SECTION III: Special Topics

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Chapter 9: Basic Overview of Texas Laws and Regulations Affecting Oil and Gas

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Introduction

The Texas Railroad Road Commission (RRC) is the governmental regulatory body of the oil and gas production industry in Texas.

Two other state agencies which are regularly involved in the development of oil and gas are the Texas General Land Office (GLO) and the Texas Comptroller. The GLO is responsible for leasing state property (approximately 20.4 million acres) for oil and gas development and the Comptroller is responsible for collecting severance taxes on the production of oil and gas. As of June, 2008, severance taxes in Texas are 4.6% on oil/condensate and 7.5% on natural gas. A Regulatory Fee of $0.000667 for each thousand cubic feet of gas produced is also imposed. The due dates for paying severance taxes are monthly on the 20th day of the 2nd month following the production month; or yearly, if qualified, on February 20 of each year for the preceding year.

Out of the 254 counties in Texas, only about 35 do not have any recent oil and gas production. As a result of this early and prolific production in Texas, along with the constitutional focus on economic development, the state is often thought to have the largest and best-development body of oil and gas jurisprudence in the world and has even seen many international courts adopt Texas law as the standard for performance in oil and gas contexts.

Types of Ownership of Real Property

The Rule of Capture. The Rule of Capture originated from English hunting law, but somehow ended up as the basic rule allowing for the taking of oil and gas from beneath the surface even though it may have originated under someone else's land and migrated to another owner's. Without economic development incentives of the Rule of Capture, oil and gas production would be an entirely different creature. As time has moved on, the Rule of Capture has since been restricted in an effort to make a more even playing field. The biggest modification to the Rule of Capture is the correlative rights doctrine. In general, the correlative rights doctrine allows equal rights between adjacent land or mineral owners.

Ownership. Surely, property can be owned by a single person or several persons; however, divided ownership occurs more frequently in mineral ownership than in other types of property ownership. Special problems or unique applications may arise when the mineral estate is owned by more than one person. Furthermore, shared ownership may be concurrent as in the case of cotenants or it may be successive as in the case of life tenants and remaindermen.

Bundle of Sticks. Often, ownership of minerals in Texas and elsewhere is analogized as a "bundle of sticks" with each "stick" being a specific ownership right able to be conveyed or held. The sticks usually consist of the right of ingress and egress (a.k.a the right to enter and drill), the right to sign a lease, the right to receive bonus payments, the right to receive delay rentals, the right to produce the minerals, and the right to receive royalty payments. These sticks belong to the mineral owner; however, once a lease is signed, the mineral estate owner is left with the right to receive royalty, the right to receive delay rentals, the right to use the surface, the receipt of bonus, and a **possibility of a reverter**.

The right to lease is usually referred to as the **executory** right or sometimes as the executive right. **Bonus** is compensation for granting a lease; **delay rentals** are compensation for deferring drilling; and **royalty** is simply a share of production which is free of the cost of production. Like the fee ownership itself, each of these incidents of mineral ownership is alienable, divisible and inheritable. The mineral owner can transfer all or

any part of the mineral estate. The mineral owner can transfer a portion of the mineral estate, thereby creating a cotenancy of the whole, or transfer any of the individual incidents of mineral ownership such as the executory right, the royalty, or the like, or transfer the whole estate.

Fee Simple. Fee ownership (technically fee simple ownership) is ownership of property in total. When someone owns a whole share of property outright that can only be divested by conveyance, foreclosure, forfeit or adverse possession, they have fee simple ownership.

Fee Simple Determinable. A fee simple deter-minable is ownership of property only when a certain event happens, like a future date or after a specific death. "To Sally Smith for ten years, and then to Jeff Doe," "To the Benevolent Fund Trust, so long as the property is used as a school for the deaf, and then to the heirs of Adam Barnes," "To John Smith for the life of Sally Smith, and then to the heirs of Herman Moore" are all examples of fee simple determinable ownership.

Life Estates. Life estates are fee simple determinable ownerships. More specifically, a life estate is ownership of a property given to someone for the term of a life (usually the recipient's life), and then upon that person's death, to another person or entity. A life estate is an example of a split estate and triggers special requirements in an oil and gas leasing scenario. The person(s) or entity, who gets the property after the death of the principle is called a remainderman, or remaindermen (and the property owned is often called the *remainder*). One can convey or create a life estate for the life of someone who is not a party to the life estate. For instance, Joe Smith creates a life estate by conveying property "To Misty Jones for her life and then to Franklin Williams." Misty Jones could sell her ownership to Jason Jackson, but Jason would only own the interest for the life of Misty Jones.

The remainderman holds a future interest that will become a current interest only at the death of the life estate holder. Life estates are usually created by testament (will), intestacy, or by another instrument, usually a conveyance. Usually, a life estate is written as "to Joe Smith for his life, and then to Sally Smith." Texas intestacy law may also create a statutory life estate for the benefit of a surviving spouse under the proper conditions (see **Succession** elsewhere in this chapter). Often, for practical reasons, a life estate is created by will when a person remarries later in life and has adult children from a previous marriage who may be antagonistic to the new spouse. Under intestacy, using the previous "new spouse" scenario, the new spouse would receive nothing when the spouse with pre-existing children died (other than his or her share of community property). Even if the relationship with the new step-parent was good, the child(ren) could still force the surviving spouse out of the non-community property marital home.(Often the relationship between the children and the new spouse is not good and ouster is expected so a will is necessary to protect the new spouse.)

However, the property rights of the life estate holder are not complete. Life estate holders can live upon and use the land, but cannot commit "waste." Waste is an act which decreases the value of the loaned or which uses up something that cannot be replaced, such as minerals removed by mining or oil and gas production, unless the Open Mine Doctrine applies. The Open Mine Doctrine holds that if a life estate is created while waste is already being committed (as from an already producing Oil, Gas, Mineral Lease or OGML), the life estate holder is entitled to continue that same waste to his or her benefit. That is, the life estate holder gets the revenue and does not share it with the remainderman. If the life estate is created by will or deed, then the rules for waste and income can be determined by the testator/grantor.

Leasing issues. As between the life tenant and remainderman, who does one obtain a lease from? Because the remainderman has no present right of possession and the life tenant is obliged not to commit waste, both are necessary parties to the lease. Therefore, a lease solely by one, without the joinder or ratification of the other, is necessarily void.

Accounting issues. When a lease is executed by both the life tenant and remainderman, how is the money due under the lease, such as bonus, royalty, and delay rentals, divided between them? The general rule hinges on whether the distribution is from the corpus (body of the estate which is used up or produced, such as minerals), which goes to the remainderman (although held in suspense until the life tenant dies) or from the current income and interest on the proceeds from the corpus currently in suspense, which goes to Life Tenant. So, delay rentals are considered current income and paid to the life tenant, but royalty and bonus are considered corpus.

The proceeds from the corpus are suspended by the accounting department and placed in an interest-bearing account, and the life tenant receives the interest. The corpus, usually consisting of the royalty and bonus, goes to the remainderman after the life tenant passes away. However, the life tenant and remainderman can amend the way the distributions are made by written agreement or application of the Open Mine Doctrine as described above.

Practical considerations for life estates. In the oil and gas leasing context, usually once a lease is signed, any future conveyances are made subject to it, as well as other things in the public records that came before the new transaction. So, once a lease is signed, a new purchaser of the same property or minerals takes the interest subject to the terms of the existing lease; however, the royalty, shut-ins, and delay rentals are transferred to the new purchaser (unless the conveyance instrument states otherwise). But, with a life estate, the remaindermen do not take subject to a lease signed only by the life estate holder. So, it is very important to have remaindermen sign the same lease as the life estate holder, or at least to ratify the lease signed by the remainderman. Otherwise, when a life tenant dies and the remaindermen take ownership, the property/minerals are considered unleased. Sometimes, in order to get a lease from the life estate holder and the remaindermen, if they are not on good terms, there may need to be a compromise and/or a stipulation of interest, or at least a stipulation directing how payments should be distributed. The remaindermen usually have little current incentive, other than goodwill, to sign a lease because, unless otherwise stipulated, the law requires the life estate holder to get only the interest earned from the profits from the land, and the corpus (body, or profits) to be held in suspense until the death of the life estate holder, upon which the corpus is distributed to the remaindermen. This is a problem because the life estate holder may live a long, long time or the remainderman could die before getting the corpus. So, a stipulation could help spread the wealth between the life estate holder and the remaindermen immediately.

Reversionary Interests. Reversionary interests are also subject to an event happening. For instance, a person donates property to a church "so long as the property is used for a school." Once the property ceases to be used for a school, the property goes back, or reverts, to the original owner (unless further instructions were given in the source deed or some other later deed or testament). Notice the slight distinction between a fee simple determinable and a reversionary interest—with a reversionary interest, the interest goes back to the original owner, and with the fee simple determinable, the property can go to anyone else.

Cotenancy. Cotenancy is the ownership or possession of a unit of property by two or more persons or entities. Cotenants often share equally, but that is not always necessary. Cotenancy can involve two people or a million, with ownership of 99.99999999 percent to 0.000000001 percent. While cotenancy is a common occurrence found in the leasing of minerals, and can also lead to some of the toughest problems to solve because not everyone may want to lease or may not even be found. One saving grace in the oil and gas industry is that only one cotenant—no matter how big or how small—can sign an oil, gas and mineral lease (OGML) to access the whole property and all of the minerals. However, one cotenant must usually account to other cotenants for their proportionate share, but in OGML leasing, the proportionate reduction clause (discussed later) relieves that burden from the signing cotenant. However, when something like timber sales occur, the selling cotenant must account to the other cotenants for their fair share. This applies only when there is a profit from the land. If there is an improvement to the property, the non-improving cotenants are not required to pay their fair share for the improvement.

Any Texas cotenant can explore, drill, and produce the minerals or lease his or her share of the minerals without obtaining the consent of the other cotenants. That is, one cotenant cannot exclude the other from producing. The operating cotenant (personally or through a lessee) is called the developing cotenant and the non-operating cotenant is called the non-consenting cotenant. The developing cotenant must account to the non-consenting cotenant for the non-consenting cotenant's proportionate share of the net profits, unless otherwise contracted. However, the developing cotenant cannot assess operating or drilling costs to the non-consenting cotenant unless there are net profits from production of the minerals. Thus, the developing cotenant bears the entire costs and risk of failure of well. But, if the well is profitable, the developing cotenant must share the profits with the non-consenting cotenant on a pro-rata basis after accounting for the proportionate share of the cost of the well. And finally, the non-consenting cotenant can always ratify the lease to start receiving a proportionate share of the royalty immediately rather than waiting until payout to claim his or her share of the net profits.

Sometimes cotenants execute OGMLs with different lessees. When this occurs, the lessees become cotenant lessees so each has a like right to drill and produce the minerals. When multiple lessees exist as cotenants, complicated accounting and operating problems are bound to occur, so they usually enter into a Joint Operating Agreement to manage the complex relationship.

Cotenants and foreign pipelines. Normally, a pipeline is necessary to remove and market gas from a well. An OGML almost always allows for a pipeline or pipelines to be laid across the associated tracts so long as the gas transported is from the wells on the OGML or those tracts pooled/unitized along with it. However, when a foreign pipeline (often called *off-lease* or *out-of-unit*) which carries gas not associated with the tract owner's OGML must cross a tract, it requires the approval of all cotenants; however, in practice, many companies simply lease as many cotenants as possible early on so that the pipeline can be laid and then get assent from the remaining cotenants thereafter. The biggest problem with this approach is when one of the remaining, unsigned cotenants objects to granting a right of way. Although the law allows for the possibility of requiring the removal of the pipeline, most courts would only do so in egregious situations. Most courts would simply require damages from the trespasser because public policy should desire the development of oil and gas for the benefit

of the public. Furthermore, many pipeline companies become registered as public utilities and therefore acquire the right of condemnation, which can be used against unsigned or uncooperative cotenants (or sole owners).

Partition. In Texas, a cotenant has an absolute right to partition property, regardless of any inequities caused by the partition to other cotenants. Partition is a judicial proceeding and partitions can be granted either in kind (by dividing the property) or by forced sale (ordering the property sold, then dividing the proceeds). But, the right to partition does not extend to non-possessory interests such as royalty interests. Furthermore, the judicial costs to bring a partition action are borne among all cotenants in their proportionate share based on ownership regardless of which cotenant brings the action.

Community property. Texas recognizes community property ownership by spouses, so that property acquired during marriage is presumptively community property. The presumption is rebuttable, but property inherited, acquired as settlement for personal injuries, or acquired exclusively with separate funds will be considered separate property.

Before 1968, husbands could convey community property, except homestead property, without **joinder** (agreement) of his wife. But in1968 this law changed and real property titled in the name of one spouse can be encumbered and conveyed by the title holder, even if the property is community. However, if the real property is considered homestead, each spouse must participate in the conveyance. The homestead property right is important because even if the real property is considered the separate property of one spouse, the other spouse has homestead rights (if the property qualifies as detailed elsewhere in this chapter). Determining if real property is homestead is a question of fact for a jury. So, as a practical consideration when acquiring real property rights from a married person, one should obtain signatures from both spouses.

Separate property. Separate property generally consists of property acquired while single. Or, if married, property acquired by gift, inheritance, or personal injury settlement/recovery is considered separate property. Property possessed by either spouse during the marriage is presumed to be community property, but this presumption can be rebutted by use of "clear and convincing evidence."

Normally, both spouses execute oil and gas leases jointly, whether the mineral interest is community property or separate property. However, if the mineral interest is separate property, the owning spouse alone can execute a binding oil and gas lease, unless the lease is upon homestead property where joinder of both spouses is required.

Homestead. The TEXAS PROPERTY CODE defines two types of homesteads, urban and rural, both of which are determined at the time they are designated. It is certainly possible for a rural homestead to exist in a municipality if it was created prior to meeting the rules for an urban homestead, but became encompassed by the municipality due to later growth. An urban homestead is property located within a municipality that is served by police and fire departments. Furthermore, the urban homestead must be serviced by at least three of these services: electric, gas, sewer, storm sewer, and water.

Originally, the urban homestead exemption was defined by its dollar value, not acreage. Early on, the urban homestead was limited to $2,000 in value. But in 1983, a constitutional amendment replaced the dollar value limitation with an acreage limit. Between 1983 and 1999, the urban homestead was limited to one acre. However, this was

further amended in 1999 to ten acres. Multiple lots may make up an urban homestead as long as all the lots are adjacent and total no more than ten acres in aggregate.

Under the TEXAS CONSTITUTION, rural homesteads may consist of no more 200 acres for a family and 100 acres for a single person. A tract or tracts that contain more than acres than the acres shown above can still make up part of a homestead, but the acreage outside of the limit does not qualify for any homestead exemptions or protections. The TEXAS PROPERTY CODE does not officially define "rural," but it is usually interpreted as homesteads that do not qualify under the urban homestead rules.

One important note is that homestead rights do not extend to severed minerals. If the mineral estate has not been severed from the surface estate and if the surface estate is a homestead, both spouses must execute an oil and gas lease or it is inoperative as to the non-joining spouse. Neither spouse may convey or encumber the homestead without the joinder of the other spouse.

Types of ownership interests important in oil and gas

Net Revenue Interest. The fraction of production that the lessee/operator gets to keep once all other interests are deducted is called the *net revenue interest* (NRI). The interests deducted from the NRI usually consist of overriding royalty interests (ORRI), Non-Participating Royalties (NPRI), and royalties.

Overriding Royalty Interests. Overriding royalty interests (ORRIs) are usually created by the Lessee in return for something of value provided in direct relation to the prospective development of an oil or gas well either monetarily or by expertise, as in the case of compensating the discovering geologist. ORRIs burden only the Lessee's interests and never come from any share of royalty.

Non-Participating Royalty Interests. A Non-participating Royalty Interest (NPRI) is one conveyed or reserved by a present (or former) mineral or royalty owner. An NPRI can be perpetual or it can be limited to a specific term and like royalty, is taken out of the Lessor's interest. In contrast, ORRIs are taken out of the Lessee's interest. Because the NPRI does not correlate to a specific OGML, unlike the royalty interest or ORRI, it does not terminate when the lease terminates. NPRIs are coupled to the property interest.

It is important to note that NPRIs do not include the executory right unless that "stick" is specifically conveyed. The royalty owner almost always retains the executory right. However, the executory right holder must wield this right with utmost good faith and fair dealing (not fiduciary, but close). For instance, the executory right holder cannot arrange for a better deal than they are entitled to the detriment of the NPRI holder. Good faith and fair dealing requires the executory right holder to act with due regard for the interest of the non-executory and be willing to execute a lease on the same terms and conditions as a reasonable prudent landowner would do if there was no non-executory interest. If case law would have required a fiduciary relationship, then the executory right holder would be required to subordinate his interest to that of the non-executory.

The importance of legal descriptions

One of the most important concepts in Texas oil and gas law, as well as real estate law, is the legal description. Without a proper legal description, a conveyance is void for vagueness—it must be specific enough to tell the public exactly where the property is located. In some instances broad legal descriptions, such as "All my property in Harrison County, Texas" may be sufficient, but "All my property in Texas" will not be

held to be sufficient enough. Usually, a legal description is much more detailed than the last two examples.

Under the Statute of Frauds, an enforceable contract for the sale of real property must be in writing and signed by the person charged with the promise. With sales contracts, both the buyer and seller must sign because the buyer promises to buy and the seller promises to sell at a specific price.

Noticeably absent from the Texas statute is the requirement of a legal description. The Texas Supreme Court has ruled, however, that a sales contract must contain or at least reference an existing document that describes the land with reasonable certainty. Cases abound regarding what meets the "reasonable certainty" test. For example, suppose the description states "my land in Brazos County, Texas." Does this meet the test? According to the Texas Supreme Court, it does if the evidence reveals the seller owns only one tract in the county.

The following are examples of legal descriptions found in Texas instruments:

Example 1:
2.0661157 acres (300 feet by 300 feet square) out of a 25.72 acre tract or parcel of land situated in the JOHN WELCH SURVEY, A-846, about 10 miles southeast from the City of Henderson, Texas, described as the "Third Tract" in Partition Deed recorded at Volume 2061, Page 320, of the Official Public Records of Rusk County, Texas, further described as a part of 42.99 acres described as "First Tract" in Partition Deed to Gertrude Martin recorded in Volume 782, Page 8 of the Deed Records of Rusk County, Texas; **said 25.72 acre** tract being more fully described as follows:

BEGINNING at a 1/2 inch iron pipe found at the SEC of said 42.99 acre tract from which a 10 inch sweet gum (found marked) bears N 86 deg. 28' E 15.26 feet;
THENCE N 89 deg. 05' 41" W along NBL of a called 75.80 acre tract described as "First Tract" in Partition Deed to Gilbert Gene Griffith and recorded in Volume 1264, Page 476 of said Deed Records, 849.89 feet to a steel spike set in County Road No. 368;
THENCE N 01 deg. 08' 41"E across said 42.99 acre tract at 17.86 feet a 1/2 inch iron rod set and continuing in all 1,316.90 feet to a 1/2 inch rod set on the NBL of said 42.99 acre tract from which a 28 inch Shumard Oak (marked by T. Truitt) bears S 55 deg. 47' E 26.32 feet and a 36 inch Shumard Oak (marked by T. Truitt) bears S 60 deg. 44' W 8.93 feet;
THENCE S 89 deg. 13' 54" E along SBL of a called 100 acre tract described in Deed to Faye Saxon Brady and recorded in Volume 733, Page 294, of said Deed Records, 850.03 feet to a 1 inch iron pipe found at the NEC of said 42.99 acre tract from which a 3 inch dogwood tree (marked by T. Truitt) bears S 38 deg. E 11.90 feet and a 7 inch Post Oak (marked by T. Truitt) bears N 47 deg. W 19.25 feet;
THENCE S 01 deg. 09' 02" W along the EBL of said 42.99 acre tract, 1,318.93 feet to the beginning and CONTAINING 25.72 acres.

Example 2:
All that certain 25.27 acre tract or parcel of land situated in the JOHN WELCH SURVEY, A-846, Rusk County, Texas; located about 10 miles S 40 E from the City of Henderson and being a part of a called 110 acre tract described in deed to Clara Mae Welch, et al from Bryant Griffith, et al dated August 1959 and recorded in Volume 684, Page 591 of the Deed Records of Rusk County, Texas; more particularly described as follows:
BEGINNING at an iron stake found at the SWC of said 110 acre tract being a corner on the NBL of a called 19 acre tract described in Deed of Trust from Elaine Wilson Warlick to Elizabeth McMurray, Trustee dated August 29, 1979 and recorded in Volume 274, Page 145 of the Deed of Trust Records of Rusk County, Texas; said iron stake witnessed by a 12 inch S.G. found marked and bears N 45 E 27.0 feet;
THENCE along the called EBL of a proposed 13.97 acre tract as follows:
N 2° 55' 30" W 472.61 feet;
N 2° 41' 30" E 235.0 feet to an old auto spring found at the SEC of a called 19 acre tract described in deed

to Cliff D. Brooks, et ux from Mable Hall Denton, et vir dated December 1, 1970 and recorded in Volume 919, Page 327 of said Deed Records;
THENCE N 1° 03' 30" W 606.0 feet to the SWC of a called 42.99 acre tract received by Gertrude Martin in Partition Deed dated October 21, 1963 and recorded in Volume 782, Page 9 of said Deed Records; said corner witnessed by a 1-1/4 inch iron pipe which bears S 31° 22' E 11.85 feet;
THENCE N 89° 04' 30" E, along the SBL of said 42.99 acre tract, 510.0 feet to a steel spike with bottle cap from which a 12 inch Pin Oak bears N 23 E 14.4 feet and a 15 inch Pin Oak bears N 63-1/2 W 31/15 feet;
THENCE S 1° 03' 30" E, at 3.1 feet the center of County Oiled road, at 22.47 feet a ¾ inch iron pipe in fence and in all, 400.0 feet to a ¾ inch metal tube from which a 16 inch Pine bears N 43 E 21.9 feet;
THENCE N 88° 56' 30" E, along marked line, 466.96 feet to a one inch metal tube from which a 17 inch Pine bears N 58 W 38.5 feet and a 28 inch Pin Oak bears S 7-1/2 W 92.4 feet;
THENCE S 1° 03' 30" E, along marked line, 912.17 feet to a one inch metal tube set on the NBL of said Warlick 19 acre tract from which a rock found at its NEC bears N 88° 58' E 196.30 feet; from said tube a 12 inch Elm bears N 65-1/2 E 19.5 feet and a 22 inch R.O. bears S 8 W 22.35 feet;
THENCE S 88° 58' W 976.96 feet to the Place of Beginning CONTAINING 25.27 acres of land.

Example 3:
ALL MINERALS, RIGHT AND TITLE THAT IS IN THE SIMON DEL RIO SURVEY, A-34 IN RUSK COUNTY, TEXAS.

Example 4:
Tract One: 339. 24 acres of land, more or less, out of the A. Nunley Survey, A-176, in Madison County, Texas, and being more particularly described in that certain Warranty Deed from John M. Wallace and Ruby Nell Wallace to John Watson and Gladys Watson, dated August 2, 1990, and recorded at Volume 370, Page 169, of the Deed Records of Madison County, Texas.

Tract Two: 288.18 acres of land, more or less out of the A. Nunley Survey, A-176, Madison County,

Texas, being more particularly described as 448.18 acres of land in a deed dated June 4, 1970 from J. O. Thompson, et al to John P. Watson, recorded in Volume 184, Page 405, Deed Records, Madison County, Texas; SAVE AND EXCEPT 160.00 acres of land, more particularly described in a Quitclaim acknowledged on May 3, 2007 from TexCal Energy South Texas L.P. to John P. Watson and wife, Gladys A. Watson, recorded in Volume 866, Page 305, Official Records, Madison County, Texas.

As you see, the types of legal descriptions and their complexity vary greatly. Particular scrutiny must be placed on reservations ("save and except" language) so that net acreage may be calculated correctly. Courts have interpreted what constitutes good legal descriptions in such a way that one can never be too sure that a broad legal description will be upheld under judicial scrutiny. Furthermore, very specific legal descriptions will certainly be held to the exacting specifications as described.

Plotting acreage calls can also be somewhat complex. The old-fashioned way to plot was to use a protractor and Allen scales, but with computers, programs like DeedPlotter by GreenBriar Graphics have become the norm and can make the process of plotting much easier. Deed plotting programs can determine the total amount of acreage as well as logically close missing or bad deed calls automatically. The plats created are also an important part of any lease package or lease purchase report (LPR). And, because they are visual, they can assist in finding where the surface is located on topographical maps or even tax assessor plats.

Surveying by Metes and Bounds or Township and Range. Township and range is the prevalent method for surveying across the United States. It uses a series of square township and ranges, further divided into square sections of 640 acres. Of course, errors in early surveying were common, so

most sections do not truly equal 640 acres; even with modern surveying techniques using a subcentimeter-accurate GPS, there still is some inaccuracy. Also, there are irregular sections made up of something less than 640 acres when surveys encounter bodies of water or state borders.

However, most of Texas uses metes and bounds for property surveying. Metes and bounds are not setup on any meridian system and can be any shape or size, based on distance and direction from a starting point. This irregular method of surveying has led to the saying that "once you learn how to run title in Texas, you can run title anywhere." However, west Texas does have several counties which do subscribe to township and range surveying.

Measurement terms. In Texas, early measurement terms in conveyances seem like something from another world and time. Many of the early measurement terms were of Spanish origin, such as the commonly encountered *vara*. The vara, Spanish for *yard*, was defined as three geometrical feet. In addition, the vara differs in length between eastern Texas and western Texas. The vara is usually larger in east Texas than west Texas—some Spanish land grants have wide swings in the distance covered by a vara. Some standardization finally occurred when the surveyors in Stephen F. Austin's pre-Republic colony chose to use 33.3333 inches to the vara and was adopted by the Texas legislature in 1919. Prior to 1919, relying on 33.3333 inches to the vara can only be considered speculation. Labors (177.14 acres or 1 million square varas) and leagues (equal to 25 labors or 4428 acres) were also common early Texas measurement terms.

Commonly encountered modern measurement terms include: rods (16.5 feet), acre (43,560 square feet), arpent (approximately 191.8 feet, or 0.845 acres if square), chain (66 feet), and link (1/100th of a chain or 7.92 inches).

Mineral severance. In Texas, once the minerals are severed, they are always severed unless merger occurs. Severance is commonly seen as a conveyance with a reservation of the mineral to the grantor, but can occur in a variety of ways. This permanent severance means that in the oil and gas context, there are always two estates to be concerned with: the surface estate and the mineral estate. Special circumstances can create a merger, thereby recombining the surface and mineral estates when the surface owner and the mineral owner are one and the same.

Dominant estate. In Texas, as in most states, the mineral estate is the dominant estate. Therefore, the mineral estate has privileges and preferences over the surface. For instance, if the surface owner and mineral owner of a particular tract of land were different, how could the mineral owner produce his or her minerals if the surface owner controlled access to the property?

So, in Texas, the mineral owner can use as much surface of the land as reasonably necessary to produce the minerals. And, the mineral owner can do so without any compensation whatsoever to the surface owner; however, most operators will pay what are called "surface damages" for the fair use of the surface as a show of good will. Without these payments, surface owners may be reluctant to "let" development occur on the surface even though the mineral estate is dominate—these surface owners may later create obstacles to development that require restraining orders to prevent. Furthermore, a scorned surface owner somehow seems to always end up owning the minerals in the next tract to be leased by the exploration company.

Surface estate vs. mineral estate. What constitutes the surface estate and the mineral estate? Once severed, how deep down do "the minerals" start? What can the surface

owner produce? First, courts will look at the intent from the "four corners" on the instrument in which there is the question. Often, the lessee and the lessor will negotiate which things belong to which estate. However, if there is no defining language, the court will apply one of two tests.

If the severance occurred before June 8, 1983, the court will use the "surface destruction test." The surface destruction test simply meant that the surface did not include substances which cause substantial destruction to the surface estate to be removed. Under this test, surface owners in Texas wound up owning many valuable substances, which in other states would have been considered to belong to the mineral estate.

If the severance occurred on or after June 8, 1983, the court will use the "natural and ordinary meaning test." The defining court case regarding these two tests did not officially define this test. However, from the language in the case, it is believed that a substance will be construed as a mineral if it is generally regarded as a mineral in the community at the time and place where the severance took place. While this test seems to incorporate a scientific definition, there is no generally accepted meaning of "minerals."

These tests become extremely important in areas with lignite (coal) surface strip mining like in east Texas.

Warranty deed vs. quitclaim. Generally, deeds to real property come in three types. A **general warranty deed** warrants to the grantee that the grantor has done nothing to cloud the title and subrogates the grantor's rights of action and transfers any guarantees owned by grantor from previous owners for possible past title clouds. A **special warranty deed** just warrants to grantee that grantor has done nothing to cloud the title, but offers no protection for clouds by previous owners. A **quitclaim deed** simply gives to the grantee whatever the grantor owned, if anything. Thus, a quitclaim is a very weak deed that has no cause of action for title clouds, other than possibly fraud in the inducement concerning the acceptance the deed by the grantee.

After-acquired title doctrine. Although this concept is seldom seen, it does occur. If a person over-conveys property with a deed other than a quitclaim—that is, when someone sells more than he or she owns—and that person later acquires more ownership of the same property that was over-conveyed, that new acquisition, by rule of law, automatically transfers *eo instante* (immediately) to the person who was conveyed less than originally purported. This is *not* the same as a lease with a proportionate reduction clause which states that it covers more (gross) acreage than the net acreage. Warranty language is not specifically important when applying this rule. Courts will look for the equitable principles of "good faith, right conscience, fair dealing and sound justice" when determining if the rule should be applied, but a specific quitclaim deed will not be considered for application of the after-acquired title doctrine.

The effect of the after-acquired title doctrine is binding not only on the original grantor and his or her heirs and successors, but, after recording, it also binds subsequent purchasers from the original grantor who acquired the grantor's interest with actual or constructive notice of the grantor's prior conveyance. A subsequent purchaser under the original grantor, who may or may not have actual notice of what the grantor represented that the grantor was conveying, is nonetheless put on constructive notice by the recordation of the original conveyance instrument in the records of the county where the property is located. Such a purchaser cannot claim to be an innocent purchaser entitled to recover the original grantor's after-acquired interest. These prior recordings can be of particular

importance when determining title ownership and can easily be overlooked.

For instance, Jane knows she will inherit ten acres from her mother when she dies. Jane sells to Ted ten acres today. When Jane's mother dies six months later, and her mother's will does so devise the ten acres to Jane, these ten acres flow through Jane to Ted and vest in Ted immediately at the moment of Jane's mother's death. Often a conveyance as such would even state the facts above and leave the title examiner in the dark. Usually, the application of after-acquired title is not so obvious. The court in *Duhig y. Peavy-Moore Lumber Co.,* stated: "It is the general rule, supported by many authorities, that a deed purporting to convey a fee simple or a less definite estate in land and containing covenants of general warranty will estop the grantor from asserting an after-acquired title or interest in land, or the estate which the deed purports to convey, as against the grantee and those claiming under him."

A more conventional, yet difficult example would be where five brothers and sisters inherit 100 acres from their mother. The brothers and sisters believe they each own 1/5th (20%), or 20 undivided net acres out of 100. Joe, one of the siblings, sells his 20 acres to Jack, a friend. However, what the brothers and sisters did not know is that their mother had actually sold ten acres out of the 100 to Harold, a local cattle rancher, a long time ago. So, what each sibling inherited was 1/5th, 20%, or 18 undivided net acres out 90. As a result, the conveyance of 20 acres from Joe to Jack only contained 18 acres because that is all Joe owned. Now, five years later, Joe decides that he would really like to own some of the family land, so he buys five undivided acres from his sister Mary. Instantly at the time of Joe's acquisition of the five acres, two of the five acres immediately flowed from Joe to Jack to make Jack's acquisition of 20 acres whole and Joe is left with the remaining three acres.

It is easy to confuse the above scenarios with the conveyance that purports to convey "all my right, title and interest" in a specifically described 75 acre tract. If the seller only owned one-half of the tract at the time the conveyance was made, and then later acquires the remaining acreage, the remaining acreage *does not* flow through to the buyer through the application of the after-acquired title doctrine. Courts will effectively read into the conveyance instrument to change "all my right, title and interest" to "all my right, title and interest *that I currently own*." This reading into would satisfy the equitable principles of "good faith, right conscience, fair dealing and sound justice."

Accommodation Doctrine (aka Reasonable Accommodation Doctrine). The accommodation doctrine is relatively new in the oil and gas industry, but has lately eroded the dominance of the mineral estate in favor of surface owners. The doctrine simply states that when a pre-existing surface use can be "easily" accommodated by the oil and gas company, then the oil and gas company must accommodate. The seminal case on this subject is *Getty Oil Co. v. Jones* which was decided in 1971. In this case, a farmer who had been using a rolling, circular irrigation system to water his crops would have been prevented from watering his crops by the height of the production equipment on his surface estate. The court ruled that the oil and gas company had to dig down a few feet and locate the production equipment in the lowered area so the circular irrigation system could pass without obstruction. This doctrine requires the use to exist prior to the lease, not some made up or future use—it seems that a proposed well location is *always* the exact spot the surface owner wanted to build his or her multi-million dollar house.

As far as what "easily" means, the case law holds that "easily" means the accommodation must not increase the cost to the oil and gas company *and* that the oil and gas company

does not have to go "off-lease" to accommodate the surface owner. In one instance, an operator was using fresh water from a water well to waterflood an oil well. The water use was depleting reservoirs necessary for the watering of cattle on the property. The cattle rancher surface owner claimed that the operator could "easily" get water off-site for its well at minimal cost. The court ruled in favor of the operator in this example.

The Accommodation Doctrine has been further refined over the years and is fact driven. Usually a jury is required to settle the questions of fact, and expert testimony is usually required. To prevent such judicial scrutiny, one should take accommodation into account when drafting the source instruments.

Fraction of a fraction (or double fraction) problem. Oil and gas interests are more often than not fractionally owned, usually because of cotenancy or buying and selling of fractional interests. When a royalty owner conveys a one-half royalty to another person, does that mean one-half of an existing royalty, one-half of future royalties, or does it convey a royalty of 50%? The distinction usually hinges on the use (or non-use) of the word "of." For instance, a one-half royalty is a large royalty of 50%. But, one-half *of* royalty means one-half of whatever the royalty is or will be in the future.

In the latter instance, if a lease for one-sixth is already in operation and the lessor sells a "one-half of royalty" to John, John will actually get one-half of the royalty the lessor is getting (1/2 of 1/6 = 1/12). If the first instance comes into play, and there is no current lease on the premises, getting a lease may be a problem because John would be entitled to a royalty of one-half of all the production from the tract making it economically dangerous at best for the operator.

Duhig Rule—Overconveyance. An over-conveyance can occur when prior fractional mineral reservations occurred in the title, yet the existing reservations are not recited in a current conveyance where the grantor is also reserving a fractional mineral interest. Perhaps the best way to demonstrate the problem is to give an example.

John conveys Blackacre to Andrew but reserves one-fourth (1/4) of the minerals. Andrew later conveys Blackacre to Brent, but reserves one-half (½) of the minerals without reciting anything about prior conveyances. What fraction of the minerals does each own? John gets ¼, Andrew gets ½ and Brent gets ½, totaling 1¼. Of course, this is impossible. So, the court has interpreted this style of conveyance to mean that where full effect cannot be given to both the interest granted and the interest reserved, priority will be given to the interest granted. If the grantor overconveys by warranty deed, the overconveyance comes out of the grantor's interest. So, in this example, applying the Duhig Rule, the court would leave John with one-quarter, Andrew with one-quarter, and Brent with one-half.

Richard W. Hemingway defined the Duhig Rule as:

Where a grantor conveys an interest in the minerals and in the same instrument reserves a mineral interest, and where there is a prior interest outstanding that is not excepted from the operation of the deed, so that effect may not be given to both the interest that grantor has purported to convey and the interest grantor has attempted to reserve, under. . . [the Duhig Rule] the grantee is not limited to a suit in damages for failure of title, but the attempted reservation will fail to the extent necessary to make the grantee whole. Where complete failure of the reserved interest is insufficient to make the grantee whole, he will also have a cause of action in damages. . . .[1]

[1] *The Law of Oil and Gas*, 3rd ed.

It is important to note that this rule applies to warranty deeds only and not quitclaim deeds. If the grantee cannot be made whole based on the Duhig Rule, he or she would get whatever fractionalized interest is remaining, as well as a cause of action for damages to make up for the missing fraction. For an example of how a cause of action for damages would play out, redo the previous example but have John reserve three-quarters (¾) of the minerals.

The Duhig Rule applies to both mineral and royalty interests; however, it does not apply to oil and gas leases. The Texas Supreme Court has specifically held that Duhig does not apply to oil and gas leases, even though in Texas, an oil and gas lease is a conveyance. It is industry custom for lessors to execute oil and gas leases which purport to cover the entire mineral interest, even though they own only an undivided interest in the leased premises. There is a special clause in the lease, called the *proportionate reduction clause* which operates to reduce the lessor's interest under an OGML, if the lessor owns less than 100%. The proportionate reduction clause effectively eliminates the need for the Duhig Rule.

Duties of the mineral estate holder to the surface estate. In Texas, the mineral estate may be severed from the surface estate by a grant of the minerals in a deed or lease, or by reservation in a conveyance. A grant or reservation of minerals by the fee owner creates a horizontal severance and the creation of two separate and distinct estates: an estate in the surface and an estate in the minerals.

There is no implied duty of an oil and gas lessee or owner to restore the surface to its original condition so long as the production activities were conducted in a non-negligent manner, i.e. the operator did not use more of the surface than reasonably necessary. The duties of the mineral estate holder can be summarized as being required (a) to exercise its implied easements over the surface non-negligently, (b) to use only as much of the surface as is "reasonably necessary", and (c) to operate with due regard to the rights of the surface owner in cases where reasonable alternatives are available on the leased premises.

Adverse possession.
Surface. It is possible to get legal title to land one does not own. This is accomplished by adverse possession. Often property is adversely possessed by accident, but it can be also be adversely possessed completely with intent to dispossess another with no legal reason. Statutorily, Texas has several different terms required for adverse possession, based on how good the possessor could have believed the title to be.[2]

Under color of title (where the title on its face is good and is not a quitclaim), adverse possession can be had after three years. Under the five-year statute, the owner must file suit to recover the property before a possessor cultivates, uses or enjoys the property; pays the property taxes for five consecutive years before they become delinquent; and claims the property under a duly registered warranty deed.

In this instance, the adverse possessor may not claim the land based on a forged instrument or quitclaim deed. Simply paying property taxes cannot cause adverse possession under the five-year statute. Therefore, one cotenant that pays all the property taxes for five consecutive years cannot get the other cotenants' interests under this law.

Under the ten-year statute, no legitimate title or deed or payment of taxes is necessary for claiming. Tolling can happen when an owner has a disability which causes the running time period to abate while the disability exists.

[2] § 16.021 et seq. of the TEXAS CIVIL PRACTICES AND REMEDIES CODE

Therefore, a fourth period of 25 years exists for adverse possession. Under the 25- years statute, an owner must bring suit within 25 years of the adverse possession even if disability exists or existed. So the maximum number of years required to adversely possess a property is 25 years, no matter what disabilities the rightful owner has.

The time periods required for adverse possession do not require the same person to physically occupy the land the entire period—successive possessors can tack periods of occupancy together to meet the adverse possession time requirements. However, successive possessors must take immediate possession with no gaps of possession between.

Possession must also adhere to these rules: it must be (1) open, (2) hostile (adverse to the interest of others—not necessarily violent), (3) continuous (can even include time periods of subsequent possessors), and (4) peaceable (no one trying to force the possessor off the land. Usually these rules are most visibly found by the use of fences and/or farming or ranching. Building a house or barn would also show ownership intent. These rules are in place to provide the public with notice that someone may have an adverse claim. If the adverse possession is hidden, no one is on public notice.

When one adversely possesses property, he or she only adversely possesses what he or she is using, which is not necessarily the entire property. If a person builds a house and a one-acre garden on 100 acres, he or she will probably only adversely possess a few acres. More specifically, under the statute, if the land is not enclosed, the claim is limited to 160 acres.

But, perhaps the biggest problem with adverse possession is that it is almost never in the public records unless it is adjudicated. For oil and gas landmen, a physical inspection of the property is always required because it may reveal adverse possession or even a producing well, either of which may cause considerable title problems later unless found out early on.

Minerals. When talking about minerals, adverse possession requires adherence to the above rules and statutes, but it also requires the actual production of the minerals. In general, adverse possession of a severed mineral interest is accomplished by drilling a well and producing it continuously, openly, and visibly. The same requirements that apply to adverse possession generally also apply to oil and gas—one must act like the owner or act as if he or she is operating under the prior lease. Adverse possession of minerals generally involves the production of minerals after a lease has expired due to cessation of production, with the operator producing again at a later time without obtaining new leases (often called a *holdover* lessee). But because Texas is an owner-ship in place state, the illegally producing lessor will not earn title to the minerals in the ground by adverse possession, only for the minerals he or she has already produced, and will not be charged with conversion.

Usually, when operating under an OGML, an operator may cease production for a variety of legitimate reasons: to make repairs, to re-work the well-bore, to wait for better commodity prices, etc. Besides lease savings clauses which would work to prevent the lease from being lost from non-production, Texas courts recognize a common law doctrine known as the temporary cessation of production doctrine (TCOP). TCOP is what saved a well during these temporary periods of non-production before savings clauses became popular.

The *Pool* case set the standard in Texas, where the Texas Supreme Court reasoned that
". . . once the leases terminated, the Lessees had no

right to explore for, produce or sell the oil and gas. . .Those rights reverted to the Lessors . . After the leases allegedly terminated, the Lessee continued production and sale of all the oil and gas and payment of royalty on only a relatively small percentage of the proceeds was open, notorious, and hostile to the Lessors, who received payments each month of only 1/8 royalty for more than ten years after they say the leases terminated. . . Adverse possession of a terminated oil and gas lease by a hold-over Lessee begins instantly after the lease terminates, if the Lessee continues operating the leasehold, producing and selling O&G and paying only a royalty interest to the Lessee."

Thus, the Court believed that if the mineral owners accepted royalties for a long enough period, the producer was deemed to have adversely possessed a leasehold estate. By continuing to pay royalties, lessees can only adversely claim an estate consistent with their expired lease—no more, no less. In order to claim title to the minerals, the lessee would have had to stop paying royalties *and* continue to openly produce the minerals. Thus a holdover lessee will be granted a *constructive* lease.

Cotenants and adverse possession. To adversely possess a property interest against a cotenant, in addition to the normal requirements discussed elsewhere in this chapter, one must also give actual or constructive notice to the other cotenants of his or her intent to adversely possess. This level of notice is required because each and every cotenant is allowed to go onto the property and use it non-exclusively. Therefore, one would not be on casual notice of an adverse possession claim just because one of the cotenants is legally on the property. Usually courts will accept facts where the adverse possessor told his or her cotenants that the property belonged solely to the adverse possessor (actual) or where the adverse possessor physically prevented cotenants from accessing the property such as with fences, gates, or physical removal (constructive).

The lease

The Oil, Gas and Mineral Lease (OGML) is not really a traditional lease at all; it is actually a fee simple determinable with possibility of reverter. This legalese means that the lease is an actual interest in real property, and therefore subject to the statute of frauds. In a real property context, the statute of frauds requires any contracts to be in writing, not oral. Furthermore, whether or not these writings are recorded in the public records at the local courthouse is not important for statute of frauds purposes. However, it is very important when it comes to determining if a subsequent purchaser is a *bona fide* purchaser for value if there is a duplicate conveyance of the same interest.

OGMLs are generally executory contracts, meaning that only the lessor need sign it for it to be effective. The payment and acceptance of consideration by the lessor, delivery of the instrument to the lessee without rejection, and further actions upon it by the lessee make it mutual. Usually, consideration for an OGML is in the form of a draft or check. Although drafts are slowly being phased out due to bank and lessor reluctance to accept them along with their redemption costs, they still play an important role in leasing. Drafts generally are not payable until certain conditions are met, i.e. the lease has been signed, the title has been researched, etc. Most drafts come with 10 to 90 day wait periods to allow for all the conditions to be met before the bank will release the funds.

However, once an OGML has been signed and accepted, to change it technically requires the signature of both lessor and lessee, even to correct a simple typographical error. Changes to an OGML can be made by a variety of instruments: amendment to the original OGML, correction of the original OGML, taking a new lease, releasing the original OGML, or a combination of these.

An important distinction needs to be made between conditions and covenants. Conditions which are breached can terminate the lease. Covenants that are breached simply allow for an action for damages and generally will not cause a lease to terminate. For example, the remedy for nonpayment of royalty is an action for damages; not an action for forfeiture of the lease. In Texas, it is well settled that failure to pay royalties normally does not result in termination of the lease, but rather, merely an action for damages. However, failure to properly pay delay rentals, if required, is a condition resulting in forfeiture. As a result, most if not all Texas OGMLs are "paid-up" leases, effectively paying in advance all delay rentals so that the harsh penalty of lease termination for failure to pay delay rentals is eliminated.

Canons of construction

Typically, the lease is strictly construed against the lessee as the drafter and one with the upper-hand as to knowledge of the terms. This determination is based on the many canons of construction. These determinations include canons that: (a) instruments are construed against the party preparing the instrument; (b) that typewritten or handwritten provisions prevail over inconsistent printed provisions; (c) that in the event of conflict between provisions, specific provisions prevail over general provisions; and (d) that general words that follow specific words will be interpreted by the rule of *ejusdem generis* to refer to things of the same kind as those described by the specific words. There are many other such canons and some actually conflict with others.

Canons of construction are not rules of law, but rather are statements of judicial preference. Because the choice and use of canons of construction is discretionary with the courts, results are sometimes inconsistent. Although the stated purpose of the use of canons is to ascertain the intent of the parties, many applications of canons actually defeat the intent of the instrument. They are really used when the parties' intent is not so clear on the face of the instrument. There seems to be an inverse relationship between a court's desire to allow in extrinsic evidence beyond the four corners of a document and a court's application of the canons of construction. When courts allow extrinsic evidence to be admitted into evidence, their reliance on canons of construction are minimized.

The Four Corners canon is the primary canon of construction. Courts look to the four corners of the instrument at the very beginning of their analysis to determine the intent of the parties. Where possible, courts attempt to harmonize the various clauses of the instrument by seeking to ascertain objective evidence of the parties' intent from the instrument. Where the Four Corners canon has failed to provide clear evidence of the parties' intent, only then do courts begin to rely on the other canons of construction—these other canons are really regarded as "secondary" canons. The following are widely considered secondary canons:

a) The Greatest Estate canon states that a deed that does not specifically limit the size or nature of the interest conveyed will be interpreted as conveying everything that the grantor owns. Thus, the grantor will convey all the grantor owns except for those things specifically reserved;

b) The In Sequence canon allows the court to interpret the language reciting what was granted before they interpret the language telling what was reserved. Therefore, the effect of each part of the conveyance is determined in sequence without reference to other parts of the document. So, when a clash between the language in the granting clause and reservation clause exists, then using positioning the

granting clause will trump the reservation clause; and

c) The Literal Interpretation canon requires that the words of a conveyance be given their literal, technical meaning. In this case, the canon assumes that the drafter knew exactly what he or she wanted to grant or reserve and thus did so properly.

Parts of the Texas Oil, Gas & Mineral Lease Explained

Underlines and borders added for visual emphasis only

1. **Lease Type**

The most common form of OGML in Texas is often referred to as the *Producer's 88*. In its preprinted form, people familiar with the lease may rely on it (and this portion of this chapter uses the most common terms within a lease). However, today, many landmen print out what claims to be a Producer's 88 on a computer which may or may not conform strictly to the original, pre-printed form. Therefore, it is always necessary to ready every non-pre-printed lease word-for-word. A simple changed comma or word can change the meaning of an important covenant or condition.

Producers 88 (4-89) Paid Up Special

With 640 Acres Pooling Provision
TEXAS STANDARD FORM

2. **Title**

There are many types of leases. If a lease is not paid up, it is the responsibility of the lessee to timely pay additional rentals annually. This creates an unnecessary administrative burden on the lessee. Rubrics really do not matter because the language of the body of the lease is controlling.

PAID UP OIL AND GAS LEASE

3. **Effective Date**

If an effective date is not listed, then the execution date is the effective date.

THIS LEASE AGREEMENT is made and effective as of the 28th **day of July, 2006**, between**,**

4. **Parties**

Getting the parties and capacities right is of utmost importance and can cause an otherwise valid lease to fail. See "Execution of Documents" for a definitive explanation of the proper forms of naming.

John Smith, husband of Betty Smith, dealing with his separate property, whose address is: **4423 Tonca St., Pasadena, Texas 77504,** as Lessor (whether one or more),**XYZ LAND SERVICES, INC., A Texas Corporation,** whose address is: **1500 Fiduciary Street, Somewhere, Texas 75001,** as Lessee.

5. **Draftsmanship**

The drafting of an instrument is usually construed against the drafter because the drafter had control of the language inserted in the instrument. This clause mitigates that rule of law.

6. **Consideration**

Without valid consideration, a conveyance is void. Consideration is an exchange of something valuable, usually cash, but can be a swap or for love and affection (donation). Failure of consideration will kill a conveyance. Usually, it is inconsequential that the consideration is stated at a lower amount (usually $1 or $10) than the actual transaction amount (the bonus). However, a lease usually also recites "…and other valuable consideration" (or "OVC") just in case a low dollar amount is determined insufficient enough to constitute adequate consideration.

> In consideration of a cash bonus in hand paid and the covenants herein contained, Lessor hereby grants, leases and lets exclusively to Lessee the following described land, hereinafter called leased premises:

7. **Legal Description**

See "Legal Descriptions" elsewhere in this chapter.

> Property Description
> 2.48 acres of land, more or less, a part of the David Cook Survey, A-19, Nacogdoches County, Texas, situated about 13 miles west of the City of Nacogdoches, described as Tract 4, Exhibit "D", in a Correction Partition Deed being a part of the residue of 49.5 acres from H.L. Ball to W.C. Smith, dated December 27, 1945, recorded in Vol. 169, Pg. 354, Deed Records of Nacogdoches County, Texas. Herein, being 2.48 acres, more or less.

8. **Special Provisions**

This is where riders are added or changes are made to the existing lease, but most often a statement is made to see the Exhibit.

> **Special Provisions - FOR ADDITIONAL LEASE PROVISIONS SEE EXHIBIT "A" ATTACHED HERETO AND MADE A PART HEREOF.**

9. **Situs, Gross Acreage, Mother Hubbard, Reversion, Purpose, Supplemental Instruments, After-Acquired Title**

Where does the property lie? How many gross acres? Why do we state gross acres instead of net acres? Where do we get this number? What is the lease for? What is reversion? Three types of Mother Hubbard: (1) Strips and gores; (2) All parcels adjacent or contiguous; or (3) Combination Hubbard and After-Acquired Title. Basically, the Mother Hubbard clause lets one include that small pieces of land not necessarily covered by record title to be included in the leased premises such as road right-of-ways, property acquired by adverse possession, improper descriptions and surveys.

