rules and regulations regarding existing underground injection wells--could have a very negative effect on enhanced recovery. " One of the large companies responding similarly stated: "The recently proposed EPA rules concerning secondary recovery operations could essentially prohibit new enhanced projects. " One State agency which has authority over several hundred enhanced recovery projects with many more potential projects in the State said that no permit had been denied for such projects but that "Many may be denied next year if the Federal UIC [underground injection control] Regulation is administered as written. " The American Petroleum Institute has also conducted a survey of major and independent producers and has concluded that "Without doubt the proposed regulations will interfere with and impede underground injections and substantially decrease the ultimate production and recovery of hydrocarbons." [70]

In light of the number of such comments, it is clear that EPA-proposed regulations are perceived as having, or as likely to have, an adverse impact on enhanced recovery operations.

## Operational Aspects of Enhanced Oil Recovery

### Potential Liability to Nonjoining Interests

Relatively few reported cases have arisen in which non joining interests have made claims for damages against unit operators for enhanced recovery activities, and fewer still in which damages have been awarded. However, the issue is an important one as is suggested by the number of articles that have been written on the subject.[71] As one writer has commented, the small number of cases is "like the top of an iceberg, it does not reveal the trouble underneath—the number of secondary [i.e., enhanced] recovery projects delayed or hamstrung by threats of litigation, and the heavy price sometimes exacted by the owners of minority interests in exchange for cooperation.[72] For this reason, it is important to examine briefly the legal theories upon which claims or liability might be based, the treatment of these by the courts in the past, and possible approaches to the problem in the future.

The legal theory upon which a claim for damages may be based will depend in part upon the relationship between the claimant who has not joined the unit and the operator responsible for the enhanced recovery project. If the claimant is a lessor or cotenant of the operator, the claim in most circumstances will be that the operator has breached a duty owed to the claimant or that the operator has caused waste of property jointly owned by both the operator and the cotenant. If the claimant is a neighbor owning an interest in the reservoir, the claim may be based on a theory of trespass, strict liability (ultrahazardous activity), nuisance, or fault. In general, the courts have shown a disinclination to award damages on any of these grounds except the very last—fault.

As discussed in an earlier section, the lease itself governs most relations between lessor and lessee. Most leases are silent with respect to enhanced recovery, however, and it is necessary to examine implied rights and obligations that arise out of the basic relationship. These can be put under many headings, but the general principle that is most important is that the lessee must act in good faith and do nothing to injure the value of the leasehold. While the same relationship is not present in a cotenancy situation, it is nevertheless well recognized that one cotenant should do nothing to reduce the value of the joint property without the consent of the other. In either circumstance, the most likely claim to be raised by a non joining lessor or cotenant is that the lessee/operator is causing or permitting *oil* and/or gas to be drained away from the property. Cases have been adjudicated in several jurisdictions on this basis and will be described briefly.

In the case of Tide Water Associated Oil Co. v. Stott,[73] a pressure maintenance program was undertaken with the approval of the Texas Railroad Commission by the lessee of the claimants. The lessors (claimants) refused to join in the unit. The lessee was also the lessee on other nearby tracts and maintained its lease on the lessors' lands by continuing to conduct primary operations there. The lessors sued the lessee on the theory that it was causing drainage of "wet" gas from under their tracts to the other tracts operated by the lessees. The Fifth Circuit Court of Appeals held in favor of the lessee, saying that there was no liability to the nonconsenting lessors because they had been given an opportunity to join in the unit operations on a fair basis.

In the case of *Carter Oil Co. v. Dees,*[74] a lessee sought a declaratory judgment allowing it to convert an oil production well to a gas injection well for enhanced recovery operations. The lessor opposed this, claiming it would cause drainage of oil from underneath his property. Despite a contrary ruling on an identical case the previous year by the Seventh Circuit Court of Appeals,[75] the Appellate Court of Illinois held for the lessee on the ground that the additional oil gained by the project through drainage from other land would more than compensate for the loss from the lessor's land.

After the Dees case, the Illinois legislature passed an act that expressly stated that enhanced recovery was in the public interest. When a group of nonconsenting lessors and cotenants attempted to block a waterflood operation in the case of Reed v. Texas Company, [76] the Illinois Supreme Court relied upon the legislation to hold for the operator. The court held that the claimants had been offered **an** opportunity to participate in the program on a fair basis, that the State mining board had approved the project, and the project was in the public interest; it stated:

> If a **minority of one or more persons affected by the operation** could prevent it by refusing to join in the agreement, they could then force the others to choose between leaving a large part of the oil underground, or consent to granting the dissidents an unreasonably large percentage of the oil. in other words, the power to block a repressure program by refusing to sign the unitization agreement, would be the power to insist upon unjust enrichment. Surely a court of equity would not support such a rule.

In somewhat similar cases, the North Dakota[77] and Mississippi[78] Supreme Courts followed the same line of reasoning in holding for the operators of other enhanced recovery projects.

It should be observed that despite the denial of damages to lessors, the lessee-operators in cases such as the Stott case must still satisfy other requirements of their leases to keep them valid. Thus in Stott the operator had to maintain separate production activities on the leases and had to account to the claimants separately from the unit operation. However, the courts have shown a willingness to support enhanced recovery despite competing claims of property rights in minerals. An express statement by the legislature in favor of enhanced recovery can be of considerable support for this predisposition in litigation of this nature.

When it is a neighboring interest owner who is claiming damages the theories asserted in support of liability are different. By and large, however, the courts have tended to support enhanced recovery and, with certain exceptions which will be noted, have denied liability.