Said lands being located in the county of **Smith**, State of Texas, containing **2.48** gross acres, more or less (including any interests therein which Lessor may hereafter acquire by reversion, prescription or otherwise), for the purpose of exploring for, developing, producing and marketing oil and gas, along with all hydrocarbon and nonhydrocarbon substances produced in association therewith. The term "gas" as used herein includes helium, carbon dioxide and other commercial gases, as well as hydrocarbon gases. In addition to the above-described leased premises, this lease also covers accretions and any small strips or parcels of land now or hereafter owned by Lessor which are contiguous or adjacent to the above-described leased premises, in consideration of the aforementioned cash bonus, Lessor agrees to execute at Lessee's request any additional or supplemental instruments for a more complete or accurate description of the land so covered. For the purpose of determining the amount of any shut-in royalties hereunder, the number of gross acres above specified shall be deemed correct, whether actually more or less.

ITEMS 3, 4, 6, 7, 8, & 9, above, taken together are considered the Granting Clause.

The Granting clause must address at least three factors that interact to determine the breadth of the rights granted: (1) What rights are given to use the land; (2) What substances are covered; and (3) What land and what interests are subject to the lease.

10. **Habendum, Primary Term, HBP, Paying Quantities**

How many years for primary term? This clause also implies that a well must be "commenced" within the primary term. What do they mean by commenced? Do you need to be drilling? No. Almost any action, done in reasonably and in good faith will suffice. For instance, placing a location stake, along with reasonable action thereafter will usually suffice. What is "paying quantities"? In Texas, "production" means being sold.

The primary term of the lease is the time that the lease is valid without having to drill a well. Usually a three year primary term is common, however, one can find five and even ten year primary terms, as well as six months or one year. The primary term allows the operator ample time to drill a well on a tract of land. There are many pre-drilling issues that require a considerable amount of time.

The habendum clause, also known as the secondary term clause, states that if a well is producing at the end of the primary term (or at least operations to drill a well have started) then the lease continues in effect until production ceases permanently (or, if operations to drill a well have begun that it is completed as a producing well within a reasonable time).

Often the habendum clause is modified by the shut-in, temporary cessation of production, or force majuere clauses..

This lease, which is a "paid-up" lease requiring no rentals, shall be in force for a primary term of three **(3)** years from the date hereof, and for as long thereafter as oil or gas or other substances covered hereby are produced in paying quantities from the leased premises or from lands pooled therewith or this lease is otherwise maintained in effect pursuant to the provisions hereof.

11. **Royalty/In-Kind, Taxes, Shut-in**

Gas transportation costs are usually deducted from the royalties for gas. Royalties, by their own nature, are free of drilling and operating costs, but not those after the well gets to the wellhead. Unlike failure to pay delay

rentals, failing to pay a royalty, even intentionally, is not cause for terminating a lease, only for the recovery of damages. Failure to pay royalties is common if there is a dispute over ownership. However, in Texas, after being more than 60 (for oil) or 90 (for gas) days late, the Lessor is entitled to interest—only if there is no dispute as to ownership.

Perhaps the most important term in an OGML for both Lessor and Lessee is the royalty. The royalty gives the mineral owner a share in production equal to the royalty. For example, a 3/16ths royalty would give the mineral owner a cost-free 3/16ths value of the production and the operator would get the remaining 13/16ths. The royalty, in a "standard" lease is free of the cost of lease acquisition and drilling costs; however, the costs for transportation, marketing, compression, treatment, and the like are shared between Lessor and Lessee, unless otherwise negotiated. Furthermore, when tracts are unitized and leases are pooled, these fractional royalties become further divided and usually requires a Division Order Analyst to keep under control.

Why would a well be shut-in? The usual reason is because the well has come in successfully, but pipelines from the well to the marketing point have not been completed. Why would an operator lay a pipeline prior to determining if the well will be good? Other common reasons to shut in a well include reworking well problems, searching for alternate markets, and low market value.

12. Payment Address and Method

Where do you want us to send the money? This clause states specifically where royalties are to be sent. If this were not a paid-up lease and delay rentals were expected, this would be much more important to get right.

> All shut-in royalty payments under this lease shall be paid or tendered to Lessor **DIRECT TO LESSOR AT ABOVE ADDRESS** or its successors, which shall be Lessor's depository agent for receiving payments regardless of changes in the ownership of said land. All payments or tenders may be made in currency, or by check or by draft and such payments or tenders to Lessor or to the depository by deposit in the U.S.Mails in a stamped envelope addressed to the depository or to the Lessor at the last address known to Lessee shall constitute proper payment. If the depository should liquidate or be succeeded by another institution, or for any reason fail or refuse to accept payment hereunder, Lessor shall, at Lessee's request, deliver to Lessee a proper recordable instrument naming another institution as depository agent to receive payments.

13. Cessation of Production, Additional Drilling Obligation

Once a well is drilled, what can cause the lease to fail? How to save the lease? Once a satisfactory well has been drilled, what are the Lessee's further obligations? The Lessee's diligence in trying to restore production is clearly an important factor when considering whether cessation of production is temporary or permanent.

If Lessee drills a well which is incapable of producing in paying quantities (hereinafter called "dry hole") on the leased premises or lands pooled therewith, or if all production (whether or not in paying quantities) permanently ceases from any cause, including a revision of unit boundaries pursuant to the provisions of Paragraph 6 or the action of any governmental authority, then in the event this lease is not otherwise being maintained in force it shall nevertheless remain in force if Lessee commences operations for reworking an existing well or for drilling an additional well or for otherwise obtaining or restoring production on the leased premises or lands pooled therewith within 90 days after completion of operations on such dry hole or within 90 days after such cessation of all production. If at the end of the primary term, or at any time thereafter, this lease is not otherwise being maintained in force but Lessee is then engaged in drilling, reworking or any other operations reasonably calculated to obtain or restore production therefrom, this lease shall remain in force so long as any one or more of such operations are prosecuted with no cessation of more than 90 consecutive days, and if any such operations result in the production of oil or gas or other substances covered hereby, as long thereafter as there is production in paying quantities from the leased premises or lands pooled therewith. After completion of a well capable of producing n paying quantities hereunder, Lessee shall drill such additional wells on the leased premises or lands pooled therewith as a reasonably prudent operator would drill under the same or similar circumstances to (a) develop the leased premises as to formations then capable of producing in paying quantities on the leased premises or lands pooled therewith, or (b) to protect the leased premises from uncompensated drainage by any well or wells located on other lands not pooled therewith. There shall be no covenant to drill exploratory wells or any additional wells except as expressly provided herein.

Just because you get your answer does not mean it gets changed in the next sentence, next paragraph, or even the Exhibit. What is the biggest unit allowed in this lease? Is that a good or bad idea? What must the operator do to form a unit? This clause describes how royalties are to be shared in pooling situations. What is a cross-conveyance?

Lessee shall have the right but not the obligation to pool all or any part of the leased premises or interest therein with any other lands or interests, as to any or all depths or zones, and as to any or all substances covered by this lease, either before or after the commencement of production, whenever Lessee deems it necessary or proper to do so in order to prudently develop or operate the leased premises, whether or not similar pooling authority exists with respect to such other lands or interests. The unit formed by such pooling for an oil well which is not a horizontal completion shall not exceed 80 acres plus a maximum acreage tolerance of 10%, and for a gas well or a horizontal completion shall not exceed 640 acres plus a maximum acreage tolerance of 10%; provided that a larger unit may be formed for an oil well or gas well or horizontal completion to conform to any well spacing or density pattern that may be prescribed or permitted by any governmental authority having jurisdiction to do so.

14. **Pooling, Proportional Royalty**

Be sure to read every line of the lease.

15. **Proportionate Reduction**

Here is where the gross acres/net acres distinction is figured out. This clause takes the gross acres that the instrument purports to lease from the Lessor who may not own a full 100% interest, and reduces the amounts payable under the lease to that proportion which it does own. Permits Lessee to reduce lease benefits to the extent that the Lessor owns less than the full mineral interest described.

> If Lessor owns less than the full mineral estate in all or any part of the leased premises, the royalties and shut-in royalties payable hereunder for any well on any part of the leased premises or lands pooled therewith shall be reduced to the proportion that Lessor's interest in such part of the leased premises bears to the full mineral estate in such part of the leased premises.

16. **Permission to Assign, Notice Requirements, Death of Lessor**

"Now that I've signed a lease, what can I do with my land?" What really happens when there is a change in ownership of the minerals? This paragraph is for contingency planning when there is a change of ownership.

> The interest of either Lessor or Lessee hereunder may be assigned, devised or otherwise transferred in whole or in part, by area and/or by depth or zone, and the rights and obligations of the parties hereunder shall extend to their respective heirs, devisees, executors, administrators, successors and assigns. No change in Lessor's ownership shall have the effect of reducing the rights or enlarging the obligations of Lessee hereunder, and no change in ownership shall be binding on Lessee until 60 days after Lessee has been furnished the original or certified or duly authenticated copies of the documents establishing such change of ownership to the satisfaction of Lessee or until Lessor has satisfied the notification requirements contained in Lessee's usual form of division order.

17. **Release**

The Lessee is able to release any or all of the leased acreage at any time, and by doing so is relieved of its obligations as to those portions released.

18. **Right of Ingress/Egress, Right to Conduct Operations, Surface Operations**

Bundle of sticks? Accommodation Doctrine? Dominant estate? A lease impliedly creates inherent surface rights to find and develop the minerals, such as (a) the right to use and occupy the surface of the land for purposes reasonably necessary to develop and operate the lease; (b) the right to use and occupy the surface of the land at locations reasonably necessary to develop and operate the lease; (c) the right to use and consume the surface or its products in oil and gas operations. Barring lease language to the contrary, the Lessee can exercise these rights without the Lessor's permission and is NOT required to pay the Lessor for surface damages nor restore the surface at the end of operations. Other inherent duties include the duty to (a) protect against drainage, (b) drill additional wells if the first one was successful, (c) to market the product, and (d) to operate diligently and properly. However, there is NOT a duty to drill an initial exploratory well.

10. In exploring for, developing, producing and marketing oil, gas and other substances covered hereby on the leased premises or lands pooled or unitized therewith, in primary and/or enhanced recovery, Lessee shall have the right of ingress and egress along with the right to conduct such operations on the leased premises as may be reasonably necessary for such purposes, including but not limited to geophysical operations, the drilling of wells, and the construction and use of roads, canals, pipelines, tanks, water wells, disposal wells, injection wells, pits, electric and telephone lines, power stations, and other facilities deemed necessary by Lessee to discover, produce, store, treat and/or transport production. Lessee may use in such operations, free of cost, any oil, gas, water and/or other substances produced on the leased premises, except water from Lessor's wells or ponds. In exploring, developing, producing or marketing from the leased premises or lands pooled therewith, the ancillary rights granted herein shall apply (a) to the entire leased premises described in Paragraph 1 above, notwithstanding any partial release or other partial termination of this lease; and (b) to any other lands in which Lessor now or hereafter has authority to grant such rights in the vicinity of the leased premises or lands pooled therewith. When requested by Lessor in writing, Lessee shall bury its pipelines below ordinary plow depth on cultivated lands. No well shall be located less than 200 feet from any house or barn now on the leased premises or other lands used by Lessee hereunder, without Lessors consent, and Lessee shall pay for damage caused by its operations to buildings and other improvements now on the leased premises or such other lands, and to commercial timber and growing crops thereon. Lessee shall have the right at any time to remove its fixtures, equipment and materials, including well casing, from the leased premises or such other lands during the term of this lease or within a reasonable time thereafter.

19. **Force Majeure**

"If it's not my fault, no one can hold it against me." This provision protects the lessee from temporary interruptions of performing its obligations from acts of God, governmental regulation, natural disasters, and the like, which are outside its control.

20. **Top Lease Prevention/Notification/Right of First Refusal**

How realistic is this provision? This provision, if included, would require the Lessor to give notice of top lease offers and a right of first refusal to match any offers.

21. **Litigation Notice, Remedy of Breach**

Termination of the lease is not favored by the courts.

13. No litigation shall be initiated by Lessor with respect to any breach or default by Lessee hereunder, for a period of at least 90 days after Lessor has given Lessee written notice fully describing the breach or default, and then only if Lessee fails to remedy the breach or default, within such period. In the event the matter is litigated and there is a final judicial determination that a breach or default has occurred, this lease shall not be forfeited or cancelled in whole or in part unless Lessee is given a reasonable time after said judicial determination to remedy the breach or default and Lessee fails to do so.

22. **Warranty of Title/Subrogation**

General warranty language? If the Lessor owes money for prior encumbrances on the land, then the Lessee has the right to pay these costs and reimburse itself from Lessor's royalties. With a general warranty, grantor claims he or she will defend title against anyone. Many sophisticated Lessors desire to strike this clause, because if there is a title mistake discovered, the Lessee would technically have cause to seek reimbursement of any payments made to Lessee in case of title failure (royalty, bonus, shut-ins, etc.).

14. Lessor hereby warrants and agrees to defend title conveyed to Lessee hereunder, and agrees that Lessee at Lessee's option may pay and discharge any taxes, mortgages or liens existing, levied or assessed on or against the leased premises. If Lessee exercises such option, Lessee shall be subrogated to the rights of the party to whom payment is made and, in addition to its other rights, may reimburse itself out of any royalties or shut-in royalties otherwise payable to Lessor hereunder. In the event Lessee is made aware of any claim inconsistent with Lessor's title, Lessee may suspend the payment of royalties and shut-in royalties hereunder, without interest, until Lessee has been furnished satisfactory evidence that such claim has been resolved.

23. **Witness and Binding**

Lease is effective as to all successors.

IN WITNESS WHEREOF, this lease is executed to effective as of the date first written above, but upon execution shall be binding on the signatory and the signatory's heirs, devisees, executors, administrators, successors and assigns, whether or not this lease has been executed by all parties hereinabove named as Lessor.

24. **Signature Block**

This information must match the information in the parties block at the top of the lease.

LESSOR (WHETHER ONE OR MORE)

JOHN SMITH, dealing in his separate property

25. **Acknowledgement**

Be sure to follow the proper form of acknowledgement based on the Texas requirements. Although states are required to accept notarizations from other states, it is often good practice to make your acknowledgement conform to the state in which you filing even when the notarization occurs in another state. Texas has less formal notarial language requirements than many other states.

STATE OF TEXAS
COUNTYOF _____}

This instrument was acknowledged before me on the _____day of _____, 2006,by **JOHN SMITH**.

_____

Notary Public, State of Texas

26. **Exhibit (Part of Document)**

This rubric (heading) is not really part of the instrument-they are ancillary. Occasionally, you will even see a paragraph stating that rubrics are not a part of the document.

Exhibit "A"

Attached to and made a part of that certain Oil, Gas and Mineral Lease dated **July 28, 2006**, between **JOHN SMITH,** as Lessor and **XYZ LAND SERVICES, INC**., as Lessee.

Additional Lease Provisions

27. **Paid Up Provision**

No further rentals are due because they are paid in advance when a paid-up lease is used. This saves the Lessee from considerable administrative and accounting headaches. Otherwise, the lease WILL fail if the delay rental is not paid (a) in the proper amount, (b) on or before the due date, (c) to the proper persons, or (d) in the proper manner. Most current leases draft around this issue even if it is not "paid-up."

28. **Royalty Substitution**
Very common lease rider.

> 1. ROYALTY: Wherever the term "one-eight (1/8)" appears in paragraph 3 of the printed form of this lease the term **"one-fifth (1/5)"** shall be substituted.

29. **Option to Extend**
This is also a common rider. Basically, this allows you to extend the primary term for X years for a fee, usually tied to the bonus amount. This covers any "what-if scenarios." Instead of paying more up front for a 5 year lease, you pay for 3 now and 2 more later, but only if you need them.

> OPTION TO EXTEND: This lease may be extended for an additional two (2) years from the expiration of the initial primary term by Lessee's tender to Lessor (at Lessor's address) an amount equal to **$150.00** per net acre for all or any portion of the leased premises. Tender must be made within 30 days of the expiration date of the initial primary term.

30. **Horizontal Pugh Clause**
This is almost always expected in any modern lease. This clause is a negotiated compromise, between the lessee who wants a pooling clause in the lease and the lessor who does not. The Pugh clause modifies the pooling clause. Today there are several variations of Pugh clauses, but the basic idea common to all is that the Pugh clause provides that operations or production from the pooled unit will not preserve the whole lease. Rather, such operations or production will only preserve that portion of the lease which covers land in the pooled unit. A Pugh clause, in effect, severs the unpooled acreage from the pooled acreage. This is a valuable clause for the Lessor. The more acreage lessor has to lease, the more important it is for him to have a Pugh clause in his or her lease.

> PUGH CLAUSE: Notwithstanding anything to the contrary contained herein, at or after the end of the primary term, the commencement of operations for drilling or reworking of a well, or the production of oil, gas or other minerals from any well situated on lands included within a unit embracing a portion of the leased premises and other lands not covered hereby shall only serve to maintain this lease in force as to that portion of the leased premises embraced in such a unit.

31. **Exhibit Signed for Identification**
This is not required but is good to include in case there is a controversy over an alleged slipping-in of special provisions which the lessor did not agree to. Even when multiple lessors sign the lease, only one signature is necessary here.

> SIGNED FOR IDENTIFICATION:
>
> _____
>
> **John Smith**

Common Texas lease riders

Most often, OGMLs contain a variety of lease riders tacked onto the back of the lease. These riders are simply added-on conditions or covenants negotiated between lessor and the leasing agent that change the pre-printed lease form. Below is a list of common and not-so-common riders with common strikeouts shown:

Actual surface damages/ surface restoration—*to pay for or restore the surface.*
Should Lessor suffer damage to livestock, water wells, fences, roads, personal property,

buildings or other improvements as a result of operations of Lessee under this lease, Lessee agrees to pay Lessor the actual amount of the said loss.

Shut-in limitation—*maximum time to allow the shut-in of a well.*

Notwithstanding anything to the contrary contained herein, in the event a gas well is completed capable of producing gas but which is not being produced, this lease may not be maintained in effect for a period exceeding two years beyond the primary term hereof under the shut-in gas provisions included above.

or

This lease shall not be maintained by the payment of shut-in royalties as provided for in Paragraph No. _____ hereof for any period of more than two (2) consecutive years following the shutting in of a well, but this right to maintain this lease for such period of time shall be a recurring right and may be exercised at any time and from time to time whenever Lessee finds it necessary or expedient to shut-in such well or wells.

Change of pre-printed royalty.

Notwithstanding anything in this lease to the contrary, royalty on oil and gas shall be one-fifth (1/5) of oil and gas produced and saved under the terms of this lease, and wherever in Paragraph 3 of this lease the fraction one-eighth (1/8) appears, same shall be deemed to read one-fifth (1/5).

Depth limitation—*to predetermine the depth of the lease.*

It is understood and agreed that this lease covers and includes only those formations lying deeper than the depth of 7,000 feet below the surface of the earth, all formations lying above 7,000 feet below the surface of the earth being excluded from this lease and reserved to Lessor. However, Lessee shall have the right to use the surface of said land for all purposes of this lease, and shall have all easements from the surface of the earth to the depth of 7,000 feet in order to conduct operations hereunder.

or

Notwithstanding anything contained herein to the contrary, it is agreed and understood that this lease does not cover the horizons between the surface of the earth and the base of the formation, which zones are specifically excluded from the terms of this lease; provided however, Lessee is hereby specifically granted the right to use the surface and to drill through such horizons in its search for production from depths below the reserved zones with the further right to produce oil, gas and other hydrocarbons from such deeper horizons through such reserved horizons.

Vertical Pugh clause/severance/deep rights—*to sever depths below those drilled.*

Notwithstanding anything contained in Paragraph _____ or any other paragraph hereof to the contrary, it is understood and agreed that upon the expiration of the primary term, if this lease should be continued by reason of production, then in that event, all rights, covenants and conditions of this lease shall terminate as to all strata, horizons, and land situated one hundred (100') feet below the deepest depth drilled of a well situated on the lease premises or on acreage pooled therewith.

or

It is expressly agreed and provided that any well or wells drilled on the leased premises described herein will earn from the surface of the earth to _____ feet below the deepest well drilled on the land herein described, during the primary term of this lease. It is further agreed and understood that any well or wells drilled on the land described herein may be deepened to deeper horizons, and the said well or wells that are deepened will earn from the surface to _____ feet below the deepest horizon drilled. No well on the land described herein can be deepened past the primary term of this lease.

or

It is agreed and understood that, upon the expiration of the primary term of this Lease, or upon the expiration of the period by which the primary term has been extended by drilling operations, then this lease shall expire as to all rights below 100 feet below the stratigraphic equivalent of the deepest well drilled in any well drilled on the Leased Premises or on a unit with which all or a part of the Leased Premises may be pooled or unitized. Lessee agrees that it will, within sixty (60) days after the expiration of the primary term or said drilling operations, execute and file of record the appropriate act of partial release which will fully release the Lessee's rights in the lease as to all zones, depths and horizons lying below 100 feet below the stratigraphic equivalent of the deepest well drilled, on any well drilled on the Leased Premises or on a unit with which all or apart of the Leased Premises may be pooled or unitized.

Mother Hubbard limitation—*to pick up small parts of land not thought about.*

Notwithstanding anything herein to the contrary, the provision in paragraph _____ beginning "this lease also covers and includes all land owned or claimed …" and ending with "boundaries of the land particularly described above" intends solely to cover fencing and other boundary discrepancies, and is by this paragraph limited to a maximum of three percent (3%) of the _____ gross acres described.

Exclusion of other minerals.

It is specifically understood and agreed that this lease covers only oil, gas, sulfur, and associated liquid or liquefiable hydrocarbons, but this lease does not cover or include any other minerals, with all other such minerals being reserved unto the Lessor herein. Accordingly, the words "oil, gas," when used herein shall mean oil, gas sulfur, and associated liquid or liquefiable hydrocarbons and the words "all other minerals" whenever used herein shall be stricken from this lease so that such "all other minerals" are reserved unto the Lessor.

No Drill Clause (Non-Development)—so that no drilling may take place on a tract

By the acceptance hereof, Lessee agrees that no drilling, prospecting or mining operations will be conducted, or any structures or any type facilities will be constructed upon the surface of the herein leased premises without the written consent of the Lessor herein; but Lessee shall have the right to prospect, drill, mine and produce said minerals from said land by operations which it may conduct on adjoining or nearby lands through the drilling, operating and maintaining of directional wells or horizontal wells on such adjoining or nearby lands, or by operations which it may conduct upon lands with which the herein leased premises or any part thereof may be pooled.

Consent—*to require lessor consent before some action takes place.*

… Lessee shall not …. on Lessor's land without written consent of Lessor.

Pooling limitation by depth.

It is expressly agreed and provided that units pooled for gas, distillate, and/or condensate shall not exceed 320 acres plus a tolerance of ten percent (10%) for a depth of 9,500 feet or less below the surface of the earth, and shall not include more than 640 acres plus a tolerance of ten percent (10%) for any depth more than 9,500 feet below the surface of the earth.

Pugh Clause (aka Freestone Rider)—*horizontal severance of acreage not unitized*

In the event a portion of the land herein leased is pooled or unitized with other land so as to form a pooled unit or units, operations on or production from such unit or units will maintain this lease in force only as to the land included in such unit or units. This lease as to the land not included in such unit or units,

may be maintained in force and effect during the primary term hereof by the payment of a proportionate part of the rentals provided herein as to the acreage not included in such unit or units, or by the drilling or reworking operations on such acreage or production therefrom, in accordance with the terms and provisions of this lease.

or

Notwithstanding anything herein to the contrary, it is agreed that should Lessee exercise his option to pool or combine any portion of the land covered hereby with other lands, lease or leases as herein before provided, then such operations and production on and in any such pooled unit as herein provided, shall continue this lease in force and effect during or after the primary term as to that portion of the lands covered by this lease, included in such unit or units as herein above provided, but not as to such portion of said lands covered by this lease and not included in any such unit. This lease may be kept in force and effect as to such remainder in any manner elsewhere provided in this lease not inconsistent with this paragraph.

No partial pooling or unitization—*"All or Nothing," all acreage must be in a unit.*

Notwithstanding anything contained herein to the contrary, it is expressly agreed and understood that in the event that Lessee elects to pool or unitize and unitizes any of the leased premises, then all of leased premises will be included in such pool or unit.

or

If, under the provisions of paragraph _____ of this Oil, Gas and Mineral Lease, Lessee pools acreage for gas or oil, it is agreed by all parties hereto that the total mineral acreage described above will be included in such unit.

Combination Pugh and rental clause.

In the event a portion or portions of the land herein leased is pooled or unitized with other land so as to form a pooled unit or units, operations on, completion of a well upon, or production from such unit or units will not maintain this lease in force as to the land not included in such unit or units. The lease may be maintained in force as to any land covered hereby and not included in such unit or units in any manner provided for herein; provided that if it be by rental payments, rentals shall be reduced in proportion to the number of acres covered hereby and included in such unit or units. If at or after the end of the primary term, this lease is being maintained as to a part of the lands by operations on, completion of a well upon, or production from a pooled unit or units embracing lands covered hereby which is not situated in such unit or units and as to which the lease is not being maintained by operations, completion of a well, or production, Lessee shall have the right to maintain the lease as to such land by rental payments exactly as if it were during the primary term, provided that this lease may not be so maintained in force by rental payments more than _____ years beyond the of the primary term.

Release required—*to require a release of lands not held by production.*

If at any time within 2 years after the expiration of the primary term the land covered by this lease is being held solely through production from an oil or gas pooled unit, then Lessee agrees as part of the consideration for this lease, to release all acreage covered by this lease and not included within such pooled unit.

Royalty payment/interest penalty.

Lessee shall commence payment of any and all royalties on the production of oil and/or gas that are owed to Lessor within ninety (90) days after said royalties become due and payable and if Lessee does not commence making said payments within said 90 day period and continue such monthly payments thereafter, then and in that event, Lessee shall pay interest on said unpaid royalties at the rate of 10% per annum. As to each well drilled hereunder, royalty payments shall not become

due and payable until Lessor shall have returned to Lessee a duly executed Division Order directing payment of such royalties.

Free royalty—*No marketing or transportation costs.*
In computing Lessor's royalty, Lessee shall not deduct the cost of treating, garnering, transporting, dehydrating, compressing, extracting, processing, manufacturing, marketing or any other cost, whether similar or dissimilar to those enumerated.

Option to extend—*built-in option to increase primary term of OGML.*
This lease may be extended for an additional two (2) years from the expiration of the initial primary term by Lessee's tender to Lessor (at Lessor's address) an amount equal to $150.00 per net acre for all or any portion of the leased premises. Tender must be made within 30 days of the expiration date of the initial primary term.

Counterparts—*used when multiple signatories are needed who are usually far away.*
This lease may be executed in one or more counterparts which upon combination shall be considered one instrument for the purpose of recording and shall be binding on all parties who sign, regardless of whether or not all parties sign.

Consent of assignment—*so that Lessor can approve the new operator.*
All or part of this lease may not be assigned without Lessor's written consent; however, such consent will not be unreasonably withheld.

Market value clarification.
The term market value or market price as used in this lease shall be deemed to be the price which Lessee received under the terms of any, oil or gas sales contract negotiated as an arms length transaction between Lessee and purchaser, after the date thereof. Notwithstanding this or any other provision in this lease, if the price of oil or gas is regulated by law or any governmental agency, the market value for the purpose of computing royalty shall not be in excess of the price which such law or agency permits Lessee to receive and retain.

Spudding-In/Operations—*defining what constitutes "operations".*
Notwithstanding anything to the contrary contained herein, it is understood and agreed between the parties hereto that wherever the words "operations" or "commencing operations" are used herein, same shall mean actually spudding in for the drilling of a well.

In-Kind —*ability to take oil/gas in-kind based on royalty provided instead of money.*
Notwithstanding anything to the contrary contained herein, it is understood and agreed between the parties hereto that Lessor at his sole risk and expense shall have the right to take his share of royalty on gas in kind, provided that he furnish Lessee with written notice of his intentions at least sixty (60) days prior to effecting this provision.

Favored Nations—*to offer the same deal to Lessor as owners of adjacent properties.*
Should Lessee, its successors or assigns, enter into an Oil, Gas and Mineral Lease affecting lands contiguous to the leased premises, or which form, with the lands leased hereunder, part of a block created for the exploration for and development of oil and gas, which provides for a greater royalty or a greater cash consideration per acre than that provided for herein, then, in that event, Lessee shall immediately pay the difference in cash consideration to Lessor and this lease shall be deemed amended, without further act, to conform to the greater royalty of such lease.

Payment of royalty.
Within ninety (90) days after the commencement of any production under this lease, Lessee shall commence the actual payment of the royalties herein provided.

After the initial royalty payment hereunder, all payments for royalties to be made by Lessee to Lessor hereunder shall be by check delivered to Lessor monthly on or before the thirtieth (30th) day of the second month following the month during which the gas is produced. Any royalty payment not paid when due shall accrue interest at the rate of twelve percent (12%) per annum until paid.

Expanded warranty.
Anything in this lease contrary notwithstanding, the parties further agree that for all purposes of this Lease, the rights granted the Lessee are limited to those owned by Lessor, and Lessor makes no representation or warranty as to its title, or as to its ownership, of the rights or interest in the premises, either expressed or implied, not even as to the return of bonus money or the return of any other payments made to Lessor by Lessee, including, but not limited to, revenue overpayments.

Directed/Stipulated payment—*when Lessor wants royalty paid to someone else.*
Lessors named herein direct Lessee, or its assigns, to disburse monies, whether bonus, rentals, or royalties, accruing under the terms of this lease to _____, and agree that such disbursement will maintain this lease in full force and effect insofar as it affects the interest of said Lessors.

Liability clause.
Lessor grants to Lessee the full and unconditional right of assignment of this oil, gas and mineral lease and does further, upon such assignment, release and relieve the named Lessee of any and all liabilities, responsibilities, and obligations unto Lessor under this lease; however, nothing in this paragraph shall relieve the Assignee of the liabilities, responsibilities, and obligations contained herein.

Roads and alleys.
This lease covers and includes all of Lessor' rights, title and interest in and to any servitudes, rights-of-way, roads, streets, alleys, highways, bayous, streams, coulees, lakes, ditches, etc. public or private, traversing or adjoining the lands described hereinabove, whether or not specifically described.

Right of assignment.
Lessor grants to Lessee herein the full and unconditional right of assignment of this Oil, Gas and Mineral Lease and does further, upon such assignment by Lessee, release and relieve the named Lessee of any and all liabilities, responsibilities and obligations as provided for under the terms hereof; however, nothing in this paragraph shall relieve such Assignee of the liabilities, responsibilities and obligations contained herein and such Assignee, and its successors and assignees, shall not be relieved of the liabilities or obligations under this Lease unless the Lessor has discharged them expressly and in writing. Lessee agrees to furnish to Lessor a copy of any assignment involving the lands described herein, including the address and phone number of said assignees.

Sub-surface Easement.
Lessor/Grantor hereby specifically grants unto Lessee the right to a Sub-Surface Servitude of use through the subsurface of the lands subject hereto for the purpose of drilling a directional well(s) with the bottom hole location of such well(s) being situated either on the Lessor's lands as covered hereby or on lands unitized therewith, including the right to install pipe casing or other equipment necessary to produce oil, gas and associated hydrocarbons from any zone, horizon or interval in which such well(s) may be completed, with Lessee further having the right to drill, rework, plug back, sidetrack or alter such directionally drilled well(s) and the right to re-enter such well(s) and/or re-penetrate any stratum or strata found in said well(s) and to generally conduct all other such

operations as may be necessary or incidental to the directional drilling contemplated herein. The rights herein granted with respect to Lessee's use of the subsurface of the lands covered hereby will remain in full force and effect as long as Lessee/Grantee continues to use these rights, but in the event Grantee eases to use the rights herein granted for one consecutive year, this Sub-Surface servitude shall terminate. Lessee/Grantee will indemnify and hold Lessor/Grantor harmless from any and all damages to Grantor's property caused by the use of this Sub-Surface Servitude and will protect and hold Grantor harmless against any and all claims or demands by third parties arising out of or resulting from grantee's use of the Sub-Surface Servitude granted herein. The consideration paid by Lessee/Grantee is accepted as full and adequate considerations for all rights, options and privileges herein granted.

Seismic—*to allow seismic testing on the property.*
Lessor herein specifically acknowledges and allows seismic testing to be performed on or about his property for the determination of the viability of production of oil, gas, or other minerals. Such information learned during seismic investigation shall be kept confidential and only relayed to Lessee and Lessee's agents, successors and assigns.

Free Gas—*Rarely seen, allows Lessor to have free natural gas from pipeline for home.*
Lessor may take gas from the well for personal use at his residence; however, Lessor is responsible for all costs and liabilities associated with laying pipelines or connecting to Lessee's pipelines. In any event, Lessors shall give 90 days written notice to Lessee prior to commencing construction of any pipeline or connection to Lessee's pipelines.

Top leasing

Often when a lease is nearing the expiration of the primary term, the same Lessee or even another oil and gas company may decide to get a new lease prior to the expiration of the primary term. This new lease is called a *top lease* simply because it sits on top of a pre-existing lease, waiting for the underlying lease to terminate so it may spring into effect. Because the effective date of the top lease may be sometime in the future, usually the same day the underlying lease is set to expire, the top lease will not cloud title. However, some top leases may be poorly written or miscalculate the exact end of the primary term. In this case, the top lease may cloud title or even cause a Rule Against Perpetuities (RAP) problem (see below). Furthermore, if the underlying lease happens to be extended by production, a top lease should either be released or contain language causing it to fail on its own accord, thereby erasing any cloud on title.

Rule against perpetuities (RAP)

This is a complex rule that requires that a future interest must vest, if at all, within 21 years of a life in being. That is, if the interest has the possibility, no matter how slim or unlikely, to vest 21 years after the death of any person or group of persons now living, it is void. Lawyers, judges, and even law school professors alike shy away from serious discussions regarding this complex rule. Often, to explain this rule, law school professors create implausible scenarios such as the "fertile octogenarian" example.

There are cases that hold that AMI agreements to be an option and not subject to the rule against perpetuities; however imprudently drafted top leases can run a serious risk of violating this rule. Often, the reward of top leasing outweighs the risk in creating a possible RAP problem. Simply providing for the termination of an AMI within a fixed time period or requiring a top lease to begin effectively by a certain date or it must fail will usually fix any RAP problem.

Implied covenants

An implied covenant in the oil and gas context is an obligation or benefit not specified in an OGML but held by the courts to be implicit in such lease. There are three major areas in which implied covenants are found: to develop, to protect, and to manage.

Implied covenants cannot be negated by drafting around them using language stating that "there are no implied covenants" because Texas considers this unconscionable. One implied covenant is that the operator must operate as a "reasonably prudent operator." This covenant requires the operator to act as other operators in the industry would act based on the same fact situations.

Implied Covenant to Protect Against Drainage. The lessor grants an OGML to the Lessee to transfer the right to search for, develop, and produce oil and gas from the property, but neither the lessor nor the lessee usually contemplate that operations on other nearby property may cause the oil and gas under the property to be drained away. To prevent drainage from other nearby operators, the reasonably prudent operator may be required to drill replacement wells, re-work existing wells, drill additional wells or off-set wells, seek field-wide regulatory action, or even seek Rule 37 exceptions from the RRC. A lessor is entitled to recover damages from a lessee for field-wide drainage upon proof of substantial drainage of the lessor's land with additional facts that support the reasoning that a reasonably prudent operator would have acted to prevent substantial drainage from the lessor's land.

Implied Covenant to Drill. Texas does not recognize any implied covenant to drill an initial or test well, but it does recognize the implied covenant to develop (drill additional wells after the first one, if it is successful). This covenant does not apply unless and until the OGML enters into its secondary term. This covenant requires that once the lessee has drilled a well and the lease is held by production, the lessee must continue to develop as would a reasonably prudent operator under the circumstances. The reasonably prudent operator standard would additionally require the lessee to have an expectation of obtaining a reasonable profit by drilling more wells. However, an OGML will not be cancelled for breach of an implied covenant without the lessor having first given the lessee notice of the breach and demanding that the terms of the implied covenant be complied with within a reasonable time.

The Implied Covenant to Market. The implied covenant to market requires a lessee to market the production obtained within a reasonable time and at a reasonable price. The reasonably prudent operator, having taken the risk of drilling successfully, should seek to make a profit by marketing. This prudence creates a duty to market the production to the mutual advantage of both parties. Furthermore, the operator must exercise good faith in the marketing of gas, especially if the lessor and lessee are not on equal footing in the marketplace.

Implied Covenant to Operate Diligently and Properly. Every operator is required to industriously explore for minerals and diligently operate any producing well. This notion includes performing such incidental or subsidiary acts as may be reasonably necessary to accomplish the major purpose. Obtaining a drilling permit when an exception may be called for, or obtaining necessary environmental permits, or operating the well in a safe manner would fall under this covenant.

Recording statutes

Texas is a notice state; that means the statute protects a subsequent purchaser who has paid value and has no notice of the prior grant—otherwise known as a *bona fide* purchaser (BFP). To gain the benefit of the recording statute in a notice jurisdiction, an earlier

grantee must record before the completion of the conveyance to a subsequent BFP.

The notice statute grants priority to the subsequent BFP, only if at the time of delivery of the conveyance, the grantee had no notice (actual or constructive) of the prior conveyance. The subsequent BFP is protected against the prior grantee by the notice statute, even if the subsequent BFP never records the subsequent conveyance. A purchaser who has actual knowledge of a prior unrecorded competing conveyance cannot be a BFP against that conveyance and is not protected by the notice statute. In theory, this should work, but in practicality, proving who knew what and when is very difficult. It would be best not to have to rely on the "subsequent BFP without notice" rule.

Formalities of recording statutes. There are a few basic formalities that must be complied with to gain the protection of a recording act. The first and most obvious of these is that the instrument must be in writing. Also, recording an instrument in the wrong county has the same effect as not filing it at all. However, many possible interests in real property will not or cannot be recorded but do affect title to the property. Examples include: adverse possession; community property interest of a spouse who is not the grantee of a deed; resulting and constructive trust deeds; property inherited by intestacy; easement by prescription or necessity; vendor's liens; and the right of reformation or rescission.

In Texas, for an instrument to be properly recorded, it must be eligible for recording, which means it must be authorized by statute to be recorded, and it must be properly acknowledged. An instrument that is not authorized by statute to be recorded, but nonetheless gets recorded is void, has no value as evidence, and does not give constructive notice to anyone—as if it had never existed. The same proves true for an instrument that is not properly acknowledged. An instrument is properly acknowledged if it is signed and acknowledged before an officer authorized to take acknowledgments, for example, a notary public. In some states, attorneys are automatically notary publics, but in Texas, attorneys must follow the same process as anyone else in obtaining a notary public license.

To be protected by the Texas recording statutes, a buyer must be a *bona fide* purchaser (BFP). A BFP is a buyer who, in regard to a certain property, has paid valuable consideration, had no actual knowledge of a prior unrecorded deed, and had no constructive notice another's interest. To further define these terms, *valuable consideration* requires that the buyer paid a *substantial* amount for the property, which can be less than market value, but cannot be nominal or grossly deficient. As a result of these definitions, a gift deed grantee cannot be a BFP because no consideration is paid. In addition, a quitclaim deed grantee cannot be considered a BFP. The term *constructive notice* means notice as imputed by law such as those that a review of all recorded documents affecting the property or a physical inspection of the property would show.

Statute of frauds

The statute of frauds usually has four requirements when it comes to contracts. To satisfy the statute of frauds, a contract must contain the names of the parties, the important terms of the agreement, a reasonably certain description of the subject matter, and the signature of the granting party.

The statute of frauds relating to conveyances in Texas provides that no leases, estates, or interests in land are enforceable unless in writing and signed by the grantor. Thus, mortgages, OGMLs, deeds of trust, assignments, and the like all fall within the statute of frauds.

Elements of a deed

The essential elements of a deed are that it (1) be in writing, (2) contain words of grant, (3) involve a competent grantor, (4) identify the grantee, (5) provide for consideration, (6) contain an adequate legal description, (7) be signed by the grantor, and (8) be delivered to the grantee. In addition, a deed may include warranties, recitals of encumbrances, the date, witnesses and acknowledgement, among other details.

Types of records

County Records. Maintenance of certain types of records is mandated by law, but most county clerks have used considerable discretion in how the records are organized and maintained. Before 1980, county clerks were required to maintain separate volumes of books with corresponding indices for

- Deed records (beginning in 1836),
- Oil and gas lease records (beginning in 1917),
- Abstract of Judgment Records (beginning in 1879),
- Deed of Trust Records (beginning in 1879),
- Federal Tax Lien Records (beginning in 1923),
- Financing Statements (beginning in 1966),
- Lis Pendens Records (beginning in 1905),
- Mechanic's and Materialmen's Lien Records (beginning in 1939),
- Release Records (beginning in 1836),
- State Tax Lien Records (beginning in 1961),
- Utility Security Records: (beginning in 1966),
- Vendor's Lien Records (beginning in 1879),
- Birth Records and Death Records (beginning in 1903;[3],
- Marriage Records (beginning in 1837), and Probate Records (beginning in 1836).

All of the above described records are accessible by separate direct and reverse grantor/grantee indices.

Beginning in 1980, most county clerks in populated counties started microfilming records and consolidated books/indices into an *Official Public Records of Real Property,* which includes real property; personal property and chattels; and governmental, business and personal matters. Furthermore, county clerks must also maintain the following records of court: probate; county/civil; criminal; Commissioner's.

The jurisdiction to litigate title to land is in the hands of the district court. As a result, *lis pendens* records and the District Clerk's index of litigation should be reviewed for records related to property titles.

Taxes and tax records

County Records. In addition, the tax assessor or collector of each county maintains a current list of all surface owners and owners of producing oil and gas interest, but Texas does not tax minerals which are not being produced. However, the tax assessor or collector's records can usually provide a current address for all surface owners and owners of producing minerals and be helpful in locating previous or potential lessors. This tax office can also identify any taxes due on the property that might be important in case of a potential tax sale due to default.

Oil and gas production is taxed *ad valorem* (according to value) as are property taxes payable to the tax assessor. The reason why severed minerals are not taxed until they are in production is two-fold: the primary reason is that taxing districts would have too much

[3] Beginning in August 29, 1929, all County Clerks forwarded a copy of Birth Certificates and Death Certificates to the Bureau of Vital Statistics in Austin.

research to do to determine who owned the minerals; the secondary reason is that the owners of the mineral estate may not have the money to pay for the *ad valorem* taxes because they are not receiving any payments from production. When oil and gas production does occur, the operator must pay his or her fair share of taxes, necessitating the operator to pass on the royalty owner information to the taxing district. That is how the taxing district determines the mineral ownership for the purpose of ad valorem taxation.

Out of county records. In Texas, it is not as easy to determine if the state owns any minerals from the patent because the patent may not fully describe its ownership. To really find out whether the state owns any minerals from the inception of title, Texas has a series of Relinquishment Acts that specify if any minerals are reserved by the state based on the date of the patent. Before September 1, 1895, the state made no reservations. After and including September 1, 1895, the examiner must determine whether or not the land was classified as mineral or something else like dry grazing or agricultural, for example. Most of the land patented after 1895 is located in west Texas or the Texas pan-handle. If the land was patented after September 1, 1895, and the land was classified as mineral land, a reservation was made to the state in the following:

a) After and including September 1, 1895, and before August 21, 1931, the state and the surface owner shared equally in all "economic benefits";

b) Between August 21, 1931 and June 19, 1983, the state reserved a non-participating royalty of "1/8 of all sulfur and other mineral substances from, which, sulfur may be derived or produced and 1/16 of all other minerals" including oil and gas; and

c) Beginning June 19, 1931, the state could reserve no less than one-eighth (1/8) of all sulfur and one-sixteenth (1/16) of all minerals, but Texas usually reserves all the minerals.

Well-Bore Assignments

One recent oil and gas instrument under scrutiny in 2007/2008 by the Texas courts is the well-bore assignment. Often, oil and gas companies may sell a single well-bore with no additional leasehold. For years, questions regarding the rights of the well-bore assignee were pondered. Could the assignee move up-hole? Deepen the well? For the most part, assignees acted like they could do almost anything with that vertical hole in the ground. The Texas Supreme Court decided a case which mandated that without otherwise specific language, the well-bore assignee could not deepen the well, but could move up-hole. The case is still under further review and remains undecided as of June 2008, on the issue of up-hole completions because typically since leasehold is not included, up-hole completions may not be allowed by the Texas Railroad Commission (RRC).

Treatment of unleased interests. In Texas, an unleased mineral interest owner may be left out of a voluntary unit; however, the unleased cotenant's property can be included in a unit so long as one cotenant is included. But, unlike normal cotenancy rules, the leasing cotenants do not have to account to the unleased cotenants by virtue of the proportionate reduction clause in the OGML. What happens to the unleased mineral interest owners' share of production? Is he or she simply drained? Is his or her royalty/full production value held in suspense by the operator?

So long as the unleased cotenants are not in the drillsite tract, they can elect to participate in the drilling of the well and become a working interest owner, or they can sit back

and wait for the well to pay out and then get their full share of production. For example, Joe and John own 50% each in a 320 acre tract called Blackacre. Joe signs an OGML for a 1/6 royalty, but John does not. The lease is pooled with other leases and a 640 acre unit is formed. A well is drilled on the adjacent acreage next to Blackacre in the unit. John therefore owns 1/4 of all the acreage included in the unit.

What are John's options? Disregarding the slim possibility that the Mineral Interest Pooling Act applies (see elsewhere in this chapter), John can *participate* in the drilling of the well and pay his ¼ of the costs (based on his ownership). Or alternatively, John can be carried with a penalty by simply waiting until the well has paid out (the operator has recouped all his or her drilling and operating costs), and then he can receive a full ¼ of all the production (based on his ownership), even from subsequent wells on the adjacent property. More likely than not, the operator would simple rather not include Blackacre in the unit at all because ¼ of all production is too high a burden to accept because of the negative effect on the net revenue interest. The final option is that John could still sign a lease.

One must take extra precautions when researching record title to ensure that the operator does not drill upon a tract with an unleased mineral interest owner. In this rare case, the unleased owner is entitled to his or her actual share of production from the beginning of production (before payout and after payout).

Unfound Owners

Occasionally, one may not be able to find an owner of some real property. Often, with intestate succession, records and recollections of remaining family member may not be reliable. Searching using database services on the internet has brought a revolution in the ability to find missing persons. Services like obituaries.com (a free service), ancestry.com (free/pay service), the social security death index (free service), or accurint.com (a pay service) can be extremely helpful. Often when someone has moved out-of-state and died, finding information on that person's heirs is very difficult.

When all else fails, a judicial procedure can be started to obtain a receiver's lease (sometimes called a receivership lease) for oil and gas leasing. Here, the court appoints an attorney *ad litem* (for the purposes of the suit) who represents the missing person. Publication in newspapers must follow with an appropriate time to respond. However, when the time to respond to the publications has expired, the *ad litem* receiver can negotiate a lease on behalf of the missing person. Proceeds from the lease are put into the registry with the county clerk, and if no one claims these funds after a period of time, the monies escheat to the state. Usually, the researcher who performed the search must give an affidavit of all the efforts he or she used to try to find the missing person. Such research should be extensive to give rise to a receiver's lease.

Succession

No discussion of Texas oil and gas law would be complete without taking a cursory look at the common issues dealing with the death of a mineral owner.

Administration. When a mineral owner dies with a will (testament), there are a few types of administrations that can be probated. The most important note is that some executors and administrators can convey and bind real property without court intervention and some cannot. Usually it depends on if the process is labeled as independent or dependant. There are small estate administrations available when the total value of the estate is minimal. One often used form of simple probate is the Muniment of Title. This simple instrument is used to convey title to vehicles and homestead

property when a person dies intestate.

Intestacy.

Rules of Descent and Distribution (sometimes called Intestate Succession)

The applicable rules of descent and distribution in Texas are summarized as follows[4]:

i. Decedent's Community Property
   a. Dies with no children
      i. then all to surviving spouse
   b. Dies with spouse and children
      i. If the decedent died before September 1, 1993 then
         1. the decedent's share of the community to the decedent's children, per stirpes.
      ii. If the decedent died on or after September 1, 1993, then
         1. If all of the decedent's children are of the decedent's marriage to the surviving spouse then
            a. the decedent's share of the community to the surviving spouse.
         2. If at least one or more of decedent's children are not born of the decedent and current spouse then
            a. the decedent's share of the community to all of the decedent's children, per stirpes.

ii. Decedent's Separate Property
   a. Survived by spouse and children then
      i. One-third (1/3) life estate to spouse with remainder in children; two-thirds (2/3) in fee to children (real estate only).

iii. Survived by spouse and no children then
   a. One-half (½) to spouse and one-half (½) to "heirs at law."
      i. "Heirs at law" are:
         1. Surviving parents – one-half (½) each
            a. If only one parent survives, the other one-half (½) to brothers and sisters, *per stirpes*.
      ii. If no parents, brothers, sisters, nieces or nephews, then all to surviving spouse.

If the unmarried person dies intestate and has no surviving heir, the property will escheat to the state of Texas under PROPERTY CODE § 71.001. Texas adopted a rule that provides that half-blooded collaterals receive half shares of intestate property. Furthermore, stepchildren may not inherit from their stepparents under Texas intestacy law (but can certainly inherit under a will). And, if a person dies intestate in another state, the intestacy laws of the situs (place where the property is) decides what happens to that property.

Per stirpes means devised equally based on surviving lineage. For instance, John dies with three children (Alex, Bailey, and Chad) and no spouse. However, Chad predeceased his father, John, but left two surviving children behind. If John's children were to receive per stirpes, Alex would receive one-third (1/3), Bailey one-third (1/3), and Chad's children one-half (½) of one-third (1/3) each. Chad's issue would share equally in his share of proceeds.

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[4] PROBATE CODE, § 45 & 38

Affidavit of heirship.
Often when a person dies intestate (without a will), some documentation is needed in the county records as to the formal identity of the heirs of the decedent. So, in comes the frequently encountered affidavit of heirship. This ancillary probate procedure is set forth in TEXAS PROBATE CODE § 52 and is a statement of facts concerning the decedent's family history, genealogy, marital status and the identity of his or her heirs. The affidavit of heirship's validity is premised upon its being executed by the maker and acknowledged before a notary public, and having been of public record for five (5) or more years in the deed records. Title companies and transfer agents may proceed on the basis of an affidavit of heirship being on record for less than the five (5) year requirement as a business risk. Although most title companies generally require a minimum of three (3) affidavits from totally disinterested persons, sometimes one affiant is all one can get to sign an affidavit—and sometimes this affiant is interested, but the affiant may be the only one with direct knowledge. Often, landmen and title opinion attorneys will rely on these affidavits as a matter of industry standard, even ones more recent than five years. An affidavit of heirship may allow a decedent's heirs to expeditiously transfer title from the decedent's estate consisting primarily of a homestead without resorting to a judicial proceeding. The legislature has provided a statutory form for such affidavits as follows on the next page.

AFFIDAVIT OF FACTS CONCERNING THE IDENTITY OF HEIRS

Before me, the undersigned authority, on this day personally appeared _____ ("Affiant") (insert name of affiant) who, being first duly sworn, upon his/her oath states:

1. My name is _____ (insert name of affiant), and I live at _____ (insert address of affiant's residence). I am personally familiar with the family and marital history of _____ ("Decedent") (insert name of decedent), and I have personal knowledge of the facts stated in this affidavit. ").] [*In a non-statutory probate court, also add the last three digits of each applicant's social security number and driver's license number*].
2. I knew decedent from _____ (insert date) until _____ (insert date). Decedent died on _____ (insert date of death). Decedent's place of death was _____ (insert place of death).
At the time of decedent's death, decedent's residence was _____ (insert address of decedent's residence).
3. Decedent's marital history was as follows: _____ (insert marital history and, if decedent's spouse is deceased, insert date and place of spouse's death).
4. Decedent had the following children: _____ (insert name, birth date, name of other parent, and current address of child or date of death of child and descendants of deceased child, as applicable, for each child).
5. Decedent did not have or adopt any other children and did not take any other children into decedent's home or raise any other children, except: _____ (insert name of child or names of children, or state "none").
6. (Include if decedent was not survived by descendants.) Decedent's mother was: _____ (insert name, birth date, and current address or date of death of mother, as applicable).
7. (Include if decedent was not survived by descendants.) Decedent's father was: _____ (insert name, birth date, and current address or date of death of father, as applicable).
8. (Include if decedent was not survived by descendants or by both mother and father.) Decedent had the following siblings: _____ (insert name, birth date, and current address or date of death of each sibling and parents of each sibling and descendants of each deceased sibling, as applicable, or state "none").
9. (Optional.) The following persons have knowledge regarding the decedent, the identity of decedent's children, if any, parents, or siblings, if any: _____ (insert names of persons with knowledge, or state "none").
10. Decedent died without leaving a written will. (Modify statement if decedent left a written will.)
11. There has been no administration of decedent's estate. (Modify statement if there has been administration of decedent's estate.)

12. Decedent left no debts that are unpaid, except: _____ (insert list of debts, or state "none").
13. There are no unpaid estate or inheritance taxes, except: _____ (insert list of unpaid taxes, or state "none").
14. To the best of my knowledge, decedent owned an interest in the following real property:
_____ (insert list of real property in which decedent owned an interest, or state "none").
15. (Optional.) The following were the heirs of decedent: _____ (insert names of heirs).
16. (Insert additional information as appropriate, such as size of the decedent's estate.)

Signed this ___ day of _____, ___.

_____
(signature of affiant)

State of _____
County of _____

Sworn to and subscribed to before me on _____ (date) by _____ (insert name of affiant).

_____
(signature of notarial officer)
(Seal, if any, of notary) _____
(printed name)_____
My commission expires: _____

REGULATORY

Function of the RRC. The Texas Railroad Commission (RRC) handles the regulatory side of oil, gas, and mineral permitting and was set in place with a mission to protect correlative rights and to assure that production activities continue in an organized, safe manner. The most commonly seen RRC rules are Rule 37 and 38 which deal with the default "state-wide rules" for well spacing and density. Please note that special field rules exist throughout Texas which change these spacing and density rules depending on which field one is operating. To determine if the area in question has special field rules without knowing the name of the field, third-party maps from companies like GeoMap may be necessary.

The Texas RRC is broken up into 12 districts, most with their own local office. One may obtain district records directly from the district office or online using the RRC Online Services over the Internet (back to 1981). As of June, 2008, the districts and office cities are: 1 & 2, San Antonio; 3, Houston; 4, Corpus Christi; 5 & 6, Kilgore; 7B, Abilene; 7C, San Angelo; 8 & 8A, Midland; 9, Wichita Falls; and 10, Pampa. (See next page)

DIST	PHONE#	FAX#	ADDRESS	CITY, ZIP
01 & 02	(210) 227-1313	(210) 227-4822	115 E Travis St., Ste 1610	San Antonio 78205-1689
03	(713) 869-5001	(713) 869-9621	1706 Seamist Dr., Ste 501	Houston 77008-3135
04	(361) 242-3113	(361) 242-9613	P O Box 10307	Corpus Christi 78460-0307
05 & 06	(903) 984-3026	(903) 983-3413	619 Henderson Blvd	Kilgore 75662-5998
7B	(325) 677-3545	(325) 677-7122	3444 N. First St., Ste. 600	Abilene 79603
7C	(325) 657-7450	(325) 657-7455	622 S. Oakes St., Ste. J	San Angelo 76903
08 & 8A	(432) 684-5581	(432) 684-6005	Conoco Towers 10 Desta Dr., Suite 500E	Midland 79705
09	(940) 723-2153	(940) 723-5088	5800 Kell Blvd	Wichita Falls 76310
10	(806) 665-1653	(806) 665-4217	P O Box 941	Pampa 79066-0941

The main office contact information for the RRC Oil & Gas Division, as of June, 2008 is as follows:

OIL AND GAS DIVISION AUSTIN OFFICE

1701 North Congress Avenue
Austin , Texas 78701

P.O. Box 12967
Austin , Texas 78711-2967

(512) 463-7288
(TDD) (800) 735-2989

TITLE	PHONE#	FAX#
Director	(512) 463-6810	(512) 463-7005
Deputy Director	(512) 463-6810	(512) 463-6780
Assistant Director Technical Permitting	(512) 463-6954	(512) 463-6780
Assistant Director Administrative Compliance	(512) 463-6838	(512) 463-6955
Assistant Director Site Remediation	(512) 463-6765	512) 463-2388
Deputy Director Field Operations	(512) 463-6830	(512) 463-7328
Publications/Oil and Gas Forms	(512) 463-6882	
24 Hour Emergency	(512) 463-6788	

The RRC's regulatory guidance is provided by statutes in the TEXAS ADMINISTRATIVE CODE, TITLE 16 (ECONOMIC REGULATION), PART 1 (RAILROAD COMMISSION OF TEXAS), CHAPTER 3 (OIL & GAS DIVISION).

The general regulatory process, in order, is as follows:

- Identification
  - Before beginning any operations, you must file an organization report showing legal identity (corporation, partnership, etc.), principal officers, and addresses. A form of financial security is required. Rule §3.1
    - Complete Form P-5
    - Send to RRC main Austin Office
- Permitting
  - Size and Shape
    - Standard Size and Shaped Tract -Attach a plat and a check for the appropriate fee based on total depth, payable to the State Comptroller. Send the original form and fee to Austin. Send a copy of the form and plat to the appropriate District Office. An additional fee is required for statewide rule exceptions. Rules §3.5, §3.37, & §3.78 - Complete Form W-1
      - Send to RRC main Austin Office and District Office
    - Non-Standard Size and Shaped Tract submit this additional form if your tract is sub-standard or non-standard size or shape under applicable spacing and density rules. A fee is required for rule exceptions. Rules §3.37, §3.38, & §3.78
      - Complete Form W-1A
    - Send to RRC main Austin Office and District Office
  - Drill, ReComplete, or ReEnter for Directional or Horizontal Wells
    - Application for Permit to Drill, ReComplete, or ReEnter Supplemental Directional Well Information. Rules §3.37, §3.38, & §3.78
      - Complete Form W-1D
      - Send to RRC main Austin Office and District Office
    - Application for Permit to Drill, ReComplete, or ReEnter Supplemental Horizontal Well Information. Rules §3.37, §3.38, & §3.78
      - Complete Form W-1H
      - Send to RRC main Austin Office and District Office
- Pooled Tracts
  - File Form P-12 with the certified plat for each pooled unit. Rules §3.37 & §3.40
    - Complete Form P-12
    - Send to RRC main Austin Office and District Office
  - Sour Gas - File Form H-9 in triplicate 30 days prior to drilling if drilling in potential sour gas zones. Rule §3.36
    - Complete Form P-12
    - Send to RRC District Office
- Drilling (A copy of RRC Drilling Permit must be on drill site at all times)
  - STEP 1 Request information concerning water protection requirements from the Texas Commission on Environmental Quality (TCEQ), formerly known as the Texas Natural Resource Conservation Commission, at (512) 239-0515. Rule §3.13
    - TCEQ, P.O. Box 13087, Austin, TX 78711-3087; Main Switchboard (512) 239-1000
    - A Surface Casing Letter from the TCEQ may be required to specify the depths that must be protected for groundwater.

If one is required, you must provide a location map with abstracted surveys and if plugging or re-entering an existing well it must include a copy of the electric log. This letter must be attached to the RRC Drilling Permit. This letter may be required if:

- Drilling a new oil or gas well as covered by RRC form W-1
- Drilling an enhanced-recovery injection well as covered by RRC form H-1
- Drilling a cathodic protection well
- Drilling a core test hole
- Plugging and abandoning an existing oil or gas well as covered by RRC form W-3A
- Doing a fluid level test on an inactive well as covered by RRC form H-15
- Converting an existing well to a water well as covered by RRC form P-13
- Saltwater Disposal Letter from the TCEQ may be required for a Class II disposal well covered by RRC form W-14
- A Seismic Letter from the TCEQ may be required if you would need to analyze geological features with a seismic shot hole program

- STEP 2 Verify that drilling fluid pits have been constructed in compliance with Rule 8. Maintain careful surveillance of pit conditions throughout remaining operations. Rule §3.8
  - Sour Gas Wells - Verify compliance with Rule 36 prior to drilling potential sour gas zones.Rule §3.36
  - Inclination Determinations Have inclination determinations beginning no deeper than 500 feet below surface and each 500 to 1,000 feet thereafter, depending on bit change. File an original and copy when completed. A directional survey is required when the inclination survey shows excessive deviation. Rule §3.11
    - Complete Form W-12
    - Send to RRC District Office

- Cementing
  - Surface Casing
    - STEP 1 Notify the District Office at least 8 hours prior to running and cementing surface casing. If any deviation from setting the required surface casing is planned, request alternative method in writing prior to drilling. Call RRC District Office. If problems are experienced (cement does not reach surface, etc.), notify District Office for possible corrective measures. Rule §3.13 Call RRC District Office

- STEP 2 Both you and the cementer must fill out and sign portions of Form W-15. File an original and copy with other forms as required. Rule §3.13 Complete Form W-15 and send to RRC District Office
- STEP 3 Install and test blow-out preventer. Rule §3.13

- Intermediate or Production Casing
  - STEP 1 Notify the District Office at least 8 hours prior to running and cementing casing. Rule §3.13 Call District Office
  - STEP 2 Both you and the cementer must fill out and sign portions of Form W-15. File an original and copy with other forms as required. Rule §3.13 Complete Form W-15 and send to RRC District Office
- Completion
  - STEP 1 Install wellhead upon completion - before perforation and testing. Rule §3.13
  - STEP 2 Switch production into tanks once completion fluids have been displaced. Rule §3.8
  - STEP 3 File a Certificate of Compliance to designate gatherer(s). Rule §3.58 Complete Form P-4 and send to RRC main Austin Office
  - STEP 4 If lease tanks have been filled during testing, file Form P-8 - Request for Clearance of Storage Tanks for Authorization of Removal of Fluids with the appropriate district office. Rule §3.58 Complete Form P-8 and send to RRC District Office

- Testing
  - Oil Wells
    - STEP 1 Notify the District Office as soon as you are ready to test the well. Rules §3.16 & §3.51 Call RRC District Office
    - STEP 2 File report in duplicate either within 30 days of well completion or within 10 days of the test showing the 24-hour production capability and gas/oil ratio, whichever is the earlier date. Rules §3.16 & §3.51 Complete Form W-2 and send to RRC District Office
    - STEP 3 For pooled tracts, file Form P-12 and certified plats in duplicate with the W-2 for each pooled unit. Rules §3.31 & §3.40 Complete Form P-12 and send to RRC District Office
    - STEP 4 File a plat in duplicate if special field rules have been granted by hearing. Rule §3.16 Have plat prepared and send to District Office
    - STEP 5 File an electric log status report with all completion reports and with plugging reports on dry holes. If confidentiality is not requested attach the appropriate log. Rule §3.16 Complete Form L-1 and send to RRC District Office
    - STEP 6 Post well and lease identification signs immediately upon assignment of lease number. Rule §3.3
  - Gas Wells
    - STEP 1 Notify the District Office as soon as you are ready to test the well.
      Rules §3.16, §3.28, & §3.31 Call RRC District Office
    - STEP 2 File report in duplicate either within 30 days of well completion or within 15 days of the test showing absolute open-flow potential test, whichever is the earlier date. Rules §3.16, §3.28, & §3.31
    - Complete Form G-1 and send to RRC District Office

- STEP 3 Attach G-5 and Back Pressure Curve to G-1 if 4 point or 1 point potential test is run. Rules §3.16, §3.28, §3.31, & §3.53 Complete Form G-5 and Back Pressure Curve and sent to RRC District Office
- STEP 4 For pooled tracts, file Form P-12 and certified plat in duplicate with the G-1 for each pooled unit. Rules §3.31 & §3.40 Complete Form P-12 and send to RRC District Office
- STEP 5 For acreage allocation, file form in duplicate with the required plat if special field rules have been granted by hearing. (All assigned acreage must be productive.) Rule §3.31 Complete Form P-15 and send to RRC District Office
- STEP 6 File electric log status report with all completion reports and with plugging reports on dry holes. If confidentiality is not requested attach the appropriate log. Rule §3.16 Complete Form L-1 and send to RRC District Office
- STEP 7 Notify the District Office 24 hours prior to conducting your 72-hour deliverability test. Rules §3.28, §3.53, & §3.55 Call RRC District Office
- STEP 8 File an initial deliverability report following testing if the well is connected to a sales line. Rules §3.28, §3.53, & §3.55 Complete Form G-10 and send to RRC main Austin Office

- Production
  - Oil Wells
    - Production Reports
      - Monthly Report production, disposition and/or storage of both oil and casinghead gas. All production on the lease must be measured and reported. Rules §3.27 & §3.58 Online via RRC Online System
      - Annually File a well status report showing a 24-hour test. Most producing one well leases are not required to be tested annually. More frequent tests may be required for wells on commingled leases. Rules §3.26, §3.27, §3.49, §3.52, & §3.53 Complete Form W-10 and send to RRC main Austin Office
  - Gas Wells
    - Production Reports
      - Monthly Report production and disposition of both gas and condensate. All production on this lease must be measured and reported. A PR is not required if the gas well is shown as shut-in on the gas well schedule unless there is stock on hand. Rules §3.27 & §3.54 Online via RRC Online System
      - Semi-Annually File semi-annual 72-hour deliverability test results. Report required information on shut-in and other non-producing wells in accordance with instructions on the form. After initial testing, wells with production and deliverability under 100 MCF per day are exempt from testing unless commingled. Rules §3.28, §3.53, & §3.55 Complete Form G-10 and send to RRC main Austin Office
  - Dry Holes and Inactive Wells
    - STEP 1 File an application for a Rule 14(b)(2) plugging extension if you do not wish to immediately plug the well.

File the P-5PB(2) (Blanket Performance Bond), P-5LC (Irrevocable Documentary Blanket Letter of Credit), P-5PB(1) (Individual Performance Bond), or a W-1X application. (The W-1X requires a fee per well.) Rule §3.14 Complete Form SWR 14(b)(2) and related forms if necessary and send to RRC main Austin Office

- STEP 2 At least five days in advance of plugging operations, file in duplicate a request for approval of proposed procedure for plugging. If the rig is on location, plugging approval may be secured by telephone. NOTE: A current (less than five years old) TCEQ (formerly Texas Natural Resource Conservation Commission) letter showing the depth of fresh water must be on file.(See 3(a)(i) above). Rule §3.14 Complete Form W-3A and send to RRC main Austin Office
- STEP 3 Notify the District Office at least four hours prior to start of plugging operations (a 24-hour notice is requested, if possible). Rule §3.14 Call RRC District Office
- STEP 4 File in duplicate, a completed plugging report within 30 days of plugging, including the W-15 cementing report. (Also file log, if dry hole.) Rules §3.14 & §3.16 Complete Form W-3 and send to RRC District Office

- Clean-Up
  - Reserve or mud pits with chloride concentration of:
    - <u>6,100 mg/L or less</u>: Dewater and backfill within one year of completing drilling. Rule §3.8
    - <u>Over 6,100 mg/L</u>: Dewater within 30 days and backfill within one year of completing drilling operation. Rule §3.8
  - COMPLETION PITS Dewater within 30 days and backfill within 120 days of well completion. Rule §3.8
- Accidents/Blowouts/H_2S Releases
  - STEP 1 For accidents, blowouts, or H_2S releases immediately notify the District Office by telephone. Rules §3.20 & §3.36 Call RRC District Office
  - STEP 2 Write a letter explaining in detail problems encountered and steps taken to resolve the situation. Rules §3.20 & §3.36
    - Write Letter and send to RRC District Office
      i. In the case of a fire, leak, spill, or break causing loss of over five (5) barrels of crude oil, gas well liquids or products, NOTIFY the District Office by telephone and FILE Form H-8 in duplicate when appropriate measures have been taken. Rule §3.20 Call RRC District Office and complete Form H-8 and send to RRC District Office

Railroad Commission rules

No discussion of the RRC is complete without taking a look at Rules 37 and 38. These two rules are staples of the oil and gas industry in Texas. Although other rules are also important, one cannot drill a well without understanding these crucial rules.

Rule 37. Adopted in 1919, Rule 37 establishes the general minimum well spacing rules in the absence of special field rules. Currently, under Rule 37, wells must be at least 467' from any lease, property or subdivision line and 1,200' between each other in the same reservoir. If there are special circumstances, the RRC may grant an exception to Rule 37 to allow wells to be closer to lease lines or other wells. These exceptions require an open hearing. Typical reasons for exceptions are to drill offset wells to prevent drainage, thereby protecting correlative rights.

The main reasons why the RRC would grant a Rule 37 exception are: (a) to allow the operator to locate his or her well-bore directly above the reservoir (geological), (b) to prevent drainage (an unconstitutional taking), and (c) to allow small tracts to produce, albeit on a reduced allowable proportionate to its size.

Rule 38. Rule 38 sets the minimum spacing density per well at 40 acres. Using conventional wisdom at the time, the spacing density was thought as the maximum distance surrounding a well which could be drained by it. Putting wells too closely together simply caused competition between the wells and further reduced the total amount of oil or gas capable of being produced because the more holes drilled into the ground reduced the natural drive mechanisms of the reservoir, generally water or gas drives.

Rule 11. Rule 11 requires that "all wells shall be drilled as nearly as vertical as possible by normal, prudent, practical drilling operations." The rule specifically addresses two classes of wells (a) wells that are intentionally deviated (such as directionally-drilled wells), and (b) wells that are not intentionally deviated but where the cumulative displacement is such that the well-bore could have crossed the lease or property line.

Many more rules and forms exist.

Pooling and unitization

Pooling of leases in Texas is usually accomplished voluntarily due to language in the oil, gas and mineral lease (OGML); however, some are created by the regulatory powers of the Texas RRC. Pooling is simply aggregating a group of leases to obtain in order to form a unit. The OGML usually allows pooled leases to be unitized with a proration of royalties spread across the royalty owners in the unit. Units are created by forming outlines of acreage that conform to the boundaries of a group of leases (called *unitization*).

Although pooling and unitization are distinct concepts with minor but complex differences, because they are so related, these concepts are often and regrettably used interchangeably, even by experts and regulatory agencies. The five types of common units in Texas are:

1) Drilling unit: The acreage area shown on the Form W-1 application for the permit to drill. It is the area shown to establish that the applicant has sufficient unassigned acreage to satisfy the density requirement.

2) Proration unit: The acreage designated on a Form P-15 with an attached plat showing the acreage assigned to the well for proration purposes where field rules provide for the setting of allowables on an acreage basis, in whole or in part. The proration unit is designated after the well is drilled and

completed, and only productive acreage can be assigned to a proration unit. The designation of a proration unit can be changed at any time.

3) Voluntary pooled unit: The most common unit in Texas, is a unit formed by the voluntary joinder of separate ownership interests. A voluntary pooled unit is created by the community lease (where more than one tract is shown on a lease—these are automatically considered *poolable* even without specific language allowing it); pooling under a specific lease pooling clause (modern OGMLs since the 1940s usually include this language as part of the body of the lease); or pooling by agreement of the interest owners in the property to be pooled (an ancillary agreement). Any amount of acreage can be pooled by this kind of pooling agreement.

4) Pooling and cooperative agreements: These are RRC approved units necessary to effect secondary or tertiary recovery operations for oil or gas, usually for water flooding. Gas represssurization and CO2 scrubbing are also legitimate uses. These pooled units do not bind a landowner, royalty owner, lessor, lessee, overriding royalty owner, or any other person who does not execute the cooperative agreement.

5) The forced pooled unit under the Mineral Interest Pooling Act (see heading below).

The purpose of forming a unit is two-fold: (1) to protect the operator from claims for violating correlative rights and anti-trust claims; and (2) to allow a unit operation to form an area large enough to properly drain the oil and gas with several wells. Usually the operator wants to form the largest unit he or she possibly can so the greatest amount of acreage can be held with a single well (as long as it is reasonable and prudent). Holding a unit with a single or a few wells helps operators develop PUDs (proven, but undeveloped well locations) which the operator can sell for a profit without expending any money to develop them. Most units are allowed to be 640 acres (plus 10 percent tolerance, bringing the total to 704 acres); however, unit can be other maximum sizes based on RRC regulation for minimum or maximum size, lease language, geography, or simply the amount of acreage the operator has under lease. Forty acre oil units are common, as are tract wells (simply a well on a single tract). The RRC will allow production for a single tract, even if it is not large enough to satisfy its minimize size requirements; however, that well will be given a reduced *allowable*—allowing it to produce oil and gas, but at a proportionally lesser rate than a well in the same field which has satisfied the minimum size requirements.

Normally the RRC requires that at least 65% of the royalty interest and 85% of the working interest commit to the unit agreement before a hearing on approval will be granted. Importantly, subsurface movement of hydrocarbons and water pursuant to a RRC approved secondary/tertiary recovery operation does *not* result in a trespass. Thus, RRC approval is an important protection for the operator of the unit from lawsuits by arguably adversely affected nearby landowners. Also of note, drilling and proration units have no effect on title—these are simply regulatory depictions.

Mineral Interest Pooling Act (MIPA)/Forced Pooling

Sometimes oil and gas units are formed so that a tract or tracts are left out of a unit and end up being between units, completely surrounded without an opportunity to form its own unit under the existing field rules. Certainly, if the tract can support getting a

drilling rig onto it, Texas cannot deny a tract owner from preventing drainage and drilling his or her own well, albeit with production being reduced in proportion to the relevant field rules. But, drilling an individual's own well is more fantasy than reality. Would it not be better to allow the small tract owners to be able to force their tracts into an existing unit?

Texas does in fact have a forced pooling act; however, it is so rarely used that it might as well not exist. Why is forced pooling seen as important in other states where it is rarely necessary and not in Texas where it can happen more frequently? No one knows. Generally, in other states with township and range surveying, conventional oil and gas units are drawn square based on sectional quadrants. However in Texas, with metes and bounds surveying, having small tracts left out of a unit, and not able to be in any other unit, is a real possibility.

The rules required for application of the MIPA are:

1. The field must have been discovered after March 8, 1961 (the date of the *Normanna* decision);
2. It is not a wildcat well, which do not qualify for forced pooling;
3. Special field rules applicable to the field in which the tract lies must be in place;
4. There must be two or more separately-owned tracts; these cannot be used merely to pool separate interests in the same tract;
5. One of the interest owners with the right to drill must have drilled or proposed to drill a well on the existing or proposed proration unit;
6. The units are limited to 160 acres for oil, and 640 acres for gas, both with a 10% tolerance;
7. State owned lands are not included;
8. Pooling must result in the avoidance of the drilling of unnecessary wells, the protection of correlative rights, or the prevention of waste; and
9. Prior to applying for forced pooling, there must have been a fair and reasonable offer to pool as determined by the RRC.

Division orders and calculating royalties and interests

Role of division order analysts. Division order analysts are in charge of determining what to pay to all the interest owners by calculating their fractional ownership: royalty, overriding royalty, and working interests. Division order analysts may also be required to determine types of interests important to the oil and gas operator. One of the most important interests to calculate is the net revenue interest.

Calculating the net revenue interest

A net revenue of 75% or greater is the usual desire of a lessee and could be considered a *de facto* minimum industry standard. For example, a single lease unit with a one-fifth royalty and an ORRI of 2% would give the lessee a 78% NRI. In addition, net revenue is calculated on a unit basis by accounting for each royalty proportionately to the net acreage it contributes to the unit.

Suppose a 320-acre unit is created out of three tracts: Tract 1 is 200 acres at a 1/5 royalty, Tract 2 is 100 acres at 3/16 royalty, and Tract 3 is 20 acres at 1/4 royalty. Furthermore, in this example, a consulting geologist is given a 1% ORRI and another 2% ORRI is given to the company which put the prospect together by purchasing all the leases. What is the lessee's unit NRI?

Tract NWI
Tr 1 200 acs/320 acs in unit =
.625 X 4/5 = .50000000 Net Working Interest
Tr 2 100 acs/320 acs in unit =
.3125 X 13/16 = .25390625 Net Working Interest
Tr. 3 20 acs/320 acres in unit = .0625 X ¾ = .046875

Unit NWI
Tr 1 .50000000
Tr 2 .25390625
Tr 3..04687500
.80078125 NWI
Unit NWI –Unit ORI = NRI
.80078125 -.03(Total Unit ORI) =
.77078125 NRI

When making calculations for the purpose of division orders or any other real property interests, the *de facto* rule of thumb is to use eight decimal places when determining interests.

Furthermore, division order analysts may have additional accounting-based roles which require them to determine items which may be deducted as expenses from the typical calculations.

Calculating royalties on pooled units. An individual tract may be covered by one or more leases. A pooled unit always involves more than one tract and more than one lease. To pay the royalty due under each lease, the lessee must review each lease along with the pooling agreement or declaration if one is not so included in the OGML, along with any division orders. Production from a unit may be sold under more than one contract. Certainly there is only one market value for the proceeds from the sale of minerals, but an operator may be subject to one or more fixed contracts for the sale price. To further complicate the issue, some of the leases may be proceeds leases and some may contain market value language—making the accounting calculations difficult.

Texas uses the *tract allocation* rule to separate gas sales produced from pooled units. The tract allocation method requires royalty owners to be paid on the basis of the amount received by their individual lessee from the sale by their lessee of the production of gas from the unit allocated to the tract in which the royalty owner owns an interest.

The language in the OGML usually provides for royalty allocation on a surface acreage basis. Thus, the lessee allocates actual production from the pooled unit to each tract on the basis of that tract's surface acreage contribution to the pooled unit. For example, a 64-acre tract in a 640 acre pooled unit would be allocated ten percent of the oil and gas production. So, the lessor of the 64-acre tract should receive royalty on that share of production consistent with the terms of his or her royalty clause.

Types of post-production costs which can be deducted. Without express language in an OGML indicating otherwise, Texas courts allow lessees to deduct post-production expenses regardless if the lease has a market value royalties clause or proceeds royalty clauses. The lessee usually is required to bear all costs of exploration and production, but the expenses after production (downstream) are borne proportionately between the lessor and lessee

Permissible Deductions
Case law in Texas permits the following post-production expenses to be deducted from royalties:

a) gross production and severance taxes; transportation charges;
b) expenses of treatment of make the gas marketable such as hydrogen sulfide removal;
c) expenses of compressing the gas to make delivery into a pipeline; and

d) processing costs incurred in extracting liquids (dehydration), and other value-adding costs.

However, the language of the OGML controls what costs may be deducted from royalty. The specific agreement between the parties will control what happens, even to the detriment of the parties' intent. For example, in one recent case, the court construed a lease with specific language that required the lessee to reimburse the lessor for severance taxes, although these taxes are generally permissible deductions.

One other important distinction in determining what is deductible is assessing where the gas is sold. Gas is usually sold at the – wellhead or downstream. Texas law has been consistent as to deductions of post-production expenses for sales that occur downstream.

Administrative Marketing Expenses

Although there is no case law that addresses deducting administrative marketing expenses from royalties as a post-production cost, this expense is to many other deductible expenses except is not paid to a third party. But, normal lease language, as well as case law, would allow the cost to be deductible when performed by a third party at an arm's length. It then is logical that the cost should be deductible as an expense if the operator provides the service directly.

Although not directly on point, regulatory accounting may offer some guidance in how this expense should be handled. The Texas State Comptroller allows operators to deduct many expenses when determining the taxable value of gas for severance purposes, including some marketing expenses. Normally, the deductible expenses the state allows for severance tax purposes include compression, dehydration, "sweetening," and delivering the gas to the purchaser. But, because the administrative marketing expenses are "in-house" the State Comptroller would likely not allow administrative marketing fees to be deductible from severance taxes.

Relevant statutory laws as applicable to division orders.

Payment of Proceeds

The TEXAS NATURAL RESOURCES CODE, SUBCHAPTER J. § 91.402 contains the law requiring the timely payment of proceeds from the sale of oil or gas. The proceeds must be paid to the proper party on or before 120 days after the end of the month of first sale of production from the well. After that time, payments must be made as specified in the lease or other written agreement; however, if the lease or other agreement does not specify the time for payment, subsequent proceeds must be paid no later than *60 days* after the end of the calendar month in which subsequent *oil* production is sold; or *90 days* after the end of the calendar month in which subsequent *gas* production is sold.

Payments may be withheld without interest beyond the time limits above when:

1) there is a dispute concerning title that would affect distribution of payments;
2) a reasonable doubt exists that:
    a. the payee has sold or authorized the sale of its share of the oil or gas to the purchaser of such production; or
    b. has clear title to the interest in the proceeds of production;
3) a requirement in a title opinion places in issue the title, identity, or whereabouts of the payee and that has not been satisfied by the payee after a reasonable request for curative information has been made by the payor.

Division Orders

In Texas, a division order may not amend any lease or operating agreement between the interest owner and the lessee or operator or any other contracts for the purchase of oil or gas. As a condition for the payment of proceeds from the sale of oil and gas production to payee, a payor shall be entitled to receive a signed division order from payee containing *only* the following provisions:

a) the effective date of the division order, transfer order, or other instrument;
b) a description of the property from which the oil or gas is being produced and the type of production;
c) the fractional and/or decimal interest in production claimed by payee, the type of interest, the certification of title to the share of production claimed, and, unless otherwise agreed to by the parties, an agreement to notify payor at least one month in advance of the effective date of any change in the interest in production owned by payee and an agreement to indemnify the payor and reimburse the payor for payments made if the payee does not have merchantable title to the production sold;
d) the authorization to suspend payment to payee for production until the resolution of any title dispute or adverse claim asserted regarding the interest in production claimed by payee;
e) the name, address, and taxpayer identification number of payee;
f) provisions for the valuation and timing of settlements of oil and gas production to the payee; and
g) a notification to the payee that other statutory rights may be available to a payee with regard to payments.

In the alternative, the statutory form of division order is as follows and should substantially follow the form and content (see next page):

DIVISION ORDER

TO:

(Payor) Property No.

Effective (Date)

The undersigned severally and not jointly certifies it is the legal owner of the interest set out below of all the oil and related liquid hydrocarbons produced from the property described below:

OPERATOR:

Property name:

County: State:

Legal Description:

OWNER NO.

TAX I.D./SOC. SEC. NO. PAYEE

DIVISION OF INTEREST

THIS AGREEMENT DOES NOT AMEND ANY LEASE OR OPERATING AGREEMENT BETWEEN THE INTEREST OWNERS AND THE LESSEE OR OPERATOR OR ANY OTHER CONTRACTS FOR THE PURCHASE OF OIL OR GAS.

The following provisions apply to each interest owner ("owner") who executes this agreement:

TERMS OF SALE: The undersigned will be paid in accordance with the division of interests set out above. The payor shall pay all parties at the price agreed to by the operator for oil to be sold pursuant to **this** division order. Purchaser shall compute quantity and make corrections for gravity and temperature and make deductions for impurities.

PAYMENT: From the effective date, payment is to be made monthly by payor's check, based on this division of interest, for oil run during the preceding calendar month from the property listed above, less taxes required by law to be deducted and remitted by payor as purchaser. Payments of less than $100 may be accrued before disbursement until the total amount equals $100 or more, or until 12 months' proceeds accumulate, whichever occurs first. However, the payor may hold accumulated proceeds of less than $10 until production ceases or the payor's responsibility for making payment for production ceases, whichever occurs first. Payee agrees to refund to payor any amounts attributable to an interest or part of an interest that payee does not own.

INDEMNITY: The owner agrees to indemnify and hold payor harmless from all liability resulting from payments made to the owner in accordance with such division of interest, including but not

limited to attorney fees or judgments in connection with any suit that affects the owner's interest to which payor is made a party.

DISPUTE; WITHHOLDING OF FUNDS: If a suit is filed that affects the interest of the owner, written notice shall be given to payor by the owner together with a copy of the complaint or petition filed.

In the event of a claim or dispute that affects title to the division of interest credited herein, payor is authorized to withhold payments accruing to such interest, without interest unless otherwise required by applicable statute, until the claim or dispute is settled.

TERMINATION: Termination of this agreement is effective on the first day of the month that begins after the 30th day after the date written notice of termination is received by either party.

NOTICES: The owner agrees to notify payor in writing of any change in the division of interest, including changes of interest contingent on payment of money or expiration of time.

No change of interest is binding on payor until the recorded copy of the instrument of change or documents satisfactorily evidencing such change are furnished to payor at the time the change occurs.

Any change of interest shall be made effective on the first day of the month following receipt of such notice by payor.

Any correspondence regarding this agreement shall be furnished to the addresses listed unless otherwise advised by either party.

In addition to the legal rights provided by the terms and provisions of this division order, an owner may have certain statutory rights under the laws of this state.

_____
Signature of Witness

_____
Social Security/ Interest Owner Tax I.D. No.

_____
Address

Failure to furnish your Social Security/Tax I.D. number will result in withholding tax in accordance with federal law, and any tax withheld will not be refundable by payor.

If an owner in a producing property will not sign a division order because it contains provisions in addition to those provisions provided for in this section, payor cannot withhold payment solely because of this refusal. If an owner in a producing property refuses to sign a division order which includes only the provisions specified in the statute, the payor may withhold payment without interest until the division order is signed.

Payment may be remitted to a payee annually for the aggregate of up to 12 months accumulation of proceeds if the payor owes the payee a total amount of $100.00 or less for production from all oil or gas wells for which the payor must pay the payee. However, the payor may hold accumulated proceeds of less than $10.00 until production ceases or the payor's responsibility for making payment for production ceases, whichever occurs first. On the written request of the payee, the payor must remit payment of accumulated proceeds to the payee annually if the payor owes the payee less than $10.00. On the written request of the payee, the payor will remit the payment of the proceeds to the payee monthly if the payor owes the payee more than $25.00 but less than $100.00.

Division orders are binding for the time and to the extent that they have been acted on and made the basis of settlements and payments, and, from the time that notice is given that settlements will not be made on the basis provided in them, they cease to be binding. Division orders are terminable by either party on 30 days written notice.

The execution of a division order between a royalty owner and lessee or between a royalty owner and a party other than the lessee does not change or relieve the lessee's specific, expressed, or implied obligations under an oil and gas lease, including any obligation to market production as a reasonably prudent lessee. Any provision of a division order between payee and its lessee which is in contradiction with any provision of an oil and gas lease is invalid to the extent of the contradiction.

A division order may be used to clarify royalty settlement terms in the oil and gas lease. With respect to oil and/or gas sold in the field where it was produced or at a gathering point in the immediate vicinity, the terms *market value*, *market price*, *prevailing price in the field*, or other similar language, when used as a basis of valuation in the oil and gas lease, are defined as the amount realized at the mouth of the well by the seller of the production in an arm's-length transaction.

What must be reported with each payment

a) property identification (name, number, or both; and county and state)
b) sales month and year
c) volume sold
d) price per barrel or mcf
e) severance or other taxes deducted
f) other deductions or adjustments
g) net value
h) owner decimal interest
i) owner gross value
j) owner net value
k) address and phone number where additional information can be obtained

Annual notice to royalty owners

At least once every 12 months, a payor must provide the following statement to each royalty interest owner to whom the payor makes a payment:

> SECTION 91.504 of the TEXAS NATURAL RESOURCES CODE, gives an owner of a royalty interest in oil or gas produced in Texas the right to request from a payor information about itemized deductions, the heating value of gas, and the Railroad Commission of Texas

identification number for the lease, property, or well that may not have been provided to the royalty interest owner. The request must be in writing and must be made by certified mail. A payor must respond to a request regarding itemized deductions, the heating value of gas, and the Railroad Commission of Texas identification number by certified mail not later than the 60th day after the date the request is received.

Royalty Owner Requests
If a royalty owner notifies the payor in writing of failure to make timely payment, the payor must either make payment or respond in writing within 30 days of receipt of the notice. Requests sent by certified mail for information regarding itemized deductions, adjustments, the heating value of gas, or the Railroad Commission of Texas identification number for the lease, property, or well must be responded to within 60 days of receipt of the request. Additional requests sent by certified mail for information not covered by the statutes must be responded to within 30 days of receipt of request.

Payment of Interest on Late Payments
If payment has not been made for any reason in the time limits specified, the payor must pay interest to a payee beginning at the expiration of those time limits at two percentage points above the percentage rate charged on loans to depository institutions by the New York Federal Reserve Bank, unless a different rate of interest is specified in a written agreement between payor and payee.

However, interest payments do not apply where payments are withheld or suspended by a payor beyond the time limits specified § 91.402 of the TEXAS NATURAL RESOURCES CODE, SUBCHAPTER J, for things like title problems or a sale of an interest. Furthermore, the payor's obligation to pay interest and the payee's right to receive interest terminate on delivery of the proceeds and accumulated interest to the comptroller as provided by TITLE 6, TEXAS PROPERTY CODE.

Nonpayment of oil and gas proceeds or interest
If a payee seeks relief for the failure of a payor to make timely payment of proceeds from the sale of oil or gas or an interest in oil or gas as required, the payee must give the payor written notice by mail of that failure as a prerequisite to beginning judicial action against the payor for nonpayment. The payor has 30 days after receipt of the required notice from the payee in which to pay the proceeds due, or to respond by stating in writing a reasonable cause for nonpayment. A payee has a cause of action for nonpayment of oil or gas proceeds or interest on those proceeds in any court of competent jurisdiction in the county in which the oil or gas well is located. If a suit is filed to collect proceeds and interest, the court must include in any final judgment in favor of the plaintiff an award of reasonable attorney's fees and a minimum of $200 in actual damages.

Notice of change in payor
Following a change in payor, the new payor must give written notice to each payee to whom the payor is responsible for distributing oil or gas proceeds. The notice must be given to the payee or the payee's designee at the payee's or designee's most recent known address. Upon receipt of payee's address from the operator or lessee, the payor must provide the notice within the time permitted for payment of proceeds and in accordance with the conditions for payment provided by § 91.402, TEXAS NATURAL RESOURCES CODE, SUBCHAPTER J.

The notice must include the information required by § 91.502(1), (2), and (12) and § 91.503 of the TEXAS NATURAL RESOURCES

CODE, SUBCHAPTER J along with the payor's telephone number.

The notice may be given by any writing, including a division order, check stub, or attachment to a payment form. A payor that is obligated to pay interest to a payee under § 91.403 of the TEXAS NATURAL RESOURCES CODE, SUBCHAPTER J and that does *not* give the payee a notice required by this section is liable to the payee for interest under that section at a rate that is two percent more than the rate provided by that section.

Special information required on production from tight formations

A payor of proceeds from the sale of gas produced from a tight formation as defined by § 29(C) (2) (B), INTERNAL REVENUE CODE OF 1986, annually, not later than March 15, must furnish the payee a statement providing the information necessary to compute the federal income tax credit provided by that section for the gas for which payment was made in the preceding year, including information as described in § 91.502(1) of the TEXAS NATURAL RESOURCES CODE, SUBCHAPTER J; and the volume of the gas, measured in thousands of cubic feet and heating value; or millions of British thermal units for each thousand cubic feet.

CHAPTER 10: KANSAS ISSUES AFFECTING LAND TITLE AND THE DIVISION ORDER ANALYST

Linda Barry CDOA

Introduction

When working with title issues in Kansas, it is important to keep in mind that a *mineral interest* is real property and *a royalty interest* is personal property. Real property can be held in three different ways in Kansas: separate property, tenants in common, and co-tenancy.

Separate property is defined as all property owned before any current marriage or acquired after marriage by gift, **devise** (a gift of real property given by will) or descent (transmission of real or personal property of someone who dies intestate).

Tenants in Common occurs when a person owns an undivided interest in land. That interest passes to his or her heirs or devisees upon his or her death. In Kansas, the presumption is that all property acquired during a valid marriage is owned by tenants in common.

Co-tenancy is also known as *joint tenancy*. Ownership as a joint tenant is defined as two or more persons who own an undivided interest in a piece of property. When one of the joint tenants dies, the property **vests in** (comes into the possession of) the surviving joint tenant(s).

An interest in property can be transferred to another through *dower*. This is defined as that part of a husband's property which his wife inherits for life. Common law dower is abolished in Kansas. In lieu of this, a surviving spouse is given the right to receive an undivided one-half interest in all of the real estate in which the deceased spouse had a legal and equitable interest at any time during the marriage.

The manner in which the property was held greatly affects the documentation required to pass title when the mineral or royalty owner dies.

If the owner was not married at the time of his or her death, or if the owner was married at the time of his or her death, the division order analyst needs to determine if the property was held as separate property or as tenants in common.

If the property was not held by joint tenants, the division order analyst needs to determine (1) if the deceased owner had a valid will, and (2) if probate will be held in Kansas.

If an interest was held in joint tenancy, the surviving joint tenants would own the oil and gas interests and production proceeds in equal shares. To transfer the ownership, the analyst needs only to obtain (1) adequate proof of death (usually an official copy of the death certificate), and (2) proof that all taxes have been paid.

In the case of separate property or property held by a tenant in common, the analyst will need more documentation than needed for a transfer of property involving a joint tenant.

Kansas intestate succession:

If the decedent did not have a will or if the will is not offered for probate, the heirs can rely upon a procedure, established by Kansas statute, to determine **descent** (transmission of real property belonging to someone who died intestate). It states in part:

"When a person has been dead for more than six months and has left property and no petition has been filed for probate or administration commenced then any

person interested in the estate may petition the District Court for determination of descent in the county of the decedent's residence or any county where any property or any interest in property is situated."

The district court will determine descent under Kansas laws of intestate succession or under the terms of a settlement agreement. Then the district court will issue a Decree of Descent. However, if it has been less than ten years since the death, the court will not issue a Decree of Descent until the taxes have been paid. When the district court issues the Decree of Descent, the heirs will have marketable title by filing a complete transcript of the proceedings with the district count in each county where property is located.

When the division order analyst is advised that no will exists or that it will not be offered for probate in Kansas, he or she should request (1) an official copy of the death certificate, (2) Letters of Administration, and (3) the Decree of Descent filed in the county where the property is located.

Note: Most companies allow for the use of an Affidavit of Heirship to determine ownership if the interest is small and there has been a small dollar amount of proceeds paid to the deceased owner in the last year. If an Affidavit of Heirship is used, this document does not give the heir marketable title; it only allows for the payment of proceeds.

The district court will most often use the Kansas Laws of Intestate Descent and Distribution for determining the ownership of a property. If the division order analyst is using an Affidavit of Heirship, he or she will also use these laws. See Table I for a summary of these laws.

Kansas testate succession:

Any person of sound mind and possessing rights of majority may dispose of property by will. To be effectual, the will must be admitted to probate in a district court in the state of Kansas. Every will must be written (not oral) and must be signed at the end by the testator, or by someone for him or her, in his or her presence and at his or her express direction. It must be attested and subscribed in the presence of the testator by two or more witnesses, who say the testator subscribed or heard him or her acknowledge the same. Holographic wills are not recognized. Either spouse may will away his or her separate property. He or she may will the one-half to his or her property subject to homestead and statutory allowances. However, neither spouse may will away from the other more than one-half of his or her property, unless the other spouse consents to this in writing, executed in the presence of two or more competent witnesses, or elects to take under the will.

When advised of the death of an owner who has died testate (with a will), most companies request the following:

- If the estate is still open:
  - An official copy of the death certificate;
  - Copy of the will;
  - Order admitting the will to probate;
  - Letters Testamentary;
- If the estate is closed:
  - An official copy of the death certificate;
  - Copy of the will
  - Copy of the Journal Entry of Final Settlement
  - Receipt for payment of taxes.

The information shown above is usually sufficient to allow the payment of proceeds to the estate while probate is still

open and to pay the devisees when the estate closes. On some occasions, the information in these documents will indicate that a copy of the entire probate proceedings will be necessary in order to determine the correct ownership.

Kansas Deeds

As in every state, property can be transferred by **deed**. As with all deeds, a valid deed must include:

- the names of the grantor(s) and grantee(s);
- the address of the parties to the deed;
- words of grant;
- statement of consideration;
- description of the property and interest transferred;
- the date of the deed and the effective date of the deed;
- execution by grantor(s)
  Note: a mark may be used;
- an acknowledgement;
- recordation in the county where the property is located.

It is not necessary in Kansas to have the signatures on the deed witnessed, even if the grantor is signing with his or her mark. A spouse need not join in the execution of a conveyance *except* the conveyance of a homestead.

Deeds creating Life Estates are commonly used in Kansas, as in other states, to avoid probate. The only difference between these deeds and other deeds is that they contain a reservation of an interest for the grantor's life, with the remainder going to the grantees. It is important to note that by this deed, the life tenant has conveyed his or her interest and, by doing this, cannot convey further. The remaindermen (grantees) are the only parties who may transfer an interest, subject to the life estate of the grantor.

Divorce and Kansas title

After a petition for divorce is filed, . action may not be taken by the Kansas district court for sixty days. After that time, a Decree of Divorce or Decree of Annulment may be issued by the court. It becomes final when the time for appeal expires **Note:** this time for appeal is usually written in the decree . The court may order that the real and personal property be divided and order that deeds or similar conveyances be executed and recorded.

Guardianships and Conservatorships

A *guardian* is any person who has been appointed by a court to act for a disabled person or a minor. A *conservator* is the same as a guardian except the conservator has control of an estate. Proceedings to appoint a guardian or conservator are held in the district court of residence of the ward. Guardians and conservators are always subject to the control and direction of the district court. A conservator, with the approval of the court, may (1) sell, lease, or mortgage real property including minerals; (2) prosecute and defend suits; (3) sell assets of the estate; (4) invest funds; (5) acquire title to real property; and execute an oil and gas division order.

Termination of a guardianship or conservatorship of a minor occurs upon the death of the ward or upon attainment of legal age or marriage. Guardianship or conservatorship of a disabled person terminates upon the death or restoration to capacity of the ward.

Trusts

In Kansas, as in other states, the most common question associated with oil and gas interests held in trust is "Does the trustee have the power to perform a certain act, for example, sign a division order or execute a deed or assignment?"

To answer this question, the analyst must obtain and examine the trust agreement. But since trustees are often reluctant to give an analyst a copy of the trust agreement, in January 2004, Kansas passed KS Statute No 58a-1013. This statute states in part:

"Instead of furnishing a copy of the Trust instrument to a person other than a qualified beneficiary, the Trustee may furnish to the person an acknowledged Certification of Trust. This Certification of Trust contains the following information:

- that the trust exists and the date the trust instrument was executed;
- the identity of the settlor;
- the identity and address of the currently acting trustee;
- the powers of the trustee;
- the revocability or irrevocability of the trust and the identity of any person who can revoke the trust;
- the authority of co-trustees to sign or otherwise authenticate and whether all or less than all are required in order to exercise powers of the trustee;
- the trust's tax identification number;
- the manner of taking title to trust property

A Certification of Trust may be signed or otherwise authenticated by any trustee. A certification must state that the trust has not been revoked, modified or amended in any manner that would cause the representation contained in the Certification of Trust to be incorrect.

The recipient of a Certification of Trust who acts in reliance upon a Certification of Trust without knowledge that the representations contained in it are incorrect, is not liable to any person for so acting and may assume without inquiry the existence of the facts contained in the certification. A person who enters in good faith into a transaction in reliance upon a Certification of Trust may enforce the transaction against the trust property as if the representations contained in the certification were correct. A person making a demand for the Trust Agreement in addition to a Certification of Trust and/or excerpts from the Trust agreement is liable for damages if the court determines that the person did not act in good faith in demanding the Trust Agreement.

In summary, when an analyst is working with a transfer of interest into a trust, the analyst should request: a copy of the Trust Agreement, although a Certificate of Trust can be accepted for Kansas properties. Copies of critical excerpts of the Trust Agreement can also be accepted.

Special concerns for the Kansas division order analyst

The **Kansas Corporation Commission (KCC)** supervises and regulates the Kansas oil and gas industry. As in other states, the KCC approves and records the locations and production of all units in the state and determines the allowables, spacing, and so forth. It is important to note there are no spacing orders as such in Kansas, but field rules establish the norms for the unit size. Also, the KCC allows non-contiguous units.

An **Affidavit of Production** is a document unique to Kansas. When a well begins producing, an Affidavit of Production must be filed of record in order to protect the producer's unit and provide the statutory notice of production. The affidavit should be a sworn statement by a company officer or agent stating the following:

- the exact description of the unit;
- description of leases contained in the unit;
- location of the well;
- statement of notice of production in accordance with Kan. Stat. 50-205;
- statement that the lease or leases perpetuated by production from the described unit.

Table I – Summary of Intestate Laws of Kansas

Kansas		
Leaving spouse and no descendents	Spouse takes entire estate	
Leaving spouse and descendents	Spouse takes one-half	Descendents share one-half. Descendents of pre-deceased children inherit per stirpes.
Half-blood	Children of half blood inherit with children equally with children of the whole blood through the common parent only. If siblings are born of different unions, property is equally divided between paternal and maternal lines of the deceased: siblings fully related in blood take in both lines and those related by half-blood take each in his own line.	
Leaving parents, but no spouse or descendents	The surviving parent or parents take the entire estate.	
Leaving no parents, spouse or descendents	The shares attributable to the parents shall pass, in equal shares, to the heirs of the parent (excluding their respective spouses). If one parent left no heirs, then that share shall also pass to the heirs of the other parent.	
Laughing heirs	No heir shall inherit, except by lineal descent, to a person more than six degrees removed from the decedent.	
Murder	A murderer may not inherit, treated as though predeceased decedent.	