In injection programs, the fluid injected sweeps from the injection well towards the production well (s). The migration of the fluid can cross property lines, and this fact has led to claims of trespass by neighboring interest owners who have not joined in the unit or enhanced recovery program when they have felt the production from their land was reduced by the fluid sweep. The most important case dealing with this claim of trespass is a Texas case, *Railroad Commission v. Manziel.*[79] In rejecting the neighbor's claim of trespass, the Texas Supreme Court adopted the theory advanced by Professor Howard Williams and Dean Charles Meyers of a negative rule of capture. [80] Just as one may produce oil or gas even though it migrates from the property of another, so too may one inject a substance into the ground for production purposes even though it migrates and causes loss of production for a neighbor. The court also supported its denial of liability by noting that enhanced recovery is in the public interest. No case involving enhanced recovery has been found which has granted damages on a theory of subsurface trespass by injection of fluids.

For some types of ultrahazardous activities there is strict liability (liability without a showing of negligent operations) for damages flowing from the activity. This legal theory overlaps with the principle of nuisance, and the two may be treated together even though one does not usually think of enhanced recovery as being ultrahazardous.[81] In an important recent case arising in Oklahoma, the Tenth Circuit Court of Appeals upheld a decision in favor of a claimant for damages for a non-negligent waterflood project. The court, in *Greyhound Leasing and Financial Corporation v. Joiner City Unit,*[82] relied upon a nuisance provision in the Oklahoma Constitution which states that no private property shall be taken or damaged for private use unless by consent of the owner. Although the unit operator had had the project approved by the Corporation Commission and had offered the claimant an opportunity to participate in the unit, the court found liability. It is possible that the court in another jurisdiction might hold in this manner even without such a State constitutional provision. Because the more exotic methods of enhanced recovery are relatively new and untried, there is a greater possibility that a court might find them ultrahazardous than with normal waterflood operations. The possibility of liability on this ground could be a disincentive to operations even though a number of authorities have expressed disfavor with such a result. Producers in five States indicated that they have enhanced recovery projects being inhibited by fear of such liability.

The final basis for liability for enhanced recovery operations is fault, which includes negligent actions, wanton disregard of the rights of others, and intentional harm. Liability arising from such actions is well recognized whether primary or enhanced recovery operations are involved. In virtually all instances the actions of the operator will be beyond those included in the order of the State commission. Few would contend that operators should have their negligent or intentionally harmful acts excused simply because they are engaged in enhanced recovery operations, although questions might be raised about the standard of care that should be applied to operators in such projects.

In general, the courts have looked with disfavor upon claimants who have been offered an opportunity to join in an enhanced recovery operation on a fair and equitable basis and have refused to join. The commission approval of the projects and public interest in enhanced recovery of oil tend to negate the possibility of liability for non-negligent operations and lend support to the other legal theories—such as the negative rule of capture—upon which a court might decide a claim for damages from a nonconsenting interest owner. A State statute expressing encouragement for enhanced recovery will also tend to negate liability. However, the uncertainty of the law in many jurisdictions makes the undertaking of enhanced recovery without joinder of all the interests in the unit either voluntarily or through compulsory unitization a risky business. Not only may operations result in liability, but the mere possibility that a court might so hold could discourage unitization by recalcitrant minority interests and could provide them strong leverage in bargaining over the participation formula.

## Environmental Requirements

Both State and Federal environmental requirements might affect enhanced recovery in several ways. First, they may cause delay in the approval and initiation of projects. Second, they may make enhanced recovery projects a greater economic risk because they could increase costs, could cause liability for violations of the requirements, or could force the shutting down of projects. Such possibilities could discourage efforts to undertake EOR projects. It should be noted that present environmental requirements seem to be restricting only with respect to enhanced recovery in California, and EPA's proposed underground injection regulations discussed in a previous section. The areas of environmental regulations that may be of significance for present or future operations relate to requirements for environmental impact statements, air quality standards, and limitations on water pollution.

### Environmental Impact Statements

Environmental impact statements are now required for certain State activities in several States

**and** for all Federal actions and, proposals significantly affecting the quality of the human environment. In 1970, the California Legislature enacted the Environmental Quality Act,[83] which requires various State and local governmental entities to submit environmental impact reports before undertaking certain activities. The affected State and local agencies are compelled to consider the possible adverse environmental consequences of the proposed activity and to record such impacts in writing. At least one producer has reported that this California requirement has caused "delay in waterflood projects due to delay in permits because of environmental assessment studies." These and other requirements had, said the producer, resulted in "presently over 1-year delay in obtaining permits. "

The National Environmental Policy Act of 1969 in section 102 (2) (c)[84] requires an environmental impact statement to be completed for every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. Since the Federal Government is now involved with enhanced recovery only in limited areas on Federal lands, this Act does not have much effect on enhanced recovery. However, should the Federal Government become involved in regulation of enhanced recovery, an environmental impact statement would probably have to be filed to meet the requirements of section 102(2) (c).

## Air Pollution

Air quality requirements are primarily of significance for thermal recovery projects. The legislation of greatest importance in this area is the Federal Clean Air Act of 1970,[85] and the State implementation plans enacted pursuant to it,

**Under the Clean Air Act, EPA has established primary and secondary ambient air quality standards. The primary standards are designed to protect the public health and the secondary standards are to protect the public welfare. It is the responsibility of the States to promulgate plans to attain these standards for each of the pollutants for which the EPA has set standards. Limitations** for air pollution from new sources of pollution are established by EPA itself. **In addition, the Clean Air Act has been interpreted by the courts as requiring agencies to prevent any significant deterioration in air quality in areas already meeting the standards. Both State and Federal** governments can enforce the Clean Air Act, and stiff penalties may be assessed for violation of regulations.