CHAPTER 11: ARKANSAS LAND TITLES

William Warren

All references to "Std." refer to the Title Standard set out in the 2000 Edition of the Standards for Examination of Real Estate Titles in Arkansas published by the Arkansas Bar Association.

Grantors

When title to real property is conveyed (transferred from one person or entity to another), the marital status of the **grantor** (the person or institution that conveys property to another) must be determined. If the grantor is married, the spouse must also sign the document in order to release the spouse's **dower** (a widow's share for life of her husband's estate) or **curtesy rights** (a husband's right, after his wife's death, to certain kinds of property that she had inherited) and other rights of a **tenancy by the entirety** (ownership of property, real or personal, by a husband and wife). If the grantor lives on the property to be conveyed, his or her spouse must also sign the document to convey their homestead rights.

Second, if the grantor is a legal entity such as a corporation or partnership, the division order analyst must verify that the party executing the document has the authority to do so.

Other considerations that are relevant when the grantor or grantee is a trust or trustee will be discussed later.

Husband and Wife[1]

In Arkansas, when dealing with real property, both spouses must *always* execute any document conveying title or any similar document. There are two reasons for this: First, any conveyance to a husband and wife creates a tenancy by the entirety unless otherwise stated . This is true even if the document does not state that the parties are husband and wife.

Second, even if the property is owned by only one spouse, the other spouse must release his or her **dower or curtesy interest.**

As with any other joint tenancy, upon the death of one spouse, the property passes to the survivor. However, a tenancy by the entirety, unlike other joint tenancies, is not destroyed by a conveyance by only one spouse. Such a conveyance merely conveys any **possessory rights** (a right to exert control over certain land to the exclusion of others) and rights to income and profits from the property, subject to the right of survivorship in the other spouse. One spouse may convey his or her interest in property owned as tenants by the entirety to a third party, while the other spouse does not join in the conveyance. If the conveying spouse dies first, the **grantee** has no right against the survivor.

However, if the conveying spouse is the survivor, the grantee takes the entire title as it would have been taken by the grantor.

A divorce however, may destroy the tenancy by the entirety, depending on when it occurred.

Before March 28, 1947, a court could destroy a tenancy by the entirety only with the consent of the parties, since vested interests could not be affected retroactively.

Between March 29, 1947 and March 7, 1975, courts had the power to dissolve a tenancy by entirety. However, there was no dissolution unless the court specifically said so. Tenancies created prior to March 28, 1947 still could not be destroyed since they were vested interests and the regulating statute was not retroactive.

After March 8, 1975, a divorce decree automatically dissolved a tenancy by entirety unless specifically stated otherwise .

[1] Std. 7.2

Dower and Curtesy[2]

Dower and curtesy rights are the provisions the law makes for a widow or widower out of the real and personal property of the deceased spouse for the support of the surviving spouse and the children. In Arkansas the portion of the decedent's estate that is subject to dower and curtesy depends on who the surviving heirs are and whether the property is a new acquisition or ancestral property.

If a decedent leaves *a surviving spouse and a child or children*, the dower or curtesy interest of the surviving spouse is one-third of all property for life regardless how the lands were acquired.

If a decedent leaves *a surviving spouse and no children*, the dower or curtesy interest of the surviving spouse is one-half of the lands that were *not* ancestral in **fee simple** (permanent and absolute possession of property without restrictions) and a **life estate** (an estate held for life) in one-half of all ancestral lands.

In 1969 Arkansas abolished the distinction between ancestral estates and new acquisitions for the purposes of intestate succession , but left intact the distinction as it applies to dower and curtesy. The conflicting provisions can be reconciled if the division order analyst remembers that the distinction between ancestral and new estates was abolished only as to the **heritable estate**. The heritable estate is that portion of the intestate's estate that may pass by inheritance, after providing for dower or curtesy rights, homestead rights, any statutory rights granted the surviving spouse and minor children and the costs of the administration of the estate.

The distinction between ancestral property and new acquisitions for dower and curtesy only affects the heritable estate when (1) the decedent left no direct descendants (children, grandchildren, and so on), and (2) the decedent and his or her surviving spouse were married less than three years.

If the decedent and his or her surviving spouse had been married *more* than three years and there are no children, the surviving spouse receives his or her curtesy or dower and all of the heritable estate. Since the surviving spouse receives all of the estate, the distinction between ancestral property and new acquisitions is irrelevant.

If the decedent is survived by a wife and a child or children, the wife only receives her dower interest, a one-third life estate, and all of the heritable estate goes to the children. Once again the distinction between ancestral property and new acquisitions is irrelevant.

Dower and curtesy may be released by execution of the same instrument or by execution of a separate instrument, but they must be released. That is, they cannot be conveyed. Prior to March 25, 1981, women could extinguish the curtesy rights of their husbands by conveying the property without the husband's signature. Specific language releasing dower and curtesy is common in Arkansas forms but not necessary. If both spouses sign the document, their dower or curtesy rights are automatically released.

Homestead[3]

In Arkansas, homestead is defined as:

- The domicile of an individual or family, *not within any city, town or village*. It may consist of not more than 160 acres of land if less than $2,500 in value, or 80 acres of land without regard to value.
- The domicile of an individual or family *within any city, town or village*. It may consist of not more than one acre of land unless the equity value exceeds the sum of $2,500 or up to one-fourth acre without regard to value.

[2] Std. 7.5

[3] 7.5

•Any homestead outside any city, town, or village, owned and occupied as a residence, which is annexed to or made part of an incorporated city or town within the state of Arkansas located on land that is rural in nature and has a significant agricultural use.

Once property has been designated as a homestead, it will not be considered abandoned if the owner temporarily lives elsewhere. Abandonment is largely a question of intent . Before August 13, 1993 homestead rights could only be released by a single instrument signed by both spouses. This was later changed .

Corporations and LLCs

If an entity is a corporation or **LLC** (limited liability company), it can be assumed that the corporation or LLC was in good standing and that the person or persons who executed the instrument were duly authorized to do so .

Partnerships.[4] When dealing with transfers from a partnership, it is important to know whether the property being transferred is actually partnership property and whether the partner(s) executing the document has the authority to do so. Most of the time the document itself or information contained in the files will provide the answers to these questions. For those times the answer to either question is uncertain, Arkansas' version of the Uniform Partnership Act provides some useful guidelines.

1. A **partnership** is defined as the association of two or more persons to carry on as co-owners a business for profit, whether or not the persons intend to form a partnership. However, joint tenancy, **tenancy in common**, **tenancy by the entireties**, joint property, common property or partial ownership does not by itself establish a partnership, even if the co-owners share profits made by the use of the property.[5]
2. Property is partnership property if it is acquired in the name of the partnership or in the name of one or more partners with an indication in the instrument transferring title to the property of the person's capacity as a partner or of the existence of a partnership but without an indication of the name of the partnership.[6] For example: Woodrow Boudreau and Justin LeBlanc, partners or Elizabeth Boudreau, partner.
3. Subject to a statement of partnership authority, any partner may execute any instrument in the partnership name, and it will be binding, if the transaction is apparently in the ordinary course of business for the partnership and the person with whom the partner was dealing did not know nor should have known that the partner lacked authority. If the act was not apparently in the course of the partnership business, it is only binding on the partnership if it was actually authorized by the other partners.
4. A partnership may file a statement of partnership authority, giving one or more partners authority to conduct certain acts. A grant of authority to transfer real property in a statement that has been filed of record is conclusive in favor of a person who gives value without knowledge to the contrary, so long as a statement containing a limitation on that authority is not of record.
5. A partner may file a statement of denial limiting or denying a person's authority to act.
6. Each partner has equal rights in the management and conduct of the partnership business unless changed by

[4] **Std. 4.8**

[5] A.C.A. 4-46-202

[6] A.C.A. 4-46-204

written agreement.

7. The spouse of a partner has no dower or curtesy rights in partnership property.

Grantees

Joint Tenants.[7] *Before July 15, 1991*, if the intent of the conveyance as determined by "the four corners of the deed" was to create a joint tenancy with right of survivorship, then one was created, even without express wording.[8]

After July 15, 1991 a conveyance must contain language expressly creating a joint tenancy or it will be a tenancy in common.[9]

Unlike in a tenancy by the entirety, a conveyance by one joint tenant destroys the joint tenancy and the two owners become tenants in common.

Minors. The Uniform Transfers to Minors Act[10] provides a method to transfer property to a minor without involving the court system. This eliminates the need for a guardian which must be appointed by a court and have all of their actions approved by the court. It is generally easier for a custodian to administer the property under this act than it is for a trustee of property placed in a trust.

To transfer real property to a custodian for a minor all it takes is a deed, assignment, or other instrument of conveyance that substantially uses the following language: *Grantor hereby conveys to Billie Ray Cyrus as Custodian for Hanna Montana under the Arkansas Uniform Transfers to Minors Act, Grantee.*

It should be noted that the grantor and the custodian cannot be the same person or legal entity. A custodian, acting in a custodial capacity, has all the rights, powers and authority over custodial property that unmarried adult owners have over their own property. The custodian has certain duties regarding the custodial property and must keep records subject to inspection by a parent or legal representative of the minor. The custodian is also liable for breach of his or her responsibilities.

Trusts.[11] It is unclear whether a trust can hold title to real property in Arkansas, as there are no statutes and no case law. When conveying to a trust, it is safer to put title into a trustee, for example, James T. Kirk, Trustee of the James T. Kirk Interstellar Galactic Trust.

Even though title is actually going to the trustee, it is vitally important to include the trust as part of the name of the grantee. A conveyance to James T. Kirk, Trustee, without mention of the trust conveys title to James T. Kirk, individually, not the trust.[12] In this instance, James T. Kirk can transfer, encumber or otherwise do anything with the property he wishes. In addition, his wife, Green Lady Kirk, must execute any documents in order to release her dower interest.

The only exception to this rule is that property may be transferred to a trust by a Beneficiary Deed, which will be discussed later on.[13] If a deed or assignment into a trust has no trustee named, there is no legally valid reason not to accept the document.

What is being given

Descriptions.[14] There are a variety of problems that can arise in a legal description. The description may not close, it may not have a good point of beginning, it may be overly broad or it may just make no sense at

[7] Std. 8.1.3
[8] A.C.A. 18-12-106
[9] A.C.A. 18-12-603
[10] A.C.A. 9-26-201, et seq
[11] Std. 4.7.1 & 4.7.2
[12] A.C.A. 18-12-604
[13] A.C.A. 18-12-608
[14] Std. 21

all. If the description is truly indefinite, the document does not convey any title.

In general, a conveyance must only describe the land with sufficient certainty to identify the land by any reasonable construction.[15] If descriptive words within the document furnish a key to identification of the property, nothing more is required.[16]

What does all this mean? Set out below are some examples provided by the Arkansas Supreme Court of valid and invalid descriptions that may be helpful.

1. The use of the word *part* invalidates a description unless the description goes on to specifically describe the part.[17] However, the phrase "It is my intention to convey all of real estate belonging to me" has been held to be a sufficient key to identify the lands intended to be conveyed, even though the abbreviation for part was used in the description. For example, "Pt. E/2 NW/4 of Sec. 12-17N-4W" was held valid since the phrase quoted above was included in the description.[18]
2. If a description does not close, it is defective, making the instrument voidable. Thus a court could correct the defect in a suit for reformation.
3. If a description has an uncertain point of beginning, it is void and cannot be reformed.[19]
4. A description of "All property owned in Pope County" is valid.[20]
5. An incorrect statement of acreage does not affect the validity of the description.[21] If the deed calls for 100 acres, but the tract actually described contains 253.93 acres, the entire tract is conveyed.[22]
6. A legal description does not have to contain the name of the county if it contains the correct section, township and range.[23]

Rights of way

It is not uncommon to see a call in a description that either excepts a right of way or goes to the boundary line of a right of way, such as "the North right of way of Hwy. 96". In either case, when a right-of-way is still in use, there is a presumption that the conveyance extends to the center of the right-of-way unless a contrary intention is clearly stated. This presumption applies to private and public roads and railroad rights-of-way.[24] A grantee takes to the center of an abandoned easement only when the grantor explicitly expresses that intention.[25]

Life estates

A **life estate** may be created through the operation of dower and curtesy, by reservation or by conveyance. Set out below are some items to keep in mind when dealing with a life estate.

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[15] *Snyder v. Bridewell*, 167 Ark. 8, 267 S.W. 561 (1924)

[16] *Gibson v. Pickett*, 256 Ark. 1035, 512 S.W.2d 532 (1974); *Miller v. Best*, 235 Ark. 737, 361 S.W.2d 737 (1962); *Burns v. Meadors*, 225 Ark. 1009, 287 S.W.2d 893 (1956); *Turrentine v. Thompson*, 193 Ark. 253, 99 S.W.2d 585 (1936)

[17] *Browning v. Hicks*, 243 Ark. 394, 420 S.W.2d 545 (1967)

[18] Ketchum v. Cook, 220 Ark. 320, 247 S.W.2d 1002 (1952)

[19] Mode v. Henley, 227 Ark. 875, 302 S.W.2d 73 (1957)

[20] Snyder v. Bridewell, 167 Ark.8, 267 SW 561 (1924)

[21] Wyatt v. Wycough, 232 Ark. 760, 341 S.W.2d 18 (1960)

[22] Scott v. Dunckel Box & Lumber Co., 106 Ark. 83, 152 S.W. 1025 (1912)

[23] , Stephens v. Ledgerwood, 216 Ark. 404, 226 S.W. 2d 587 (1950)

[24] Abbott v. Pearson, 257 Ark. 694, 520 S.W.2d 204 (1975)

[25] , Abbott, supra

1. Probably the life tenant and the remainderman have to execute an oil and gas lease or leases in order to have an effective lease. There is no case law on this point, but it makes sense that a commitment from both parties would be required.
2. **Bonus**, **delay rental** and interest on royalty are income and are payable to the life tenant.
3. Where a life estate is created by conveyance or reservation, the royalty itself is considered part of the corpus and is reserved for the remainderman unless the Open Mine doctrine applies. In this case, the life tenant is entitled to the royalty. A lease alone is enough to open the mine.[26] As a practical matter, most oil and gas companies obtain a payment directive from the parties, directing how to make payments.
4. If a life estate consists of the dower or curtesy of the surviving spouse, the life tenant is entitled to his or her fraction of the royalty.[27]
5. It is not possible to create a life estate in a stranger to the title by reservation.[28] If, for example, Oliver Douglas owns Hooterville Farms, he cannot reserve a life estate in "Oliver *and* Lisa Douglas". The effect of such a reservation would be to create a life estate in Oliver only. Some states allow an exception to the rule when the stranger in title is a spouse, but Arkansas does not.

Mineral reservations and conveyances

Strohacker Doctrine.[29] "A reservation or grant of 'minerals' or 'mineral rights' without specific reference to any specific mineral includes only those that were commonly known and recognized by legal or commercial usage in the area where the land is situated at the time the instrument was executed".[30]

Most of the deeds where Strohacker is applicable were executed around the turn of the 20th century, although there are cases pending at this time in the Fayetteville Shale play that seek to apply Strohacker to deeds executed in the 1940s and 1950s.

There are very few hard and fast dates for a person trying to interpret a generic mineral reservation to hang his or her hat on. The Arkansas Supreme Court has provided help in a handful of counties.
Miller County, 1892 and 1893: Oil and gas not included in "all coal and mineral deposits".[31]

Union County, 1900: Oil and gas not included in "mineral interest".[32]

Logan County, 1905: Gas included in "all of the coal, oil and mineral".[33]
For other areas, a general rule used by most landmen and title attorneys is that if the reservation was before 1900, oil and gas were not included. If the reservation was after 1905 oil and gas were included. In between is a gray area in which the correct answer is a question of fact. The earliest oil and gas leases recorded in the area and the earliest drilling activity in the area are facts that could sway a court one way or the other. Courts have also taken into account newspaper articles from the time period, historical essays and other written materials.

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[26] Warren v. Martin, 168 Ark. 682, 276 S.W. 367 (1925)
[27] A.C.A. 28-11-304
[28] Rye v. Bauman, 231 Ark. 278, 329 S.W.2d 161 (1959)
[29] Std. 19.5
[30] Ahne v. Reinhart & Donovan Company, 240 Ark. 691, 401 S.W.2d 565 (1966); Missouri Pacific Railroad Co. v. Strohacker, 202 Ark. 645, 152 S.W.2d 557 (1941)
[31] *Missouri Pacific Railroad Co., supra*
[32] *Stegall v. Bugh*, 228 Ark. 632, 310 S.W.2d 251 (1958)
[33] *Ahne, supra*

Duhig Rule. A grantor may not purport to convey and warrant an interest and then attempt to reserve a portion of that interest, thus breaching his or her warranty. Consequently, if full effect cannot be given to both the grant and the reservation, priority will be accorded the grant prior to attempting to fulfill the reservation.[34] In Arkansas the Duhig rule only applies to the construction of a reservation in a warranty deed when the immediate parties to the deed are not the parties to the lawsuit.[35]

In cases involving a dispute between the original grantor and grantee, the courts attempt to determine their intent. The Duhig Rule could also be applied to a mineral deed that contains a warranty clause.

If all of the following items are present, Duhig applies. If any one item is not present, it does not:

1. The instrument is a warranty or mineral deed that contains a warranty clause.
2. Less than the grantor's entire mineral ownership is being transferred (i.e., grantor is reserving part of the mineral interest).
3. The grantor owns less than the entire mineral interest at the time of conveyance.
4. Nowhere in the deed does the grantor indicate that he or she is also excepting from the warranty any prior reservations or conveyances of record.

Example of Duhig Application: Jack Daniels owned the surface and all of the minerals under the NE/4 SE/4. In 1961, he conveyed one-half of the minerals under the NE/4 SE/4 to Hans. By 1986, Natural Gas, Inc. had drilled two successful gas wells in a unit containing the NE/4 SE/4, so when Mr. Daniels sold the property to D. Yan Kee, he attempted to reserve the remaining one-half of the minerals to himself.

The description in the warranty deed read, "NE/4 SE/4 of Sec. 42-6N-32W, RESERVING UNTO GRANTOR, JACK DANIELS, an undivided one-half interest in the oil and gas and other minerals in and under the above described property." Going down the checklist, (1) the instrument is a warranty deed, (2) less than 100% of the mineral ownership is being transferred, (3) Jack owned less than 100% of the minerals at the time of the conveyance, and (4) Jack did not mention the prior conveyance of one-half of the minerals. Therefore the attempted reservation fails and the one-half of the minerals that Jack owned pass to Mr. Kee.

The rational is that when the warranty deed reads "grant, bargain, sale and convey the NE/4 SE/4 to D. Yan Kee", it is warranting that fee simple title to Mr. Kee or as much title is owned, in this case title to the surface and one-half of the minerals. If the owner (in this case, Jack Daniels) then attempts to reserve one-half of the minerals to himself, he violates the warranty because he cannot convey the surface and one-half of the minerals and keep one-half of the minerals since he owns only one-half to begin with. In order to not violate the warranty on the surface and one-half of the minerals, the one-half of the minerals Mr. Daniels attempted to reserve must go to Mr. Kee, leaving Mr. Daniels with nothing.

Acknowledgments

There isn't really anything unique or unusual about the Arkansas acknowledgment form. The various forms for different entities may be found in the Arkansas statutes, and Arkansas will accept any acknowledgement

[34] *A Survey of Recent Cases, Legislation & Rules Pertaining to Arkansas Oil & Gas Interests* by Kevin S. Vaught

[35] *Hill v. Gilliam*, 284 Ark. 383, 682 S.W.2d 737 (1985)

form that is legal in another state if the document was executed in another state. Even an acknowledgment by telephone is valid if the party executing the document is known to the notary public and the notary can recognize the voice of the executing party.[36]

Anyone who has examined title knows that many mistakes are made both in drawing up an acknowledgment and in filling in the blanks. The good news is that Arkansas has curative statutes that correct these errors.[37] The bad news is that there is a date, August 13, 1993, which marks a change in the curative statutes. Instruments in writing that have been recorded and which are defective or ineffectual because of the defects listed below, due to the curative statutes, are binding *ad effectual* just as if there was no defect.

Instruments in writing executed before August 13, 1993 are considered binding and effective despite the following defects:

1. Failure of a spouse's signature on an instrument affecting title to the homestead to be properly acknowledged.
2. Omission of words required by law in the certificate of acknowledgment by the officer certifying the acknowledgement.
3. Failure of the officer to attach his or her seal to the certificate.
4. Attachment of a seal to the certificate that does not bear the words and devices required by law.
5. Certification by an officer who was (a) a mayor of a city or an incorporated town and was not authorized to certify the acknowledgment, or (b) the deputy of an official authorized by law to take acknowledgments though the deputy was not so authorized.
6. Failure of the officer to state the date or the correct date of the expiration of his or her commission on the certificate.
7. Failure of the officer to correctly date the certificate of acknowledgment or state the county wherein the acknowledgment was taken.
8. Certification in any county of the state by a person holding an unexpired commission as notary public who had, at the time of the certification, ceased to be a resident of the county within and in which he or she was commissioned.

Instruments in writing executed after August 13, 1993 are considered binding and effective despite the following defects:

1. Failure of the officer to attach his or her seal to the certificate.
2. Attachment of a seal to the certificate that does not bear the words and devices required by law.
3. Failure of the officer to state the date or the correct date of the expiration of his or her commission on the certificate.
4. Failure of the officer to correctly date the certificate of acknowledgment or state the county wherein the acknowledgement was taken.
5. Certification in any county of the state by a person holding an unexpired commission as notary public who had, at the time of the certification, ceased to be a resident of the county within and in which he or she was commissioned.

Where to record the document

In most counties, it is easy to determine where to record a document. Most documents can be recorded at the Circuit Clerk's office in the county courthouse located in the county seat. However, there are 10 Arkansas counties that are divided into two judicial districts, meaning there are two county seats, two courthouses

[36] Stallings v. Poteete, 17 Ark. App. 62, 702 S.W.2d 831 (1986

[37] A.C.A. 16-47-108 and A.C.A. 18-12-208

and two sets of records.

A county judicial district is defined as that portion of the specified county in which the real estate under examination is located and in which there is maintained a permanent set of records pertaining to such real estate.[38]

Any instrument affecting title to real estate must be filed in the proper county judicial district. If a document is not filed in the correct county judicial district, there is no constructive notice and any statutory requirements, such as those dealing with foreclosure, may not be satisfied.[39] Essentially, a document filed in the wrong judicial district may as well have not been filed at all.

Currently the 10 counties that have two judicial districts are Arkansas, Carroll, Clay, Craighead, Franklin, Logan, Mississippi, Prairie, Sebastian and Yell. Most circuit clerks or assessors can provide a map or listing of the lands within each district. However, in Sebastian County, the Fort Smith District includes everything within the city limits of Fort Smith, and the Greenwood District includes the remainder of the county. Therefore, any time the city of Fort Smith annexes a parcel of land, the correct place to file legal documents affecting that parcel changes from Greenwood to Fort Smith. To be safe, the documents can be filed in both places.

Effective January 1, 2001, Sebastian County moved the recording duties from the Circuit Clerk to the County Clerk. They are the only county to this.

Odds and ends

Mineral tax forfeitures.[40] Prior to April 15, 1985, the law in Arkansas concerning mineral tax deeds was clear and unambiguous. A deed for minerals that had been forfeited for taxes was void unless the mineral assessment was subjoined to the surface assessment.[41] *Subjoined* means that the severed mineral assessment must appear immediately below the surface assessment for the same property. At that time, there was not a county in Arkansas that subjoined the surface and mineral assessments and had oil or gas production.

After April 15, 1985, A.C.A. 26-26-1112 provided that county assessors may maintain separate records for severed mineral interests if they are maintained by legal description in the same manner as the surface. Most Arkansas title attorneys believe that this had the effect of making mineral tax deeds voidable, rather than void due to the great potential for defects in both the assessment and forfeiture procedures.

There is another statute that must be kept in mind in any discussion about mineral tax deeds. A.C.A. 26-37-314 purports to breathe life into all mineral tax forfeitures, even those that occurred before April 15, 1985. The purpose of the statute is to allow surface owners an opportunity to redeem severed minerals that have been forfeited for nonpayment of taxes. In an effort to get around the ruling in *Sorkin v. Meyers, supra*, the legislature inserted Paragraph (e) which states:

(e)(1) No deed issued under this section shall be void or voidable on the ground that the assessment of the property taxes on the severed mineral interest was not subjoined to the assessment of the property taxes on the surface realty.

(e)(2) This subsection shall be retroactive to all certifications of delinquent mineral

[38] Std. 1.5
[39] *Henson v. Fleet Mortgage Co.*, 319 Ark. 491, 892 S.W.2d 250 (1995)
[40] std. 19.3
[41] *Sorkin v. Myers*, 216 Ark. 908, 227 S.W.2d 958 (1950

interests in the records of the office of the Commissioner of State Lands.

A.C.A. 26-37-314 (e)(1) and (2) appear to breathe life into the old mineral tax deeds I told you were void earlier. However, Section 17 of Article 2 of the Arkansas State Constitution prohibits the legislature from passing an ex post facto law or any law impairing the obligation of contracts. An ex post facto law is one that is "passed after the occurrence of a fact or commission of an act, which retrospectively changes the legal consequences or relations of such fact or deed".[42]

To sum it up, Paragraph (e) is an *ex post facto* law that also impairs the obligations of contracts. As such it is extremely doubtful that it would withstand a judicial challenge. However, until such a challenge is successfully made, this statute is still the law.

There are many other problems with mineral tax deeds. Some of the more common that could cause a mineral tax deed to be voided by a court of law are:

1. Some counties still don't assess minerals in the manner required.[43]
2. Legal descriptions contained on the assessments and the tax deeds are often incomplete or inaccurate.
3. Notice to the mineral owner that the tax was owed may not be adequate (see Conway County in particular).
4. The procedures for forfeiture are often not followed to the letter which the Arkansas Supreme Court has stated must be done.

If any of these factors is present, the severed mineral owner would stand a good chance of challenging the validity of the forfeiture and consequently the tax deed itself. The court would not even have to address the constitutional questions. The problem for a title examiner when presented with a mineral tax deed for minerals assessed after April 15, 1985 is that he or she has no way to determine from the record if any of the above defects exist. Ensuring that the mineral tax deed is valid requires research into the method of assessment and the forfeiture and sale procedures.

The problem for a division order analyst when presented with the same mineral tax deed is whether to transfer the interest or not. This is best referred to the legal department or local counsel for further review. If the interest is substantial, the records at that courthouse should be examined for defects. If they are, this would be good reason to suspend the interest and inform both parties. If not, then until the statute is overturned, it is the law.

Some factors to consider when making the decision to suspend or not include (1) whether the division order analyst has had any contact with the severed mineral owner; (2) whether the division order analyst has a title opinion stating that the severed mineral owner should receive royalties; (3) the size of the interest in question; and (4) whether any of the defects listed above is readily present.

Statutory Pugh clause

A.C.A. 15-73-201 created a statutory Pugh clause for all oil and gas leases executed on or after July 4, 1983. It has generally been interpreted to mean that an oil and gas lease will hold lands outside a producing unit for one year after the end of the primary term.

Forced pooling procedures

Arkansas has a forced pooling procedure[44] that grants the Arkansas Oil and Gas Commission the authority to integrate

[42] *Black's Law Dictionary, Revised Fourth Edition*
[43] A.C.A. 26-26-1112
[44] A.C.A. 15-72-302(e)

separately owned tracts embraced in a drilling unit when the owners fail or refuse to do so voluntarily, provided that persons who own at least an undivided fifty percent (50%) interest in the right to drill and produce oil or gas, or both, from the total proposed unit area agree. In Arkansas this is known as *integration*. The application is normally filed by the proposed operator and may seek to integrate both working interest and mineral owners.

A drilling unit is comprised of regular governmental sections with an area of approximately 640 acres. Upon showing of good cause, the unit may be split into the North half of one section and the South half of another section. Parts of multiple sections may be combined if the sections are fractional (substantially smaller than 640 acres), such as those along the Arkansas River, in order to create a unit of approximately 640 acres.

An integration order may remain in force for period of no longer than the later of one (1) year following the effective date of the order, or one (1) year following the cessation of drilling operations or production within the unit. After that, the order of the commission and its provisions automatically terminate.[45]

An unleased mineral owner will receive the equivalent of the best terms given to any leases party within the drilling unit. If some leases were taken for three-sixteenths royalty and a $250 per acre bonus and others for a one-quarter royalty and $50 per acre bonus, the order normally gives the integrated party the same options. If no election is made within a 15 day period of receipt of the order, the integrated party is deemed to have leased at the option chosen by the operator in the order.

It has not been established by case law or statute whether drilling operations can be commenced on lands owned by an integrated mineral owner. In theory, the integrated owner is subject to the terms of a standard lease form attached to the integration order, which grants the right to drill and conduct other surface operations to the lessee. However, it is uncertain whether this amounts to taking the property unconstitutionally.

Integration Procedures A/K/A Forced Pooling

Arkansas has a forced polling procedure that is part statutory and part regulatory in nature. I have attached the pertinent statutes and Arkansas Oil and Gas Commission (AOCG) rules at the back of the paper for your future reference. A.C.A. 15-72-302(e) grants the AOGC the authority to integrate separately owned tracts embraced in a drilling unit when the owners thereof fail or refuse voluntarily to do so provided that persons who own at least an undivided fifty percent (50%) interest in the right to drill and produce oil and gas, or both, from the total proposed unit area agree thereto. In Arkansas we call this "Integration".

APPLICATION AND HEARING

An application for integration is filed with the AOGC by the proposed operator and may seek to integrate both working interest and mineral owners. AOGC Rule A-2 sets out the specific requirements for filing an application.

1. Fourteen (14) copies of the application, including exhibits must be sent to the AOGC 20 days prior to the first day of the next regularly scheduled hearing.
2. Hearings begin on the fourth Tuesday of each month and run until completed.
3. The hearing sites alternate between Fort Smith and El Dorado except in February when they are held in Hot Springs in conjunction with the Natural Resources Law Institute.

[45] A.C.A. 15-72-302(e)(3)

4. Notice of hearing shall be mailed to all interested parties at least 10 days prior to the date of the hearing but no more than 30 days prior to the hearing **and** a notice must also be published for at least 1 day in the newspaper of general circulation in each county containing a portion of the land identified in the application.
5. At the hearing the applicant will put on its evidence first. This shall include (1) name and address of applicant; (2) reason for integrating the interests; (3) legal description of the drilling unit; (4) geologic report indicating the potential reservoirs; (5) names of all owners who have not leased, agreed to participate or otherwise contracted their interest; (6) resume of efforts showing the applicant has attempted to reach an agreement with each party; (7) proof as to the highest and/or best cash bonus and royalty terms that the applicant has knowledge of within the unit.
6. After that any other party may put on evidence. All witnesses are subject to cross-examination by other parties as well as the Commissioners.
7. At the end of the hearing a motion is made to accept the application and it is voted on by the Commissioners. There are 9 commissioners and all applications must be approved by at least 5 votes.

DRILLING UNIT

A drilling unit is generally comprised of regular governmental sections with an area of approximately 640 acres. Upon showing of good cause the unit may be split into the North half of one section and the South half of another section. Part of multiple sections may be combined if the sections are fractional (substantially smaller than 640 acres), such as those along the Arkansas River, in order to create a unit of approximately 640 acres.

There are a couple of notable exceptions to the 640 drilling unit. One is for wells drilled in the Fayetteville shale and other unconventional sources of supply. In these areas a drilling unit may consist of 2 adjoining sections where a horizontal well crosses unit boundaries. In this instance the costs and revenue are split based on acreage allocation as defined in Rule B-43 (o)(2)(E).

The second exception is for the Lower Carpenter formation which is generally less than 2500 feet. Production was widely obtained in this formation before the AOGC was formed and it remains an uncontrolled zone. The unit for a well completed in the Lower Carpenter is the size and shape of the lease it is drilled on unless there is a voluntary declaration of pooling filed.

INTEGRATION ORDER

1. Orders are effective for no longer than1 year from the date of the order or as long as a well located within the unit is capable of producing oil or gas in paying quantities. Generally the order calls for either 6 months or 1 year.
2. Orders cover all depths and formations.
3. An unleased mineral owner may elect to (1) lease for the best terms as established at the hearing; (b) participate in the well; or (3) go non-consent. If a mineral owner goes non-consent 1/8 of the interest is deemed royalty and paid to the mineral owner. An owner who makes no election is deemed leased.
4. A non-committed working interest owner may elect to (1) participate in the well or (2) go non-consent.
5. Non-consent terms are defined in the Order and can either be permanent or subject to redemption after a predetermined penalty.

6. Unleased mineral owners that fail to elect are subject to an oil and gas lease that is attached as an exhibit to the application.
7. A JOA is also attached to the application and all integrated parties are subject to its terms. The form is set by the AOGC.

Instruments executed by a stranger to title[46]

An instrument in the chain of title that was executed by a stranger to the title may be disregarded as a stray instrument *if* the following conditions are met:

1. The instrument contains no recitals (other than the legal description) linking it with the record title.
2. It is not linked by reference to an unrecorded instrument.
3. It is older than 10 years.
4. The grantee has never attempted to re-convey the land, or any interest therein, as of record.
5. The chain of title is otherwise clear.
6. It is not the last instrument of record by date.
7. There is no indication of ownership in or through the grantee contained in the current records of the tax assessor in the county judicial district where the land is situated.

In the Killam[47] case, TXO relied on a title opinion that had ignored a stray mineral deed. Neither the grantor nor the grantee appeared in the chain of title. The title examiner had considered the instrument a stray deed. However, there had been a mineral deed into the grantor that had never been recorded. Since the grantee's interest was assessed on the tax rolls, the Court said this should have put TXO on notice that there was possibly another claimant to that interest.

For the most part, this kind of problem is going to arise only if the division order analyst is setting up a new well and must chain title from a landman's run sheet or an abstract. If the division order analyst is presented with a deed by an outside party, it is best to ask that party to provide a chain of title from a point in time when the title is certain to the present.

Beneficiary deed

A beneficiary deed conveys an interest in real property, including any debt secured by a lien on real property, to a grantee designated by the owner[48]. It expressly states that the deed is not to take effect until the death of the owner. While the Supreme Court has yet to rule on several questions regarding the statute, some points are clear:

1. No legal or equitable interest vests in the grantee until the death of the owner prior to the revocation of the beneficiary deed.
2. A beneficiary deed transfers the interest to the designated grantee beneficiary upon the death of the owner, subject to any mortgages, oil and gas leases, security pledges or other encumbrances made by the owner whether the encumbrance was made *before or after* the execution of the beneficiary deed.
3. The owner may designate a successor grantee beneficiary.
4. The owner may place conditions that must occur before the successor grantee is vested with any interest.
5. A beneficiary deed may be used to transfer property to a trust.
6. A beneficiary deed may be revoked by the owner at any time prior to his or her death.
7. The revocation has to be executed <u>and</u> recorded before the death of the owner.

[46] std. 3.1

[47] *Killam v. Texas Oil and Gas Corp.*, 303 Ark.547, 798 S.W.2d 419 (1990)

[48] A.C.A. 18-12-608

8. If an owner executes more than one beneficiary deed concerning the same real property, the recorded beneficiary deed that is signed last is the one that is effective.
9. Any third party that owes an obligation to the grantee beneficiary may require that person to provide reasonable evidence that the owner is deceased and that he or she did not revoke the deed prior to his or her death.

There are other nuances that concern taxes and Medicare eligibility and multiple owners and multiple grantees that are beyond the scope of this paper. However, it is important to remember that title does not transfer until the death of the owner and only if it has not been revoked.

CHAPTER 12: CALIFORNIA LEGAL AND PRACTICE SUMMARY

JOHN ("JACK") QUIRK
Bright and Brown

Interests in and ownership of real property

Limited Adoption of the common law of England. Civil Code section 22.2: The common law of England, so far as it is not repugnant to or inconsistent with the Constitution of the United States, or the Constitution or laws of this State, is the rule of decision in all the courts of this State.

Civil Code section 4: The rule of the common law, that statutes in derogation thereof are to be strictly construed, has no application to this Code. The Code establishes the law of this State respecting the subjects to which it relates, and its provisions are to be liberally construed with a view to effect its objects and to promote justice.

Civil Code section 779: HEIRS OF A TENANT FOR LIFE, WHEN TO TAKE AS PURCHASERS. When a remainder is limited to the heirs, or heirs of the body, of a person to whom a life estate in the same property is given, the persons who, on the termination of the life estate, are the successors or heirs of the body of the owner for life, are entitled to take by virtue of the remainder so limited to them, and not as mere successors of the owner for life. [Abrogation of the common law Rule in Shelley's Case.]

Probate Code section 21108: COMMON LAW RULE OF WORTHIER TITLE; INTEREST TRANSFERRED TO TRANSFEROR'S OWN HEIRS OR NEXT OF KIN. The law of this state does not include (a) the common law rule of worthier title that a transferor cannot devise an interest to his or her own heirs or (b) a presumption or rule of interpretation that a transferor does not intend, by a transfer to his or her own heirs or next of kin, to transfer an interest to them. The meaning of a transfer of a legal or equitable interest to a transferor's own heirs or next of kin, however designated, shall be determined by the general rules applicable to the interpretation of instruments. [Abrogation of the common law Doctrine of Worthier Title.]

Nature of Property. Civil Code section 654: PROPERTY, WHAT. The ownership of a thing is the right of one or more persons to possess and use it to the exclusion of others. In this Code, the thing of which there may be ownership is called property.

Civil Code section: property is either real or immovable; or personal or movable.

Civil Code section 658: Real or immovable property consists of: (1) Land; (2). That which is affixed to land; (3) That which is incidental or appurtenant to land; and (4) That which is immovable by law; except that for the purposes of sale, emblements, industrial growing crops and things attached to or forming part of the land, which are agreed to be severed before sale or under the contract of sale, shall be treated as goods and be governed by the provisions of the title of this code regulating the sales of goods.

Civil Code section 659: Land is the material of the earth, whatever may be the ingredients of which it is composed, whether soil, rock, or other substance, and includes free or occupied space for an indefinite distance upwards as well as downwards, subject to limitations upon the use of airspace imposed, and rights in the use of airspace granted, by law.

Civil Code section 660: A fixture is a thing deemed to be affixed to land when it is attached to it by roots, as in the case of trees, vines, or shrubs; or imbedded in it, as in the case of walls; or permanently resting upon it, as in the case of buildings; or permanently attached to what is thus permanent, as by means of cement, plaster, nails, bolts, or screws; except that for the purposes of sale, emblements, industrial growing crops and

things attached to or forming part of the land, which are agreed to be severed before sale or under the contract of sale, shall be treated as goods and be governed by the provisions of the title of this code regulating the sales of goods.

Civil Code section 662: An appurtenance is deemed to be incidental or appurtenant to land when it is by right used with the land for its benefit, as in the case of a way, or watercourse, or of a passage for light, air, or heat from or across the land of another.

Civil Code section 663: Every kind of property that is not real is personal.

Interests In Property. Civil Code section 678: OWNERSHIP, ABSOLUTE OR QUALIFIED. The ownership of property is either: (1) Absolute; or (2) Qualified.

Civil Code section 679: WHEN ABSOLUTE. The ownership of property is absolute when a single person has the absolute dominion over it, and may use it or dispose of it according to his pleasure, subject only to general laws.

Civil Code section 680: WHEN QUALIFIED. The ownership of property is qualified: (1) When it is shared with one or more persons; (2) When the time of enjoyment is deferred or limited; and (3) When the use is restricted.

Civil Code section 681: SEVERAL OWNERSHIP, WHAT. The ownership of property by a single person is designated as a sole or several ownership. [Ownership "in severalty.]

Civil Code section 682: OWNERSHIP OF SEVERAL PERSONS. The ownership of property by several persons is either: (1) Of joint interests; (2) Of partnership interests; (3) Of interests in common; (4). Of community interest of husband and wife. {Potentially confusing—but ownership by one person is "several" or "ownership in severalty" while ownership by several persons is not "several" ownership.]

Civil Code section 683: JOINT TENANCY; DEFINITION; METHOD OF CREATION. (a) A joint interest is one owned by two or more persons in equal shares, by a title created by a single will or transfer, when expressly declared in the will or transfer to be a joint tenancy, or by transfer from a sole owner to himself or herself and others, or from tenants in common or joint tenants to themselves or some of them, or to themselves or any of them and others, or from a husband and wife, when holding title as community property or otherwise to themselves or to themselves and others or to one of them and to another or others, when expressly declared in the transfer to be a joint tenancy, or when granted or devised to executors or trustees as joint tenants. A joint tenancy in personal property may be created by a written transfer, instrument, or agreement.

Civil Code section 683.2: JOINT TENANCY; SEVERANCE; RIGHT OF SURVIVORSHIP; APPLICABLE LAW.

> (a) Subject to the limitations and requirements of this section, in addition to any other means by which a joint tenancy may be severed, a joint tenant may sever a joint tenancy in real property as to the joint tenant's interest without the joinder or consent of the other joint tenants by any of the following means: (1) Execution and delivery of a deed that conveys legal title to the joint tenant's interest to a third person, whether or not pursuant to an agreement that requires the third person to reconvey legal title to the joint tenant. (2) Execution of a written instrument that evidences the intent to sever the joint tenancy, including a deed that names the joint tenant as transferee, or of a written declaration that, as to the interest of the joint tenant, the joint tenancy is severed.

(b) Nothing in this section authorizes severance of a joint tenancy contrary to a written agreement of the joint tenants, but a severance contrary to a written agreement does not defeat the rights of a purchaser or encumbrancer for value in good faith and without knowledge of the written agreement.

(c) Severance of a joint tenancy of record by deed, written declaration, or other written instrument pursuant to subdivision (a) is not effective to terminate the right of survivorship of the other joint tenants as to the severing joint tenant's interest unless one of the following requirements is satisfied: (1) Before the death of the severing joint tenant, the deed, written declaration, or other written instrument effecting the severance is recorded in the county where the real property is located. (2) The deed, written declaration, or other written instrument effecting the severance is executed and acknowledged before a notary public by the severing joint tenant not earlier than three days before the death of that joint tenant and is recorded in the county where the real property is located not later than seven days after the death of the severing joint tenant.

(d) Nothing in subdivision (c) limits the manner or effect of: (1) A written instrument executed by all the joint tenants that severs the joint tenancy. (2) A severance made by or pursuant to a written agreement of all the joint tenants. (3) A deed from a joint tenant to another joint tenant.

(e) Subdivisions (a) and (b) apply to all joint tenancies in real property, whether the joint tenancy was created before, on, or after January 1, 1985, except that in the case of the death of a joint tenant before January 1, 1985, the validity of a severance under subdivisions (a) and (b) is determined by the law in effect at the time of death. Subdivisions (c) and (d) do not apply to or affect a severance made before January 1, 1986, of a joint tenancy.

Civil Code section 684: PARTNERSHIP INTEREST, WHAT. A partnership interest is one owned by several persons, in partnership, for partnership purposes.

Civil Code section 685: INTEREST IN COMMON, WHAT. An interest in common is one owned by several persons, not in joint ownership or partnership.

Civil Code section 686: WHAT INTERESTS ARE IN COMMON. Every interest created in favor of several persons in their own right is an interest in common, unless acquired by them in partnership, for partnership purposes, or unless declared in its creation to be a joint interest, as provided in Section 683 [above], or unless acquired as community property.

Civil Code section 687: COMMUNITY PROPERTY DEFINED. Community property is property that is community property under Part 2 (commencing with section 760) of Division 4 of the Family Code [i.e., "Except as otherwise provided by statute, all property, real or personal, wherever situated, acquired by a married person during the marriage while domiciled in this state is community property."]

Civil Code section 688: INTERESTS AS TO TIME. In respect to the time of enjoyment, an interest in property is either: (1) Present or future; and either (2) Perpetual or limited

Civil Code section 689: PRESENT INTEREST, WHAT. A present interest entitles the owner to the immediate possession of the property.

Civil Code section 690: FUTURE INTEREST,

WHAT. A future interest entitles the owner to the possession of the property only at a future period.

Civil Code section 691: PERPETUAL INTEREST, WHAT. A perpetual interest has a duration equal to that of the property.

Civil Code section 692: LIMITED INTEREST, WHAT. A limited interest has a duration less than that of the property.

Estates In Real Property. Civil Code section 761: ENUMERATION OF ESTATES. Estates in real property, in respect to the duration of their enjoyment, are either: (1) Estates of inheritance or perpetual estates; (2) Estates for life; (3) Estates for years; or, (4) Estates at will.

Civil Code section 762: FEE SIMPLE OR ABSOLUTE FEEL Every estate of inheritance is a fee, and every such estate, when not defeasible or conditional, is a fee simple or an absolute fee.

Civil Code section 763: CONDITIONAL FEES AND ESTATES TAIL ABOLISHED. Estates tail are abolished, and every estate which would be at common law adjudged to be a fee tail is a fee simple; and if no valid remainder is limited thereon, is a fee simple absolute.

Civil Code section 765: Estates of inheritance and for life are called estates of freehold; estates for years are chattels real; and estates at will are chattel interests, but are not subject to enforcement of a money judgment.
Civil Code section 766: An estate during the life of a third person, whether limited to heirs or otherwise, is a freehold.

Civil Code section 768: REVERSIONS. A reversion is the residue of an estate left by operation of law in the grantor or his successors, or in the successors of a testator, commencing in possession on the determination of a particular estate granted or devised.

Civil Code section 769: REMAINDERS. When a future estate, other than a reversion, is dependent on a precedent estate, it may be called a remainder, and may be created and transferred by that name.

Servitudes. Civil Code section 801: The following land burdens, or servitudes upon land, may be attached to other land as incidents or appurtenances, and are then called easements:

(a) The right of pasture;
(b) The right of fishing;
(c) The right of taking game;
(d) The right-of-way;
(e) The right of taking water, wood, minerals, and other things;
(f) The right of transacting business upon land;
(g) The right of conducting lawful sports upon land;
(h) The right of receiving air, light, or heat from or over, or discharging the same upon or over land;
(i) The right of receiving water from or discharging the same upon land;
(j) The right of flooding land;
(k) The right of having water flow without diminution or disturbance of any kind;
(l) The right of using a wall as a party wall;
(m) The right of receiving more than natural support from adjacent land or things affixed thereto;
(n) The right of having the whole of a division fence maintained by a coterminous owner;
(o) The right of having public conveyances stopped, or of stopping the same on land;
(p) The right of a seat in church;
(q) The right of burial;
(r) The right of receiving sunlight upon or over land as specified in section 801.

Civil Code section 802: The following land burdens, or servitudes upon land, may be granted and held, though not attached to land:

(b) The right to pasture, and of fishing and taking game.
(a) The right of a seat in church.
(b) The right of burial.
(c) The right of taking rents and tolls.
(d) The right of way.
(e) The right of taking water, wood, minerals, or other things [the *profit a prendre*: a right to remove a part of the substance of the soil; which is the nature of fee ownership of oil and gas rights under California law. *Callahan v. Martin* (1935) 3 Cal.2d 110, discussed further below.]

Civil Code section 803: DESIGNATION OF ESTATES. The land to which an easement is attached is called the dominant tenement; the land upon which a burden or servitude is laid is called the servient tenement.

Civil Code section 804: BY WHOM GRANTABLE. A servitude can be created only by one who has a vested estate in the servient tenement.

Civil Code section 805: BY WHOM HELD. A servitude thereon cannot be held by the owner of the servient tenement.

Civil Code section 806: EXTENT OF SERVITUDES. The extent of a servitude is determined by the terms of the grant, or the nature of the enjoyment by which it was acquired.

Civil Code section 807: APPORTIONING EASEMENTS. In case of partition of the dominant tenement the burden must be apportioned according to the division of the dominant tenement, but not in such a way as to increase the burden upon the servient tenement.

Civil Code section 808: RIGHTS OF OWNER OF FUTURE ESTATE. The owner of a future estate in a dominant tenement may use easements attached thereto for the purpose of viewing waste, demanding rent, or removing an obstruction to the enjoyment of such easements, although such tenement is occupied by a tenant.

Civil Code section 809: ACTIONS BY OWNER AND OCCUPANT OF DOMINANT TENEMENT. The owner of any estate in a dominant tenement, or the occupant of such tenement, may maintain an action for the enforcement of an easement attached thereto.

Civil Code section 810: ACTIONS BY OWNER OF SERVIENT TENEMENT. The owner in fee of a servient tenement may maintain an action for the possession of the land, against any one unlawfully possessed thereof, though a servitude exists thereon in favor of the public.

Civil Code section 811: HOW EXTINGUISHED. A servitude is extinguished: (1) By the vesting of the right to the servitude and the right to the servient tenement in the same person; (2) By the destruction of the servient tenement; (3) By the performance of any act upon either tenement, by the owner of the servitude, or with his assent, which is incompatible with its nature or exercise; or (4) When the servitude was acquired by enjoyment, by disuse thereof by the owner of the servitude for the period prescribed for acquiring title by enjoyment.

Acquisition of Property. Civil Code section 1000: PROPERTY, HOW ACQUIRED. Property is acquired by:(1) Occupancy; (2) Accession; (3) Transfer; (4) Will; or (5) Succession.

Civil Code section 1006: Occupancy for any period confers a title sufficient against all except the state and those who have title by prescription, accession, transfer, will, or succession; but the title conferred by occupancy is not a sufficient interest in real property to enable the occupant or the occupant's privies to commence or maintain an action to quiet title, unless the occupancy has ripened into title by prescription.

Civil Code section 1007: Occupancy for the period prescribed by the Code of Civil Procedure as sufficient to bar any action for the recovery of the property confers a title thereto, denominated a title by prescription, which is sufficient against all, but no possession by any person, firm or corporation no matter how long continued of any land, water, water right, easement, or other property whatsoever dedicated to a public use by a public utility, or dedicated to or owned by the state or any public entity, shall ever ripen into any title, interest or right against the owner thereof. [Code of Civ. Procedure section 318: "No action for the recovery of real property, or for the recovery of the possession thereof, can be maintained, unless it appear that the plaintiff, his ancestor, predecessor, or grantor, was seized or possessed of the property in question, within five years before the commencement of the action."]

Civil Code section 1014: ALLUVION. Where, from natural causes, land forms by imperceptible degrees upon the bank of a river or stream, navigable or not navigable, either by accumulation of material or by the recession of the stream, such land belongs to the owner of the bank, subject to any existing right of way over the bank.

Civil Code section 1015: SUDDEN REMOVAL OF BANK. If a river or stream, navigable or not navigable, carries away, by sudden violence, a considerable and distinguishable part of a bank, and bears it to the opposite bank, or to another part of the same bank, the owner of the part carried away may reclaim it within a year after the owner of the land to which it has been united takes possession thereof.

Transfer. Civil Code section 1039: TRANSFER, WHAT. Transfer is an act of the parties, or of the law, by which the title to property is conveyed from one living person to another.

Civil Code section 1052: WHEN ORAL. A transfer may be made without writing, in every case in which a writing is not expressly required by statute. [But, section 1091, below.]

Civil Code section 1054: DELIVERY NECESSARY. A grant [i.e., "transfer"] takes effect, so as to vest the interest intended to be transferred, only upon its delivery by the grantor.

Civil Code section 1055: DATE. A grant duly executed is presumed to have been delivered at its date.

Civil Code section 1056: DELIVERY TO GRANTEE IS NECESSARILY ABSOLUTE. A grant cannot be delivered to the grantee conditionally. Delivery to him, or to his agent as such, is necessarily absolute, and the instrument takes effect thereupon, discharged of any condition on which the delivery was made.

Interpretation of Grants. Civil Code section 1066: GRANTS, HOW INTERPRETED. Grants are to be interpreted in like manner with contracts in general, except so far as is otherwise provided in this Article.

Civil Code section 1067: LIMITATIONS, HOW CONTROLLED. A clear and distinct limitation in a grant is not controlled by other words less clear and distinct.

Civil Code section 1068: RECITALS, WHEN RESORTED TO. If the operative words of a grant are doubtful, recourse may be had to its recitals to assist the construction.

Civil Code section 1069: INTERPRETATION AGAINST GRANTOR. A grant is to be interpreted in favor of the grantee, except that a reservation in any grant, and every grant by a public officer or body, as such, to a private party, is to be interpreted in favor of the grantor.

Civil Code section 1070: IRRECONCILABLE

PROVISIONS. If several parts of a grant are absolutely irreconcilable, the former part prevails.

Civil Code section 1072: WORDS OF INHERITANCE UNNECESSARY. Words of inheritance or succession are not requisite to transfer a fee in real property.

Civil Code section 1091: REQUISITES FOR TRANSFER OF CERTAIN ESTATES. "An estate in real property, other than an estate at will or for a term not exceeding one year, can be transferred only by operation of law, or by an instrument in writing, subscribed by the party disposing of the same, or by his agent thereunto authorized by writing.

Civil Code section 1092: STATUTORY FORM OF REAL PROPERTY GRANT. A grant of an estate in real property may be made in substance as follows:

> "I, A B, grant to C D all that real property situated in (insert name of county) County, State of California, bounded (or described) as follows: (here insert property description, or if the land sought to be conveyed has a descriptive name, it may be described by the name, as for instance, 'The Norris Ranch.')

Witness my hand this (insert day) day of (insert month), 20___.

Civil Code section 1093: CONSOLIDATION OF SEPARATE AND DISTINCT LEGAL DESCRIPTIONS INTO SINGLE INSTRUMENT OF CONVEYANCE OR SECURITY DOCUMENT; EFFECT ON SEPARATE NATURE OF PROPERTY. Absent the express written statement of the grantor contained therein, the consolidation of separate and distinct legal descriptions of real property contained in one or more deeds, mortgages, patents, deeds of trust, contracts of sale, or other instruments of conveyance or security documents, into a subsequent single deed, mortgage, patent, deed of trust, contract of sale, or other instrument of conveyance or security document (whether by means of an individual listing of the legal descriptions in a subsequent single instrument of conveyance or security document, or by means of a consolidated legal description comprised of more than one previously separate and distinct legal description), does not operate in any manner to alter or affect the separate and distinct nature of the real property so described in the subsequent single instrument of conveyance or security document containing either the listing of or the consolidated legal description of the parcels so conveyed or secured thereby.

Civil Code section 1095: ATTORNEY IN FACT, HOW MUST EXECUTE FOR PRINCIPAL. When an attorney in fact executes an instrument transferring an estate in real property, he must subscribe the name of his principal to it, and his own name as attorney in fact.

Effect of Transfer. Civil Code section 1104: WHAT EASEMENTS PASS WITH PROPERTY. A transfer of real property passes all easements attached thereto, and creates in favor thereof an easement to use other real property of the person whose estate is transferred in the same manner and to the same extent as such property was obviously and permanently used by the person whose estate is transferred, for the benefit thereof, at the time when the transfer was agreed upon or completed.

Civil Code section 1105: WHEN FEE SIMPLE TITLE IS PRESUMED TO PASS. A fee simple title is presumed to be intended to pass by a grant of real property, unless it appears from the grant that a lesser estate was intended.

Civil Code section 1106: SUBSEQUENTLY ACQUIRED TITLE PASSES BY OPERATION OF LAW. Where a person purports by proper instrument to grant real property in fee simple, and subsequently acquires any title, or claim of title thereto, the same passes by

operation of law to the grantee, or his successors.

Civil Code section 1107: GRANT, HOW FAR CONCLUSIVE ON PURCHASERS. Every grant of an estate in real property is conclusive against the grantor, also against every one subsequently claiming under him, except a purchaser or encumbrancer who in good faith and for a valuable consideration acquires a title or lien by an instrument that is first duly recorded.

Civil Code section 1108: CONVEYANCES BY OWNER FOR LIFE OR FOR YEARS. A grant made by the owner of an estate for life or years, purporting to transfer a greater estate than he could lawfully transfer, does not work a forfeiture of his estate, but passes to the grantee all the estate which the grantor could lawfully transfer.

Civil Code section 1112: A transfer of land, bounded by a highway, passes the title of the person whose estate is transferred to the soil of the highway in front to the center thereof, unless a different intent appears from the grant.

Civil Code section 1113: IMPLIED COVENANTS. From the use of the word "grant" in any conveyance by which an estate of inheritance or fee simple is to be passed, the following covenants, and none other, on the part of the grantor for himself and his heirs to the grantee, his heirs, and assigns, are implied, unless restrained by express terms contained in such conveyance: 1. That previous to the time of the execution of such conveyance, the grantor has not conveyed the same estate, or any right, title, or interest therein, to any person other than the grantee; 2. That such estate is at the time of the execution of such conveyance free from encumbrances done, made, or suffered by the grantor, or any person claiming under him. Such covenants may be sued upon in the same manner as if they had been expressly inserted in the conveyance.

Civil Code section 1114: The term "encumbrances" includes taxes, assessments, and all liens upon real property.

Nature of oil and gas rights

California oil and gas law owes much to a deliberate and express effort of California courts to take into account their perceptions (and in some instances their misperceptions) concerning both (1) the physical and geophysical nature or native condition of oil and gas "in place" within the subsurface formations and reservoirs in which it has accumulated in nature and (2) the scientific and engineering principles involved in oil and gas exploration, discovery and production.

A migratory or "fugacious" substance. An insight into judicial thinking concerning the essential nature of oil and gas can be obtained from the decisions in *Acme Oil and Mining Co. v. Williams* (1903) 140 Cal. 681:

> "There are few other mining enterprises where delay is so dangerous, and where diligence in securing immediate possession of the mineral is so necessary as in mining for oil. As to the precious metals, fixed in veins which hold them, they remain intact until extracted. [¶] Oil, on the contrary, is of a fluctuating, uncertain, fugitive nature, lies at unknown depths, and the quantity, extent, and trend of its flow are uncertain. It requires but a small surface area, in what is known as an oil district, upon which to commence operations for its discovery. But when a well is developed

> the oil may be tributary to it for a long distance through the strata which holds it." (*Acme Oil and Mining Co. v. Williams* (1903) 140 Cal. 681, 684-685.)

and *People v. Associated Oil Co.* (1930) 211 Cal. 93:

> " '… when a well is developed the oil may be tributary to it for a long distance through the strata which holds it. This flow is not inexhaustible, no certain control over it can be exercised, and its actual possession can only be obtained, as against others in the same field, engaged in the same enterprise, by diligent and continuous pumping. It is the property of anybody who can acquire the surface right to bore for it, and when the flow is penetrated, he who operates his well most diligently obtains the greatest benefit, and this advantage is increased in proportion as his neighbor similarly situated neglects his opportunity.' The same rule would apply to natural gas." [1]

This potential subsurface movement or flow of oil and gas, which is a function of the porosity and permeability of the native formation, leads to a recognition (and perhaps, in some early instances, an overemphasis upon) the migratory or "fugacious" nature of oil and gas. In this respect, oil and gas has much in common with another valuable but migratory subsurface substance – groundwater. However, unlike groundwater, oil and gas have little or no value or use in the form produced, but require varying degrees of treatment, processing and refining to yield a commercially valuable production. Also, unlike groundwater, oil and gas has little or no value for application to or use within the specific lands from which they may be produced. For these and other reasons, and although the law of groundwater was well established before any substantial commercial production of oil and gas in this state, the oil and gas law that has developed in California owes very little to groundwater law apart from some common concepts and terms.[2]

Unique substances; a unique body of law

The unique nature (and value) of oil and gas, and the fact that the practical need for a body of oil and gas law did not arise until relatively late in the overall development of common law and other legal principles, has been in some respects a liberating influence in the development of oil and gas law, although it has contributed on occasion to substantial unwarranted confusion and complexity. These considerations can be seen at play in the seminal matter of *Dabney-Johnston Oil Corp. v. Walden* (1935) 4 Cal.2d 637:

> "The failure of those who are dealing in oil rights to precisely describe the nature of the interests granted is due in part to the recent development of the oil industry. The law pertaining thereto is still in a formative stage. An analysis of the

[1] (*People v. Associated Oil Co.* (1930) 211 Cal. 93, 101-102.)

[2] (*See, e.g., Katz v. Walkinshaw* (1903) 141 Cal. 116, 136-137; and *Western Gulf Oil Co. v. Superior Oil Co.* (1949) 92 Cal.App.2d 299, 307-308.)

> nature of oil interests which may be created involves an application of the common-law rules which crystallized before there were extensive dealings in subsurface fugacious substances. In the several jurisdictions in this country there is a contrariety of description as to the nature of these interests, and in a single jurisdiction, as in this state, there are conflicting expressions as to the description of oil interests. (*See*, *Callahan v. Martin* (1935) 3 Cal.2d 110, 117-118.) It is not surprising, in view of the lack of a definite terminology descriptive of these interests, that those who are dealing in oil interests have difficulty in describing the interest transferred, and that ambiguous and uncertain instruments are presented to the courts for analysis. Such instruments must be construed as a whole in the light of the circumstances under which they were executed and the expressed intent of the parties at that time."[3]

and still, fifty years later, in *Lynch v. State Board of Equalization* (1985) 164 Cal.App.3d 94:

> "If precedent teaches anything it is that oil and gas interests are truly *sui generis*. These interests first became economically significant at a time when our basic notions of property had already crystallized. At that time the ultimate world importance of petroleum could not have been remotely anticipated. The courts attempted to fashion rules of law by analogies drawn from other fields of law which were often inapt for comparison. But oil and gas interests are by their very nature unique, and the attempt to classify them in legal terms presents 'as thorny a problem as has challenged the ingenuity and wisdom of legislatures [and courts].' As a consequence those who dealt in oil and gas interests had difficulty in describing the interests transferred and ambiguous and uncertain instruments were presented to courts for analysis. With respect to these interests the California Supreme Court has lamented: 'Their nature is far from certain or definite. They are obscure to say the least.' Thus, 'the nature of the interests which may exist in oil and gas, is complex, partly because of the inexactness of the terminology which is available to describe them.' " (*Lynch v. State Board of Equalization* (1985) 164 Cal.App.3d 94, 98-99; citations omitted throughout.)

Seminal decisions in 1935. A considerable part of California oil and gas law came into existence in a remarkable series of 1935 State Supreme Court decisions including *Callahan v. Martin* (1935) 3 Cal.2d 110, *Dabney-Johnston Oil*

[3] (*Dabney-Johnston Oil Corp. v. Walden* (1935) 4 Cal.2d 637, 650-651.)

Corp. v. Walden (1935) 4 Cal.2d 637, and *Dabney v. Edwards* (1935) 5 Cal.2d 1. These cases effectively establish the nature and incidents of the ownership of "oil and gas rights" in the State of California. While it is important to know what the Court decided on these questions, it is no less important to be aware of the "models" and concepts they rejected.

In what sense oil and gas are owned. Addressing the basic nature of ownership of oil and gas rights, in *Callahan*, the Court rejected the so-called theory of "ownership in place" which considers oil and gas within the subsurface of specific land to be owned in place, either in absolute or defeasible fee, by the owner of the land. This theory was and remains the theory of ownership of oil and gas rights in Texas and in many other oil and gas producing jurisdictions. In preference to that theory, *Callahan* (by implication, made express in *Dabney-Johnston v. Walden*) adopted what might best be called the theory of "ownership of operating rights," which at least has much in common with the law of several other oil and gas producing jurisdictions, including Oklahoma. This ownership "of operating rights" does not include any interest in specific oil and gas but, rather, the right to conduct operations for finding and producing oil and gas within specific lands. *Callahan* referred to such rights in describing prior California decisions which "unequivocally declare that the owner of the land does not have an absolute title to oil and gas in place as corporeal real property, but, rather, the exclusive right on his premises to drill for oil and gas, and to retain as his property all substances brought to the surface on his land." [4][5]

The matter is more directly stated in *Dabney-Johnston v. Walden*, in which the Court holds that "The owner of land has the exclusive right on his land to drill for and produce oil. This right inhering in the owner by virtue of his title to the land is a valuable right which he may transfer. The right when granted is a profit *a´ prendre*, a right to remove a part of the substance of the land. A profit *a´ prendre* is an interest in real property in the nature of an incorporeal hereditament [i.e., akin to an easement].... The profit *a´ prendre,* whether it is unlimited as to duration or limited to a term of years, is an estate in real property. If it is for a term of years, it is a chattel real, which is nevertheless an estate in real property, although not real property or real estate. Where it is unlimited in duration, it is a freehold interest, an estate in fee, and real property or real estate." [6/7]

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[4]"The following land burdens, or servitudes upon land, may be attached to other land as incidents or appurtenances, and then are called easements: …. (5) The right of taking water, wood, minerals, and other things." (California Civil Code § 801.) (California Civil Code § 802.)

[5] (*Callahan v. Martin* (1935) 3 Cal.2d 110, 117.)

[6]The statement in *Dabney-Johnston v. Walden* that ownership of oil and gas rights in perpetuity, or for an unlimited duration, "is a freehold interest, an estate in fee" is an early example of confused characterization through misdirected emphasis on the common law classifications of real property interests. As later explained in *Gerhard v. Stephens* (1968) 68 Cal.2d 864, 877-880 and 883-886, the terms "fee" in reference to ownership of oil and gas rights in perpetuity, or for an indefinite term is in reference solely to the <u>duration</u> of rights and is not descriptive of the character of the interest as, for example, in reference to the "fee simple" interest in Blackacre. *Gerhard* is most noted for its central holding that, because oil and gas rights, even if held "in fee," are an encumbrance or burden on the fee simple interest, akin to an easement, they can be abandoned in the same manner as easements. (*Id.*, at pp. 886-892.)

Royalty Interests and accrued revenue. All oil royalty interests, whether or not they can be fitted into the category of rent, must be considered as incorporeal interests in real property, subject to the same requirements and protected by the same safeguards. This applies to royalties reserved by the lessor in an oil and gas lease, a reservation of an "overriding royalty" by a lessee making a sub-lease, a "royalty" granted by a landowner without having previously leased the land to another, and a grant of an "overriding royalty" granted by an operating lessee.

"Thus, although only a portion of the oil royalties here considered can actually be compared to rent in the traditional sense, the purpose and scope of all such royalty interests are so similar that all should be considered equally to be incorporeal interests in real property, subject to the same requirements and protected by the same safeguards."[8]

However, oil and gas upon production and severance from the land, as well as the revenue accruing to a royalty interest in connection with production, are personal property.[9]

Severance (separation) and leasing of oil and gas rights. Apart from the basic theory of the ownership of oil and gas rights, it is appropriate to distinguish among oil and gas rights (a) in their initial form as an incident of the ownership of a "fee simple" interest in real property, and (b) as they may exist in the form of a "mineral fee" interest, after separation or severance by grant or reservation from the fee simple (or so-called "surface" interest), and (c) as they may exist through a fixed term or determinable oil and gas "lease."

In *Dabney-Johnston v. Walden*, in addition to the holding that the right to drill for and produce oil and gas is in the first instance an incident of the fee simple ownership of land, the Court held that "although the oil and gas in place doctrine is rejected, interests in oil rights which are estates in real property may be granted separate and apart from a grant of surface [i.e., fee simple] title. The grantee of the profit [i.e., of the right to drill for and produce oil and gas] has a right to such possession of the surface as is necessary and convenient for the exercise of the profit, but he has no general estate in the surface."[10]

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[7] (*Dabney-Johnston Oil Corp. v. Walden* (1935) 4 Cal.2d 637, 649.)

[8] *La Laguna Ranch Co. v. Dodge* (1941) 18 Cal.2d 132, 138-140

[9] *Callahan v. Martin* (1935) 3 Cal.2d 110, 123

[10] The statement in *Dabney-Johnston* that "... interests in oil rights … may be granted separate and apart from a grant of <u>surface</u> title," which suggests that the resulting interests are correctly termed the "surface" and the "oil and gas" (or "mineral") fee interest, as well as its statement that the grantee of the oil and gas interest "has no general estate in the surface," and statements, such as in *Wall v. Shell Oil* that "The owner of oil rights has a right to develop them, and the *owner of the surface area* has a right to develop that," have resulted in a widespread and generally accepted reference to the fee simple interest exclusive of the minerals as the "surface" interest (even in judicial decisions). This reference may be simple and convenient, but it has the disadvantage of both understating and overstating the interest involved. Ownership of the fee simple interest, whether or not the mineral interest has been severed, concerns far more than the mere "surface" of the property.

Similarly, in the context of the mineral lessee's rights to use and possession of the "leased" property, *Callahan* held that "Under the usual oil and gas lease the owner-lessor transfers to his lessee his right to drill for and produce oil and other substances. The rights of the lessee present a clear case of a profit *a´ prendre* in gross, a right to remove a part of the substance of the land. If the oil and gas lessee is not granted exclusive possession of the surface by the terms of the lease, he has nevertheless a right to such possession as is necessary and convenient for the exercise of the profit which, in fact, may preclude any other surface possession. This profit *a´ prendre* vests in the lessee an incorporeal hereditament, a present estate, an interest in the land, which is a chattel real if it is to endure for years."[11/ 12]

Thus, both the owner of severed fee oil and gas rights and the oil and gas lessee have the *dominant* but *purposeful* interest in the burdened land. They are permitted any use, activity or improvement within the scope of that purpose, and to that extent their use, activity and improvement rights are superior to those of either the mineral encumbered fee simple owner or their oil and gas lessor. Therefore, for example, the appropriate question is never whether the owner of severed oil and gas rights, or an oil and gas lessee, has the right to construct a pipeline—the question is whether the pipeline is being constructed for a use related to finding and producing oil and gas within the lands in question.

The competing land use rights of the fee simple, or mineral encumbered fee simple, interest owner, on one hand, and of the oil and gas rights lessee, or fee oil and gas rights owner, on the other, was considered by the Court of Appeals in *Wall v. Shell Oil Co.* (1962) 209 Cal.App.2d 504.

> "The law is clear that '[t]he grantee of the profit has a right to such possession of the surface as is *necessary and convenient* for the exercise of the profit, but he has no general estate in the surface.' Reasonableness in the exercise of rights is a fundamental tenet of the law, whether in the field of real property or in the countless other areas of personal relationships. It is

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Conversely, the fee simple interest exclusive of the minerals does not include "ownership" of the surface. Between the two, the mineral interest includes the paramount right to the use of the surface and subsurface insofar as necessary and convenient to enjoyment of the mineral interest, the exercise of which, "in fact, may preclude any other surface possession." (*Callahan v. Martin* (1935) 3 Cal.2d 110, 122; *Dabney-Johnston Oil Corp. v. Walden* (1935) 4 Cal.2d 637, 649-650.) Ownership of fee oil and gas rights has been classified under California law as a profit a prendre, an incorporeal hereditament, indistinguishable in most respects from an easement. (*Gerhard v. Stephens* (1968) 68 Cal.2d 864, 890). Rather than "surface" interest, I prefer to refer to the fee simple interest exclusive of severed and separately held fee oil and gas rights as the "mineral encumbered fee simple" interest—or merely the "mineral encumbered fee."

[11] Rejecting the theory that an oil and gas lease creates only an inchoate interest in the lessee prior to discovery of oil and gas and that prior to such discovery "no estate vests in him." (*Id.*, at p. 123, quoting and overruling on the point *Brookshire Oil Co. v. Casmalia Co.* (1909) 156 Cal. 211, 215.)

[12] *Callahan v. Martin* (1935) 3 Cal.2d 110, 122

> true also that the necessary and convenient use of the surface in the exercise of the profit 'in fact may preclude any other surface possession....' It is equally clear that, as conditions change, the 'reasonableness' of any particular exercise of a right may also change. An act which would be reasonable in the wilderness might be totally unreasonable in an urban area. The owner of oil rights has a right to develop them, and the owner of the surface area has a right to develop that. Society has an interest in both such developments. Though the right of the owner of land subject to a prior oil and mineral estate is subordinate thereto, yet he may exercise and develop his rights of ownership to the fullest, even though this exercise may in some degree affect the rights of the oil and mineral owner, so long as they do not prevent his enjoyment of his prior rights or unreasonably interfere therewith."[13]

In applying this "reasonableness" standard, it might be helpful to consider the language of the Court in *Keys v. Romley* (1966) 64 Cal.2d 396, involving an upper landowner's diversion of surface water runoff and actions (or inaction) by the lower owner in response. "It is ... incumbent upon every person to take reasonable care in using his property to avoid injury to adjacent property through the flow of surface waters. Failure to exercise reasonable care may result in liability by an upper to a lower landowner. It is equally the duty of any person threatened with injury to his property by the flow of surface waters to take reasonable precautions to avoid or reduce any actual or potential injury." (*Id.*, p. 409.) "The issue of reasonableness becomes a question of fact to be determined in each case upon a consideration of all the relevant circumstances.... It is properly a consideration in land development problems whether the utility of the possessor's use of his land outweighs the gravity of the harm which results from his alteration of the flow of surface waters. The gravity of harm is its seriousness from an objective viewpoint, while the utility of conduct is its meritoriousness from the same viewpoint." (*Id.*, p. 410.)

Implications of subdivision of land on oil and gas rights. In addition to considering the abstract extent of oil and gas rights activity, use and improvement within the burdened lands, *Wall v. Shell Oil* also addressed the implications of the vertical subdivision of land upon the lateral extent of land area available for oil and gas activity, use and improvement.

> "The true rule is that (1) where the owner of a parcel of land sells a portion thereof reserving or excepting the oil and mineral rights therein, or where a person purchases the oil and mineral rights in a specific tract of land, the surface area of such lands may be subjected only to such burdens as are reasonably necessary to the full enjoyment of the mineral estate in such particular specific parcels and the surface

[13] (*Wall v. Shell Oil Co.* (1962) 209 Cal.App.2d 504, 516-517.)

> area may not be burdened by installations or surface fixtures designed to serve oil producing facilities located without the parcels; but (2) the owner of the surface area [i.e., fee simple interest] in the parcel following such sales or transfers may not by any subsequent subdivision of the surface area deprive the owner of the oil and mineral estate of his rights in the entire parcel.
>
> Further, each subsequent purchaser of a subdivision thereof, taking with notice of the prior sale and reservation of rights, takes knowing that his surface ownership may be burdened in part, and, in very rare cases perhaps, in its totality, by the reasonable exercise of the rights of the owner of the oil and mineral estate; and this without regard to whether or not the oil or mineral underlies the particular subdivision, or whether the facilities located thereon serve facilities located without the subdivision, so long as they do not lie beyond the original tract."[14]

"Correlative Rights". One further word concerning a frequent misstatement related to the so-called "Doctrine of Correlative Rights" which originated as a groundwater law doctrine. In the groundwater context, Correlative Rights can be defined as the right of each owner of land overlying a body or flow of groundwater to a reasonable use of that water for his own land, although such use may interfere with or reduce the flow of water to the land of another, provided, though, that he has no right in doing so to an unreasonable diversion of water either for the sale or transportation to distant lands or otherwise to injure the water bearing strata. (*Katz v. Walkinshaw* (1903) 141 Cal. 116.) In an oil and gas context, "Correlative Rights" can be defined to include the right of each person owning land over an oil and gas bearing formation (1) to produce from their lands without waste their fair share of that oil and gas and (2) to be protected against waste of and damage to a common source of supply.[15]

Many oil and gas producing jurisdictions protect such Correlative Rights in oil and gas through legislative, judicial and/or administrative enactments or proceedings which prescribe such things as the location of wells, the allowed rates of production from wells, and the identities and respective interests of the persons who are entitled to share in the benefits of production. California does not to any significant extent control such matters through formal proceedings. Instead, California generally follows an unfettered version of the Rule of Capture which, as expressed in *Callahan,* 3 Cal.2d at 117, recognizes the exclusive right of the owner of oil and gas rights "to drill for oil and gas [on his premises], and to retain as his property all substances brought to the surface on his land." With such statements in mind, it is frequently stated that California law does not recognize or protect Correlative Rights. This is, I believe, a misstatement. The truth is that, for better or worse, California generally enforces Correlative Rights in the field—rather than in the legislature, courthouse or

[14] (*Wall v. Shell Oil Co.* (1962) 209 Cal.App.2d 504, 513.)

[15] 8 Williams & Meyers, Oil and Gas Law, "Manual of Terms," "Correlative Rights," pp. 225-226.

hearing room—by adhering to the Rule of Capture and allowing, and often encouraging, each mineral interest owner to drill and operate their own wells as efficiently and profitably as they are able. In brief, California, at least in theory, enforces Correlative Rights in oil and gas by encouraging the maximization of production from every potentially productive property. Speaking generally, given the physical reality that is reflected in the Rule of Capture (that oil and gas belong to whomever can produce them), many other jurisdictions attempt to protect the correlative rights of potential producers by legislative, judicial or administrative measures to minimize or mitigate the effects of the Rule of Capture -- while California oil and gas law broadly speaking endeavors to protect correlative rights by giving the Rule of Capture full and unimpaired play.[16]

California's "index" system of recording land records

Why Recording? Discussion of California's recording system for land records begins with the English Common Law Rule, because that is where the relevant statute takes us.

> "The common law of England, so far as it is not repugnant to or inconsistent with the Constitution of the United States, or the Constitution or laws of this State [California], is the rule of decision in all the courts of this State." [17]

The English Common Law had nothing to say about recording of land records—because the English common law did not recognize a system for the recording or registration of land records. The Common Law rule that applied to conflicting titles was "*prior in tempore portior est in jure*" meaning "First in time is first in right." (Not, as sometimes claimed, "First in line gets the largest portions.")

Every deviation from the Common Law has an intended purpose, to address some perceived shortcoming in the Common Law (whether wise or otherwise is beyond the scope of this paper). The purposes of the recording statute are well outlined in the following passage from a 1906 California Supreme Court decision:

> "It is hardly necessary to point out that under the system of registration of land titles which has grown up in all of the states of this Union **it is practically essential to the security of ownership in real property that there exist some method by which the title can be made clear of record**. Without regard to the effect of duly recorded instruments as constructive notice (whether or not the record remains in actual existence), the registration of titles has become so thoroughly imbedded in our system

[16] With the perhaps unfortunate consequence that the primary effective regulation of the California oil and gas industry often seems to be through application of zoning, land use, environmental and health and safety regulations.

[17] Cal. Civ. Code, §22.2

of dealing with lands that **a title which cannot be traced and established by some form of public record is practically unmerchantable**. It is of course true that for many centuries lands have been transferred in England, whence we have, in the main, derived our system of real property law, without any considerable resort to a public recording scheme. But in this country the system of registration has become so completely established that the courts can take judicial notice of the fact that **in the great majority of cases parties dealing in real estate rely for the proof of their titles upon the chain of title that will be disclosed by an examination of the records, and in a small degree, if at all, upon the possession of the original instruments composing that chain**. In many instances, indeed, these instruments are not preserved for any great length of time."[18]

[18] (*Title & Document Restoration Co. v. Kerrigan* (1906) 150 Cal. 289, 305.)

Hence, the recording system serves two major complimentary purposes: to protect land titles and to inform concerning land titles. *First*, the recording statute enables a purchaser or encumbrancer—by themselves recording—to establish and "protect" their place in line or "priority" as to those who record after them. *Second*, it creates a "conclusive" depository of records for review enabling a new purchaser or encumbrancer, by undertaking that review, to determine the pre-existing state of title to which they will be subject.

What Does Recording Accomplish? The recording statute does not abrogate or cancel the Common Law, but only supplements it. The Common Law remains "the rule of decision … so far as it is not repugnant to or inconsistent with the Constitution of the United States, or the Constitution or laws of [California]." (Cal. Civ. Code, § 22.2.) Therefore, the rule continues to be "First in time is first in right," *except where otherwise provided in the relevant recording statute*. The principal provisions of California's statute for the recording of real property records are found in Civil Code section 1213 and section 1214, but it seems to make more sense for our purposes to consider them in the opposite order:

> **§ 1214. Prior recording of subsequent conveyances, mortgages, judgments.** Every conveyance of real property or an estate for years therein, other than a lease for a term not exceeding one year, is void as against any subsequent purchaser or

> mortgagee of the same property, or any part thereof, in good faith and for a valuable consideration, whose conveyance is first duly recorded, and as against any judgment affecting the title, unless the conveyance shall have been duly recorded prior to the record of notice of action.[19]

This provision creates a device by which a subsequent purchaser or encumbrancer may reverse the Common Law Rule concerning priorities of land titles by avoiding the effect of a previously created conveyance. Thus, California is a so-called "Notice-Race" recording statute—protecting the "first to record in good faith," or without notice of the prior conveyance.[20]

In addition to providing a method by which the Common Law Rule of priorities may be avoided for the benefit of a subsequent purchaser, the statute also provides a method by which the "first in time" may also protect themselves against subsequent conveyances—preserving the Common Law priority, by also being the first to record. The recording statute does not entirely supplant the Common Law Rule but merely creates a procedure through which the preservation or avoidance of the Common Law Rule is dependent upon the act of recording. Do not overlook the fact that the recording statute excepts from its application the interest of a prior purchaser or encumbrancer who preserves their priority under the Common Law rule, protecting themselves against the claim of a subsequent purchaser, by being themselves the first to record. Also note that any knowledge of a subsequent conveyance or encumbrance is irrelevant to the rights of a prior purchaser or encumbrancer who first records! WHY—because their priority is established by the Common Law Rule; the priority of the prior purchaser or encumbrancer is not created by the recording statute. Rather, by being the first to record, the prior purchaser or encumbrancer prevents the subsequent purchaser from gaining any benefit against him from the recording statute. Also note that even when a subsequent purchaser or encumbrancer is first to record, the prior conveyance or encumbrance is not entirely "void" – only void as against a specific subsequent purchaser or encumbrancer:

- of the same property, or any part thereof
- in good faith
- for a valuable consideration
- whose conveyance is first duly recorded

Each of these elements has developed a very specific (and sometimes surprising) meaning. We will explore them further below.

First, though, recall that in addition to affording ***protection***, whether against prior or subsequent conveyances, the recording statute serves to create and provide a "conclusive" body of documents that can be reviewed by a potential purchaser or encumbrancer for

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[19] **§ 1215. Conveyance defined.** The term "conveyance," as used in Sections 1213 and 1214, embraces every instrument in writing by which any estate or interest in real property is created, aliened, mortgaged, or encumbered, or by which the title to any real property may be affected, except wills.

[20] A definite minority of jurisdictions have so-called "Pure Race" recording statutes—meaning that recording protects the first to record with or without knowledge of the prior conveyance. A rule that might be preferred, on one hand, by felons and, on the other, by persons who have no belief in Original Sin.

information to determine the state of title to which they would be subject. This conclusive body of documents represents the matter "of record" to which a present conveyance is subject or, in other words, the matter to which a present purchaser or encumbrancer would be subject. The general content of this "conclusive" body of documents is as provided in Civil Code section 1213:

> **§ 1213. Record of conveyances; constructive notice; recording certified copies; effect.** Every conveyance of real property or an estate for years therein acknowledged or proved and certified and recorded as prescribed by law from the time it is filed with the recorder for record is constructive notice of the contents thereof to subsequent purchasers and mortgagees; ….[21]

Once again, we are going to see below that some of these fairly straightforward sounding terms and phrases has developed a very specific (and sometimes very surprising) meaning.

Where and when is a conveyance "duly recorded"? Civil Code section 1170 provides that "An instrument is deemed to be recorded when, being duly acknowledged or proved and certified, it is deposited in the Recorder's office, with the proper officer, for record." But we have already seen that Civil Code section 1213 ascribes "constructive notice" to a conveyance "recorded as prescribed by law," while section 1214 refers to the "conveyance … first duly recorded." But what does it mean (or what is required) for an instrument to satisfy these requirements. Surprisingly to some, a conveyance is not duly recorded merely because it has been accepted for filing and filed by a county recorder.

Record In Each Relevant County. First, and rather obviously, Civil Code section 1169 requires that "Instruments entitled to be recorded must be recorded by the County Recorder of the county in which the real property affected thereby is situated." Note, though, that if you have a document affecting land in several counties, you do not necessarily need to have an original for recording in each. Civil Code section 1218: "*Recording certified copies of instrument or certified copy of record; effect.* A certified copy of an instrument affecting the title to real property, once recorded, or a certified copy of the record of such instrument may be recorded in any other county, and, when so recorded, the record thereof has the same force and effect as though it was of the original instrument."

Check Back Later To Confirm Indexing. However, it turns out that *proper indexing* is also *essential* to "recording" as (and for the reasons) explained in *Hochstein v. Romero* (1990) 219 Cal.App.3d 447, 452, California courts have consistently held that the conclusive imputation of notice of recorded documents depends upon proper indexing because a

[21] "…and a certified copy of such a recorded conveyance may be recorded in any other county and when so recorded the record thereof shall have the same force and effect as though it was of the original conveyance and where the original conveyance has been recorded in any county wherein the property therein mentioned is not situated a certified copy of the recorded conveyance may be recorded in the county where such property is situated with the same force and effect as if the original conveyance had been recorded in that county."

subsequent purchaser should be charged only with notice of those documents which are locatable by a search of the proper indexes and, conversely, that, if a document has been improperly indexed and is therefore not locatable by a proper search, mere recordation is insufficient to charge the subsequent purchaser with notice.

> … before constructive notice will be conclusively presumed, the document must be "recorded as prescribed by law." (Civ. Code, § 1213.) A document not indexed as required by statute (see Gov. Code, §§ 27230-27265), does not impart constructive notice because it has not been recorded "as prescribed by law." The policy of the law [requiring recordation and indexing] is to afford facilities for intending purchasers ... in examining the records for the purpose of ascertaining whether there are any claims against [the land], and for this purpose it has prescribed the mode in which the recorder shall keep the records of the several instruments, and an instrument must be recorded as herein directed in order that it may be recorded as prescribed by law. If [improperly indexed], it is to be regarded the same as if not recorded at all."[22] Thus, it is not sufficient merely to record the document. "California has an 'index system of recording,' and ...*correct indexing is essential* to proper recordation.

But if you are going to be granting security interests in oil and gas (or other minerals or timber) upon its production or severance from the land, you should be aware of a difference between the provisions of the California Uniform Commercial Code, on one hand, and those of the California Civil Code and decisional authority, on the other, concerning the consequences of improper indexing of documents filed for the perfection of a security interest. As already noted above, California Civil Code section 1213, which limits the effect of materials recorded in county real property records to such as are "acknowledged or proved and certified and recorded as prescribed by law," has been consistently interpreted to make the county recorder, in effect, the agent of the grantee (i.e., Secured Party, in the present context). (*Lewis v. Superior Court* (1994) 30 Cal.App.4th 1850.) Thus, the California Supreme Court has held that a recorded mortgage of land erroneously indexed only as a "note and pledge as security" did not impart constructive notice to a subsequent purchaser of the real property who is not obligated to examine the record of an instrument that is shown by the recorder's index to affect only personal property. (*Rice v. Taylor* (1934) 220 Cal. 629.) You should note, however, that California (Uniform) Commercial Code section 9517 provides, "The failure of the filing office to index a record correctly **does not affect** the effectiveness of the filed record," thus imposing the risk of filing-office error on a person subsequently searching the record.

It remains an unsettled question which of these rules applies, and thus where the risk or failure to properly index resides, when the filing officer is the county recorder under the

[22] *Cady v. Purser* (1901) 131 Cal. 552, 558 [63 P. 844].

California Uniform Commercial Code, as in the case of fixture filings, security interests in as-extracted collateral, etc.

What Can Properly Be Recorded? California Government Code section 27280(a) provides that "Any instrument or judgment affecting the title to or possession of real property may be recorded pursuant to this chapter."[23] But what is the effect of something that is accepted for recording (and indexed) which should not have been recorded?

- An instrument, not entitled to go upon record, is not constructive notice, although recorded.[24]
- We agree with appellee's counsel that an instrument, not entitled to go upon record, is not constructive notice, although recorded. [Citations omitted.] "But we do not agree that such an instrument may not impart actual notice to one who has seen it of record, for the law is that if the purchaser does actually see the instrument of record, it constitutes notice. It is difficult to imagine any reason why this should not be the law, since it is immaterial where the purchaser sees the instrument, whether on the record or elsewhere."[25]

So if your due diligence review includes a document from the seller's files or from a title plant that was not entitled to be recorded, you cannot avoid notice of the contents of that document, and it's implications, by arguing that the document should not have been recorded.

Who Is Protected? Civil Code section 1214 affords the protection of the recording statute to "any subsequent purchaser or mortgagee of the same property, or any part thereof, in good faith and for a valuable consideration, whose conveyance is first duly recorded." Here, "good faith" involves a lack of knowledge of the prior conveyance; the recording statute does not protect subsequent purchasers or encumbrances who take with knowledge of the prior conveyance. Hence, an unrecorded instrument is valid between parties that have notice of the instrument.[26]

Also note Civil Code section 1096 concerning persons or entities who change their name after acquiring property in a prior name:

> "Any person in whom the title of real estate is vested, who shall afterwards, from any cause, have his or her name changed, must, in any conveyance of said real estate so held, set forth the name in which he or she derived title to said real estate. Any conveyance, though recorded as provided by law, which does not comply with the foregoing provision shall not impart constructive notice of the contents thereof to subsequent purchasers and encumbrancers, but such conveyance is valid as between the parties thereto and those who have notice thereof."

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[23] There are numerous other more specific authorizations for recording such things as notices of commencement of a quiet title action (Cal. Code Civ. Proc., § 761.010), oil and gas lien (Cal. Code Civ. Proc., § 1203.58), mechanic's lien filings (Cal. Civ. Code, § 3109, et seq.), notices to preserve various interests or rights in real property under the Marketable Record Title Act (Cal. Civ. Code, § 880.020, et seq.), etc.

- [24] *Hale v. Pendergrast* (1919) 42 Cal.App. 104, 107.

[25] *Parkside Realty Co. v. MacDonald* (1913) 166 Cal. 426, 431.

[26] Cal. Civ. Code, § 1217

In Good Faith. The *notice* of a prior but unrecorded conveyance which is discussed in Civil Code section 1217 is not limited to actual specific knowledge of the existence of a prior conveyance. As provided in Civil Code section 18, "Notice is: 1. Actual—which consists in express information of a fact; or 2. Constructive—which is imputed by law." With respect to such *constructive notice*, Civil Code section 19 provides that:

> "Every person who has actual notice of circumstances sufficient to put a prudent man upon inquiry as to a particular fact, has constructive notice of the fact itself in all cases in which, by prosecuting such inquiry, he might have learned such fact."

Thus, a person who is the eyes of the law is obliged to inquiry based on the facts and circumstances known to them, is held to have knowledge of the facts and information which would be unearthed by that inquiry—whether or not they actually undertake such an inquiry. This just means that "constructive notice" is the same as actual knowledge. Taken together with the provisions of the recording statute, it follows that a potential purchaser or encumbrancer who has constructive knowledge of facts bearing on title to the specific real property in question is in the same position in the eyes of the law as if they had actual knowledge of those facts. If a reasonable person in your position would inquire, then you cannot avoid the knowledge which that inquiry would reveal, and the implications of that knowledge, by declining to make the inquiry.

The recording statute itself is a potential source of *constructive notice*, because as a matter of law—under Civil Code section 1213—duly recorded conveyances are *constructive* notice of their contents to subsequent purchasers or encumbrances. This knowledge, the knowledge that would be acquired from a review of the relevant record, is imputed to subsequent purchasers and encumbrancers whether or not they actually review the official records pertaining to the specific property in question.

Deliberate Ignorance and Other "Off-Record" Sources. Of course, the official real property records are not the sole source of notice or knowledge concerning matters affecting title to real property. In *Beach v. Faust* (1935) 2 Cal.2d 290, the Supreme Court reversed a decision of a trial court involving a quitclaim deed from an individual who had been adjudicated a bankrupt in federal court but the bankruptcy decree was not recorded at the time and the particular real property asset involved had not been included in his bankruptcy court filing or otherwise made known to the trustee in bankruptcy until sometime later. The trial court held that a purchaser without actual knowledge of the bankruptcy who paid $100 for a quitclaim deed from the bankrupt and recorded that quitclaim deed before recording of a subsequent deed out of a bankruptcy sale was not entitled to the benefit of the recording statute "on the theory that the bankruptcy proceeding in the federal court was constructive notice *per se* to all intending purchasers that Marks, the original owner of the property, had been declared a bankrupt." (*Id.* at 292.) In reviewing the matter, the Supreme Court considered (a) the intended purpose and effect of the recording statute, (b) the extent to which matters appearing outside the official land records (e.g., bankruptcy court records) operate to provide constructive notice in the same way as the official land records, and (c) whether the fact that a quitclaim deed was involved had any effect upon the "good faith" of the purchaser.

Intended Purpose and Effect of Recording Statute.

> "**The recording laws were not enacted to**

> **protect those whose ignorance of the title is deliberate and intentional, nor does a mere nominal consideration satisfy the requirement that a valuable consideration must be paid.** Their purpose is to protect those who honestly believe they are acquiring a good title, and who invest some substantial sum in reliance on that belief." (*Beach v. Faust, supra*, 2 Cal.2d at 292-293, emphasis added.)

Constructive Notice from Other "Records".

> "The adjudication of Marks in the bankruptcy court was not of itself notice *per se,* and the trustee was required within thirty days after the adjudication to file a certified copy of the decree of adjudication in the office where conveyances of real estate are recorded in every county where the bankrupt owned real estate not exempt from execution." (*Beach v. Faust, supra*, 2 Cal.2d at 293, citation omitted.)

Good Faith Purchaser by Quitclaim

> "That a deed conveys merely 'the right, title and interest' of the grantor does not prevent the grantee from being a purchaser for a valuable consideration, without notice, within the recording laws, so as to be protected from unrecorded instruments affecting the title to the property of which he had no notice. …. It has long been the accepted rule in this state that real estate, or an interest in real estate, can be aliened or assigned by a quitclaim deed. Such a deed is good as against even an unrecorded grant, bargain and sale deed." (*Beach v. Faust, supra*, 2 Cal.2d, citations omitted throughout.)

But do not be misled by this discussion into believing that information obtained from sources other than the official land records cannot provide either actual or constructive notice of prior acts such as to deprive a subsequent purchaser or encumbrancer who first records of the protection of the recording statute. Consider the two cases of *Triple A Management Co. v. Frisone* (1999) 69 Cal.App.4th 520 and *In Re Marriage of Gloney* (2001) 91 Cal.App.4th 429. In each of these cases, the Court of Appeal not only held that information actually obtained from sources other than the official land records was "notice" to a subsequent purchaser (*Gloney*) or encumbrancer (*Triple A*), but also that such "notice" to the escrow agent of the subsequent purchaser (*Gloney*) or encumbrancer (*Triple A*), in the course and scope of that agency, was properly imputed as notice to their principal, i.e., the subsequent purchaser (*Gloney*) or encumbrancer (*Triple A*) themselves.

> "Several limitations are inherent in the protection

> afforded a good faith encumbrancer for value, however; two such limitations are relevant in the present case. First, the subsequent encumbrancer is permitted only to rely on the recorded state of title as that state of title objectively presents itself: **the subsequent encumbrancer is not entitled to view the record either through rose-colored glasses or with blinders on**. That is, he is not entitled to interpret ambiguities in his own favor nor is he entitled to ignore reasonable warning signs that appear in the recorded documents. Second, **a lender is not entitled to ignore information that comes to him from *outside* the recorded chain of title, to the extent such information puts him on notice of information that reasonably brings into question the state of title reflected in the recorded chain of title**.[27]

The first of these points is potentially quite problematic, since it requires that documents in the official land records be reviewed not only for their obvious intended purpose but also for ambiguity:

> ' " When a 'conveyance in a chain of title under which a purchaser for value claims shows on its face it is so ambiguous as to leave room for reasonable difference of opinion as to what was granted, or when the grant contains limiting or qualifying words sufficient to cast reasonable doubt on what was intended to be granted, **the purchaser will be chargeable with notice of this ambiguity**, and the effect of these limiting or qualifying words, and **his rights, if controversy comes up, must be left to be determined by the courts**,' ..." [28]

Also, "knowledge" or "notice" may sometimes consist of information known to an agent and imputed to its principal. In general:

> "The basis for imputing knowledge to the principal is that **the agent has a legal duty to disclose information obtained in the course of the agency and material to the subject matter of the agency, and the agent will be presumed to have fulfilled this duty**. The scope of the imputation of knowledge is directly related to the scope of the duty arising from the agency

[27] *Triple A*, *supra*, 69 Cal.App.4th 520, 530-531

[28] *Triple A*, *supra*, 69 Cal.App.4th at 532

agreement; it has nothing to do with whether the agent actually has the information in question or has it only constructively or whether it is practical to expect the agent to remember something that happened months ago."[29]

For Value. As already suggested above, the protection of the recording statute is not available to every grantee or encumbrancer who merely takes "in good faith" or without notice of prior conflicting rights. It is also necessary that the subsequent grantee or encumbrancer have acquired their rights "for value." The following, from *James v. James* (1926) 80 Cal.App. 185, concerning a conveyance from a father to his son who took without notice of a prior conveyance made from the father to his wife, is instructive:

> "The defendant in this case, basing his claim upon a deed executed and recorded subsequent to the execution and delivery of an unrecorded deed, takes upon himself the burden of showing that the deed accepted by him was received without actual knowledge of the prior unrecorded deed <u>and, also, that he has, in fact, parted with a valuable consideration as the purchase price of the property</u>. ….[¶] 'To entitle a party to protection as such purchaser, **he must prove the payment of the purchase money in good faith and without notice, actual or constructive, prior to and down to the time of its payment**, for **if he had notice at any moment of time before the payment of the money, he is not a *bona fide* purchaser**.' Nor can the recitals contained in the deed as to the consideration paid be accepted as *prima facie* proof of such payment. Such recitals are but the declarations of the grantor. The respondent relies upon and the court apparently accepted as sufficient the recital in the instrument executed and delivered by Thomas F. James to the defendant Howard T. James, purporting to convey the property described in the complaint, wherein it is stated that the said Thomas F. James for a consideration of ten dollars, 'to him in hand paid, the receipt whereof is hereby acknowledged, does hereby grant to Howard T. James' all right, title, and interest of the grantor in and to the premises in controversy. … "The burden of

[29] *Triple A*, *supra*, 69 Cal.App.4th at 534-535

proving [consideration] rested upon him (grantee), and the recitals in the deed are not, as he contends, *prima facie* proof of a valuable consideration. Such recitals are but the declarations of the grantor, and it has never been held that the declarations of a vendor or assignor, made after the sale or assignment, can be received to defeat the title of the vendee or assignee. **A party seeking to bring himself within the statute cannot rely upon the recitals of his deed, but must prove the payment of the purchase money *aliunde*.**"[30] In 9 California Jurisprudence, section 45, page 145, we find the following: "Where the payment of a valuable consideration becomes a material question, the recital in a deed of a valuable consideration paid by the grantee is only evidence of such payment as against the grantor, or against those claiming under the grantor by a subsequent conveyance; but it is evidence of the payment of a valuable consideration only as against those claiming under the grantor by conveyance subsequent to the same. It is, therefore, not evidence as against strangers, nor as against the owner of a prior equity, nor as against one claiming under a prior deed from the same grantor. ... **One claiming as a *bona fide* purchaser for a valuable consideration under a second deed, but recorded first in point of time, must affirmatively prove the payment by other evidence than the deed itself**.' [31]

The same rule applies to a good faith encumbrancer seeking the protection of the recording statute. "A good faith encumbrancer for value who first records takes its interest in the real property free and clear of unrecorded interests. 'An encumbrancer in good faith and for value means a person who has taken or purchased a lien ... and who has parted with something of value in consideration thereof...."[32]

"Down the Road" Bona Fides.

What happens when a subsequent purchaser or encumbrancer who takes with notice, and so cannot take "in good faith," transfers their rights to another who takes "in good faith"? Does that remote purchaser become a bona fide purchaser or encumbrancer *Down the Road*? Yes, with one significant exception, as we will see shortly.

Succession to Bona Fides

What happens when a good faith purchaser or encumbrancer for value attempts to transfer

[30] "From another source."

[31] *James v. James, supra,* 80 Cal.App. at 193-194, emphasis added

[32] *Triple A Management Co v. Frisone*, *supra,* 69 Cal.App.4th at 530

their interest to another person who cannot take "in good faith" because that proposed transferee already has notice of a prior transaction. Is that transferee entitled to the protection of the recording statute despite their own antecedent knowledge? Normally, yes. But with the same very significant exception. The two relevant rules are set forth as follows in *Los Angeles Investment Co. v. Torchia* (1930) 106 Cal.App. 21, 27-28:

> "There are two special rules on the subject, which have been settled since an early day, one being a mere application of the general doctrine, and the other a necessary inference from it.
>
> "The *first* is, that if a second purchaser, for value and without notice, purchases from a first purchaser who is charged with notice, he thereafter becomes a *bona fide* purchaser and is entitled to protection. This statement may be generalized. If the title to land, having passed through successive grantees, and subject in the hands of each to prior outstanding equities, comes to a purchaser for value and without notice, it is at once freed from these equities; he obtains a valid title, and with a single exception, the full power of disposition. This exception is, that such a title cannot be conveyed free from the prior equities, back to a former owner who was charged with notice. If 'A,' holding title affected with notice, conveys to 'B,' a *bona fide* purchaser, and afterwards takes a reconveyance to himself, all the equities revive and attach to the lands in his hands, since the doctrine requires not only valuable consideration and absence of notice, but also good faith.
>
> "The second rule is that if a second purchaser with notice acquires title from a first purchaser who was without notice, and *bona fide*, he succeeds to all the rights of his immediate grantor. In fact, when land once comes, freed from equities, into the hands of a *bona fide* purchaser, he obtains a complete *jus disponendi*, with the [same] exception last above mentioned, and may transfer a perfect title even to volunteers."