The precise applicability of the Federal and State requirements under the Clean Air Act depends upon the size and type of equipment used in steam generation, the quality of the fuel used for providing a heat source, and the quality of the air in the State and region where the operations take place. Since most ongoing thermal projects are located in California, it is the State in which there is an indication as to the impact of such air requirements. One producer there indicated that an application for a number of enhanced recovery projects was being delayed while EPA sought additional data on the air quality impact of the equipment to be used. The same producer suggested that some 25 projects were being delayed due to present and pending air-quality and land-use regulations. "Thermal recovery projects," it stated, "have been delayed due to EPA and County Air Pollution Control District regulations and permit requirements. " At least three other large and small producers stated that they had multiple projects being delayed by California air-quality requirements. Hydrogen sulfide regulations in Texas have been made more stringent in recent years, but no producer indicated that this has had an adverse impact on enhanced recovery.

## Water Pollution

The most important aspect of water pollution, namely pollution of ground water through seepage from flooding operations, is governed under State and Federal law by the Safe Drinking Water Act as previously discussed. Additionally, the Federal Water Pollution Control Act Amendments of 1972[86] (FWPCA) regulate water quality. Under the FWPCA the discharge of pollutants into navigable waters without a permit is prohibited. The term "navigable waters" is very broadly defined. Severe penalties are provided for violation of the requirements of the Act.

## Other Environmental Regulation

There are other local, State, and Federal regulations that can affect enhanced recovery. Land-use planning restrictions and zoning, toxic substance regulation, noise level limits, occupational health and safety requirements, and other measures may impact upon enhanced recovery operations in one way or another. However, the degree of impact is highly speculative at this point.

# Water Rights

All types of enhanced recovery, as previously noted, require water either for flooding purposes or for steam generation. Water of low quality has seemed adequate in the past, but for some of the more sophisticated techniques of enhanced recovery, fresh water will be more desirable. Questions of water rights for enhanced recovery have generated problems and litigation in the past, and it can be expected that such issues could become more important in the future. A brief treatment of the principles that have guided the courts with respect to water rights suggests the problems that may be faced in acquiring water for enhanced recovery.

Before discussing the law applicable to water, it is necessary to mention some of the classifications of water that are made, for the rights may turn on the classification. Water, of course, may be found on the surface of the earth or underground. Surface waters may be classified as diffused (having no defined channel or course such as a marsh), water courses, lakes, springs, or waste water. Underground waters may be classified as underground streams or as percolating waters (having no flow or water course) .[87]

The right to own or use water can present questions in three basic areas. First, there may be controversy arising between lessor and lessee, or between surface owner and mineral interest owner, as to water found on or adjacent to the land where the oil is located. Second, questions can arise between those who wish to use water for enhanced recovery and others who assert rights to the water but have no relationship with the enhanced recovery project or land on which it is located. Third, and perhaps overlapping the other two, will be matters of regulation of water use by the States.

## Lessor-Lessee Rights

The litigation that has arisen in the past with respect to water rights for enhanced recovery has dealt primarily with the respective rights of lessor and lessee, or surface owners and owners of mineral interests beneath the surface. For simplification, reference will be made simply to lessor and lessee. In such litigation, it has been presumed that the original owner of the surface owned the right to the water and could dispose of it for enhanced recovery purposes; the question litigated has been whether there was such a disposition, either expressed or implied.

The first type of issue that has arisen is whether a grant of "oil, gas, and other minerals" (or a similar phrase) has included water as a mineral. Courts have held that freshwater is not a mineral within the meaning of this clause in an oil **and gas lease or deed.[88] instead, the courts treat fresh water as belonging to the surface estate whether the water occurs at the surface or must be brought from the underground. Therefore, the lease or deed from the surface** owner must expressly grant rights to use of this water, or the rights to the water must arise as part of an implied right to use of the surface for the development of the mineral estate. One Texas court made a distinction between fresh water and salt water, holding that salt water is part of the mineral estate,[89] but the Texas Supreme Court has since said that salt water and fresh water alike should be treated as belonging to the surface estate.[90]

Many oil and gas leases do contain an express grant of right to the lessee to use water from the lease premises. They often contain a provision such **as** the following:[91]

> The lessee shall have the right to use, free of cost, water, gas and oil found or located on said land for its operations thereon, except water from the wells of the lessor.

Does this provision, which does not mention enhanced recovery, authorize the use of water from the land for enhanced recovery purposes when such techniques were not known in the

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area or to the industry when the lease was granted? It is generally treated as authorizing the use of water on the leased premises for enhanced recovery, but a notable Texas case, *Sun Oil Co. v. Whitaker,*[92] to be discussed shortly, declined to rule on this question when given the opportunity. A problem with a clause such as the one quoted is that the water for enhanced recovery may have to be used on other lands and this is not permitted by the provision. However, the royalty owners agreement will include a provision for this when there is unitization. if a nonroyalty interest owner is the owner of the surface, other agreement will have to be made to authorize the use of the water off the leased property.

Finally, even if there is no express provision for use of water for enhanced recovery, there will generally be an implied right to use of the water. As stated in a previous section, the lessee has the right to use so much of the surface as may be reasonably necessary to effectuate the purposes of the lease having due regard for the rights of the owner of the surface. This will include water, and several courts have expressly applied this implied right doctrine to water (both fresh and salt) for use in enhanced recovery operations. [93]

The most recent and important of these decisions is *Sun 0il Co. v. Whitaker.*[94] In this Texas case, one Gann gave a lease to Sun Oil in 1946 and then conveyed away the surface rights to Whitaker in 1948. The lease had an express provision for the use of water substantially like the one quoted above. After years of production by primary methods, Sun decided to waterflood the formation. It received authority from the Texas Railroad Commission to use fresh water for this purpose, and began producing water from a nonreplenishable water formation for the program. The owner of the surface, Whitaker, was using fresh water from the same formation for irrigation of farmland. Sun sought to prevent Whitaker from interfering with its production, and Whitaker in the same suit sought to prevent Sun from using the water for enhanced recovery. The court held, without ruling on the extent of the express provision, that the oil and gas lessee's estate was the dominant estate, that the lessee had an implied grant of free use of such part and so much of the premises as was reasonably necessary to effectuate the purpose of the lease, that the implied grant extended to and included the right to use water in such amounts as would be reasonably necessary to carry out its operations under the lease, and that the waterflood operation was reasonably necessary to carry out the purposes of the lease. It should be noted that the court found that no other source of usable water on the leased tract was available, and that the decision was by a narrow majority of five to four. With only a slight change of facts this court and any other could easily hold to the contrary, so that an enhanced recovery project operator is certain of his rights to water only if they have been expressly granted for enhanced recovery purposes.[95]

## Riparian and Appropriation Rights

When the rights to water of parties other than the lessor and lessee are considered, several rules of ownership of rights must be taken up. These are the doctrines of riparian rights and rights of prior appropriation, and some States follow a combination of these two.[96] Which rule applies to a particular State has largely been determined by the climate and geographical region in which the State is located. Generally speaking, these doctrines apply to watercourses with underground waters being governed by a theory of absolute ownership or a reasonable use limitation only. However, in some States, the rights doctrines will apply to underground water as well as surface water.

*Riparian Rights.*—The doctrine of riparian rights is found to apply in some 31 States (table C-2) located primarily in the eastern half of the United States, where there is more water. Under this principle, the owner of land adjacent to a watercourse (the riparian owner) is entitled to reasonable use of such amount of water as he can put to a beneficial purpose. A reasonable use is such that it will not unduly disturb a lower riparian's right to some minimum flow of water and which is suitable to the character and size of the particular watercourse. A limitation on the right is that the water must be used on the riparian owner's premises, or at least within the watershed. In States following this principle, percolating waters are generally treated as being subject to absolute ownership by the surface owner or a principle like the rule of capture is applied, so that the underground waters may be sold and transported away from the watershed.

The significance for enhanced recovery under the riparian rights approach is that production of oil is a beneficial use as is required under the doctrine, and water generally will be available from one source or another. However, whether the water is from a watercourse or from underground it may be necessary for the operator to contract for the water. Use of the water for waterflooding can be enjoined by lower riparian owners only if they can show that there has been an excessive or unreasonable taking of the water, leaving them with less than their fair share.

Rights of Prior Appropriation.—The doctrine of prior appropriation developed in the more arid regions of the United States and presently applies in nine States, commonly designated as the Rocky Mountain States. Prior appropriation is the taking of a portion of a natural supply of water, in accordance with law, with the intent to apply it to some beneficial use within a reasonable time. As before, enhanced recovery operations do constitute a beneficial use of the water.[97] The right to the water is fixed by time, not by location on the watercourse. Thus, an upstream appropriator who is later in time (junior appropriator) in his appropriate ion is subordinate in right to a downstream prior (senior) appropriator's right to the water. Appropriation is a vested right then to take or divert and consume the same quantity of water forever.

Ownership of land is generally a prerequisite to appropriation. However, as has been stated by one authority that "[i] n the absence of statute, it has always been the rule in States following the appropriation doctrine that an appropriator may change the use and place of use so long as the change does not injure other appropriators. [98] This means that, subject to State regulation, a party may acquire or dispose of his appropriation rights. The importance of this is that operators are faced with the problem that with prior appropriation the right is perpetual with no provisions for short term appropriation of water. The ability to buy and sell rights is significant, for the use of water for enhanced recovery is of limited amount and duration; the operator must buy on a short-term basis, if possible, or appropriate the water and sell the rights after completion of operations. Where the operator is a junior appropriator, he is subject to having his water diminish or cease entirely in times of shortage.

*Dual System.*—Some 10 States apply a combination of the two principles described above known as the California doctrine. That is, they follow a rule that a riparian owner may take water from a source but only as much **as he** can put to a reasonable beneficial use. Surplus water is subject to appropriation by nonriparian owners or to export by riparian owners to nonriparian lands; but this appropriation or export is junior to the prior rights of the riparian appropriators. Beyond this, generalization is very difficult, for the States have gone in different directions through court decisions and legislation.

As stated previously, EOR is regarded as a beneficial use of water. While a nonriparian operator may acquire rights for water in the dual-system States, his rights will be subject to prior appropriation by those senior in rights to him. Ground water is likely to be the subject of special legislation in such States.

## State Regulation of Water Use

The trend in the current development of water law has been, as noted by the leading authority on the subject, "toward more public regulations through permit systems, accompanied by new legislative efforts in some States to recognize the interrelationship between many surface and ground water sources and to combine the controls and management under one statute.[99] Regulation is more comprehensive generally in the more arid Western States than in the more humid Eastern States, although the Eastern States do regulate pollution of waters. A number of Western States following the prior appropriation doctrine have agencies which regulate the acquisition, transfer, or change of appropriation rights. Because regulation of ground water is of relatively recent date in most States, its treatment in statutes tends to be more comprehensive than for surface waters, and the permit systems are more extensive.