Hence, to be truly afforded the protection of the recording statute, a good faith purchaser or encumbrancer for value must be able to transfer their interest and rights to another, even to another whom by virtue of their notice of events would not independently qualify as a good faith purchaser or encumbrancer in their own right.[33]

[33] More elegantly stated in *Jones v. Independent Title Co.* (1944) 23 Cal.2d 859, 861: "A bona fide purchaser can convey his entire interest or title free and clear of outstanding but undisclosed and unrecorded equities prior in point of time to the claims of such

Additionally, it is not necessary for a transferee to give value in order to pass along the benefit of the recording statute:

> "[E]ven if the grantee of a bona fide purchaser received the property as a gift he 'could rely upon the consideration paid' by his grantor and that, in effect, he 'would be subrogated to' the latter's rights. Consequently, whether plaintiff did or did not give consideration to Collins for the deed from Collins to plaintiff is immaterial here, as is also the fact that he had at least constructive notice of defendant's trust deed before receiving the deed from Collins." [34]

But no "re-birth" of bona fides.
The exception common to both of those rules is that a **former owner** who had notice of a prior transaction before he first acquired title cannot obtain the benefit of the recording statute even by succeeding to a party who has properly obtained that benefit—a purchaser who takes with notice of a prior purchaser cannot through any series of subsequent transactions restore himself to "good standing" under the recording statute. A good faith purchaser or encumbrancer for value, who has the benefit of the recording statute against a prior unrecorded instrument, cannot pass along the benefit of that protection back to someone who was prior to him in the title to the same property but who took with notice of the prior rights in question.

Reviewing the chain of title.
"Record title" simply refers to the sum total of information concerning specific real property which would be obtained from a review of the relevant record. (We will consider further just what is in the "relevant record" when we discuss the "Chain of Title," below.)

It follows that "record title" with respect to specific real property is the same for everyone—because the official record is the same for everyone.
But "actual title" is dependent upon the specific actual and constructive knowledge ("notice") of specific individuals and so may vary among individuals.

The recording statute affords its protection to the purchaser or encumbrancer "of **the same property, or any part thereof**." But the California land title records are not organized and maintained on a tract basis, and access to the records for the purpose of review and information is through an index of the "grantor" and "grantee" names. The most usual way to conduct a search in official land records is to begin by sequential review back in time through the "grantee" index, starting with the contemplated "grantor" and searching back in the "grantee" index to find conveyances into them. Those conveyances are then reviewed until the appropriate conveyance into the contemplated grantor is located, their grantor identified, and then the "grantee" index review repeated for that name until the relevant conveyance into them is located. This process is continued sequentially back in time until the search arrives at patent or the earlier available conveyance. From that point the search is conducted through sequential review of the grantor index forward in time, first locating all instruments affecting all or any part of the

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purchaser, even (with one exception which is not involved here) to a transferee or grantee with notice of such equities."

[34] *Jones v. Independent Title Co., supra,* 23 Cal.2d at 861-862

property in question out of that initial owner up to and including the conveyance of the property in question from that initial owner; then locating all instruments affecting all or any part of the property in question out of that second owner up to and including the conveyance of the property in question from that second owner to the next owner, and so on up to and including the present contemplated grantor.

The "Wild Deed". There is generally no need to review for instruments made and recorded out of a particular prior owner prior to the time they acquired title. But what about an instrument that is made after they acquired title but recorded before the deed by which they acquired? That was the question presented in *Far West Savings & Loan Assn. v. McLaughlin* (1988) 201 Cal.App.3d 67. As discussed in that decision, at page 70, McLaughlin claimed under a deed of trust from Geiger dated August 3, 1982 and recorded August 10, 1982, although the grant deed into that trustor, dated July 8, 1982, was not recorded until August 10, 1982. Far West claimed under the July 8, 1982 deed from Geiger to GTB Properties, a July 1, 1983 deed from GTB to Stapleton and a July 1 deed of trust from Stapleton to Far West, all recorded July 1, 1983. The central question was whether Far West had constructive notice of the 1982 Geiger-McLaughin deed of trust which had been recorded some 11 months before the July 1983 recording of the deed into Geiger. The Court of Appeal affirmed the decision of the trial court that Far West did not take with notice of that prior deed of trust.

> "Proper recordation of a real property instrument is necessary to impart constructive notice of its contents. (Civ. Code, §§ 1213, 1214.) If an instrument cannot be located by searching the "grantor" and "grantee" indices of the public records, the instrument does not constitute constructive notice and later bona fide purchasers or encumbrances are not charged with knowledge of its existence. [¶] The GTB deed of trust was recorded *before GTB obtained record title*. Therefore, it must be termed a "wild" document, i.e., one recorded outside the chain of title. As such, a search of the grantor/grantee indices could not have disclosed its existence. "One who is not connected by any conveyance whatever with the record title to a piece of property and makes a conveyance thereof, does not thereby create any defect in the record title of another when such title is deducible by intermediate effective conveyances from the original owners to that other .... Such a deed would not even be constructive notice." [¶] This same rule applies to a conveyance by a person who is in the chain of title, but who makes a conveyance *prior to his acquisition of record title*. His conveyance, at the time it is made, is that of a stranger to the title; and, although he afterwards

gains record title and makes another conveyance, the second grantee is not bound, in his search of the record, to determine whether his grantor, or any grantor in the chain, made a conveyance *before such grantor became a part of the chain*. The second grantee who purchases for value and records first will prevail by virtue of the terms of the recording statute. He has no constructive notice of the deed to the first grantee, for the record of such deed, made before the grantor had title, *is not in the chain of title*. **For the first grantee to prevail he would have to have recorded his deed *again* (1) *after* record title had come to his grantor and (2) *before* the second grantee had given value**. [¶] McLaughlin did not later record again after GTB acquired record title; therefore, the GTB deed of trust remained outside the chain of title. Contrary to McLaughlin's argument, the later recordation, on July 1, 1983, of the July 8, 1982, Geiger grant deed to GTB did not bring the GTB deed of trust into the chain of title. To accomplish that, McLaughlin would have had to record the GTB deed of trust again, *after the grant deed to GTB had been recorded, and before Far West gave value*. This, of course, did not happen. Nor did the earlier date of the Geiger deed to GTB impart a duty to search beyond the chain of title. "Priorities, and the title examination, are determined by the date of *recording* and not the date of *execution*." (*Far West Savings & Loan, supra*, 201 Cal.App.3d at pp. 73-74.)

Similarly, in *Ludy* v. *Zumwalt* (1927) 85 Cal.App. 119, plaintiff gave Zumwalt an option to purchase her land, left unrecorded, after which Zumwalt contracted with a water company to irrigate it, by a contract giving the water company a prior lien on the land for charges. This contract, with that lien, was recorded. Later, Zumwalt exercised his option and plaintiff conveyed to him, taking a note and purchase money mortgage for the price. Zumwalt defaulted in both payment of the water charges and the note, and the water company claimed its prior lien upon the land. The court held that the **record of the prior lien was not notice to plaintiff because, at the time it was recorded, Zumwalt had no title** and an encumbrance given by him was outside the chain.

Notarial acknowledgement.

Civil Code section 1181: <u>Notaries public; officers before whom proof or acknowledgment may be made.</u> The proof or acknowledgment of an instrument may be made before a notary public at any place within this state, or within the county or city and county in this state in which the officer specified below was elected or appointed, before any of the following:

(1) A clerk of a superior court.
(2) A county clerk.
(3) A court commissioner.
(4) A retired judge of a municipal or justice court.
(5) A district attorney.
(6) A clerk of a board of supervisors.
(7) A city clerk.
(8) A county counsel.
(9) A city attorney.
Secretary of the Senate.
(10) Chief Clerk of the Assembly.

Civil Code section 1182: Proof or acknowledgment of instrument; out of state**.** The proof or acknowledgment of an instrument may be made without this state, but within the United States, and within the jurisdiction of the officer, before any of the following:

(1) A justice, judge, or clerk of any court of record of the United States.

(2) A justice, judge, or clerk of any court of record of any state.

(3) A commissioner appointed by the Governor or Secretary of State for that purpose.

(4) A notary public.

(5) Any other officer of the state where the acknowledgment is made authorized by its laws to take such proof or acknowledgment.

Civil Code section 1185: **Acknowledgments; requisites; civil penalties**

(a) The acknowledgment of an instrument shall not be taken unless the officer taking it has satisfactory evidence that the person making the acknowledgment is the individual who is described in and who executed the instrument.

(b) For the purposes of this section "satisfactory evidence" means the absence of any information, evidence, or other circumstances which would lead a reasonable person to believe that the person making the acknowledgment is not the individual he or she claims to be and any one of the following:

(1)(A) The oath or affirmation of a credible witness personally known to the officer, whose identity is proven to the officer upon presentation of any document satisfying the requirements of paragraph (3) or (4), that the person making the acknowledgment is personally known to the witness and that each of the following are true: (i) The person making the acknowledgment is the person named in the document. (ii) The person making the acknowledgment is personally known to the witness. (iii) That it is the reasonable belief of the witness that the circumstances of the person making the acknowledgment are such that it would be very difficult or impossible for that person to obtain another form of identification. (iv) The person making the acknowledgment does not possess any of the identification documents named in paragraphs (3) and (4). (v) The witness does not have a financial interest in the document being acknowledged and is not named in the document. (B) A notary public who violates this section by failing to obtain the satisfactory evidence required by subparagraph (A) shall be subject to a civil penalty not exceeding ten thousand dollars ($10,000). An action to impose this civil penalty may be brought by the Secretary of State in an administrative proceeding or any public prosecutor in superior court, and shall be enforced as a civil judgment. A public prosecutor shall inform the secretary of any civil

penalty imposed under this subparagraph.

(2) The oath or affirmation under penalty of perjury of two credible witnesses, whose identities are proven to the officer upon the presentation of any document satisfying the requirements of paragraph (3) or (4), that each statement in paragraph (1) of this subdivision is true.

(3) Reasonable reliance on the presentation to the officer of any one of the following, if the document is current or has been issued within five years: (A) An identification card or driver's license issued by the California Department of Motor Vehicles. (B) A passport issued by the Department of State of the United States.

(4) Reasonable reliance on the presentation of any one of the following, provided that a document specified in subparagraphs (A) to (E), inclusive, shall either be current or have been issued within five years and shall contain a photograph and description of the person named on it, shall be signed by the person, shall bear a serial or other identifying number, and, in the event that the document is a passport, shall have been stamped by the United States Immigration and Naturalization Service: (A) A passport issued by a foreign government. (B) A driver's license issued by a state other than California or by a Canadian or Mexican public agency authorized to issue drivers' licenses. (C) An identification card issued by a state other than California. (D) An identification card issued by any branch of the Armed Forces of the United States. (E) An inmate identification card issued on or after January 1, 1988, by the Department of Corrections and Rehabilitation, if the inmate is in custody. (F) An inmate identification card issued prior to January 1, 1988, by the Department of Corrections and Rehabilitation, if the inmate is in custody.

(c) An officer who has taken an acknowledgment pursuant to this section shall be presumed to have operated in accordance with the provisions of law.

(d) Any party who files an action for damages based on the failure of the officer to establish the proper identity of the person making the acknowledgment shall have the burden of proof in establishing the negligence or misconduct of the officer.

(e) Any person convicted of perjury under this section shall forfeit any financial interest in the document.

Note that Code section 1185, as amended effective January 1, 2008, no longer permits an acknowledgment based on the notary's "personal" knowledge of a party, but requires that the acknowledgment be based on "satisfactory evidence that the person making the acknowledgment is the individual described in and who executed the document."

Civil Code section 1189: Certificate of acknowledgment; form; sufficiency of out of state acknowledgment; force and effect of acknowledgment under prior laws; civil penalties.

(2) A notary public who willfully states as true any material fact that he or she knows to be false shall be subject to a civil penalty not exceeding ten thousand dollars ($10,000). An action to impose a civil penalty under this subdivision may

be brought by the Secretary of State in an administrative proceeding or any public prosecutor in superior court, and shall be enforced as a civil judgment. A public prosecutor shall inform the secretary of any civil penalty imposed under this section.

(b) Any certificate of acknowledgment taken in another place shall be sufficient in this state if it is taken in accordance with the laws of the place where the acknowledgment is made.

(c) On documents to be filed in another state or jurisdiction of the United States, a California notary public may complete any acknowledgment form as may be required in that other state or jurisdiction on a document, provided the form does not require the notary to determine or certify that the signer holds a particular representative capacity or to make other determinations and certifications not allowed by California law.

(d) An acknowledgment provided prior to January 1, 1993, and conforming to applicable provisions of former Sections 1189, 1190, 1190a, 1190.1, 1191, and 1192, as repealed by Chapter 335 of the Statutes of 1990, shall have the same force and effect as if those sections had not been repealed.

Civil Code section 1213 seems to require that a conveyance be "acknowledged or proved and certified" in order to provide constructive notice. Certainly you will find county recorder's staff refusing to accept unacknowledged or improperly acknowledged instruments for recording. But Civil Code section 1207 provides a mechanism to "reinvigorate" defective instruments that manage to get through.

> **§ 1207. Defectively executed instruments; validity**. Any instrument affecting the title to real property, one year after the same has been copied into the proper book of record, kept in the office of any county recorder, imparts notice of its contents to subsequent purchasers and encumbrancers, **notwithstanding any defect, omission, or informality in the execution of the instrument, or in the certificate of acknowledgment thereof, or the absence of any such certificate**; ….[35]

Limits of subscribing witness acknowledgments.
California Government Code section

[35] "… but nothing herein affects the rights of purchasers or encumbrancers previous to the taking effect of this act. Duly certified copies of the record of any such instrument may be read in evidence with like effect as copies of an instrument duly acknowledged and recorded; provided, when such copying in the proper book of record occurred within five years prior to the trial of the action, it is first shown that the original instrument was genuine."

27287:

> **§ 27287. Acknowledgment of execution or proof by subscribing witness required before recording; exceptions**. [With certain exceptions], before an instrument can be recorded its execution shall be acknowledged by the person executing it, or if executed by a corporation, by its president or secretary or other person executing it on behalf of the corporation, or, **except for any quitclaim deed or grant deed other than a trustee's deed or a deed of reconveyance, mortgage, deed of trust, or security agreement**, proved by subscribing witness or as provided in Sections 1198 and 1199 of the Civil Code, and the acknowledgment or proof certified as prescribed by law.

Making Marketable Title

The Uniform Marketable Record Title Act (California Civil Code section 880.020, et seq.) The Marketable Record Title Act (the "Act") has to be understood, first, in reference to the problem which it is intended to address and, second, in reference to the solution by which it would address that problem. Both of those subjects are addressed in the first section of the Act, Civil Code section 880.020.

The Problem.

> "Real property title transactions should be possible with economy and expediency" and "the status and security of recorded real property titles should be determinable to the extent practicable from an examination of recent records only." However, "Interests in real property and defects in titles created at remote times, whether or not of record, often constitute unreasonable restraints on alienation and marketability of real property because the interests are no longer valid or have been abandoned or have otherwise become obsolete." "**Such [remote in time] interests and defects produce litigation to clear and quiet titles, cause delays in real property title transactions, and hinder marketability of real property**."

The Solution.

> "It is the purpose of the Legislature in enacting this [Act] **to simplify and facilitate real property title transactions** in furtherance of public policy **by enabling persons to rely on record title to the extent provided in this title**, with respect to the property interests specified in this title, subject only to the limitations expressly provided in this title and notwithstanding any provision or implication to the contrary in any other statute or in the

common law. This title shall be liberally construed to effect the legislative purpose."

The Act's operation is limited in certain respects, first, in section 880.030, to avoid interfering with the application of beneficial principles and policies and, second, in section 880.240, to avoid affecting the rights of public entities or of persons in actual possession of the affected real property, and to avoid extinguishing solar conservation easements authorized by statute.

§ 880.030. Construction not to limit or affect equitable principles or recording statutes

Nothing in this title shall be construed to:

(a) Limit application of the principles of waiver and estoppel, laches, and other equitable principles.

(b) Affect the operation of any statute governing the effect of recording or failure to record, except as specifically provided in this title.

§ 880.240. Interests not subject to expiration pursuant to title

The following interests are not subject to expiration or expiration of record pursuant to this title:

(a) The interest of a person in possession (including use or occupancy) of real property and the interest of a person under whom a person in possession claims, to the extent the possession would have been revealed by reasonable inspection or inquiry.

(b) An interest of the United States or pursuant to federal law in real property that is not subjected by federal law to the recording requirements of the state and that has not terminated under federal law.

(c) An interest of the state or a local public entity in real property.

(d) A conservation easement pursuant to Chapter 4 (commencing with Section 815)…

Also, the operation of the Act against a particular interest can be "suspended" by commencement of proceedings concerning that interest up to the time that the interest would expire under the Act—but not thereafter.

§ 880.260. Action or proceeding tolling expiration or expiration of record

An interest in real property, as specified in this title, does not expire or expire of record and is not unenforceable pursuant to this title at the time prescribed in this title if within the time an action is commenced to enforce, establish, clear title to, or otherwise affect the interest and a notice of the pendency of the action is recorded as provided by law. For the purpose of this section, action includes special proceeding and arbitration proceeding.

Otherwise, the times specified in the Act for taking some action and for the expiration of rights in the absence of specified action are absolute.

§ 880.250. Absolute nature of times prescribed; extending time; revival of interests

(a) The times prescribed in this title for expiration or expiration of record of an interest in real property or for enforcement, for bringing an action, or for doing any other required act are absolute and apply notwithstanding any disability or lack of knowledge of any person or any provisions for tolling a statute of limitation and

notwithstanding any longer time applicable pursuant to any statute of limitation.

(b) Nothing in this title extends the period for enforcement, for bringing an action, or for doing any other required act, or revives an interest in real property that expires and is unenforceable, pursuant to any applicable statute of limitation.

VASTLY oversimplified, the basic operation of the Act is to clear title of dated interests and rights in accordance with the following formula:

NO USE + NO RECORD = EXPIRED SPECIFIED PERIOD OF TIME

In spite of the simplicity of that basic structure, the actual operation of the Act in regard to the various types of interests affected involves significant variation in regard to details, qualifications and exceptions concerning the actual operation of the Act. In spite of the simplicity of that basic structure, the actual operation of the Act in regard to the various specific types of interest affected involves significant variation in regard to details, qualifications and exceptions. The specific interests the Act addresses are: (a) Ancient Mortgages and Deeds of Trust, (b) Mineral Rights, (c) Unexercised Options, (d) Powers of Termination, (e) Unperformed Contracts for the Sale of Real Property, and (f) Abandoned Easements. We shall see that there is wide variation in the specific provisions of the as pertains to these varying interests.

Preservation of Interests By Notice of Intent to Preserve.

§ 880.310. Recordation of notice of intent

(a) If the time within which an interest in real property expires pursuant to this title depends upon recordation of a notice of intent to preserve the interest, a person may preserve the person's interest from expiration by recording a notice of intent to preserve the interest before the interest expires pursuant to this title. Recordation of a notice of intent to preserve an interest in real property after the interest has expired pursuant to this title does not preserve the interest.

(b) Recordation of a notice of intent to preserve an interest in real property does not preclude a court from determining that an interest has been abandoned or is otherwise unenforceable pursuant to other law, whether before or after the notice of intent to preserve the interest is recorded, and does not validate or make enforceable a claim or interest that is otherwise invalid or unenforceable. Recordation of a notice of intent to preserve an interest in real property creates a presumption affecting the burden of proof that the person who claims the interest has not abandoned and does not intend to abandon the interest.

It is difficult to overstate the importance of that opening "**If**." It is *not* the case that a notice of intent to preserve is available to preserve all of the interests which are addressed by the Act. However, where such a notice is available to preserve an interest, the Act prescribes who can effectively record such a notice (section 880.320) and what must be included in the notice (section 880.330), along with a permissible form of notice (section 880.340), prescribes the place of recording (section 880.305) and prohibits

misuse of the notice for the purpose of slandering the title of another (section 880.360) .

§ 880.320. Persons entitled to record notice of intent

A notice of intent to preserve an interest in real property may be recorded by any of the following persons:

(a) A person who claims the interest.

(b) Another person acting on behalf of a claimant if the person is authorized to act on behalf of the claimant or if the claimant is one of a class whose identity cannot be established or is uncertain at the time of recording the notice of intent to preserve the interest.

§ 880.330. Requisites of notice of intent

Subject to all statutory requirements for recorded documents:

(1) A notice of intent to preserve an interest in real property shall be in writing and signed and verified by or on behalf of the claimant. If the notice is made on behalf of a claimant, the notice shall include a statement of the authority of the person making the notice.

(2) The notice shall contain all of the following information:

(a) The name and mailing address of the claimant. If the notice is made by or on behalf of more than one claimant the notice shall contain the name and mailing address of each claimant.

(b) A statement of the character of interest claimed. The statement shall include a reference by record location to the recorded document that creates or evidences the interest in the claimant.

(c) A legal description of the real property in which the interest is claimed. The description may be the same as that contained in the recorded document that creates or evidences the interest in the claimant.

§ 880.340 See Appendix for sample Notice of Intent to Preserve Interest.

§ 880.350. County of recording notice of intent

(a) A notice of intent to preserve an interest in real property shall be recorded in the county in which the real property is situated.

(b) The county recorder shall index a notice of intent to preserve an interest in real property in the index of grantors and grantees. The index entry shall be for the grantor, and for the purpose of this index, the claimant under the notice shall be deemed to be the grantor. If a notice of intent to preserve is recorded by or on behalf of more than one claimant, each claimant shall be deemed to be a grantor and a separate index entry shall be made for each claimant.

§ 880.360. Slandering title; recording notice of intent

A person shall not record a notice of intent to preserve an interest in real property for the purpose of slandering title to the real property. If the court in an action or proceeding to establish or quiet title determines that a person recorded a notice of intent to preserve an interest for the purpose of slandering title, the court

shall award against the person the cost of the action or proceeding, including a reasonable attorney's fee, and the damages caused by the recording.

ANCIENT MORTGAGES AND DEEDS OF TRUST

Time for Expiration. 10 years if final maturity date or last date for payment is "ascertainable from the recorded evidence of indebtedness." Otherwise, 60 years after recording

Available Notice of Intent to Preserve? Yes, but only *one time* for a further ten years.

§ 882.020. Expiration date; lien of security interest of record; power of sale deemed exercised

(a) Unless the lien of a mortgage, deed of trust, or other instrument that creates a security interest of record in real property to secure a debt or other obligation has earlier expired pursuant to [Civil Code] Section 2911, the lien expires at, and is not enforceable by action for foreclosure commenced, power of sale exercised, or any other means asserted after, the later of the following times:

(1) If the final maturity date or the last date fixed for payment of the debt or performance of the obligation is ascertainable from the **recorded evidence of indebtedness**, 10 years after that date.

(2) If the final maturity date or the last date fixed for payment of the debt or performance of the obligation is not ascertainable from the **recorded evidence of indebtedness**, or if there is no final maturity date or last date fixed for payment of the debt or performance of the obligation, 60 years after the date the instrument that created the security interest was recorded.

(3) If a notice of intent to preserve the security interest is recorded within the time prescribed in paragraph (1) or (2), 10 years after the date the notice is recorded.

(b) For the purpose of this section, a power of sale is deemed to be exercised upon recordation of the deed executed pursuant to the power of sale.

(c) The times prescribed in this section may be extended in the same manner and to the same extent as a waiver made pursuant to Section 360.5 of the Code of Civil Procedure, except that an instrument is effective to extend the prescribed times only if it is recorded before expiration of the prescribed times.

§ 882.030. Effect of expiration of lien of security interest

Expiration of the lien of a mortgage, deed of trust, or other security interest pursuant to this chapter or any other statute renders the lien unenforceable by any means commenced or asserted thereafter and is equivalent for all purposes to a certificate of satisfaction, reconveyance, release, or

other discharge of the security interest, and execution and recording of a certificate of satisfaction, reconveyance, release, or other discharge is not necessary to terminate or evidence the termination of the security interest. Nothing in this section precludes execution and recording at any time of a certificate of satisfaction, reconveyance, release, or other discharge.

§ 882.040. Application of chapter

(a) Subject to Section 880.370 (grace period for recording notice) and except as otherwise provided in this section, this chapter applies on the operative date to all mortgages, deeds of trust, and other instruments that create a security interest in real property to secure a debt or other obligation, whether executed or recorded before, on, or after the operative date.

(b) This chapter shall not cause the lien of a mortgage, deed of trust, or other security interest in real property to expire or become unenforceable before the passage of five years after the operative date of this chapter.

Mineral rights: General provisions

§ 883.110. Mineral right defined

As used in this chapter, "mineral right" means an interest in minerals, regardless of character, whether fugacious or nonfugacious, organic or inorganic, that is created by grant or reservation, regardless of form, whether a fee or lesser interest, mineral, royalty, or leasehold, absolute or fractional, corporeal or incorporeal, and includes express or implied appurtenant surface rights.

§ 883.120. Application of chapter; mineral rights reserved to United States; mineral rights not subject to expiration

(a) This chapter does not apply to a mineral right reserved to the United States (whether in a patent, pursuant to federal law, or otherwise) or to an oil or gas lease, mining claim, or other mineral right of a person entitled pursuant thereto, to the extent provided in Section 880.240.

(b) This chapter does not apply to a mineral right of the state or a local public entity, or of any other person, to the extent provided in Section 880.240.

§ 883.130. Abandoned mineral rights

Nothing in this chapter limits or affects the common law governing abandonment of a mineral right or any other procedure provided by statute for clearing an abandoned mineral right from title to real property.

§ 883.140. Abandoned Mineral Lease Right

This section is not truly part of the Act as proposed; rather, it was engrafted by the California legislature into the Act from former Civil Code section 794. A few important points are:

- Notice of Intent to Preserve is not required.
- Within 30 days after demand following expiration or abandonment, the lessee must quitclaim the lease.
- Judicial action required to enforce the obligation; lessee in the action liable for costs including attorney fees and a $150.00 penalty.

§ 883.140. Mineral right lease; expiration or abandonment; quitclaim deed

(a) As used in this section:

(1) "Lessee" includes an assignee or other successor in interest of the lessee.

(2) "Lessor" includes a

successor in interest or heir or grantee of the lessor.

(b) If the term of a mineral right lease has expired or a mineral right lease has been abandoned by the lessee, the lessee shall, within 30 days after demand therefor by the lessor, execute, acknowledge, and deliver, or cause to be recorded, a deed quitclaiming all interest in and to the mineral rights covered by the lease. If the expiration or abandonment covers less than the entire interest of the lessee, the lessee shall execute, acknowledge, and deliver an appropriate instrument or notice of surrender or termination that covers the interest that has expired or been abandoned.

(c) If the lessee fails to comply with the requirements of this section, the lessee is liable for all damages sustained by the lessor as a result of the failure, including, but not limited to, court costs and reasonable attorney's fees in an action to clear title to the lessor's interest. The lessee shall also forfeit to the lessor the sum of one hundred fifty dollars ($150).

(d) Nothing in this section makes a quitclaim deed or other instrument or notice of surrender or termination, or a demand therefor, a condition precedent to an action to clear title to the lessor's interest.

Termination of dormant mineral right

The time for expiration is 20 years**.** A Notice of Intent to Preserve is required, but there is no limit to the number of times for filing. Also, there is no need to specifically identify the property involved; a general reference to "any and all mineral rights claimed by claimant in any real property situated in the county" is sufficient. Late filed notice is permitted, so even if the time provided has long past, the mineral interest can still be preserved by filing after a lawsuit is commenced to have the interest declared dormant.[36] The same is true in regard to easements, but nowhere else in the Act.

Note: There is no express requirement that such a late notice be any more specific as to the property involved than is permitted for such a notice of intent to preserve mineral rights generally, but it would be pretty foolish to take that approach.

§ 883.210. Action to terminate dormant mineral right. The owner of real property subject to a mineral right may bring an action to terminate the mineral right pursuant to this article if the mineral right is dormant.

§ 883.220. Dormant rights; conditions

For the purpose of this article, a mineral right is dormant if all of the following conditions are satisfied for a period of 20 years immediately preceding commence-ment of the action to terminate the mineral right:

(a) There is no production of the minerals and no exploration, drilling, mining, development, or other operations that affect the minerals, whether on or below the surface of the real property or on other property, whether or not unitized or pooled with the real property.

(b) No separate property tax assessment is made of the mineral right or, if made, no taxes are paid on the assessment.

[36] § 883.230(C)(2) and § 883.250

(c) No instrument creating, reserving, transferring, or otherwise evidencing the mineral right is recorded.

§ 883.230. Notice of intent to preserve mineral right; effect

(a) An owner of a mineral right may at any time record a notice of intent to preserve the mineral right.

(b) In lieu of the statement of the character of the interest claimed and the record location of the documents creating or evidencing the mineral rights claimed as otherwise required by paragraph (2) of subdivision (b) of Section 880.330 and in lieu of the legal description of the real property in which the interest is claimed as otherwise required by paragraph (3) of subdivision (b) of Section 880.330 and notwithstanding the provisions of Section 880.340 or any other provision in this title, a notice of intent to preserve a mineral right may refer generally and without specificity to any or all mineral rights claimed by claimant in any real property situated in the county.

(c) A mineral right is not dormant for the purpose of this article if:

(1) A notice of intent to preserve the mineral right is recorded within 20 years immediately preceding commencement of the action to terminate the mineral right.

(2) A notice of intent to preserve the mineral right is recorded pursuant to Section 883.250 after commencement of the action to terminate the mineral right.

§ 883.240. Actions; place; procedure

(a) An action to terminate a mineral right pursuant to this article shall be brought in the superior court of the county in which the real property subject to the mineral right is located.

(b) The action shall be brought in the same manner and shall be subject to the same procedure as an action to quiet title pursuant to Chapter 4 (commencing with Section 760.010) of Title 10 of Part 2 of the Code of Civil Procedure, to the extent applicable. (Added by Stats.1984, c. 240, § 2.)

§ 883.250. Late notice of intent to preserve mineral right; condition of dismissal of action

In an action to terminate a mineral right pursuant to this article, the court shall permit the owner of the mineral right to record a late notice of intent to preserve the mineral right as a condition of dismissal of the action, upon payment into court for the benefit of the owner of the real property the litigation expenses attributable to the mineral right or portion thereof as to which the notice is recorded. As used in this section, the term "litigation expenses" means recoverable costs and expenses reasonably and necessarily incurred in preparation for the action, including a reasonable attorney's fee.

§ 883.260. Termination under article; effect. A mineral right terminated pursuant to this article is unenforceable and is deemed to have expired. A court order terminating a mineral right pursuant to this article is equivalent for all purposes to a conveyance of the mineral right to the owner of the real property.

§ 883.270. <u>Application of article</u>
Subject to Section 880.370 (grace period for recording notice), this article applies to all mineral rights, whether executed or recorded before, on, or after January 1, 1985.

UNEXERCISED OPTIONS

The time for expiration is (six) 6 months.[37] But what if the recorded memorandum of option does not make it clear what the option term is (or whether it has an expiration date)? Note that this was handled by an amendment with respect to Ancient Mortgages and Deeds of Trust to refer not to the record but to the "recorded evidence of the indebtedness." In the same way an amendment has been proposed here to make it clear that the option expires six months after recording unless an expiration date of the option is clear on the face of the recorded evidence of the option.
A Notice of Intent to Preserve is not required. The Act recognizes a potential for recording an "instrument that…extends the option" but it is not clear whether this can be done more than once. It is also not clear about the specific effect in terms of time of expiration which results from recording a memorandum of extension that does not specify the date when the extended option expires.

§ 884.010. Expiration date; recorded instrument.

[37] §884.010

If a recorded instrument creates or gives constructive notice of an option to purchase real property, the option expires of record if no conveyance, contract, or other instrument that gives notice of exercise or extends the option is recorded within the following times:

(a) Six months after the option expires according to its terms.

(b) If the option provides no expiration date, six months after the date the instrument that creates or gives constructive notice of the option is recorded.

§ 884.020. Effect of expiration of record. Upon the expiration of record of an option to purchase real property, the recorded instrument that creates or gives constructive notice of the option ceases to be notice to any person or to put any person on inquiry with respect to the exercise or existence of the option or of any contract, conveyance, or other writing that may have been executed pursuant to the option.

§ 884.030. Application of chapter

(a) Except as otherwise provided in this section, this chapter applies on the operative date to all recorded instruments that create or give constructive notice of options to purchase real property, whether executed or recorded before, on, or after the operative date.

(b) This chapter shall not cause an option that expires according to its terms within one year before, on, or within one year after the operative date of this chapter to expire of record until one year after the operative date.

(c) This chapter shall not cause an

option that provides no expiration date and that is recorded before the operative date of this chapter to expire of record until five years after the operative date of this chapter.

(d) Nothing in this chapter affects a recorded instrument that has ceased to be notice to any person or put any person on inquiry with respect to the exercise or existence of an option pursuant to former Section 1213.5 before the operative date of this chapter.

Powers of termination

Uniquely among all of the Act's provisions, this chapter first abolishes one kind of legal interest or estate, converting it into another, then provides the terms and time for the expiration of the "surviving" interest. It abolishes the FSD [and FSSEI] in favor of FSSCS. Fee Simple Determinable [Possibility of Reverter] (and fee simple subject to executory interest [executory interest]) — present interest on condition with automatic expiration—are abolished.

Fee Simple on Condition Subsequent [Power of Termination] are converted by statute into a present interest on condition that requires action by the future interest holder to bring about termination.

§ 885.010. Definitions

(a) As used in this chapter :

(1) "Power of termination" means the power to terminate a fee simple estate in real property to enforce a restriction in the form of a condition subsequent to which the fee simple estate is subject, whether the power is characterized in the instrument that creates or evidences it as a power of termination, right of entry or reentry, right of possession or repossession, reserved power of revocation, or otherwise, and includes a possibility of reverter that is deemed to be and is enforceable as a power of termination pursuant to Section 885.020.

(2) "Power of termination" includes the power created in a transferee to terminate a fee simple estate in real property to enforce a restriction on the use of the real property in the form of a limitation or condition subsequent to which the fee simple estate is subject, whether the power is characterized in the instrument that creates or evidences it as an executory interest, executory limitation, or otherwise, and includes the interest known at common law as an executory interest preceded by a fee simple determinable.

(b) A power of termination is an interest in the real property.

(c) For the purpose of applying this chapter to other statutes relating to powers of termination, the terms "right of reentry," "right of repossession for breach of condition subsequent," and comparable terms used in the other statutes mean "power of termination" as defined in this section.

§ 885.015. Application of chapter; power of termination

This chapter does not apply to any of the following:

(a) A power of termination conditioned upon the continued production or removal of oil or gas or other minerals. [See § 885.020 & § 885.010(a)(1).]

(b) A power of termination as to separately owned improvements or fixtures conditioned upon the continued leasehold or possessory interest in the underlying land.

§ 885.020. Fees simple determinable and possibilities of reverter abolished

Fees simple determinable and possibilities of reverter are abolished. Every estate that would be at common law a fee simple determinable is deemed to be a fee simple subject to a restriction in the form of a condition subsequent. Every interest that would be at common law a possibility of reverter is deemed to be and is enforceable as a power of termination.

§ 885.030. Expiration dates; recorded instruments; contrary provisions

(a) A power of termination of record expires at the later of the following times:

(1) Thirty years after the date the instrument reserving, transferring, or otherwise evidencing the power of termination is recorded.

(2) Thirty years after the date a notice of intent to preserve the power of termination is recorded, if the notice is recorded within the time prescribed in paragraph (1).

(3) Thirty years after the date an instrument reserving, transferring, or otherwise evidencing the power of termination or a notice of intent to preserve the power of termination is recorded, if the instrument or notice is recorded within 30 years after the date such an instrument or notice was last recorded.

(b) This section applies notwithstanding any provision to the contrary in the instrument reserving, transferring, or otherwise evidencing the power of termination or in another recorded document unless the instrument or other recorded document provides an earlier expiration date.

§ 885.040. Obsolete powers; expiration; grants to public entities, etc.

(a) If a power of termination becomes obsolete, the power expires.

(b) As used in this section, a power of termination is obsolete if any of the following circumstances applies:

(1) The restriction to which the fee simple estate is subject is of no actual and substantial benefit to the holder of the power.

(2) Enforcement of the power would not effectuate the purpose of the restriction to which the fee simple estate is subject.

(3) It would be otherwise inequitable to enforce the power because of changed conditions or circumstances.

(c) No power of termination shall expire under this section during the life of the grantor if it arises from a grant by a natural person without consideration to a public entity or to a society, corporation, institution, or association exempt by the laws of this state from taxation.

§ 885.060. Effect of expiration of power; application to equitable servitude; construction of law

(a) Expiration of a power of termination pursuant to this chapter makes the power unenforceable and is equivalent for all purposes to a termination of the power of record and a quitclaim of the power to the owner of the fee simple estate, and execution and recording of a termination and quitclaim is not necessary to terminate or evidence the termination of the power.

(b) Expiration of a power of termination pursuant to this chapter terminates the restriction to which the fee simple estate is subject and makes the restriction unenforceable by any other means, including, but not limited to, injunction and damages.

(c) However, subdivision (b) does not apply to a restriction for which a power of termination has expired under this chapter if the restriction is also an equitable servitude alternatively enforceable by injunction. Such an equitable servitude shall remain enforceable by injunction and any other available remedies, but shall not be enforceable by a power of termination. This subdivision does not constitute a change in, but is declaratory of, the existing law. However, nothing in this subdivision shall be construed to make enforceable any restriction prohibited or made unenforceable by other provisions of law, including Section 53.

§ 885.070. Operative date; application of chapter; prior breach of restriction on fee simple estate

(a) Subject to Section 880.370 (grace period for recording notice) and except as otherwise provided in this section, this chapter applies on the operative date to all powers of termination, whether executed or recorded before, on, or after the operative date.

(b) If breach of the restriction to which the fee simple estate is subject occurred before the operative date of this chapter and the power of termination is not exercised before the operative date of this chapter, the power of termination shall be exercised, or in the case of a power of termination of record, exercised of record, within the earlier of the following times:

(1) The time that would be applicable pursuant to the law in effect immediately prior to the operative date of this chapter.

(2) Five years after the operative date of this chapter.

(c) As used in this section, "operative date" means the operative date of

this chapter as enacted or, with respect to any amendment of a section of this chapter, the operative date of the amendment.

Unperformed contracts for the sale of real property

The time for expiration is (five) 5 years after the date provided in the contract for conveyance [or timely, one-time, extension], or if there is none, after the last date for satisfaction of conditions provided in the contract [or timely, one-time, extension]. But this is subject to a timely waiver or extension (§ 886.030(b)). A Notice of Intent to Preserve is not required.

§ 886.010. Definitions

As used in this chapter:

(a) "Contract for sale of real property" means an agreement wherein one party agrees to convey title to real property to another party upon the satisfaction of specified conditions set forth in the contract and which requires conveyance of title within one year from the date of formation of the contract, whether designated in the agreement a "contract for sale of real property," "land sale contract," "deposit receipt," "agreement for sale," "agreement to convey," or otherwise.

(b) "Recorded contract for sale of real property" includes the entire terms of a contract for sale of real property that is recorded in its entirety or is evidenced by a recorded memorandum or short form of the contract

§ 886.020. Demand; release of unperformed contract; action to clear title

If the party to whom title to real property is to be conveyed pursuant to a recorded contract for the sale of real property fails to satisfy the specified conditions set forth in the contract and does not seek performance of the contract or restitution of amounts paid under the contract, the party shall, upon demand therefor made after the operative date of this chapter, execute a release of the contract, duly acknowledged for record, to the party who agreed to convey title. Willful violation of this section by the party to whom title is to be conveyed without good cause makes the party liable for the damages the party who agreed to convey title sustains by reason of the violation, including but not limited to court costs and reasonable attorney's fees in an action to clear title to the real property. Nothing in this section makes a release or a demand therefor a condition precedent to an action to clear title to the real property.

§ 886.030. Expiration date; recorded extension; waiver

(a) Except as otherwise provided in this section, a recorded contract for sale of real property expires of record at the later of the following times:

(1) Five years after the date for conveyance of title provided in the contract or, if no date for conveyance of title is provided in the contract, five years after the last date provided in the contract for satisfaction of the specified conditions set forth in the contract.

(2) If there is a recorded extension of the contract within the time prescribed in paragraph (1), five years after the date for

conveyance of title provided in the extension or, if no date for conveyance of title is provided in the extension, five years after the last date provided in the extension for satisfaction of the specified conditions set forth in the contract.

(b) The time prescribed in this section may be waived or extended only by an instrument that is recorded before expiration of the prescribed times

§ 886.040. Effect of expiration of recorded contract. Upon the expiration of record of a recorded contract for sale of real property pursuant to this chapter, the contract has no effect, and does not constitute an encumbrance or cloud, on the title to the real property as against a person other than a party to the contract.

§ 886.050. Application of chapter; limitation on expiration of recorded contracts

(a) Except as otherwise provided in this section, this chapter applies on the operative date to all recorded contracts for sale of real property, whether recorded before, on, or after the operative date.

(b) This chapter shall not cause a recorded contract for sale of real property to expire of record before the passage of two years after the operative date of this chapter.

Abandoned easements

As used in this chapter, "easement" means a burden or servitude upon land, whether or not attached to other land as an incident or appurtenance, that allows the holder of the burden or servitude to do acts upon the land. It does not include negative easements or easements that are part of a unified or reciprocal system for mutual benefit of multiple parties.[38] It does not affect the common law of abandonment.[39] The time for Expiration is 20 years[40] and a Notice of Intent to Preserve is required.

As in the case of Dormant Mineral Rights, easements can be preserved by filing a notice of intent to preserve them long after the 20 year filing period has expired and even after a lawsuit has been filed to have them declared abandoned.

§ 887.010. Definition
As used in this chapter, "easement" means a burden or servitude upon land, whether or not attached to other land as an incident or appurtenance, that allows the holder of the burden or servitude to do acts upon the land.

§ 887.020. Application of chapter
This chapter does not apply to an easement that is part of a unified or reciprocal system for the mutual benefit of multiple parties.

§ 887.030. Common law
This chapter supplements and does not limit or otherwise affect the common law governing abandonment of an easement or any other procedure provided by statute or otherwise for clearing an abandoned easement from title to real property.

§ 887.040. Bringing action; venue; procedure.

(a) The owner of real property subject

[38] § 886.020
[39] § 887.030
[40] (§ 887.050

to an easement may bring an action to establish the abandonment of the easement and to clear record title of the easement.

(b) The action shall be brought in the superior court of the county in which the real property subject to the easement is located.

(c) The action shall be brought in the same manner and shall be subject to the same procedure as an action to quiet title pursuant to Chapter 4 (commencing with Section 760.010) of Title 10 of Part 2 of the Code of Civil Procedure, to the extent applicable.

§ 887.050. Conditions necessary

(a) For purposes of this chapter, an easement is abandoned if all of the following conditions are satisfied for a period of 20 years immediately preceding commencement of the action to establish abandonment of the easement:

(1) The easement is not used at any time.

(2) No separate property tax assessment is made of the easement or, if made, no taxes are paid on the assessment.

(3) No instrument creating, reserving, transferring, or otherwise evidencing the easement is recorded.

(b) This section applies notwithstanding any provision to the contrary in the instrument creating, reserving, transferring, or otherwise evidencing the easement or in another recorded document, unless the instrument or other document provides an earlier expiration date.

§ 887.060. Notice of intent to preserve easement; recording

(a) The owner of an easement may at any time record a notice of intent to preserve the easement.

(b) In lieu of the statement of the character of the interest claimed and the record location of the documents creating or evidencing the easement claimed, as otherwise required by paragraph (2) of subdivision (b) of Section 880.330, and in lieu of the legal description of the real property in which the interest is claimed, as otherwise required by paragraph (3) of subdivision (b) of Section 880.330, and notwithstanding the provisions of Section 880.340, or any other provision in this title, a notice of intent to preserve an easement may refer generally and without specificity to any or all easements claimed by the claimant in any real property situated in the county.

(c) An easement is not abandoned for purposes of this chapter if either of the following occurs:

(1) A notice of intent to preserve the easement is recorded within 20 years immediately preceding commencement of the action to establish the abandonment of the easement.

(2) A notice of intent to preserve the easement is

recorded pursuant to Section 887.070 after commencement of the action to establish the abandonment of the easement and before judgment is entered in the action.

§ 887.070. Late notice of intent to preserve easement; recording; litigation expenses.
In an action to establish the abandonment of an easement pursuant to this chapter, the court shall permit the owner of the easement to record a late notice of intent to preserve the easement as a condition of dismissal of the action, upon payment into court for the benefit of the owner of the real property the litigation expenses attributable to the easement or portion thereof as to which the notice is recorded. As used in this section, the term "litigation expenses" means recoverable costs and expenses reasonably and necessarily incurred in preparation for the action, including a reasonable attorney's fee.

§ 887.090. Application of chapter; exceptions
Subject to Sections 880.370 (grace period for recording notice) and 887.020, this chapter applies to all easements, whether executed or recorded before, on, or after January 1, 1986.

Probate

The following terms and definitions need to be understood in order to understand probate issues:
Administrator. A person to whom Letters of Administration (that is authority to administer the estate of a deceased person) have been granted by the proper court but who is not nominated to administrator the estate in the decedent's will, either:

(1) under Probate Code § 8460 (because the decedent has died intestate, i.e., without leaving a valid will), or

(2) under Probate Code § 8440 (because the decedent left a will which does not nominate someone to do so or those nominated by the decedent's will waive the right or are unable or unwilling to act [see **"Administrator With The Will Annexed,"** below], or

(3) because the Court concludes that special circumstances exist requiring immediate appointment, either "for a specified term, to perform specified acts, or on any other terms specified in the court order" under Probate Code § 8540 [see **"Special Administrator,"** below].

The general priority of appointment (provided in Probate Code § 8461) is as follows:

(1) Surviving spouse
(2) Children
(3) Grandchildren
(4) Other (i.e., more remote) issue
(5) Parents
(6) Brothers and Sisters
(7) Issue of brothers and sisters
(8) Grandparents
(9) (Other) Issue of grandparents
(10) Children of predeceased spouse
(11) Other (i.e., more remote) issue of predeceased spouse
(12) Other next of kin
(13) Parents of a predeceased spouse
(14) (Other) Issue of parents of a predeceased spouse
(15) Conservator or guardian of the estate acting in that capacity at the time of death who has filed a first account and is not acting as conservator or guardian for any other person
(16) Public administrator

(17) Creditors
(18) Any other person

Administrator With Will Annexed (formerly **Administrator cta** (*cum testamento annexo*). A person to whom Letters of Administration (that is authority to administer the estate of a deceased person) have been granted by the proper court, under Probate Code § 8440, because the decedent's will does not nominate someone to do so or those nominated by the decedent's will waive the right or are unable or unwilling to act.

Administrator dbn (*de bonis non*). A personal representative of a decedent's estate who is appointed after the appointment of the estate's first personal representative, i.e., a successor representative. Technically no such capacity is recognized under California law, although California courts sometimes refer to such a position by that name. (E.g., *Lucas v. Todd* (1865) 28 Cal. 182, 185, and *Estate of Bizzell* (1916) 172 Cal. 486, 487.) Rather, he or she is properly referred to as a "successor personal representative."[41]

Conservator -- A person lawfully invested with the power, and charged with the duty, to provide for the care of another person and/or manage the property and rights of another person who, for a variety of reasons (physical infirmity, mental incompetence, or other legal incapacitation) is considered incapable of administering his or her own affairs. (See Guardian, below.)

A **Conservator of the Person** may be appointed for a person who is unable properly to provide for his or her personal needs for physical health, food, clothing, or shelter....[42].

A **Conservator of the Estate** may be appointed for a person who is substantially unable to manage his or her own financial resources or resist fraud or undue influence.... ("Substantial inability may not be proved solely by isolated incidents of negligence or improvidence.")[43]

A **Conservator of the Person and Estate** "may be appointed for a person described in subdivisions (a) and (b) [of Probate Code § 1801.]" Probate Code § 1801(c).

A **Limited Conservator,** i.e., of the person, or of the estate, or of both, may be appointed for a developmentally disabled adult.

The **Powers and Duties** of a Conservator or Guardian of the Person are generally as provided in Probate Code § 2350, et seq.; the **Powers and Duties** of a Conservator or Guardian of the Estate are generally as provided in Probate Code § 2400, et seq. "The court may, in its discretion, make an order granting the guardian or conservator any one or more of the powers specified in § 2591..." including the power to sell real and personal property.[44] Otherwise the guardian or conservator does not have a general power of disposition over real property.

Note: If the guardian or conservator has signed a lease or other conveyance, you need to see the order granting that power to that person.)

Conservatee is a person for whom a Conservator is appointed.

The **decedent** is **the** one who has died. The one invariable condition precedent to the commencement of proceedings for the probate of a decedent's estate.

Devise, when used as a noun, means a disposition of real or personal property by will.

[41] Probate Code § 8522.

[42] Probate Code § 1801(a)

[43] Probate Code §1801(b)

[44] Probate Code § 2590

When used as a verb, it means to dispose of real or personal property by will.[45]

A **Devisee** is any person designated in a will to receive a devise.[46] (See also **Heir,** below.)

An **Executor** is a person appointed by a testator in a valid will to carry out the directions and requests of the will and to administer the estate. (Probate Code § 8420, et seq.) (The common law concept of *"executor de son tort,"* an intermeddler who took possession or control over the decedent's goods and became subject to the liabilities but not the rights of a personal representative, does not apply in California. 12 *Witkin, Summary of California Law* (9th ed.) "Wills and Probate," p. 413, § 389.)

Generally, a **Fiduciary** is a person having a duty to act primarily for the benefit of another, i.e., to place the interests of another above her or his own. In the probate context, this includes "a[ny form of] personal representative, trustee, guardian, conservator, custodian under the California Uniform Transfer to Minors Act [commencing § 3900], or other legal representative subject to [the Probate Code]." (Probate Code § 39.)
A **guardian** is a person lawfully invested with the power, and charged with the duty, of taking care of the person and (under prior probate law) managing the property and rights of a minor person (referred to as the "ward") who, for a variety of reasons (age, physical infirmity, mental incompetence, or other legal incapacitation) is considered incapable of administering his or her own affairs. (See **Conservator,** above.)[47]

The **Powers and Duties** of a Conservator or Guardian of the Person are generally as provided in Probate Code § 2350, et seq.; the **Powers and Duties** of a Conservator or Guardian of the Estate are generally as provided in Probate Code § 2400, et seq. The court may, in its discretion, make an order granting the guardian or conservator any one or more of the powers specified in § 2591, including the power to sell real and personal property. (Probate Code §2590.) Otherwise the guardian or conservator does not have a general power of disposition over real property. *(So, if the guardian or conservator has signed a lease or other conveyance, you need to see the order granting that power to that person.)*

A **Guardian ad litem** is a guardian appointed by the court for the purpose of protecting the interests of a minor, an unborn, incapacitated or., incompetent person, or one or more persons who either are unascertained or whose identify or address is unknown.[48] Typically limited to protecting the interests or such person(s) in a specific proceeding for which appointed.