Whether surface waters or ground waters are to be used in enhanced recovery, it is likely, particularly in the western half of the United States, that an operator will have to be issued a permit acknowledging his right to the water prior to using the water he has acquired for the EOR project. This will probably be done through the office of a State engineer, a commission, or a water resources board in a proceeding separate from the one for a permit to inject the water. The procedure is similar to that for getting approval for the EOR project. There have been few cases arising from administrative problems involving enhanced recovery projects, and little or no indication from the literature or the questionnaires that State regulation of water rights has caused any problems for enhanced recovery. The potential for problems exists, however, because the agencies might likely become focal points for competing claims over the uses to which fresh water should be put.

**Table C-1**
**Unitization Statues: Voluntary and Compulsory**
**[Adapted from Eckman, 6 Nat. Res. Lawyer 382 (1973)]**

| Statute | Citation |
|---|---|
| Alabama | Code of Ala., Tit. 26, ~fj 179 (70) to 179(79) |
| Alaska | Alas. Stat. $31.05.110 |
| Arizona | Ariz. Rev. Stat. $$27-531 to 27-539 |
| Arkansas | Ark, Stat. Ann. 1947, $53-115, C-1 to C-8 |
| California Subsidence | Calif. Pub. Res. Code $$3321 to 3342 |
| California Townsite | Calif. Pub. Res. Code Q$ 3630 to 3690 |
| Colorado | Colo. Rev. Stat. 1963, 100-6-16 |
| Florida | Fla. Stat. Ann. ~ 377.28 (1) and (2) |
| Georgia | Ga. Code Ann. $43-717 (b) and (c) |
| Idaho | Idaho Code ~ 47-323 |
| Illinois, | Smith-Hurd, Ill. Rev. Stat. Ch. 104$84 b, c |
| Indiana | Burns Ind. Stat. ~ 46-1714 (b) and (c) |
| Kansas | Kans. Stat. Ann. $$55-1301 to 15-1315 |
| Louisiana Subsection B | La. Rev. Stat. 1950, Tit. 30, # 5B |
| Louisiana Subsection C | La. Rev. Stat. 1950, Tit. 30, $ 5C |
| Maine | Me, Rev. Stat. ~ 2159 |
| Michigan | Mich. Comp. Laws Ann. 3$319.351 et seq. |
| Mississippi | Miss. Code 1972 ~$ 53-3-101 to 53-3-110 |
| Missouri | Rev. Stat. Mo. 1969, $259,120 |
| Montana | Rev. Code of Mont. 1947, $$ 60.131.1 to 60.131.9 |
| Nebraska | Re. Rev. Stat. Neb. 1943, $57-910 |
| Nevada. ... , | Nev. Rev. Stat. 522.070 |
| New Mexico | N.M. Stat. Ann $$ 65-14-1 to 65-14-21 |
| New York. ... , | N.Y, Environ. Conserv. Law $23-090, subdivs. 1, 3-12 |
| North Dakota | No. Dak. Cent. Code $$ 38-08-09.1 to 38-08-09.17 |
| Ohio | Ohio Rev. Code $1509.28 |
| Oklahoma | 52 Okla. Stat. Ann. $~ 287.1 to 287.15 |
| Oregon | Ore. Rev. Stat. 520.270 to 520.330 |
| South Dakota | So. Dak. Comp. Laws 45-9-37 to 45-9-51 |
| Tennessee | Term. Code Ann. 60-104 (d) (13) |
| Texas | Vernon's Civ. Stat. Tex. Ann., Article 6008b |
| Utah | Utah Code Ann. 40-6-17 |
| Washington | Rev. Code Wash. ~~ 78.52.340 to 78.52.460 |
| West Virginia | W. Va. Code 1931 $4 22-4 A-8 to 22-4 A-9 |
| Wyoming | Wyo. Stat, ~ 30-222 |