An **Heir** is a person recognized by law as entitled to succeed to all or part of the assets of a decedent under the laws of intestate succession. "[Subject to the administration of decedent's estate, and the claims of beneficiaries, creditors and others as provided by law,] title to a decedent's property passes on the decedent's death to the person[s] to whom it is devised in the decedent's last will or, in the absence of such a devise, to the decedent's heirs as prescribed in the laws governing intestate succession."[49] (See also **Devise** and **Devisee,** above.)

[45] Probate Code § 32

[46] Probate Code § 34(a).
[47] Probate Code § 1500, et seq.

[48] See Probate Code §1003
[49] Probate Code §§ 7000 and 7001.

Independent Administration of Estate refers to probate proceedings in which the personal representative has enlarged advance authorization from the court, in the form of an order, permitting her or him to act in specified matters without further intervention or approval by the court, pursuant to the "Independent Administration of Estates" provisions in Probate Code § 10400, et seq.

An **Independent Personal Representative** is person administering an estate of a deceased person pursuant to the "Independent Administration of Estates" provisions in Probate Code § 10400, et seq. (See Independent Administration of Estate.)

Intestate refers to a decedent who leaves no valid will. (See **Testate,** below.)

Issue is "all of [a person's] lineal descendents of *all* generations, with the relationship of parent and child at each generation being determined by the definitions of child and parent [which see, below]."[50]

Legatee is a person designated in a Will to receive a legacy; by definition under prior law, this person would not receive a gift of land or real property (since that would have been a "devise," and they would have been a devisee, not a legatee).

The **Parent-Child** relationship ". . .exists for the purpose of determining intestate succession by, through, or from a person in the following circumstances: (a) between a person and the person's natural parents, regardless of the marital status of the natural parents [unless and until severed by adoption, Prob. Code § 6451), and (b) between an adopted person and the person's adopting parent or parents (Prob. Code § 6450), and between a person and the person's foster parent or parents in the circumstances described in Prob. Code § 6454."

A **Personal Representative** is a person (alone or jointly with others) who has the power by virtue of a court appointment to represent and manage the estate of a decedent. ("A person has no power to administer the estate until the person is appointed personal representative and the appointment becomes effective, i.e., when the person appointed is issued letters [testamentary by the court].[51] "The term includes an executor and all forms of administrator.

Residue is the surplus or remainder of a testator's estate remaining after all the debts and particular or specific devises and legacies have been satisfied. A residuary clause is a provision in a will or in a probate decree that provides for the disposition of the (usually) otherwise undescribed "rest, residue and remainder" (or equivalent words) of all or a described portion of the decedent's estate.

Supervised Probate or Supervised Administration is the administration of a decedent's estate in a proceeding authorized by law or court rule and designed to give court control of the acts of a personal representative.

Testate is a decedent for whom a valid will exists, whether or not it is in the possession of a petitioner at the commencement of probate proceedings, or is lost, destroyed, or outside the jurisdiction of the court.[52] (See **Intestate,** above.)

A **trust** is any arrangement whereby property is transferred with intention that it be administered by a trustee for the benefit of another. A trust cannot be created unless

[50] Prob. Code § 50.

[51] Probate Code § 8400

[52] Probate Code § 8000.

there is an intention to do so,[53] if there is property subject to the trust,[54] and if there is at least one beneficiary.[55]

Living Trust, or "Inter Vivos" Trust is a trust created by a trustor, etc. during his or her lifetime (as opposed to a testamentary trust which becomes effective only after the death of the testator).

Testamentary Trust is a trust created under the provisions of a will.

Trustor, Settlor, or Grantor are terms which may be used interchangeably to refer to the person who creates a trust.

A **trustee** is one who administers a trust for the benefit of another. The trustee can also be a/the beneficiary.
Note: "Unless otherwise provided in the trust instrument, a power vested in two or more trustees may only be exercised by their unanimous action." Probate Code §15620.

A **beneficiary** is one for whose benefit a trust is created or one who has the enjoyment of property of which a trustee, executor, etc., has the legal possession.

An **irrevocable trust** is a trust which cannot be revoked by the trustor, so that transfers of property are final and the property can be transferred by the trustee only to accomplish the purposes of the trust (i.e., to distribute to beneficiaries or for sale and reinvestment of the proceeds).

A **revocable trust** is a trust which can be revoked by the trustor.

A **Deed of Trust** is a conveyance of property by a debtor to a third party for the benefit of a creditor in order to secure the performance of an act, typically the repayment of money. Analogous to a "mortgage with power of sale." See Civil Code §2920, et seq.

A **ward** is a minor for whom a guardian is appointed.

Probate proceedings. Provisions which are made in the law for the care and management of the person and/or estate and, ultimately, the disposition of the assets of the estate, of persons who are unable due to death or actual or presumed incapacity, to care for and manage (and dispose of) their own person and/or estate.

Establishing the fact of death. Proceedings to establish death are necessary if title to or an interest in real or personal property is affected by the death of a person. Another person who claims an interest in the property may commence proceedings pursuant to [Probate Code §200, et seq.] to establish the fact of death. (Probate Code §200.)

Recording Evidence of Death. If title to real property is affected by the death of a person, any person may record in the county in which the property is located any of the following documents establishing the fact of the death: (a) An affidavit of death executed by a person having knowledge of the facts [and] including a particular description of the real property and an attested or certified copy of a record of death made and filed in a designated public office as required by law [or] (b) a certified copy of a court order that determines the fact of death pursuant to [Probate Code §200, et seq.] or pursuant to another statute that provides for a determination of the fact of death. (Probate Code §210.)

Ancillary probate. Also called **Probate of "Nondomiciliary Decedents' Estates",** "Ancillary administration" means proceedings

[53] Probate Code §15201
[54] Probate Code §15202
[55] Probate Code §15205

in this state for administration of the estate of a nondomiciliary decedent (Probate Code §12500, et seq.).

Affidavit for collection of a small estate by a sister state personal representative without ancillary administration "if the gross value of the decedent's real and personal property in the state [with certain exclusions, does not exceed one hundred thousand dollars **($100,000.00)],"** then the affidavit transfer of assets provisions of Probate Code §13100, et seq., may be used. [See the same below, under **"Disposition Without Probate."]**

California intestate succession. "Upon the death of a married person, one-half of the community property belongs to the surviving spouse and the other half belongs to the decedent." (Probate Code §100.) "Upon the death of a married person domiciled in this state, one-half of the decedent's quasi-community property belongs to the surviving spouse and the other half belongs to the decedent." (Probate Code §101.) "Quasi-community property of the decedent" is property of the decedent which would have been community property of the decedent and surviving spouse (and would remain such) if it had been acquired and held under the laws of the State of California concerning the acquisition of property by married couples.

Distribution or participation *per stirpes* (or by right of representation) or "per capita." If participation is *per stirpes*, or by representation or by right of representation, then "the property shall be divided into as many equal shares as there are living children of the deceased ancestor, if any, and deceased children who leave issue then living." Each living child of the designated ancestor is allocated one share, and the share of each deceased child who leaves issue then living is divided [among those then living children] in the same manner, i.e., the then living children of the deceased child participate in the property of the ancestor "by representation" in what would have otherwise been the share of their deceased parent. (Probate Code §246. See also §240.)

If participation is per capita, the property to be distributed shall be divided into as many equal snares as there are living members of the nearest generation of issue then living and deceased members of that generation who leave issue then living. Each living member of the next generation of the nearest generation of issue then living is allocated one share, and the remaining shares, if any, are combined and then divided and allocated In the same manner among the remaining issue as if the issue already allocated [i.e., the surviving members of the nearest generation] and their descendants were then deceased.

Any part of the estate of a decedent **not** effectively disposed of by will passes to the decedent's heirs as follows.

(a) Pursuant to Probate Code §6401, if there is a surviving spouse, the surviving spouse's share is one-half of the community property and one-half of the quasi-community property included in such part of the estate as well as the following interest in the separate property of the estate (remember that the estate's one-half share of community and quasi-community property is included in the separate property of the estate):

(1) the entire intestate estate if the decedent did not leave any surviving issue, parent, brother, sister, or issue or a deceased brother or sister.

(2) one-half of the intestate estate if the decedent either (A) leaves only

one child or the issue of only one child, (B) leaves no issue but leaves a parent or parents or their issue or the issue of either of them.

(3) one-third of the intestate estate if the decedent either (A) leaves more than one child, (B) leaves one child and the issue of one or more deceased children, or (C) leaves issue of two or more deceased children.

Pursuant to Probate Code §6402, the part of the intestate estate not passing to the surviving spouse (or the entire intestate estate if there is no surviving spouse except as provided in (c), below), passes as follows:

(1) to the issue of the decedent, the issue taking equally if they are all of the same degree of kinship to the decedent, otherwise *per stirpes*.

(2) if there is no surviving issue of the decedent, then to the decedent's parent or parents equally.

(3) if there is no surviving issue or parent of the decedent, then to the issue of the parents or either of them, the issue taking equally if they are all of the same degree of kinship to the decedent, otherwise per stirpes.

(4) if there is no surviving issue, parent or issue of a parent of the decedent, but the decedent is survived by one or more grandparents or issue of grandparents, to the grandparent or grandparents equally, or, if there is no surviving grandparent, then to the issue of such grandparents *per stirpes*.

(5) if there is no surviving issue, parent or issue of a parent, or grandparent or issue of a grandparent, the decedent is survived by the issue of a predeceased spouse, then to such issue *per stirpes*.

(6) if there is no surviving issue, parent or issue of a parent, grandparent or issue of a grandparent, or issue of a predeceased spouse, but the decedent is survived by [any] next of kin, then to the next of kin in equal degree, but where there are two or more collateral kindred [i.e., lines of kinship] in equal degree who claim through different ancestors, those who claim through the nearest ancestor are preferred to those claiming through a more remote ancestor.

(7) if there is no surviving next of kin of the decedent and no surviving issue of a predeceased spouse of the decedent, but the decedent is survived by the parents of a predeceased spouse or the issue of such parents, then to the parent or parents equally, or to the issue of such parents if both are deceased, the issue taking *per stirpes*.

Pursuant to Probate Code §6402.5, for purposes of distributing real property of the decedent's estate, if the decedent had a predeceased spouse who died not more than 15 years before the decedent and there is no surviving spouse or issue of the decedent, the portion of the decedent's estate attributable to the decedent's predeceased spouse [i.e., generally, the interest to which that spouse would have been entitled under (a), above, if such spouse had survived the decedent; more specifically defined in subdivision (f) of Probate Code §6402.5] passes as follows:

(1) If the decedent is survived by issue of the predeceased spouse, then to the surviving issue of the predeceased spouse per stirpes.

(2) if there is no surviving issue of the predeceased spouse, but the decedent is survived by a parent or parents of the predeceased spouse, then to the predeceased spouse's surviving parent or parents equally.

(3) if there is no surviving issue or parent of the predeceased spouse but the decedent is survived by issue of a parent of the predeceased spouse, then to the surviving issue of the parents, or either parent, of the predeceased spouse per stirpes.

(4) if the decedent is not survived by issue, parent or issue of a parent of the predeceased spouse, then to the next of kin of the decedent as provided in (b), above.

(5) if the portion of the decedent's estate attributable to a predeceased spouse who died not more than 15 years before the decedent would otherwise escheat to the state (because there is no one to take it under (b), above), then such portion of the decedent's estate passes to the next of kin of the predeceased spouse who take in the same manner as provided in (b), above, i.e., as if the predeceased spouse were the decedent.

There are also special provisions concerning the distribution of personal property relating to a predeceased spouse who died not more than 5 years before the decedent, in subdivisions (b), (c) and (d) of Probate Code §6402.5.

Extraordinary Powers .

In general, Personal Representatives, Conservators and Guardians cannot sell, lease or otherwise convey real property in the absence of specific court approval, usually in the form of an order either authorizing an attempt to sell or lease real property or an order approving a particular sale or lease (or both). (Probate Code §2550.) However, there are procedures by which the Personal Representatives of a Decedent's Estate and Conservators and Guardians may secure a more general authorization to take certain actions or to engage in certain types of transactions.

The "Independent Administration of Estates Act," Probate Code §10400, et seq., allows the court to authorize the personal representative "to administer the estate as [therein provided] without court supervision." Authority to do so may be either full authority or limited authority to proceed under the "Independent Administration of Estates" provisions.

In either case, certain actions continue to require prior court approval, such as sale of property of the estate to the personal representative or the attorney for the personal representative. Those actions are set forth in Probate Code §10501 (a).

Certain actions by a personal representative with limited authority also require prior court approval, such as the sale of real property of the estate. Those actions are set forth in Probate Code §10501(b).

Certain actions, even though not requiring prior court approval, always require prior notice to interested parties in accordance with the provisions of Probate §10580, et seq. Those actions are set forth in Probate Code §10510, et seq., and include the selling and encumbering property of the estate.

Certain actions do not require prior court approval but sometimes, depending upon the specific circumstances require prior notice to interested parties. Those actions are set forth in Probate Code §10530, et seq., and include the formation of certain leases, contracts and certain investments, including a lease of real property, including an oil and gas lease, for a term in excess of one year.

Certain actions require neither prior court approval nor prior notice to interested parties. These are described and/or set forth in Probate Code §10550, et seq. Also note that the actions included within part (4), above, also require neither prior court approval or prior notice to interested parties if the specific conditions in which such notice is required do not exist.

Pursuant to Probate Code §10591, the failure of the personal representative to give the otherwise required notice, and the taking of action by. the personal representative without such notice [assuming that the personal representative has the right to take such action without prior court approval] does not affect the validity of the action so taken or the title to any property conveyed or transferred to bona fide purchasers or the rights of third persons who, dealing in good faith with the personal representative, changed their position in reliance upon the action, conveyance, or transfer without actual notice of the failure of the personal representative to comply with the notice requirements. Furthermore, "no person dealing with the personal representative has any duty to inquire or investigate whether or not the personal representative has complied with those notice requirements]."

The "Independent Exercise of Powers" provisions for Conservators and Guardians of the Estate or of the Estate and the Person in Probate Code §2590, et seq., authorize the court in its discretion, and subject to limitations it may impose, to make an order granting a conservator or guardian any one or more or all of the powers specified in section 2591, namely:

(a) The power to contract for the guardianship or conservatorship and to perform outstanding contracts and thereby bind the estate.
(b) The power to operate at the risk of the estate a business, farm, or enterprise constituting an asset of the estate.
(c) The power to grant and take options.
(d) The power to sell at public or private sale real or personal property of the estate.
(e) The power to create by grant or otherwise easements and servitudes.
(f) The power to borrow money and give security for the repayment thereof.
(g) The power to purchase real or personal property.
(h) The power to alter, improve, and repair or raze, replace, and rebuild property of the estate.
(i) The power to let or lease property of the estate for any purpose (including exploration for and removal of gas, oil, and other minerals and natural resources **[which would not otherwise be included in a general power to lease property])** and for any period, including a term commencing at a future time.
(j) The power to lend money on adequate security.
(k) The power to exchange property of the estate.
(l) The power to sell property of the estate on credit if any unpaid portion of the selling price is adequately secured.
(m) The power to commence and maintain an action for partition.

(n) The power to exercise stock rights and stock options.
(o) The power to participate in and become subject to and to consent to the provisions of a voting trust and of a reorganization, consolidation, merger, dissolution, liquidation, or other modification or adjustment affecting estate property.
(p) The power to pay, collect, compromise, arbitrate, or otherwise adjust claims, debts, or demands upon the guardianship or conservatorship.
(q) The power to employ attorneys, accountants, investment counsel, agents, depositories, and employees and to pay the expense.

Small Estate Set-Aside.
Probate Code §6600, et seq. "A petition may be filed (in court) under this chapter requesting an order setting aside the decedent's estate to the decedent's surviving spouse and minor children, or one or more of them, as provided in this chapter, if the net value of the decedent's estate [i.e., net of certain exclusions per §6600], over and above all liens and encumbrances at the date of death and over and above the value of any probate homestead interest set apart out of the decedent's estate under section 6520, does not exceed twenty thousand dollars ($20,000.00)." (Probate Code §6602.) 8. Affidavit procedure for collection and transfer of Personal Property; when gross value of decedent's real and personal property in the state, with some exceptions, does not exceed $100,000.00. (Probate Code §13100.) Affidavit procedure for real property of small value. When the gross value of the decedent's real property in the state, with certain exceptions, does not exceed $10,000.00. (Probate Code §13200, et seq.)

Passage of property to surviving spouse without administration. Probate Code §13500, et seq.

Nonprobate transfer on death in insurance policies, contracts of employment, bonds, mortgages, pension plans, individual retirement plan, conveyance "or other written instrument of a similar nature is not invalid because the instrument does not comply with the requirements for the execution of a will, and [the Probate C]ode does not invalidate the same (Probate Code §5000), subject to the rights of creditors under any other law (Probate Code §5000(c)) and to the rights of a spouse with respect to "Nonprobate Transfers of Community Property," as provided in Probate Code §5010, et seq.

Multiple Party Accounts. Probate Code §5100, et seq. Can be arranged for:

(a) Joint Account -- This account is owned by the named parties, on death of any of them, ownership passes to the survivor(s).

(b) Pay On Death ("POD") Account, with single or multiple parties. This account is owned by the named party (single) and on his or her death passes to the named POD payee(s) or is owned by named parties (multiple), on death of any of them ownership passes to the survivor(s) and on death of all of them passes to the named POD payee(s).
(c) Joint account of Husband and Wife, with right of survivorship.
(d) Community property account.
(e) Tenancy in common.

Trusts

Creation and Validity of Trusts.
California Probate Code section 15002: Except to the extent that the common law rules governing trusts are modified by statute, the common law as to trusts is the law of this

state.

California Probate Code section 15200: Subject to other provisions of this chapter, a trust may be created by any of the following methods: (a) A declaration by the owner of property that the owner holds the property as trustee. (b) A transfer of property by the owner during the owner's lifetime to another person as trustee. (c) A transfer of property by the owner, by will or by other instrument taking effect upon the death of the owner, to another person as trustee. (d) An exercise of a power of appointment to another person as trustee. (e) An enforceable promise to create a trust.

California Probate Code section 15201: A trust is created only if the settlor properly manifests an intention to create a trust.

California Probate Code section 15202: A trust is created only if there is trust property.

California Probate Code section 15203: A trust may be created for any purpose that is not illegal or against public policy.

California Probate Code section 15204: A trust created for an indefinite or general purpose is not invalid for that reason if it can be determined with reasonable certainty that a particular use of the trust property comes within that purpose.

California Probate Code section 15205: (a) A trust, other than a charitable trust, is created only if there is a beneficiary. (b) The requirement of subdivision (a) is satisfied if the trust instrument provides for either of the following: (1) A beneficiary or class of beneficiaries that is ascertainable with reasonable certainty or that is sufficiently described so it can be determined that some person meets the description or is within the class. (2) A grant of a power to the trustee or some other person to select the beneficiaries based on a standard or in the discretion of the trustee or other person.

California Probate Code section 15206: A trust in relation to real property is not valid unless evidenced by one of the following methods: (a) By a written instrument signed by the trustee, or by the trustee's agent if authorized in writing to do so. (b) By a written instrument conveying the trust property signed by the settlor, or by the settlor's agent if authorized in writing to do so. (c) By operation of law.

California Probate Code section 15207: (a) The existence and terms of an oral trust of personal property may be established only by clear and convincing evidence. (b) The oral declaration of the settlor, standing alone, is not sufficient evidence of the creation of a trust of personal property. (c) In the case of an oral trust, a reference in this division or elsewhere to a trust instrument or declaration means the terms of the trust as established pursuant to subdivision (a).
California Probate Code section 15208: Consideration is not required to create a trust, but a promise to create a trust in the future is enforceable only if the requirements for an enforceable contract are satisfied.

Cotrustees.
California Probate Code section 15620: Unless otherwise provided in the trust instrument, a power vested in two or more trustees may only be exercised by their unanimous action.
California Probate Code section 15621: Unless otherwise provided in the trust instrument, if a vacancy occurs in the office of a cotrustee, the remaining cotrustee or cotrustees may act for the trust as if they are the only trustees.

California Probate Code section 15622:

Unless otherwise provided in the trust instrument, if a cotrustee is unavailable to perform the duties of the cotrustee because of absence, illness, or other temporary incapacity, the remaining cotrustee or cotrustees may act for the trust, as if they are the only trustees, where necessary to accomplish the purposes of the trust or to avoid irreparable injury to the trust property.

Third Party Rights and Liability.
California Probate Code section 18000: (a) Unless otherwise provided in the contract or in this chapter, a trustee is not personally liable on a contract properly entered into in the trustee's fiduciary capacity in the course of administration of the trust unless the trustee fails to reveal the trustee's representative capacity or identify the trust in the contract. (b) The personal liability of a trustee on a contract entered into before July 1, 1987, is governed by prior law and not by this section.

California Probate Code section 18001: A trustee is personally liable for obligations arising from ownership or control of trust property only if the trustee is personally at fault.

California Probate Code section 18002: A trustee is personally liable for torts committed in the course of administration of the trust only if the trustee is personally at fault.

California Probate Code section 18003: (a) A cotrustee who does not join in exercising a power held by three or more cotrustees is not liable to third persons for the consequences of the exercise of the power. (b) A dissenting cotrustee who joins in an action at the direction of the majority cotrustees is not liable to third persons for the action if the dissenting cotrustee expresses the dissent in writing to any other cotrustee at or before the time the action is taken. (c) This section does not excuse a cotrustee from liability for failure to discharge the cotrustee's duties as a trustee.

California Probate Code section 18004: A claim based on a contract entered into by a trustee in the trustee's representative capacity, on an obligation arising from ownership or control of trust property, or on a tort committed in the course of administration of the trust may be asserted against the trust by proceeding against the trustee in the trustee's representative capacity, whether or not the trustee is personally liable on the claim.

California Probate Code section 18100: With respect to a third person dealing with a trustee or assisting a trustee in the conduct of a transaction, if the third person acts in good faith and for a valuable consideration and without actual knowledge that the trustee is exceeding the trustee's powers or improperly exercising them: (a) The third person is not bound to inquire whether the trustee has power to act or is properly exercising a power and may assume without inquiry the existence of a trust power and its proper exercise. (b) The third person is fully protected in dealing with or assisting the trustee just as if the trustee has and is properly exercising the power the trustee purports to exercise.

California Probate Code section 18100.5:

(a) The trustee may present a certification of trust to any person in lieu of providing a copy of the trust instrument to establish the existence or terms of the trust. A certification of trust may be executed by the trustee voluntarily or at the request of the person with whom the trustee is dealing.

(b) The certification of trust may confirm the following facts or contain the following information:

(1) The existence of the trust and date of execution of the trust instrument.

(2) The identity of the settlor or settlors and the currently acting trustee or

trustees of the trust.

(3) The powers of the trustee.

(4) The revocability or irrevocability of the trust and the identity of any person holding any power to revoke the trust.

(5) When there are multiple trustees, the signature authority of the trustees, indicating whether all, or less than all, of the currently acting trustees are required to sign in order to exercise various powers of the trustee.

(6) The trust identification number, whether a social security number or an employer identification number.

(7) The manner in which title to trust assets should be taken.

(8) The legal description of any interest in real property held in the trust.

(c) The certification shall contain a statement that the trust has not been revoked, modified, or amended in any manner which would cause the representations contained in the certification of trust to be incorrect and shall contain a statement that it is being signed by all of the currently acting trustees of the trust. The certification shall be in the form of an acknowledged declaration signed by all currently acting trustees of the trust. The certification signed by the currently acting trustee may be recorded in the office of the county recorder in the county where all or a portion of the real property is located.

(d) The certification of trust may, but is not required to, include excerpts from the original trust documents, any amendments thereto, and any other documents evidencing or pertaining to the succession of successor trustees. The certification of trust shall not be required to contain the dispositive provisions of the trust which set forth the distribution of the trust estate.

(e) A person whose interest is, or may be, affected by the certification of trust may require that the trustee offering or recording the certification of trust provide copies of those excerpts from the original trust documents, any amendments thereto, and any other documents which designate, evidence, or pertain to the succession of the trustee or confer upon the trustee the power to act in the pending transaction, or both. Nothing in this section is intended to require or imply an obligation to provide the dispositive provisions of the trust or the entire trust and amendments thereto.

(f) A person who acts in reliance upon a certification of trust without actual knowledge that the representations contained therein are incorrect is not liable to any person for so acting. A person who does not have actual knowledge that the facts contained in the certification of trust are incorrect may assume without inquiry the existence of the facts contained in the certification of trust. Actual knowledge shall not be inferred solely from the fact that a copy of all or part of the trust instrument is held by the person relying upon the trust certification. Any transaction, and any lien created thereby, entered into by the trustee and a person acting in reliance upon a certification of trust shall be enforceable against the trust assets. However, if the person has actual knowledge that the trustee is acting outside the scope of the trust, then the transaction is not enforceable against the trust assets. Nothing contained herein shall limit the rights of the beneficiaries of the trust against the trustee.

(g) A person's failure to demand a certification of trust does not affect the protection provided that person by Section 18100, and no inference as to whether that person has acted in good faith may be drawn from the failure to demand a certification of trust. Nothing in

this section is intended to create an implication that a person is liable for acting in reliance upon a certification of trust under circumstances where the requirements of this section are not satisfied.

(h) Except when requested by a beneficiary or in the context of litigation concerning a trust and subject to the provisions of subdivision (e), any person making a demand for the trust documents in addition to a certification of trust to prove facts set forth in the certification of trust acceptable to the third party shall be liable for damages, including attorney's fees, incurred as a result of the refusal to accept the certification of trust in lieu of the requested documents if the court determines that the person acted in bad faith in requesting the trust documents.

(i) Any person may record a certification of trust that relates to an interest in real property in the office of the county recorder in any county in which all or a portion of the real property is located. The county recorder shall impose any fee prescribed by law for recording that document sufficient to cover all costs incurred by the county in recording the document. The recorded certification of trust shall be a public record of the real property involved. This subdivision does not create a requirement to record a certification of trust in conjunction with the recordation of a transfer of title of real property involving a trust.

California Probate Code section 18101: A third person who acts in good faith is not bound to ensure the proper application of trust property paid or delivered to the trustee.

California Probate Code section 18102: If a third person acting in good faith and for a valuable consideration enters into a transaction with a former trustee without knowledge that the person is no longer a trustee, the third person is fully protected just as if the former trustee were still a trustee.

California Probate Code section 18103: If an express trust relating to real property is not contained or declared in the grant to the trustee, or in an instrument signed by the trustee and recorded in the same office with the grant to the trustee, the grant shall be deemed absolute in favor of a person dealing with the trustee in good faith and for a valuable consideration.

California Probate Code section 18104:

(a) If an interest in or lien or encumbrance on real property is conveyed, created, or affected by an instrument in favor of a person in trust but no beneficiary is indicated in the instrument, it is presumed that the person holds the interest, lien, or encumbrance absolutely and free of the trust. This is a presumption affecting the burden of proof. In an action or proceeding involving the interest, lien, or encumbrance instituted against the person, the person shall be deemed the only necessary representative of the undisclosed beneficiary and of the original grantor or settlor and anyone claiming under them. A judgment is binding upon and conclusive against these persons as to all matters finally adjudicated in the judgment.

(b) An instrument executed by the person holding an interest, lien, or encumbrance described in subdivision (a), whether purporting to be the act of that person in his or her own right or in the capacity of a trustee, is presumed to affect the interest, lien, or encumbrance according to the tenor of the instrument. This is a presumption affecting the burden of proof. Upon the recording of the instrument in the county where the land affected by the instrument is located, the

presumption is conclusive in favor of a person acting in good faith and for valuable consideration.

California Probate Code section 18105: If title to an interest in real property is affected by a change of trustee, the successor trustee may execute and record in the county in which the property is located an affidavit of change of trustee. The county recorder shall impose any fee prescribed by law for recording that document in an amount sufficient to cover all costs incurred by the county in recording the document. The affidavit shall include the legal description of the real property, the name of the former trustee or trustees and the name of the successor trustee or trustees. The affidavit may also, but is not required to, include excerpts from the original trust documents, any amendments thereto, and any other documents evidencing or pertaining to the succession of the successor trustee or trustees. If title to an interest in real property is affected by a change of trustee, the successor trustee may execute and record in the county in which the property is located an affidavit of change of trustee. The county recorder shall impose any fee prescribed by law for recording that document in an amount sufficient to cover all costs incurred by the county in recording the document. The affidavit shall include the legal description of the real property, the name of the former trustee or trustees and the name of the successor trustee or trustees. The affidavit may also, but is not required to, include excerpts from the original trust documents, any amendments thereto, and any other documents evidencing or pertaining to the succession of the successor trustee or trustees.

California Probate Code section 18106:

(a) A document establishing the fact of change of trustee recorded pursuant to this chapter is subject to all statutory requirements for recorded documents.

(b) The county recorder shall index a document establishing the fact of change of a trustee recorded pursuant to this section in the index of grantors and grantees. The index entry shall be for the grantor, and for the purpose of this index, the person who has been succeeded as trustee shall be deemed to be the grantor. The county recorder shall impose any fee prescribed by law for indexing that document in an amount sufficient to cover all costs incurred by the county in indexing the document.

California Probate Code section 18107: A document establishing the change of a trustee recorded pursuant to this chapter is prima facie evidence of the change of trustee insofar as the document identifies an interest in real property located in the county, title to which is affected by the change of trustee. The presumption established by this section is a presumption affecting the burden of producing evidence.

California Probate Code section 18108: Any person whose interest is, or may be, affected by the recordation of an affidavit of change of trustee pursuant to this chapter may require that the successor trustee provide copies of those excerpts from the original trust documents, any amendments thereto, and any other documents which evidence or pertain to the succession of the successor trustee or trustees. Nothing in this section is intended to require or imply an obligation to provide the dispositive provisions of the trust or the entire trust and any amendments thereto.

Appendix: § 880.340. <u>Form of notice of intent to preserve interest</u>

Subject to all statutory requirements for recorded documents, a notice of intent to preserve an interest in real property shall be in substantially the following form:

Recording requested by:

[LEFT BLANK FOR RECORDING INFORMATION ADDED BY RECORDER]

After recording return to:

SPACE ABOVE FOR USE OF COUNTY RECORDER ONLY, PLEASE

Indexing instructions. This notice must be indexed as follows:
Grantor and grantee index--each claimant is a grantor.

NOTICE OF INTENT TO PRESERVE INTEREST

This notice is intended to preserve an interest in real property from extinguishment pursuant to Title 5 (commencing with Section 880.020) of Part 2 of Division 2 of the Civil Code (Marketable Record Title).

<u>Claimant</u> Name:
Mailing address: (must be given for each claimant)

<u>Interest</u> Character (e.g., power of termination):
Record location of document creating or evidencing interest in claimant:

<u>Real Property</u> Legal description (may be same as in recorded document creating or evidencing interest in claimant):

I assert under penalty of perjury that this notice is not recorded for the purpose of slandering title to real property and I am informed and believe that the information contained in this notice is true. If this notice is made on behalf of a claimant, I assert under penalty of perjury that I am authorized to act on behalf of the claimant.

Signed: _____ Date: _____
(claimant)

_____
(person acting on behalf of claimant)

Chapter 13: OVERVIEW OF NEW MEXICO OIL AND GAS LAW©

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Introduction

Oil and gas law in New Mexico is not unlike oil and gas law in our neighbor state to the east, Texas. New Mexico has extensive statutes on many subjects concerning oil and gas exploration, development and production. In addition, the New Mexico Oil Conservation Commission has developed extensive regulations controlling oil and gas activities. The oil and gas common or case law in New Mexico is fairly limited. The lack of case law may be indicative of the small population in the state and the significant acreage held by the federal and state governments. It may also be indicative of the detail in the state statutes and regulations that have avoided many of the issues courts have had to face in other states.

Oil and gas law for the most part is a combination of real property law and contract law. Oil and gas in place in New Mexico is deemed to be real property. An oil and gas lease conveys an estate in real property and contains numerous contractual provisions that run with the estate created. This chapter explores some of the basic concepts of oil and gas law in New Mexico. It is by no means an exhaustive treatise, but it should provide a good overview of common issues encountered.

Elements of the mineral estate

In New Mexico, the severance of the mineral estate from the surface creates a separate estate in the land and is **real property**.[1] The mineral estate includes the following attributes:

- the right to explore for, develop, produce, sever, and sell the minerals located in and under the land;
- the right to execute oil, gas, and mineral leases (**executive or executor rights**);
- the right to receive **bonuses**;
- the right to receive **delay rentals**;
- the right to receive **royalties;** and
- the right of ingress and egress and reasonable use of the surface estate to conduct mineral operations.

The mineral estate may be stripped of one or more of these attributes by execution of a deed granting a portion of these rights or a reserving a portion unto the grantor, according to the language in the deed.[2] For example, a deed may grant a "non-participating mineral interest" which gives the grantee the right to share in the gross production, but not to share in bonuses, delay rentals, executive rights, or development rights.

A lease of the mineral estate is a **conveyance** of a real property interest and vests the lessee with ownership of the mineral estate.[3] The lessee is thus granted the mineral estate in fee simple determinable[4]. As such, the lessee will retain ownership of the mineral estate for the primary term of the lease and as long thereafter as the stated minerals are produced. Theoretically, this could last forever, i.e. a fee estate. It is determinable because it terminates upon the happening of a stated event.

Oil and gas leases

The oil and gas lease forms the basis of most relationships among parties in oil and gas ventures. Oil and gas are not generally produced by the owner of the mineral estate. An oil and gas lease is generally acquired from the owner of the minerals. Many leases are acquired by speculators who do not intend to develop the leased acreage themselves. Others are acquired by an exploration company specifically interested exploring, drilling or developing promptly. The lease

[1] Terry v. Humphreys, 27 N.M. 564, 289 P. 303 (1922); Duvall v. Stone, 54 N.M. 27, 213 P.2d 212 (1949); Kaye v. Cooper Grocery Co., 63 N.M. 36, 312 P.2d 798 (1957)

[2] HNG Fossil Fuels v. Roach, 99 N.M. 216, 656 P.2d 879 (1982), *appeal after remand*, 103 N.M. 793, 715 P.2d 66.

[3] Terry v. Humphreys, 27 N.M. 564, 203 P. 539 (1922)

[4] Bolack v. Hedges, 56 N.M. 92, 240 P.2d 844 (1952)

may be assigned in whole or in part a number of times before the lease is actually drilled, or the lease may be traded or sold among production companies following substantial production. The lessee of the lease generally reflects the party that owns the oil and gas production attributable to the leased premises. There are exceptions, particularly with respect to federal oil and gas leases. This discussion primarily focuses upon fee oil and gas leases.

Standard Forms. There is no standard oil and gas lease form in New Mexico, although there are standard lease forms for federal and state lands and common forms on fee lands. An oil and gas lease partakes of both a contract and a conveyance, as it contains both *covenants and *conditions. As with all legal forms, as circumstances change, the forms have continued to evolve to address new concerns and reflect changing market conditions. Federal forms are set by the Secretary of the Interior and are changed to meet political changes and amendments to the Mineral Leasing Act of 1920. The state oil and gas lease forms are statutory, but the Commissioner of Public Lands has some discretion to use one of the three statutory forms based upon the circumstances involved.5 Private minerals are leased utilizing many different forms. There is a series of common forms printed by Hall-Poorbaugh Press in Roswell, New Mexico that have received wide acceptance in Southeastern New Mexico. The following are some of the common attributes of fee oil and gas leases in New Mexico:

Unless Lease Forms: This is the most common form and derives its name from how the lease is perpetuated. This form creates the determinable fee estate.[6]

Drill or Pay Lease Forms: The *or* lease is characterized by the right of termination

vested in the lessor due to noncompliance with a condition subsequent.[7]

Minerals Covered. In New Mexico an oil, gas and mineral lease generally will cover all minerals, while an oil and gas lease is often limited to the oil and gas minerals that may be located on the lands covered. Inclusion of language indicating other minerals are covered has led to an interpretation that sulfur, uranium, and thorium are leased by an oil, gas and other minerals lease.[8]

Date. The date of the lease, whether it be the execution date or the effective date, is critical in determining many of the rights granted. First, it provides the information necessary to determine the beginning and end of the primary term. Second, it provides the anniversary date on which annual rental payments are due in the absence of drilling operations or production. Third, it provides necessary information in the event there is a conflict created by an unscrupulous lessor who has executed multiple leases to different lessees of the same interest in the land.

Generally, the date is set out in the very first sentence of the lease. The **habendum clause** refers to the date of the lease or the "date hereof." It is becoming more common to see leases with an effective date different from the execution date. Care should be taken to make sure the proper date is referred to in the habendum clause. Also common are leases with a date different from the date of the lessor's acknowledgment. The date of the lease controls.[9] An undated lease in not void, but takes effect upon execution and delivery.[10]

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[5] *See* NMSA 1978, Sections 19-10-4.1 to .3 (1985)

[6] *Terry*, 27 N.M. at 576. Failure of the condition results in the automatic termination of the lease

[7] *See* Hemingway, Oil and Gas, Section 6.2 (2d ed. 1983).

[8] *See New Mexico & Arizona Land Co. v. Elkins,* 137 F. Supp. 767 (D.N.M. 1956).

[9] *Green v. Stanolind Oil & Gas Co.,* 200 F.2d 920 (10th Cir. 1952)

[10] *Ray v. Brush*, 112 Kan. 110, 210 P. 660

An oil and gas lease is not effective until delivery and payment of valid consideration.[11]

Parties. The parties to the lease must be set forth and are generally identified in the first paragraph of the lease. The lessor may be any owner who has a presently vested interest in the mineral estate, has not previously executed a currently existing lease, and has the capacity to execute the lease. The lessor should include the address where annual rentals, shut-in royalty and **royalty** payments are to be paid. The address of the lessee should also be identified. The following parties are proper lessors of a lease:

Conservator: A court appointed conservator on behalf of a minor or incompetent owner.[12]

Trustees: The trustee of a trust should be listed and identified as the lessor and not merely the trust.[13]

Personal Representative: The personal representative of a decedent's estate may execute a lease of an interest formerly owned by the decedent and not distributed to the heirs and/or devisees.[14]

Executive Right Owners: Owners of the executive rights if severed from other interests.

Attorney-in-Fact: Attorneys-in-fact may execute a lease on behalf of the principal only if the power of attorney includes authority to lease minerals. Power of sale does not include or imply a power to execute oil and gas leases.[15]

Married Persons: As discussed in more detail below, a married lessor should be joined by his or her spouse unless the record is clear that the interest of the lessor is separate property.[16]

Business Entities: Partnerships, corporations, and limited liability companies may be identified as the lessor since these business entities are entitled to hold title to real property.

Habendum Clause. Generally, a lease conveys the oil and gas interest for a set number of years, the primary term, and as long thereafter as oil, gas or other mineral is produced from the land or lands pooled therewith, the secondary term. Thus, the habendum clause sets the term of the interest granted. During the primary term, the lessee perpetuates the lease by paying delay rentals or commencement of drilling operations and continually prosecuting such operations. The lease continues into the secondary term by actual production of oil and gas in paying quantities or by the utilization of a savings provision in the lease.[17] Several issues impacting the habendum clause and thus determining the continued validity of the lease are delay rentals, production in "paying quantities," gas royalty calculation and payment of interest, and shut-in gas royalties, which are discussed below. Most oil and gas leases in New Mexico are commence form leases requiring the commencement of drilling operations within the primary term. The lease will generally provide that the lease will automatically expire at the end of the primary term unless drilling operations are then being conducted, which shall extend the lease for so long as the operations are diligently prosecuted with no cessation of more than a stated number of days. The term of most oil and gas leases in the state are for a specified term of years, being the primary term, and for so long thereafter as oil or gas is produced. In

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(1922)

[11] *Johnson v. Freytag*, 338 S.W.2d 257 (Tex. Civ. App. 1960)

[12] NMSA 1978, Section 45-5-424 C(11) (1975)

[13] NMSA 1978, Section 46A-8-816 I (2003); *Lee v. Catron, Catron and Pottow, P.A.,* 2006 NMCA 18, 203 P.3d 104, 105 (N.M. Ct. App. 2008)(*cert. denied*)

[14] NMSA 1978, Section 45-3-715A(9) (1975)

[15] *See Bean v. Bean*, 79 S.W.2d 652 (Tex. Civ. App. 1935)

[16] NMSA 1978, Section 40-3-13 (1973)

[17] *See* Tome v. Ringle, 56 N.M. 101, 240 P.2d 850 (1952); Hickman v. Mylander, 68 N.M. 340, 362 P.2d 500 (1961)

addition to the commence clause, there are other contractual substitutes for production allowing the lease to be extended even in the absence of actual production on the expiration date of the primary term.

Granting Clause. The granting clause of the lease causes the conveyance of the estate from the lessor to the lessee. Generally it reads ". . .grants exclusively unto the lessee for the purpose of investigating, exploring, pro-pecting, drilling and operating for and producing oil and gas. . . ."

The legal description of the property must be included sufficient to identify the land. New Mexico lease forms do not generally contain a "Mother Hubbard" clause common in other states. This is the result of the governmental survey system used in New Mexico.

The lease includes reference to surface and subsurface rights granted. In New Mexico the mineral estate is the dominant estate and the surface estate is subject to reasonable use by the mineral owner to explore for, mine, drill, produce and sever minerals.[18]

Royalty Clause. A royalty interest is also an interest in real property.[19] The royalty clause is a covenant, not a condition. Failure to pay royalty does not result in the automatic termination of the lease.[20] The covenant does run with the land. Most oil and gas leases separate the royalty on oil from royalty on gas, and they are calculated differently. If the lessor is fortunate, this clause will provide the greatest economic benefit.

Oil Royalty: Oil royalty is generally payable in kind or in cash at the option of the lessor and is free of costs of production, except its proportionate share of post production costs. These costs include transportation, production taxes, and severance taxes. The royalty is stated in a percentage or fraction of all oil produced and saved. Some federal oil and gas leases contain a royalty provision with a sliding scale or step scale royalty for which the royalty rate is dependent upon the quantity of oil or gas produced per well per month.

Gas Royalty: Gas royalty is generally payable based upon the market value at the well, when used off the premises or used in the manufacture of gasoline or other products, or on the amount realized from the sale when sold on or off the premises. This clause takes a number of forms and has been the subject of many controversies.

In determining "market value" and other royalty clause issues, primarily arising out of gas production from the leased premises, New Mexico would likely follow the Texas decisions. Often arising out of prices set in long-term gas contracts entered into by the lessees, Texas has determined that the "market value" for gas royalty payments is the fair market value at the time of production and delivery of the gas, rather than at the value at the time of the contracts. Thus, royalty owners may be entitled to royalties based on the current price even if the gas contract price is lower.[21] In New Mexico the lease will often specifically provide that the price in gas sales contracts entered into in good faith will be the "amount realized" and "price" is the net amount received by lessee after giving effect to regulatory orders and adjustments. This provision is intended to offset the Texas decisions.

With respect to the payment of royalty where one or more lessees are not actually marketing gas, the rule in New Mexico may differ from Texas. The New Mexico Proceeds Payment Act[22] requires timely payment of proceeds of

[18] Amoco Prod. Co. v. Carter Farms, 103 N.M. 117, 703 P.2d 894 (1985)(*rev'd on other grounds*)

[19] Duvall v. Stone, 54 N.M. 27, 213 P.2d 212 (1949); Fullerton v. Kaune, 72 N.M. 201, 205, 382 P.2d 529, 533 (1963)

[20] In re Antweil, 97 B.R. 65 (Bankr. D.N.M. 1989)(*rev'd on other grounds*)

[21] See *Exxon Corp. v. Middleton, 613 S.W.2d 240, 69 O&GR 115, 10 ALR 4th 712 (Tex. 1981); Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866* (Tex. 1968)

[22] NMSA 1978, Sections 70-10-1 *et. seq.* (1985)

production to all persons entitled thereto. Unless the gas royalty provision is precisely tied to the value of production actually received by the lessee, the royalty is generally payable on all gas produced, saved and sold from the premises. Therefore royalty should be paid on the production to the lessor even though the lessee is not actually marketing his or her share of the gas.

Payment of Royalty: By statute, the "party who undertakes to distribute oil and gas proceeds to the parties entitled thereto", the payor, shall make such payments not later than six months after the first day of the month following the date of first sale and thereafter not later than forty-five days after the end of the calendar month within which payment is received by the payor.[23] Payments not timely made accrue interest at the rate of eighteen percent, unless one of the following applies:

- the failure to pay is the result of good faith reliance upon a title opinion by a licensed New Mexico attorney making objection to the lack of good and marketable title of record in the party claiming entitlement to payment;
- information is received bringing into question the entitlement of the person claiming the interest;
- the amount is less than $100.00; or
- the party has failed or refused to execute a reasonable division or transfer order acknowledging the proper interest and the address to which payment is to be directed.

In these cases, the rate of interest is the discount rate of the federal reserve bank of Dallas plus one and one-half percent.[24]

Shut-in Gas Royalty: Most leases will contain some form of a shut-in well provision. A common provision in leases is a shut-in gas royalty provision requiring the payment of shut-in gas royalty normally within 60 or 90 days from the date the well is shut-in. Failure to pay the shut-in gas royalty timely will preclude the use of this savings provision to further extend the lease.[25] If the lease is within the primary term, the lessee may take the risk not to pay shut-in royalty and place the well into actual production before the end of the primary term. However, if the well is not placed into production, the shut-in royalty provision cannot be used at the end of the primary term to save the lease. Most shut-in gas royalty provisions are a condition in the lease and not a covenant, resulting in the automatic termination of the lease if the condition is not met.

Most printed lease forms used in New Mexico generally provide for the amount of shut-in royalty to be either $1.00 per acre per year or an amount equal to the amount of delay rentals depending upon the form and whether it is a paid-up lease. It is common to see sophisticated lessors provide a set fee per well per year as shut-in royalty and limit the duration the lease may be extended by payment of shut-in royalty.

Shut-in royalty is a substitute for actual production, and New Mexico would probably follow both Texas and Oklahoma in requiring the payment to be made to the royalty owners, if different from the mineral owners. Because the shut-in gas royalty is a substitute for production under the lease, it keeps the lease in effect during the secondary term without actual production or drilling operations; nonpayment would result in no production, and as discussed above, the lease terminates. Thus, the royalty owners are entitled to the payments just as they would be to royalties from actual production.[26]

Delay rentals

Under the typical "unless" lease form, the lease will automatically terminate, during the primary term, in the absence of commencing a well, producing oil or gas, or paying the yearly rental. Thus, upon payment, the lessee has the right to postpone commencement of drilling operations for another year of the

[23] NMSA 1978, Sections 70-10-1 *et. seq*. (1985)
[24] NMSA 1978, Sections 70-10-4, -5 (1991)

[25] *See e.g. Greer v. Salmon*, 82 N.M. 245, 479 P.2d 294 (1970).
[26] *See Morriss v. First National Bank of Mission*, 249 S.W.2d 269 (Tex. Civ. App.--San Antonio 1952, writ ref'd n.r.e.)

primary term.[27] Failure to make timely payment of the rental is not fatal to the lease if the lessee's actions manifest a good faith intent to continue the lease.[28] This is accomplished by an undertaking to pay the rental by customary means and in ample time for payment to reach the lessor or depository bank, and the payment's failure to reach the lessor was due to accident or mistake (i.e., lost in the mail).[29]
Modern lease forms provide for the lease's continuance upon a *bona fide* attempt by the lessee to make the rental payment and place the burden on the lessor to notify the lessee of mistakes in the rental payment. To escape many of these entanglements, the "paid-up" lease is now generally used, wherein the delay rentals for the primary term are paid in advance to the lessor.

Please note that oil and gas leases on state lands require annual rental payment even after the lease is producing. In addition, failure to timely pay annual rentals on a state lease does not result in the automatic termination of the lease.[30]

As in many contractual relations, in addition to the express provisions contained in oil and gas leases there are several implied covenants recognized by New Mexico courts. Several of the implied covenants are:

- Development: Lessee's implied covenant to develop the land with reasonable diligence after discovery of oil or gas in paying quantities.[31]
- Prevent Drainage: Lessee's implied covenant to drill an offset well to prevent drainage.[32]
- Market Production: Lessee's implied covenant to market oil or gas produced.[33]

The prudent operator standard has been applied to determine if the implied covenants have been complied with. The standard is a fact question to be determined on a case by case basis under the circumstances in question. Thus, the lessee's operations under an oil and gas lease must be what is reasonably expected of operators of ordinary prudence under the circumstances, having regard to the interests of both the lessor and lessee.[34] As the oil and gas industry continues to mature, these implied covenants will probably increase in importance and evolve into issues such as the lessor's demands for the use of secondary and tertiary recovery methods, exploration of deeper formations, and for operators to protect the lessor's rights before administrative tribunals.[35]

Pooling, communitization and unitization

Pooling and Communitization. New Mexico has enacted broad legislation regarding the establishment of spacing or proration units from which oil and gas may be produced with emphasis on protecting correlative rights without waste of oil or gas in the pool and the reservoir energy. To this end, the Oil Conservation Division (OCD) has established statewide spacing and establishes field pool rules for specific spacing where the facts indicate the state spacing pattern should be altered to carry out the goal of protecting correlative rights and preventing waste. State law[36] provides as follows:

When two or more separately owned tracts of land are embraced within a spacing or proration unit, or where there are owners of royalty interests

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[27] *Gloyd v. Midwest Refining Co.,* 62 F.2d 483, 485 (10th Cir. 1933)(applying New Mexico law).
[28] *Id.* at 486
[29] *Id.*; *Ballard v. Miller*, 87 N.M. 86, 592 P.2d 752 (N.M. 1974).