**Table C-2**
**Comparative Chart of Aspects of Unitization Statutes**

| State | Percent working or royalty int. req'd vol. = voluntary only: | Proof or findings required: Inc. ult. recovery | Prevent waste | Protect corr. rights | Add.cost not over add. recov | Unit area Part or All of Single or Multip. pools | Water rights doctrine R-riparian PA-prior appropriation D-dual system |
|---|---|---|---|---|---|---|---|
| Alabama . . . . . . ., . . . | 75 | Yes | Yes | Yes | Yes | PAM | R |
| Alaska ., . . . . . . . . . . . | 62.5 | Yes | Yes | Yes | Yes | PAS | PA |
| Arizona . . . . . . . . . . . . | 63 | Yes | Yes | Yes | Yes | PAS | PA |
| Arkansas . . . . . . . . . . | 75 | Yes | Yes | Yes | Yes | PAS | R |
| California Subsidence* | 65 | No | No | Yes | Yes | PAM | D |
| California Townsite* . . | 75 | Yes | — | Yes | Yes | AS | D |
| Colorado. . . . . . . . . . . | 80 | Yes | — | Yes | Yes | PAM | PA |
| Florida . . . . . . . ., . . . | 75 | Yes | Yes | Yes | Yes | PAM | R |
| Georgia .., . . . . . . . . . . | None | — | — | — | — | PAS | R |
| Idaho, . . . . . . . . . . . . . | vol. | — | Yes | orYes | — | PAM | PA |
| Illlnols ., . . . . . . . . . . ., | 75 | Yes | Yes | Yes | Yes | PAM | R |
| Indiana . . . . . . . . . . . . . | None | Yes | Yes | | Yes | PAS | R |
| Kansas . . . . . . . . . . . . . | 75 | Yes | Yes | Yes | Yes | PAS | D |
| Kentucky. . . . . . . . . . . | 75 | Yes | Yes | Yes | Yes | PAM | R |
| Louisiana Subsection B. | None | | Yes | | | PAS | R |
| Louisiana Subsection C | 75 | Yes | Yes | Yes | Yes | AM | R |
| Maine . . . . . . . . . . . | 85-W -65-R | Yes | — | — | Yes | PAM | R |
| Michigan” ’””’”” ““”’” | 75 | Yes | Yes | Yes | Yes | PAM | R |
| Mississippi . . . . . . . . . . | 85 | Yes | Yes | Yes | Yes | PAM | D |
| Missouri . . . . . . . . . | 75 | Yes | Yes | Yes | Yes | PAS | R |
| Montana. . . . . . . . . . . | 80 | Yes | — | Yes | Yes | PAM | PA |
| Nebraska. ., . . . . . . . . . | 75 | Yes | Yes | Yes | Yes | PAM | D |
| Nevada . . . . . . . . . . . . | 62.5 | Yes | Yes | Yes | Yes | PAS | PA |
| New Mexico, . . . . . . . . | 75 | Yes | Yes | Yes | Yes | PAS | PA |
| New York . . . . . . . . . . . | 60 | Yes | — | Yes | Yes | PAS | R |
| North Dakota . . . . . . . . | 80 | Yes | Yes | Yes | Yes | PAM | D |
| Ohio . . . . . . . . . . . . . . . | 65 | Yes | — | Yes | Yes | PAS | R |
| Oklahoma . . . . . . . . . . . | 63 | Yes | Yes | Yes | Yes | PAS | D |
| **Oregon . . . . . . . . . . . . . .** | 75 | Yes | Yes | Yes | Yes | PAM | D |
| **South Dakota.. . . . . .** | 75 | Yes | Yes | Yes | Yes | PAM | D |
| **Tennessee. ., . . . . . . . . .** | 50 | | | | | | R |
| **Texas. ., . . . . . . . . . . .** | vol. | — | Yes | Yes | Yes | PAM | D |
| **Utah. .,... . . . . . . . . .** | 80 | — | Yes | Yes | Yes | PAS | PA |
| **Washington . . . . . . . . . .** | None | Yes | Yes | Yes | Yes | AM | D |
| **West Virginia . . . . . . . . .** | 75 | Yes | Yes | Yes | Yes | AS | R |
| **Wyoming . . . . . . . . . . . .** | 80 | Yes | Yes | Yes | Yes | PAM | PA |

● See text, page 211.

Adapted in part from Eckman,6Nat Res. Lawyer 384(1973).

# APPENDIX C
# FOOTNOTES

1 The description here is of what is known as the "unless" type lease, the type in use in most States. A slightly different type lease, an "or" lease, is in use in California. The difference between the two relates primarily to the automatic termination of the lease in the primary term for the "unless" lease. H. Williams and C. Meyers, *Oil and Gas Law*, $601.5 (1975).

2 Gray, "A New Appraisal of the Rights of Lessees Under 011 and Gas Leases to Use and Occupy the Surf ace," 20 *Rocky Mt. Min. L. Inst.* 227 (1 975).

3 *Carter* 011 v. *Dees*, 92 N. E.2d, 519 (1 950).

4 Merrill, "Implied Covenants and Secondary Recovery, 4 *Okla. L. Rev* 177 (1 951); Walker, "Problems Incident to the Acquisition, Use and Disposal of Repressuring Substances Used in Secondary Recovery Opera tions, " 6 Rocky *Mt. Min L Inst* 273 (1 961); see also, H. Williams and C. Meyers, *Oil and Gas Law* § 935 (1 975), and cases and authorities cited therein.

5 Martin, "A Modern Look at Implied Covenants to Explore, Develop, and Market Under Mineral Leases, " 27th *Oil & Gas Inst* 177 (Matthew Bender 1976).

6 In re Shailer's Estate, 266 P.2d 613, 616-617 (Okla. 1 954).

7 *Tidewater Oil Co. v. Penix, 223* F. Supp. 215, 217 (E.D. Okla. 1963).

8 See generally, Interstate Oil Compact Commission, *A Study of Conservation of 011 and Gas in the United States*, 13-14 (1964).

9 The rules and regulations (No. 105) of the Arizona Oil and Gas Conservation Commission, to cite another example, provide that an 80-acre spacing will apply for oil wells in the absence of an order by the Commission providing for the spacing of wells and establishing drainage or drilling units for a reservoir.

10 A recent treatment of the subject is Bruce, "Maximum Efficient Rate—Its Use and Misuse in Production Regulation," 9 *Nat. Res. Lawyer* 441 (1 976).

11 H. Williams and C. Meyers, *Oil and Gas Law* § 901 (1975).

12 Ibid,

13 R. Myers, *The Law of Pooling and Unitization* § *3.02(2)* (2d ed. 1967).

14 H. Williams and C. Meyers, *Oil and Gas Law* § *339.3, 1975.*

15 For discussion of this unit, OTA has drawn upon Prutzman et al , "Chronicle of Creating a Fieldwide Unit, " .5th *National Inst. for Petroleum Landmen* 77 (1 964).

16 Description of the establishment of this unit is contained in R. Myers, *The Law of Pooling and* Unitization Ch. IV (2d ed. 1967) and the discussion of unit formation which follows is largely drawn from this work.

17 Ibid. § 10.08 (1 976 Supp. ).

18 Ibid. § 10.07.

19 *Enhanced Oil* Recovery, National Petroleum Council, (December 1976), 87.

20 Ibid. 88,

21 Ibid. 89,

22 R. Myers, *The Law of Pooling and Unitization* § 4.02(2d ed. 1967).

23 Ibid.

24 Ibid. § 4.06,

25 Appendix C gives the citation to each State's compulsory unitization statute and the basic requirements of each State's act(s) (tables C-1 and C-2).

26 43 U.S.C. § 1 334(a) (l).

27 OCS Order 11 (16) (Cult of Mexico Area).

28 OCS Order 11 (15) (Gulf of Mexico Area).

29 Eckman, "Statutory Fieldwide Oil and Gas Units: A Review for Future Agreements, " 6 *Nat. Res. Lawyer 339* (1 973); Lawson, "Recent Developments in Pooling and Unitization, " 23rd *Oil & Gas Inst.* 145 (1 972); R. Myers, *The Law of Pooling and Unitization*, Ch. IX (2d ed. 1967); W . Summers, *The Law of Oil and Gas*, Chs. 29, 31 (1 966); H. Williams and C. Meyers, *Oil arrd Gas Laws* § 913 (1 975).

30 Louisiana Revised Statutes, Title 30, Ch. 1, § 6(B).

31 E.g., Moore *Oil, Inc. v. Snakard,* 150 F. Supp. 250 (W.D. Okla. 1957), remanded on joint motion of parties, 249 F.2d. 318 (10th Cir. 1957).

32 11 Alaska Administrative Code § 22.540.

33 Colorado, for example, provides that any party to the commission's rehearing who is dissatisfied with the disposition of the application for rehearing, "may appeal therefrom the district court of the county wherein is located any property of such party affected by the decision, by filing a petition for the review of the action of the commission within twenty (20) days after the entry of the order following rehearing or after the refusal for rehearing as the case may be, " Colorado Revised Statutes, Title 65, Article 3$ 22(b).

34 Vernon's Tex. Ann. Civ. Stat., Article 6008b § 1

35 Louisiana Revised Statutes, Title 30, Ch. 1, § 5C.

36 Oklahoma Statutes, Title 52, $287.4.

37 Ibid. §287.6.

[38] *Producers Development Co.* v. *Magna Oil Corp*, 371 P.2d 702 (Okla. 1962).

[39] H. Williams and C. Meyers, *Oil and Gas Law* § 970 (1975), and cases discussed therein.

[40] Eckman "Statutory Fieldwide Oil and Gas Units: A Review for Future Agreement" 6 *Nat. Res Lawyer* 339, 360 (1973).

[41] E.g., Wyoming Statutes Annotated, $30-222.

[42] H. Williams and C. Meyers, *Oil and Gas Law* § 911 (1977); R Myers, The *Law of Pooling and Unitization*, Ch. XII, (2d ed. 1967)

[43] 317 US. 341 (1943).

[44] R Myers, *The Law of Pooling and Unitization* § 12.03 (1), (2d ed 1967).

[45] *United States* v. *Cotton Valley Operators Committee*, 75 F. Supp. 1, 77 F. Supp 409 (W D. La. 1948), *aff'd* 339 U.S. 940 (1950).

[46] H. Williams and C. Meyers, *Oil and Gas Law* § 953 (1975).

[47] Oklahoma Corporation Commission, General Rules and Regulations of Oil and Gas Conservation Division, § 2-261 (d)

[48] E.g, Texas Railroad Commission, Oil and Gas Division; Rule 48, New Mexico Oil Conservation Commission, Rule 701 E.3

[49] *Tide Water Associated Oil Co. v Stott, 159* F. 2d 174 [5th Cir. 1946), cert. denied 331 U.S. 817 (1947).

[50] *Dobson* v. *Arkansas Oil and Gas Commission*, 235 S W.2d 33 (Ark 1950).

[51] Other examples include *Republic Natural Gas co* v. *Baker, 197* F 2d 647 (10th Cir. 1952); *Corley* v. *Mississippi State Oil and Gas Board*, 105 S 2d 633 (Miss. 1958); *Barnwell, Inc* v. *Sun Oil Co*, 162 S 2d 635 (Miss. 1964) See generally, H Williams and C. Meyers, *Oil and Gas Law* § 933 (1975)

[52] *Union Railroad Co* v. *Oil and Gas Conservation Commission*, 284 P.2d 242 (Colo. 1955),

[53] *Helmerich & Payne, Inc.* v. *Corporation Commission*, 532 P.2d 419 (Okla. 1975).

[54] A State by State brief treatment is Interstate Oil Compact Commission, *Summary of Secondary Recovery and Pressure Maintenance Rules and Regulations in the United States* (September 1969).

[55] New Mexico Oil Conservation Commission, Rule 701 B 1,

[56] Kansas Corporation Commission, General Rules and Regulations, § 82-2-502, A well log is the written record describing the strata, water, oil or gas encountered in drilling a well with such additional information as to gas volumes, pressures rate of fill-up, water depths, caving strata, and casing record as is usually recorded in the normal procedure of drilling. *Ibid., $82-2-101,*

[57] E.g. Texas Railroad Commission, Oil and Gas Division, Rule 36(c) (1 O) pertaining to hydrogen sulfide Injections,

[58] 1 Alaska Administrative Code § 22.400(c).

[59] Michigan, for example, gives the supervisor of wells the authority, as part of his power to prevent waste, "To require the locating, drilling, deepening, redrilling or reopening, casing, sealing, operating and plugging of wells drilled for oil and gas or for secondary recovery projects, or wells for the disposal of salt water, brine or other oil field wastes to be done in such manner or by such means as to prevent the escape of oil or gas out of one stratum into another, or of water or brines into oil or gas strata; to prevent pollution damage to or destruction of fresh water supplies including inland lakes and streams and the Great Lakes and connecting waters, and valuable brines by oil, gas or other waters, to prevent the escape of oil, gas or water into workable coal or other mineral deposits; to require the disposal of salt water and brines and oily wastes produced incidental to oil and gas operations, in such manner and by such methods and means that no unnecessary damage or danger to or destruction of surface or underground resources, to neighboring properties or rights, or to life, shall result. " Mich. Comp Law Ann § 319.6(c).

[60] 42 U.S.C. §§ 300 f-300j-9.

[61] 40 CFR Part 146, 41 Fed. Reg. 36730 (August 31, 1976)

[62] 42 U, S.C.§ 300h (b)(1).

[63] Ibid. §§ 300h (b) (2).

[64] 41 Fed, Reg. 36731.

[65] Ibid.

[66] Ibid. 36744. 40 CFR § 146.47.

[67] 35 *Oil & Gas Compact Bulletin*, June 1976 p 13,

[68] Council on Wage and Price Stability Release CM' PS-204 (Oct. 27, 1976).

[69] Ibid. at 23-24.

[70] Letter of Roy F. Carlson, Production Director, American Petroleum Institute, Dallas, Tex., to Office of Water Supply, Environmental Protection Agency, Washington, D C,, under date of Jan, 12, 1977.

[71] A list of these is contained in H. Williams and C Meyers, *Oil and Gas* Law, § *204.5* (1975).

[72] Lynch, "Liability for Secondary Recovery Operations," 22nd *Oil & Gas Inst.* 37, 79(1971),

[73] 159 F. 2d 174 (5th Cir. 1946), cert. denied, 331 U S 817 (1947),

[74] 92 NE 2d 519 (Ill app. 1950).

[75] Ramsey v. Carter Oil Co., 74 F. Supp. 481 (E. D. Ill. 1947), affm'd 172 F.2d 622 (7th Cir.), cert. denied 337 U.S. 958 (1949), reh. denied, 338 U.S. 842 (1949).

[76] 159 N . E . 2d 641 (Ill 1959) .

[77] Syverson v. North Dakota State Industrial Commission, 111 N.W.2d 128 (N.D. 1961).

[78] California Co. v. Britt, 154 So.2d 144 (Miss. 1963).

[79] 361 S.W.2d 560 (Tex. 1962).

[80] H. Williams and C. Meyers, *Oil and Gas Law*, § 204.5 (1975).

[81] Lynch, "Liability for Secondary Recovery Operations," 22nd *Oil & Gas Inst* 39, 65 (1971).

[82] 444 F.2d 439 (10th Cir. 1971 ).

[83] California Public Resources Code §§ 21000-21151.

[84] 42 U.S.C. § 4332

[85] 42 U.S.C §§ 1857 *et seq*

[86] 43 U.S.C §§ 1151 *et seq*

[87] These classifications by Hutchins have been criticized but they remain useful and have been important in the development of water law. See R. Clark, *Waters and Water Rights* § 3.1 (1967).

[88] Vogel v. Cobb, 141 P.2d 276 (Okla. 1943); Mack Oil Co. v. Laurence, 389 P.2d 955 (Olka. 1964); H. Williams and C. Meyers, *Oil and Gas Law* §219.6 (1975).

[89] *Ambassador Oil co*, v. *Robertson*, 384 S.W 2d 752 (Tex. Civ. App. 1964).

[90] *Robinson v. Robbins Petroleum Corp* , 501 S. W. 2d 865 (Tex. 1973).

[91] Walker, "Problems Incident to the Acquisition, Use and Disposal of Repressuring Substances Used in Secondary Recovery Operations, " 6th *Rocky Mt. Min. L. Inst* 273 (1961).

[92] 483 S.W.2d 808 (Tex. 1972).

[93] E.g., *Holt* v . *Southwest Antioch Sand Unit*, Fifth Enlarged, 292 P.2d 998 (Okla. 1955).

[94] 483 S.W.2d 808 (Tex. 1972).

[95] A subsequent Texas case held the implied right to use water from the surface of the leasehold did not extend to use of the water for operations off the leased premises *Robinson v. Robbins Petroleum Corp.*, 501 S.W.2d 865 (Tex. 1973).

[96] The discussion which follows is drawn primarily from the following sources: R. Clark *Water and Water Rights passim* (1967); Losee, "Legal Problems of a Water Supply for the Oil and Gas Industry, " 20th *Oil & Gas Inst.* 55 (1969); Trelease, "The Use of Fresh Water for Secondary Recovery of Oil in the Rocky Mountain States, " 16th *Rocky Mt. Min. L. Inst.* 605 (1971); Walker, "Problems Incident to the Acquisition, Use and Disposal of Repressuring Substances Used in Secondary Recovery operations. " 6th *Rocky Mt. Min. L. Inst.* 273 (1961).

[97] *Mathers v. Texaco*, 421 P.2d. 771 (N. M. 1966)

[98] Losee, "Legal Problems of a Water Supply for the Oil and Gas Industry,: 20th *Oil &* Gas *Inst.* 55, 81 (1969).

[99] R. Clark, *Water and Water Rights* § 441 (1967).