[30] *See* NMSA 1978, Section 19-10-20
[31] *State ex. rel. Shell Petroleum Corp. v. Worden*, 44 N.M. 400, 103 P.2d 124 (1940); Libby v. De Baca, 51 N.M. 95, 179 P.2d 263 (1947); *Darr v. Eldridge*, 66 N.M. 260, 346 P.2d 1041 (1959)
[32] *Cone v. Amoco Prod. Co.,* 87 N.M. 294, 532 P.2d 590 (1975)
[33] *Libby*, 51 N.M. 95; *Darr*, 66 N.M. 260
[34] *See Clayton v. Atlantic Refining Co.*, 150 F. Supp. 9 (D.N.M. 1957)
[35] *See generally* Patrick H. Martin & Bruce M. Kramer, Williams and Meyers Oil and Gas Law, § 801, *et seq.* (2008)
[36] NMSA 1978, Section 70-2-17 C (1961)

or undivided interests in oil and gas minerals which are separately owned or any combination thereof, embraced within such spacing or proration unit, the owner or owners thereof may validly pool their interests and develop their lands as a unit. Where, however, such owner or owners have not agreed to pool their interests, and where one such separate owner, or owners, who has the right to drill has drilled or proposes to drill a well on said unit to a common source of supply, the division, to avoid the drilling of unnecessary wells or to protect correlative rights, or the prevent waste, shall pool all or any part of such lands or interests or both in the spacing or proration unit as a unit.

Pooling is the term used to reflect the consolidation of two or more leases to form the spacing or proration unit. Communitization is the same concept where federal or state leases are involved. Unitization, on the other hand, is a different concept and is discussed below, although the term is often misused as a substitute for pooling or communitization.

Force pooling proceedings are common in the state where an unleased mineral owner refuses to join in the proposed drilling operations or two or more working interest owners cannot agree on how operations should proceed. An operator must attempt to obtain consent for voluntary pooling of all interests within the spacing or proration unit. When consent is not obtained, the operator must commence force pooling proceedings. Failure to obtain either voluntary pooling or an order from the OCD results in the operator having to pay to each interest owner the greater of the interest it would be entitled to if pooling had occurred or the amount it is entitled in the absence of pooling.[37] This exposes the operator to having to pay the owners of the tract on which the well is located their share of 100 percent of production and owners of the other tracts within the spacing or proration unit their prorata share of production from the well.

A hearing following notice is conducted before the OCD in Santa Fe, and the OCD enters an order directing the pooling of the interests within the spacing or proration unit upon terms and conditions that are "just and reasonable and will afford to the owner or owners of each tract or interest in the unit the opportunity to recover or receive without unnecessary expense his just and fair share of the oil or gas, or both." The OCD will generally allow a risk penalty to be charged against the interests of any party that does not voluntarily join in drilling the well and will set the charges that may be charged by the operator. If an unleased mineral owner is involved, seven-eighths of his interest is considered as a working interest and one-eighth is considered a royalty interest.

The royalty interests of lessors, overriding royalty interest owners, non-participating royalty interest owners, and owners of other burdens on production also require pooling. In most oil and gas leases and assignments creating these interests, the power to pool the interest is granted to or reserved by the working interest owner. Where the instrument creating such interests is silent or does not provide for the power to pool in the working interest owner, ratification of the pooling, joinder or a forced pooling order must be secured. Where a federal lease is involved, the Bureau of Land Management must approve a communitization agreement, and where a state lease is involved, the Commissioner of Public Lands must approve a communitization agreement.

Voluntary pooling is accomplished by the agreement of all interest owners and a Designation of Pooling should be recorded in the county records.[38]

Once properly established either voluntarily or by forced pooling, operations on and production from the pooled unit is deemed

[37] NMSA 1978, Section 70-2-18B (1969)

[38] *See Owens v. Superior Oil Co.*, 105 N.M. 155, 730 P.2d 458 (1986)

for all purposes to have been conducted on each tract within the unit. Production is allocated on an acreage basis in proportion to the number of surface acres in the tract bears

to the total number of acres in the pooled unit.

Standard spacing requirements are based on the type of production (oil or gas), distance from existing production (wildcat or development), the area of the state where the well is located (Northwest or Southeast), and the depth of the producing formation. The OCD Rule 104 setting forth the standard spacing is summarized as follows:

Type	Distance*		Area**	Depth	Applicable Spacing
Gas	Wildcat	SE	Above Wolfcamp		160 acres
Gas	Wildcat	SE	Below Wolfcamp		320 acres
Oil	Wildcat	SE	All		40 acres
Gas	Wildcat	NW	All		160 acres
Oil	Wildcat	NW	All		40 acres
Gas	Wildcat	Other	All		160 acres
Oil	Wildcat	Other	All		40 acres
Oil	Development	All	All		40 acres
Gas	Development	SE	***		***
Gas	Development	NW	All		160 acres
Gas	Development	Other	All		160 acres

*A Wildcat well is a well to be drilled a distance of one mile or more from the outer boundary of a defined pool in the projected formation or from any well which has produced from the projected formation.

**Southeast New Mexico is Chaves, Eddy, Lea and Roosevelt Counties; Northwest New Mexico is Rio Arriba, Sandoval, and San Juan Counties; and Other includes all other counties in the state.

***Gas Development wells in the Southeast are spaced on 160 acres for defined gas pools in a formation younger than the Wolfcamp formation or in the Wolfcamp formation created and defined by the OCD prior to November 1, 1975 or in a Pennsylvanian age or older formation which was created and defined by the OCD prior to June 1, 1964. For defined gas pools in the Wolfcamp formation created after November 1, 1975 or in the Pennsylvanian age or older formation created after June 1, 1964 the spacing is 320 acres.

Special pool rules may vary the standard spacing pattern for a designated pool.

Upon application, notice and hearing the OCD has authority to increase or decrease the spacing unit, permit unorthodox locations, and/or allow additional wells to be drilled within the unit.[39]

[39] *See* Oil and Gas Act, NMSA 1978, Section 70-2-1, *et. seq.* (1977)

Unitization. Unitization must be distinguished from pooling or communitization agreements that are utilized to conform to state spacing requirements. Unfortunately, the terms communitization, pooling, and unitization are incorrectly, but commonly, used interchangeably. This leads to confusion and precipitates miscommunication between parties. Unitization is an attempt to provide for unified development and operation of an entire geologic prospect or producing reservoir.

The purpose of unitization is to allow the entire unit area to be operated as a single entity without regard to lease boundaries. The goal is to maximize production by using the most efficient spacing pattern and to minimize costs by providing, to the greatest extent possible, common facilities to service all the wells within the unit area. Unlike the pooling provision found in most fee leases, most lease forms do not contain an unitization provision allowing the lessee to commit the lease or a portion thereof to a unit agreement.

The agreements for exploratory units differ from unit agreements concerning enhanced recovery. Whenever the United States owns the mineral estate in more than ten percent of the lands proposed to be unitized for an exploratory unit, the BLM will insist on the use of the Model Onshore Unit Agreement for Unproven Areas (Federal Unit Agreement) promulgated in the regulations, 43 C.F.R. Subpart 3186. The unit agreement becomes effective upon approval, but the public interest requirement is satisfied only if the unit operator commences actual drilling operations and diligently prosecutes such operations in accordance with the terms of the unit agreement. If the public interest requirement is not met, the leases committed to it are treated as if the unit had never been formed, and any segregation and extensions that occurred by reason of commitment to the unit are invalid. There is no federal form of unit agreement for enhanced recovery.

A notice of the unit agreement and unit operating agreement should be recorded in the county records in which the lands are located for **constructive notice** purposes.

Marital property

New Mexico follows the community property system, modeled after the civil law of Spain and Mexico, regarding rights of spouses in property acquired during marriage.

Community property. Community property is defined by statute as "property acquired by either or both spouses during marriage which is not separate property."[40] There is a strong presumption that property acquired during marriage is community property, but the presumption may be rebutted by a preponderance of the evidence. Nichols v. Nichols, 98 N.M. 322, 648 P.2d 780 (1982); NMSA 1978, Section 40-3-12 A (1973).

Separate property. Separate property is property acquired by either spouse in the following ways:

- acquired before marriage;
- after a divorce decree is entered;
- gift;
- devise, bequest, or descent;
- designated as separate property by a written agreement between spouses; or
- designated as separate property by a judgment or decree of any court having jurisdiction[41]

In addition, property acquired by a woman by an instrument in writing in her name alone or in her name and another person not her husband prior to July 1, 1973 is presumed to be her separate property.[42] Property acquired with funds that are separate property remains separate property.

[40] NMSA 1978, Section 40-3-8 B (1973)
[41] NMSA 1978, Section 40-3-8 A (1973)
[42] NMSA 1978, Section 40-3-12B (1973)

In New Mexico, property takes its status at the time it was acquired. However, the presumption of community property overrides any attempt by a party to an instrument (either as a grantor or a grantee) to recite that the interest held or being obtained is the party's separate property.

Conveyances by spouses. Both spouses *must* join in any transfer, conveyance, mortgage, or contract to transfer, convey or mortgage any interest in community real property. This necessarily includes mineral deeds, oil and gas leases and assignments of interests in oil and gas. Any attempted conveyance of community real property by one spouse is *void* and has no effect.[43] The New Mexico legislature recently revised this statute to provide that "nothing in this section shall affect the right of a spouse not joined in a transfer, conveyance, mortgage, lease or contract to validate an instrument at any time by a ratification in writing."[44]

However, for title examiners, this revision creates some issues that have not been resolved by court interpretation. Can the non-joining spouse alone ratify a "void" instrument or does the ratification require the joinder of both spouses? Can a ratification lacking present words of grant life into a "void" conveyance? The better practice is to secure joinder of both spouses in a replacement instrument or secure a ratification containing present words of grant from both spouses.

An additional problem is that the revision does not indicate whether the legislature intended the revision to be retroactive. Therefore, it must not be given a retroactive effect, so ratifications before June 18, 1993, are not effective unless joined by both spouses and contain present words of grant.

[43] NMSA 1978, Section 40-3-13 (1973); *Marquez v. Marquez*, 85 N.M. 470, 513 P.2d 713 (1978)
[44] NMSA 1978, Section 40-3-13B (1973)

Joint tenancy. Spouses may hold property as joint tenants with right of survivorship and their interest may either be their separate property or their community property.[45]

Corporations, partnerships and Limited Liability Companies

Corporations. New Mexico corporations have the power to acquire, convey, lease or otherwise deal in real property, or any interest therein, wherever situated.[46] The authority of officers and agents of a corporation is derived from the bylaws thereof or from resolutions of the board of directors not inconsistent with the bylaws.[47] In addition, depending on the magnitude of the transaction compared to the total corporate assets, a transfer may require authorization of the board.[48] As a practical matter, the president or vice-president usually have the authority and do execute oil and gas leases. However, if there is any doubt, or an agent other than an executive officer is to sign a lease, a board resolution or other authorization should be obtained, completed with the proper acknowledgments (see New Mexico short form acknowledgment for representative capacity below)

Partnerships. In a partnership, individual partners generally have the power to convey real property in the partnership's name.[49] There are three basic exceptions. The first, an overall limitation on all conveyances, is where the grantee knows the partner lacks the authority to execute the instrument, but generally is not a problem, absent fraud,

[45] *See Swink v. Fingado*, 115 N.M. 275, 850 P.2d 978 (1993) (spouses acquiring property as joint tenants with right of survivorship does not destroy presumption of community property)
[46] *See* NMSA 1978, Sections 53-11-4D, E (1967)
[47] NMSA 1978, Section 53-11-48 (1967)
[48] NMSA 1978, Section 53-15-1, -2 (1967)
[49] *See* NMSA 1978, Sections 54-1A-301 and 303 (1996)

because the grantee wouldn't complete a transaction with such knowledge.[50] Second, if the title is in the name of one or more but not all the partners, and the partnership's interest is not disclosed in the record, the partners in whose name the title stands may convey the property.[51] Third, where the title is in the name of all the partners, they should all be a party in conveying the property.[52] It is recommended to have a lease executed in the partnership's name signed by a partner (all the partners if practical) in that capacity.

Limited partnerships. The New Mexico Uniform Revised Limited Partnership Act authorizes the transaction of any and all business by limited partnerships.[53] General partners have the right to execute leases in the name of the limited partnership.[54] Foreign limited partnerships may apply for a certificate of authority to transact business in the state. [55] However, merely owning a nonoperating mineral interest in New Mexico does not constitute transacting business.[56]

Limited Liability Companies. Limited Liability Companies (LLC) were provided for in New Mexico, in 1993, and are authorized to conduct any lawful business.[57] The management of an LLC is generally vested in the member or members, but if management is vested in a manager it must be set out in the articles of organization.[58] Thus, if there is a question about executing a lease, a look at the articles of organization should state whether management, outside of the members, is so authorized. If it is, there may be a need to examine the operating agreement to determine the full extent of the manager's authority. If a manager or management has been provided for, then unless specifically reserved to the members by the Limited Liability Company Act, the manager or managers, in accordance with the articles or agreement, have the exclusive power to make all decisions for the company. [59]

Decedents' estates

Resident Decedents. "Any part of a decedent's estate not effectively disposed of by will passes by intestate succession to the decedent's heirs" pursuant to the applicable rules of descent and distribution in New Mexico.[60] The rules are summarized as follows:

- Separate property: One-fourth goes to the surviving spouse and three-fourths goes to the surviving issue of the decedent, "by representation." If there are no surviving issue, all passes to the spouse.
- Community property: All of the decedent's one-half interest in community property passes to the surviving spouse.
- Issue: All descendants of all generations with the relationship of parent-child all descendants of all generations with the relationship of parent and child at each generation.

[50] *See* NMSA 1978, Section 54-1A-302 (1996)
[51] *See* NMSA 1978, Section 54-1A-302 (1996)
[52] *See* NMSA 1978, Section 54-1A-302 (1996)
[53] NMSA 1978, Section 54-2A-101 *et seq.* (2007)
[54] *See* NMSA 1978, Sections 54-2A-402, 406 (2007)
[55] NMSA 1978, Section 54-2A-912 (2007)
[56] NMSA 1978, Section 54-2A-903 A(9) (2007)

[57] NMSA 1978, Section 53-19-6 (1993)
[58] NMSA 1978, Sections 53-19-8, 15 (1993)

[59] NMSA 1978, Section 53-19-15B (1993)

[60] NMSA 1978, Sections 45-2-103 *et seq.* (1975)

- If the decedent is not survived by a spouse or issue, the entire estate passes to the decedent's parents or surviving parent. If both parents are deceased, the entire estate passes to the descendants of the decedent's parents or either of them, "by representation." If the decedent is not survived by any of the above, the one-half of the estate passes to the decedent's paternal grandparents or their descendants, "by representation" and the other one-half to the decedent's maternal grandparents or their descendants, "by representation", and if there are not surviving descendants on one side, the entire estate passes to the other side.

Prior to 1993, any distribution that is now "by representation" was a *per stirpes* distribution.

Passage of title. Title is generally not considered marketable in New Mexico until there has been a probate proceeding conducted on the decedent's estate.

Powers of personal representative. Original probate proceedings may be either informal or formal, requiring court approval at all phases of the administration of the proceedings. Most probates are conducted informally unless there is a contest or a desire by the personal representative to minimize his or her liability. Once appointed by the court, the personal representative generally has broad powers and wide latitude in attending to estate matters. This would include the power to execute oil and gas leases and other instru-ments concerning the decedent's minerals pending the probate proceeding. Court approval must be obtained if a formal proceeding is being conducted or the power of the personal representative is otherwise limited.

Will probated. A will is not effective until it is admitted to probate. The passage of title relates back to the date of death. A will must be probated within three years after the decedent's death. Recently the statutes were amended to allow the submission of a will in a formal testacy proceeding after three years following the decedent's death to evidence the passage of title from the decedent to the person named in the will.[61]

Deed of Distribution. Since 1975 the personal representative must execute deeds of distribution to evidence the passage of title from the estate to the heir, devisee or distributee.[62] The deed of distribution is "conclusive evidence that the distributee has succeeded to the interest of the estate . . . ."[63] However, New Mexico no longer requires that a determination of heirship be made by the court, but it is extremely helpful to future title examiners and helps insure that no third parties can attack the proceedings.

Pretermitted Heirs. Under New Mexico law, a child (or descendant of a deceased child) not mentioned in a decedent's will takes an intestate share of the estate, unless the estate was devised to the unmentioned child's other parent.[64]

Rules prior to July 1973 and other dates. After July 1, 1973, community property passes to the surviving spouse subject to the deceased's spouses power of testamentary disposition.

Prior to July 1, 1973, the wife could not dispose of her community property interest, and upon her death, it passed directly to her husband without necessity of probate.

From June 12, 1959 to July 1, 1973, the wife received the entire community estate of her husband in the absence of a will, without necessity of probate.

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[61] NMSA 1978, Section 45-3-108 (1975)
[62] NMSA 1978, Section 45-3-907 (1975)
[63] NMSA 1978, Section 45-3-908 (1975)
[64] NMSA 1978, Section 45-2-302 (1993)

Prior to June 12, 1959, upon the death of the husband, the wife received her one-half of the community property and one-fourth of the husband's one-half giving her five-eighths; the remaining three-eighths was divided among the children.

Antilapse statute. New Mexico has an antilapse statute that says "If a devisee fails to survive the testator and is a grandparent, a descendant of a grandparent or a stepchild of either the testator or the donor of a power of appointment exercised by the testator's will, the following apply: (1) if it is not a class gift and the deceased devisee leaves surviving descendants, a substitute gift is created in the devisee's surviving descendants; (2) if it is a class gift, other than a devise to issue, descendants, heirs, family or similar language, a substitute gift is created in the deceased devisee or devisee's surviving descendants.[65]

Forced heirship. New Mexico does not have a forced heirship statute.

Nonresident estate. There is nothing in New Mexico law similar to the procedure in Texas whereby authenticated copies of a decedent's will and probate from another state can simply be recorded in the county deed records and be considered effective as though the will were probated. In addition to full

ancillary probate proceedings, New Mexico does have a short form proceeding.

Foreign domiciliary proceedings. A foreign will can be probated in a relatively inexpensive "short form" procedure that will allow the personal representative to distribute the decedent's property to those entitled.[66] The authority of the foreign domiciliary personal representative in this short form proceeding is only for the duration of his or her appointment in the foreign court. Care must be taken to finalize the New Mexico matters prior to securing the discharge of the personal representative in the original foreign proceedings.

Ancillary Probate Proceedings. New Mexico does have ancillary probate proceedings similar to the original resident probate proceedings.[67]

Authenticated Copies Required. In both the short form and ancillary proceedings, authenticated or exemplified (not simply certified) copies of the foreign court's pleadings must be submitted. The authenticated copies of the petition, order admitting the will to probate, order appointing the personal representative, the will, letters testamentary, and any other orders providing for the authority of the personal representative or make a determination of heirship should be submitted for filing in the New Mexico proceeding.

Conflict of Law Rules. Title to real property in New Mexico is subject to the laws of the state of New Mexico. New Mexico law of descent and distribution determines who is entitled to an intestate decedent's estate.[68] The presumption of community property is made even if the domicile of the decedent is in a non-community property state. The presumption may be rebutted by a preponderance of the evidence.[69]

Non-resident decedent dies intestate without administration. While marketable title does not pass absent a New Mexico proceeding, it is common to rely upon affidavits of heirship and death certificates. The affidavit and certificate must be recorded in the

[65] *See* NMSA 1978, Section 45-2-603 (1993)

[66] NMSA 1978, Section 45-4-204 (1975) (not available for decedents who died prior to July 1, 1976)

[67] NMSA 1978, Section 45-4-207 (1975)

[68] *Price v. Johnson,* 78 N.M. 123, 428 P.2d 978 (1967)

[69] *Nicholas v. Nicholas*, 98 N.M. 322, 648 P.2d 780 (1982); NMSA 1978, Section 40-3-12A (1973)

county records where the decedent's real property is located. When the interest is small or the purpose is to determine from whom a lease should be secured, the expense of probate may make the desire to secure marketable title unrealistic. The strength of the affidavit may provide adequate assurance of the heirship of the decedent and those parties who may claim an interest in the decedent's property. The affidavit must be taken from someone who does not benefit from the decedent's estate and sets forth the following:

- name of the decedent;
- decedent's residence at the time of death;
- time and place of death;
- names and addresses of the decedent's heirs and each of their relationship to the decedent. This necessarily includes the surviving spouse, the children, the children of a deceased child, etc. and includes natural born and adopted children, etc.;
- marital history, including the names of each spouse and dates of marriage (and divorce) and their death if they predeceased the decedent while married;
- whether the decedent died testate or intestate and, if testate, the disposition of the decedent's will and a copy, if available, and names of the devisees, legatees and personal representative appointed therein;
- the court and location of any probate proceedings that have been commenced; and
- a description of the real property in the state owned by the decedent.

The affidavit must be sworn or affirmed under oath and properly acknowledged. The instrument must thereafter be recorded in each county where the decedent owned real property. This does not take the place of probate proceedings, but it does give some assurance of the group of people entitled to the decedent's estate. The title remains

unmarketable until proceedings in New Mexico are properly conducted.

Life tenant/remainderman

Lacking in direct New Mexico authority, the following represents the majority view, including Texas. Neither the **life tenant** nor the **remainderman** of an estate has the right to unilaterally explore for and/or produce oil, gas or minerals or exercise **executory rights**. Development of the minerals by the life tenant constitutes **waste**. Thus, each party owns a veto power over the other's right to lease or develop the property. However, the life tenant and remainderman can enter into a joint lease, each can lease their interest separately, or one can ratify the other's lease with present words of grant.[70]

The parties may agree as to the division of the rents and royalties; however, absent agreement, the life tenant is not entitled to any part of the royalties, considered as corpus, but is entitled to the income produced after investment of the royalties. Likewise, though more controversial, the majority of states treat bonuses the same as royalties. A minority view, including Oklahoma and Arkansas, allocate bonuses to the life tenant. Delay rentals are generally paid to the life tenant as income from the estate.[71]

Despite these rules, a majority of states apply the "Open Mine" doctrine in apportioning proceeds from a well or lease. It provides that if a mine has been opened before the creation of the life estate and future interest, the life tenant may develop or exploit the minerals.

[70] *See* 2 Patrick H. Martin and Bruce M. Kramer, *Williams & Meyers Oil & Gas Law*, § 512.2 (2008); *see also Lowe v. Adams*, 77 N.M. 111, 419 P.2d 764 (1966) (*citing Welborn v. Tidewater Assoc. Oil Co.*, 217 F.2d 509 (10th Cir. 1966); *Davis v. Bond*, 158 S.W.2d 297 (Tex. 1942)

[71] *See* 2 *Williams & Meyers Oil & Gas Law*, § 512.2*; Clyde v. Hamilton*, 414 S.W.2d 434 (Tex. 1967); *Franklin v. Margay Oil Corp.*, 194 Okla. 519, 153 P.2d 486 (1944)

Thus, the life tenant is entitled to the royalties, bonuses and rents derived from the mine. Under this doctrine, the life tenant enjoys the same beneficial enjoyment of the land as was derived before the creation of the life estate; however, this can be changed by express provisions to the contrary in the creating instrument. The doctrine has been applied to allow the operation and development of oil and gas on land with a lease in effect or a well in production at the time of the life estate's creation.[72]

Attorney-in-fact

General. An attorney-in-fact may execute conveyancing instruments on behalf of the principal consistent with the powers granted by the principal in a validly executed, acknowledged and recorded power of attorney instrument. It must be recorded in the county in which the real estate is located. Once recorded, the powers granted are not considered revoked until an instrument revoking the appointment is similarly recorded. Notice of death of the principal or notice of incapacity of the principal, unless the powers granted are durable, terminates the power of the attorney.[73]

The powers of the attorney-in-fact should be set forth with specificity. It has been held in New Mexico that a naked power of sale does not confer a power to lease.[74] Title examiners will require authority to deal with the mineral estate, including the leasing for oil and gas, to be set forth in the instrument granting the powers to the attorney-in-fact.

Durability. A Power of Attorney may survive the disability of the principal if the instrument contains sufficient language evidencing this intent. The statute states that the following words are sufficient: "This power of attorney shall not be affected by incapacity of the principal," "This power of attorney shall become effective upon the incapacity of the principal," or similar language.[75]

Protection to bona fide purchasers. The statutes protect bona fide purchasers and the attorney who act without knowledge of the principal's death or incapacity, if not a durable power.[76] If it is determined that the principal died or became incapacitated before the date of the execution of the conveyancing instrument by the attorney-in-fact, an affidavit from the attorney stating he or she did not have knowledge of the death or disability must be secured and recorded in the county records.

Trusts

Powers of the trustee. A trustee has all of the powers conferred by the New Mexico Uniform Trust Code unless the powers are withheld or limited by the trust instrument.[77] Such powers specifically include the entering "into a lease or arrangement for exploration and removal of natural resources ... ." New Mexico does not have much statutory or case law guidance regarding many trust issues. Title examiners are cautious and require the instruments creating a trust to be filed of record to set forth any limitations on the trustee's powers and set forth the duration of the trust. Many trustors do not want the trust agreement recorded, and it is satisfactory for a memorandum of trust to be recorded so long as it identifies the trustee, his or her powers and any limitations, and the duration of the

[72] *See* 2 *Williams & Meyers Oil and Gas Law* § 513; *see also Youngman v. Shular*, 155 Tex. 437, 288 S.W.2d 495, 5 O.&G.R. 1069 (1956); *In re Shailer's Estate*, 266 P.2d 613 (Okla. 1954)

[73] *See* NMSA 1978, Sections 47-1-5 *et. seq.* (1991)

[74] . *James v. Anderson*, 39 N.M. 535, 51 P.2d 601 (1935)

[75] NMSA 1978, Section 46B-1-101 (2007)

[76] NMSA 1978, Section 46B-1-108 (2007)

[77] NMSA 1978, Sections 46A-8-815 and 816 (2003)

trust or the events of termination.[78]

Title. Title to property should be held in the name of the trustee. Conveyances into the trust should be conveyed to the trustee, in trust for the specified trust. A trust is not a legal entity by itself. The trustee is the proper party to hold title on behalf of the trust.[79]

Conservators and guardians

New Mexico court-appointed conservators of an incompetent's estate has the authority to execute oil and gas leases without further court action.[80] Guardians of a minor have authority to act on behalf of the.[81] However, it is wise to obtain court approval of a lease acquired from a guardian acting on behalf of a minor. Foreign conservators or guardians must receive authority from a New Mexico court to exercise such authority. There is a short form proceeding for foreign conservators to establish their proof of authority.[82]

Production in paying quantities

In following the majority rule, New Mexico has required production in "paying quantities" to extend oil and gas leases into their secondary terms under their habendum clauses.[83] Likewise, New Mexico courts have required wells capable of production in "paying quantities" in order to continue lease's where the lessee is paying a shut in royalty to preserve the lease.[84] Although New Mexico is lacking in further interpretive law, it would probably follow the Texas authority on this issue.

The seminal case of *Garcia v. King* established one of the early standards and rationales for the rule requiring production in "paying quantities." To meet the standard, a well must produce sufficient oil and/or gas to pay the operating expenses and yield a profit to the lessee. The cost of drilling and equipping the well does not affect the calculation, thus the well might produce in paying quantities and still be, on the whole, unprofitable to the lessee. The rationale for the rule is that the parties do not intend for the lessee to retain the lease for speculative purposes if it is not profitable.[85]

Texas further refined the rule in *Clifton v. Koontz*, shifting the analysis from a mere profitability test to whether, under all relevant circumstances, a reasonably prudent operator would continue to operate a well, in the same manner, for the purpose of making a profit and not merely speculation.[86] The factors to be considered were:

- the depletion of the reservoir and the price for which the lessee is able to sell his produce;
- the relative profitableness of other wells in the area;
- the operating and marketing costs of the lease;
- the lessee's net profit' the lease provisions;
- a reasonable period of time under the circumstances; and

[78] *See* NMSA 1978, Section 46A-10-1012 (2003)
[79] *See* Lee *v. Catron, Catron and Pottow, P.A.*, 2006 NMCA 18, ¶ 3, 203 P.2d 104, 105 (N.M. Ct. App. 2008)(*cert. denied*)
[80] NMSA 1978, Section 45-5-424 C.(11) (1975)
[81] minor NMSA 1978, Section 45-5-209 (1995)
[82] *See* NMSA 1978, Section 45-5-432 (1975)
[83] *Hickman v. Mylander*, 68 N.M. 340, 362 P.2d 500 (1961); *Tome v. Ringle*, 56 N.M. 101, 240 P.2d 850 (1952)
[84] *See Greer v. Salmon*, 82 N.M. 245, 248, 479 P.2d 294, 297 (1970)
[85] *Id.*; 3 *Williams and Meyers Oil and Gas Law*, § 604.5
[86] 160 Tex. 82, 325 S.W.2d 684, 10 O&GR 1109 (Tex. 1959)

- whether or not the lessee is holding the lease merely for speculative purposes.

Thus, under this test the operating expenses of the well and the lessee's net profit are among the factors considered and are not the exclusively dispositive of the issue.

Surface damages

New Mexico recognizes the mineral estate's dominance over the surface estate. Lessees of the mineral estate have the right to explore for and extract the minerals and in doing so are entitled to as much of the surface area as is reasonably necessary for its drilling and production operations. However, this right must be exercised with due regard for the rights of the surface owner. Generally, any damages are measured against the reasonableness standard based on the standard theory of negligence. The theories of private nuisance and an implied covenant to restore the surface estate to its original condition have been at least implicitly rejected by New Mexico.[87]

In a Texas case, cited by the New Mexico Supreme Court in *Carter Farms*, the court discussed the respective rights of lessees and surface owners. The court stated that the lessee's use of the surface does not ordinarily contemplate the destruction or substantial impairment of the surface for agricultural purposes. In cases where there is existing use by the surface owner and there are various alternatives available to the lessee, the lessee may be required to accommodate this use. Thus, lessees can be required to accommodate the surface owner's irrigation systems by installing its pumping units in concrete cellars or by using hydraulic pumps if the lessee's use of other means is proven unreasonable.[88]

An oil and gas lessee has access to the entire surface area committed to a communitization or pooling agreement.[89] However, the New Mexico Supreme Court held that an operator may not use the surface estate of the lease outside of the communitized area to access a communitized well on adjacent land.[90]

In 2006, New Mexico enacted surface damage legislation. The New Mexico Surface Owners Protection Act[91] sets forth a procedure that must be followed before an oil and gas lessee may enter lands for exploration, drilling and production of oil and gas. The lessee must give five days notice for non-surface disturbing activities and 30 days for surface disturbing activities. The lessee must offer a surface use and compensation. If the surface owner does not enter into the agreement timely, the oil and gas lessee may enter the property and begin its operations after posting financial security with a New Mexico financial institution.

Before beginning operations in New Mexico, an operator should understand the procedures required and have a statewide bond in place to cover its operations. By statute, the operator must pay damages to the surface owner and must reclaim the land to its original condition when abandoning the oil and gas operations. **Note:** This is a departure from the common law notions of reasonable surface use.

In June 2009, the Commissioner of Public Lands for the State of New Mexico began including a surface damage policy in all agricultural leases renewals. State grazing lessees are allowed to collect actual damages and any reasonable lost business costs due to oil and gas activities on state trust lands subject to a

[87] *See Amoco Prod. Co. v. Carter Farms Co.,* 103 N.M. 117, 703 P.2d 894 (1985)(*rev'd on other grounds*)

[88] *Getty Oil Co. v. Jones*, 470 S.W.2d 618 (Tex. 1971)

[89] *See Kysar v. Amoco Prod. Co.*, 379 F.3d 1150 (10th Cir. 2004)

[90] *Kysar v. Amoco Prod. Co.,* 135 N.M. 767, 93 P.3d 1272 (2004)

[91] NMSA 1978, Section 70-12-1 *et. seq.* (2006)

grazing lease. The grazing lessee will split all damages in excess of actual damages and costs associated with lost earnings with the Commissioner. The Commissioner will receive from fifty to seventy percent of the damages received. The grazing lessee must report any payment involving surface damages and any lawsuit involving damage to state trust land to the Commissioner. Time will reveal whether this policy will actually result in oil and gas companies having to pay additional compensation for their operations on state trust lands. Paragraph 11 of the state oil and gas lease forms requires payment to the state grazing lessee or surface owner for actual damages caused to the range, livestock, growing crops or improvements.[92]

Recording and constructive notice

All instruments conveying interests in minerals or oil and gas leases should be filed of record in the office of the county clerk for the county where the land is located.[93] Failure to record does not invalidate the instrument, but **constructive notice** is provided by recording, and recording precludes a third party from securing an instrument purporting to convey the same interest and securing valid title.[94]
New Mexico follows the notice theory regarding who prevails in the event of multiple instruments to different parties conveying the same interest.[95] A purchaser of an interest is on notice of all matters affecting the real property appearing of record in the clerk's office as well as matters apparent from a visual inspection of the premises.[96]

Even assignments affecting federal oil and gas leases must be recorded in the county in addition to the required federal filing because federal records are not deemed to impart constructive notice.[97] Therefore with federal leases, there should be a double filing of all instruments; the chains of title in both the federal records and county records should be identical. By statute, the records of the Commissioner of Public Lands do impart constructive notice, so a double filing is not necessary for state oil and gas leases and assignments requiring the Commissioner of Public Land's approval.[98]

To be entitled to be recorded, the instrument must contain an acknowledgment form that substantially complies with the New Mexico statutory forms of acknowledgment.[99] In addition, a proper filing fee must be presented to the county clerk. Presently the fee is $5 for the first page and $2 for every additional page, and the clerk may charge an equipment recording fee up to $4 per instrument.[100] If an assignment or release references more than one grantor, grantee, deed, mortgage, lease or other instrument or describes more than one deed, lease or other instrument, the clerk will charge $5 for such reference.[101] If there are more than two acknowledgments, the clerk will charge an additional fee of $.50 per additional acknowledgment.[102]

Acknowledgment forms

Title examiners will reject acknowledgment

[92] NMSA 1978, Sections19-10-4.1, 4.2, and 4.3 (1985)
[93] NMSA 1978, Section 14-9-1 (1991)
[94] NMSA 1978, Section 14-8-4 (1961); *see Germany v. Murdock*, 99 N.M. 679, 662 P.2d 1346 (1983)
[95] *Angle v. Slayton*, 102 N.M. 521, 697 P.2d 940 (1985)(the order in which deeds appear in the record is not important in a notice jurisdiction)
[96] *But see,* NMSA 1978, Section 14-9-3 (1990)(possession alone under an unrecorded real estate contract shall not be construed to impart knowledge or impose a duty to inquire)
[97] *See* NMSA 1978, Section 70-1-1(1987)
[98] NMSA 1978, Section 19-10-31 (1994); *see Angle,* 102 N.M. 521
[99] *See F & S Co. v. Gentry*, 103 N.M. 54, 702 P.2d 999 (1985)\
[100] NMSA 1978, Section 14-8-12.2 (2008)
[101] NMSA 1978, Section 14-8-12.3 (2008)
[102] NMSA 1978, Sections 14-8-12.4 (1985)

forms that do not substantially comply with the statutory form of acknowledgment in existence at the time of the acknowledgment. Prior to July 1993, many acknowledgments were rejected because the form did not reflect the marital status of a husband and wife executing an instrument or left off the state of incorporation on a corporate acknowledgement. The new forms are in line with the uniform acknowledgment statute. New Mexico law states that even if an instrument containing a defective acknowledgment is actually recorded in the county records, it is not entitled to constructive notice.[103] There is a **curative statute** that provides that certain minor defects in an acknowledgment form are cured if the instrument has been of record for more than ten years.[104] A sample of the current New Mexico short form acknowledgments is included in this chapter on the next page.[105]

[103] *See* NMSA 1978, Section 14-8-4 (1988)
[104] *See* NMSA 1978, Section 14-13-25 (1991)
[105] *See* NMSA 1978, Section 14-14-8 N.M.S.A. (1993)

State of _____ }
}
County of _____ }

This instrument was acknowledged before me on _____, 20__, by _____ .

_____

My commission expires:

State of _____ }
}
County of _____ }

This instrument was acknowledged before me on _____, 20__, by _____ as (type of authority, e.g. officer, trustee, etc.) of (name of party on behalf of whom the instrument was executed).

_____

My commission expires:

CHAPTER 14: OKLAHOMA

CHAPTER 14 PART I: FREQUENTLY ENCOUNTERED TITLE PROBLEMS IN OKLAHOMA

D. Faith Orlowski

Introduction

The following is a "laundry list" of frequently encountered title problems in Oklahoma, along with a discussion of ways to avoid clouding title. References herein to *TES* refer to the Oklahoma Title Examination Standards, which can be found in Title 16 of the Oklahoma Statutes Annotated.

Transactions

Transactions must be completed accurately. Documents filed of record are only as good as the information that was verified prior to or at the transaction table.

In ascertaining record title, title attorneys and land professionals consider documents from two points of view – from the transactional perspective and from the record title perspective. If the transactional people did their jobs well, a division order analyst will effectively rely on the recorded documents.

Numerous items must be validated, confirmed, and checked at the closing that will never be reduced to record. For example, if a company is purchasing a tract of property from Apex Corporation, all the record will show is a warranty deed from Apex Corporation, signed by Jennifer Jones, Vice President, covering a certain legal description, to Big Oil Company. If the legal description matches and the vice president has signed and if Apex Corporation was the owner pursuant to the previous deed, then the division order analyst can be satisfied with this analysis.

However, in order to reach that level of reliance, the division order analyst assumed that the transactional people have previously (a) verified that the person sitting in front of him or her is Jennifer Jones and that she is the vice president of Apex Corporation; (b) that the vice president has authority to sell property as evidenced by a corporate resolution or an opinion of counsel (or both); (c) that Apex Corporation is a corporation in good standing in the state of incorporation and – if that is not Oklahoma (where the property is located) – that Apex is also domesticated in Oklahoma and in good standing in Oklahoma, and finally (d) that the legal description matches the legal description in the previous deed or, if only a portion of the tract is being conveyed, that the transferred portion is correctly described and a lot split has been performed, if necessary.

When doing a transaction, the division order analyst should also "clean up" title where possible. For example, suppose title to the property was held in Smith Company, and Apex Corporation bought all of the stock of Smith Company and eventually merged Smith Company into Apex Corporation. We assume that the transactional team has reviewed all the necessary purchase and merger documents necessary to assure himself or herself that Apex Corporation does, in fact, own the property.

The division order analyst can take affirmative action to avoid future title problems. In the warranty deed, the grantor should be identified as "Apex Corporation, successor by merger to Smith Company." (It does not even cost an extra filing fee!) It is possible to record the merger document (attached to the deed or another document with a legal description in order to get it correctly filed of record). Another choice is to file a separate affidavit reciting the facts (see "Affidavits are Friends" section). The record is only as good as the transaction that produced the document.

Correction documents

When a document affecting the title of your company has been filed of record and it contains an error, the division order analyst should file a corrected document and identify in the document the subject of the correction.

It is easy to make mistakes. However, too often a division order analyst will mark up the filed original and then resubmit it for filing. This method is the last resort. If there is an error in a recorded document affecting your company's title (such as assignment), the division order analyst should draft a new document entitled "Corrected Assignment". Since people should not have to guess why the correction document was necessary, the face of the document should include a paragraph that states:

This Corrected Assignment is executed and filed to correct the misspelling of the Assignee's name [or to correct the legal description, or whatever the problem was].

If the error was only a clerical error, it is possible to simply file an affidavit. However, correction document or not, if the "correction" decreases the amount of the grant that the Assignee received, both Assignor and Assignee must sign the correction document.

Consistency in name

Title needs to come out just exactly as it went in.

If the deed of record was into Jane Mosley and since that time, she married, do not use only her married name. Say "Jane Mosley, now known as Jane Randolph, joined by her husband, John Randolph" or "Jane Randolph, formerly known as Jane Mosley, joined by her husband, John Randolph."

If title of the purchased piece of property went into Jane Mosley, and the next deed shows a grant from John Randolph and Jane Randolph, husband and wife, to Sarah Evans, and Sarah Evans is the seller, Sarah Evans should execute a recordable affidavit as part of the closing documents. This affidavit should include the statement that Jane Mosley is one and the same person as Jane Randolph.[1]

The real problem occurs when taking title from a trust. When there is no recorded document establishing a trust, it is difficult to know the correct name of the trust. General practice dictates that if a deed is granted to "John Doe, Trustee of the John Doe Revocable Trust dated January 1, 1995", then on the Deed out, the name of the grantor should be "John Doe, Trustee of the John Doe Revocable Trust dated January 1, 1995." But what if it is not?

To illustrate, assume the deed out shows the grantor as one of the following:

(a) "John Doe Trust": First, consider who executed the document. If it was executed by "John Doe, Trustee" then, while not perfect, it still leaves little question that the grantee of the first deed and the grantor of the second Deed are one and the same. If there is a question, the examiner should require an affidavit from the trustee or a correction deed.

(b) "John Doe Trust; Sarah Doe, Trustee." The threshold inquiry is when the instrument was recorded. If it was recorded after November1, 1989, the trustee was required to file a Memorandum of Trust, and Sarah Doe may be listed as a successor trustee. If it has been recorded for five (5) years, the Rebuttable Presumpions Statute[2] authorizes the examiner to rely on the rebuttable presumption that the person executing the document was the proper person and had the authority to execute it. These resumptions are rebuttable because evidence to the contrary will invalidate the document even if the evidence arises after the transaction was

[1] See TES 7.2 or Appendix A in this chapter

[2] (16 O.S. § 53)

completed. Consequently, most examiners always require a Memorandum of Trust for this kind of situation.

(c) "John Doe, Trustee of the John Doe Revocable Trust as last dated (or amended) July 1, 1996." The attorney has no way of ascertaining from the record whether this is the same Trust named as Grantee in the above deed. Consequently, the examiner should require a recordable affidavit stating that the two trusts are, in fact, the same.

Homestead interest

Both the husband and the wife must sign the same document if a surface interest is owned.

TES 7.2 discusses the need for both husband and wife to execute a document if a surface interest is involved due to a potential **homestead** claim. Homestead is a matter of intent under Oklahoma law, and the filing of a homestead exemption in the local tax assessor's office is not dispositive. This applies to documents filed in the last ten years.

Affidavits

The division order analyst should consider affidavits to be friends and should use them.

The Oklahoma Affidavit Title Examination Standard last underwent major revisions in 1996. Standard 3.2 removed the previous qualification which prohibited reliance upon an affidavit, if it took the place of a judicial proceeding, judgment, decree, or title standard. As a result of 16 O.S. § 82, the statute provides that recorded and acknowledged affidavits are "notice of matters covered therein," relating to property, its use or its ownership.[3]

A Section 83 Affidavit may relate to:

- age, sex, birth, death, relationship, family history, heirship, names, and identity of parties (whether individual, corporate, partnership or trust);
- identity of officers of corporations;
- membership of partnerships, joint ventures and other unincorporated associations;
- identity of trustees of trusts and their respective terms of services;
- history of the organization of corporations, partnerships, joint ventures and trusts;
- marital status;
- possession; residence;
- service in the Armed Forces; and
- conflicts and ambiguities in descriptions of land in recorded instruments.

This standard cites three important statutes for its authority, all in Title 16 on Conveyances. Sections 53 and 82 of Title 16 were amended in 1994, necessitating the changes in this standard.

Section 82 was revised September 1, 1994, and now provides that the recording of an affidavit in the office of the county clerk in the county in which the real property is situated creates a **rebuttable presumption** that facts stated in a recorded affidavit are true as they relate to real estate, its use, or its ownership. The revisions made by the legislature clearly indicate that affidavits may be given more weight and used more frequently. Affidavits, which previously were regarded merely as documents giving notice of possible facts now may constitute *prima facie* evidence that those facts are true.

Powers of attorney

Powers of Attorney need to be recorded, as well as the document that is executed by the attorney-in-fact (preferably, immediately before the instrument of conveyance).

Powers of attorney create an agency

[3] See Appendix B in this chapter

relationship, and based on that relationship, the attorney-in-fact lawfully may act on behalf of his or her principal. The power of attorney document that defines the relationship sets out, not only the scope of the authority granted, but also the duration of the power.

There are various types of powers of attorney, including a limited power of attorney, general power of attorney, durable power of attorney, medical power of attorney, financial power of attorney, and a special power of attorney.

The difference between a general power of attorney and a durable power of attorney (other than any limitations found in a specific document) is that a durable power of attorney authorizes the attorney-in-fact to continue to act on behalf of the principal even after the principal becomes incapacitated.[4] The statute even sets out the exact form that should be used, or to which a specific document should substantially conform.[5]

If an attorney-in-fact acts in place of his or her principal in order to convey real property, then the power of attorney must first be recorded in the county where the land is located in order for the deed to be effective.[6]

The statute is quite emphatic in that it states

> ". . . and no deed, mortgage or release of a mortgage executed by an Attorney-in-Fact shall be received for record or recorded until the power under which the same is executed has been filed of record in the same office; and the recording of any deed, mortgage or release of mortgage *shall be of no effect for any purpose* until the power under which it is executed has been duly filed for record in the same office." [Emphasis added]

To be recorded in the tract index, the Power of Attorney must contain a legal description. Since powers of attorney rarely contain legal descriptions, the Power of Attorney should be attached to an affidavit as an exhibit in order to properly place it of record.

Powers of Attorney are revocable by the principal. To revoke a Power of Attorney, the principal must record the revocation in the same office where he or she recorded the Power of Attorney.[7]

While Power of Attorney statutes have changed several times over the past twenty years, the general rules about these documents in title have stayed the same – they must be executed, acknowledged and recorded in the manner provided by law.

However, the problems go on from there:

Homestead Issues. Do not even try to sell a piece of property which could be construed as homestead with a power of attorney and a deed. Facts: Sally Doe executes a Power of Attorney to her husband, John Doe, granting him full power to do everything in her stead. John Doe executes a deed covering a fee simple interest in real property to a third person. The deed is from John Doe, individually, and John Doe as Attorney-in-Fact for his wife, Sally Doe. This deed is *void*!

Any conveyance signed by either a husband or a wife – but not both – which covers land which is homestead (or even *may* be homestead) is void in the absence of the other spouse's signature. Also, it is general practice, at least in Tulsa and Oklahoma Counties, that a single person's or widowed person's property may not be sold by a deed executed pursuant to a Power of Attorney unless the principal is incapacitated.

[4] The Uniform Durable Power of Attorney Act is codified at 58 O.S. §§1071 – 1077

[5] § 1072.2

[6] 16 O.S. § 20

[7] 16 O.S. § 21

No power of attorney recorded. Consider the following set of facts: A deed is executed by an attorney-in-fact and is dated and filed of record on August 1, 2000. No power of attorney was recorded in that office. Is that deed valid now?

As to the Power of Attorney question, the answer is "yes". This deed is now acceptable under the statute provides that when any instrument has been recorded in the office of the county clerk in the proper county for a period of five (5) years, and the instrument contains any of the following defects:

(a) It has not been signed by the proper representative of a legal entity;
(b) The representative is not authorized to execute the instrument on behalf of the legal entity;
(c) *A power of attorney has not been filed of record for an attorney in fact executing the instrument;* [Emphasis added]
(d) The seal of the legal entity has not been impressed on such instrument or the record does not show such seal;
(e) The instrument is not acknowledged;
(f) A Deed or conveyance does not bear endorsement of approval by the appropriate governmental planning authority having jurisdiction; or
(g) Any defect in the execution, acknowledgment, recording or certificate of recording the same, such instrument shall, from and after the expiration of five (5) years from the filing thereof for record, be valid as though such instrument had, in the first instance, been in all respects duly executed, acknowledged, approved by the appropriate planning authority having jurisdiction, and certified. Such instrument or the record thereof or a duly-authenticated copy thereof shall be competent evidence without requiring the original to be produced or accounted for to the same extent that written instruments, duly executed and acknowledged, or the record thereof, are competent. However, nothing herein contained shall be construed to affect any rights acquired by grantees, assignees or encumbrancers subsequent to the filing of such instrument for record and prior to the expiration of five (5) years from the filing of such instrument for record.[8]

There was some confusion among title examiners as to when the Memorandum of Trust must be filed. Under one interpretation, a memorandum must be filed any time real property is deeded to a trust. "Trust" in this instance means to "The John Doe Family Trust" or to "John Doe, Trustee of the John Doe Family Trust." Others conclude that the deed must be directly to the trust, not to the trustee on behalf of the trust, before a Memorandum of Trust is required. In 2008, TES 15.2 was amended to clarify that if the deed was to John Doe, Trustee of the John Doe Family Trust, a Memorandum of Trust is *not* required.

Now carefully consider how this works. A deed of record is executed by an attorney-in-fact without a recorded power of attorney. Under statute 16 O.S. § 20, that deed is void. However, five years later, that deed "poofs" into validity.

[8] 16 O.S. § 27(a)

The corresponding Oklahoma Title Examination Standard is 6.7, which says in part: "Notwithstanding the foregoing, an instrument executed by an Attorney-in-Fact which has been recorded for at least five (5) years is valid, even though no power of attorney was filed of record in the office of the county clerk of the county in which the property is located."

The same is also true of corporate Powers of Attorney.[9]

Durable Powers of Attorney. Whenever a power of attorney is filed of record, at least the examiner does not need to worry about the competency of the principal when he or she sees a deed of record from the attorney-in-fact. However, even durable powers of attorney fail once the principal is deceased. Accordingly, the transactional people should verify that the principal is alive at the time the Deed is executed. The rebuttable presumption statute[10] allows one to presume this, but such presumption is rebuttable and there is no protection afforded by the statute if one relies on a bad presumption.

Joint tenancy

If property is held by two people as joint tenants with right of survivorship, and one dies, an Affidavit of Death and Termination of Joint Tenancy must be filed.

The use of joint tenancies has been the most common method of "estate planning." To create the joint tenancy, the deed must at least say: "to Bob and Myrtle, as joint tenants." It is preferable to say "as joint tenants with right of survivorship", but the tenancy will not fail without the addition of those words.

However, this is not enough. Once one of the joint tenants dies, the statutory scheme must be followed – the Affidavit of Death and Termination of Joint Tenancy with the death certificate attached must be placed of record to make the title marketable.[11] Also, unless that joint tenancy was between spouses, an estate tax release or waiver must be filed.

Limited license companies

There is no *president* of a limited liability company (L.L.C.) in Oklahoma. If title is being transferred by such an entity, it should be executed by the *manager*.

Oklahoma law only recognizes member(s) and manager(s) and, unless otherwise stated in the articles or operating agreement, the Manager(s) will manage the L.L.C.[12] Some other states allow L.L.C.s to designate officers, but Oklahoma does not. For record title transactions, the deed or mortgage must be executed by the manager. If there is more than one manager, verify whether all must sign a conveyance or whether the Operating Agreement allows only one to act. If the Operating Agreement is silent on this matter, all must sign.

Deeds to trusts

If a trust (living, revocable, express, or business) is created, the property must be deeded to the Trust or the Trustees of the Trust, and the deed must be filed of record.

Currently, title to property held in a trust may be conveyed to a trust in one of two ways:

1) In the name of the trustee(s) of the express trust;[13] or
2) In the name of the trust itself.[14]

The operative word here is *conveyed*. Even though the trust was created and the real

[9] See TES 12.5
[10] 16 O.S. § 53
[11] See 58 O.S. § 912C and TES 8.1
[12] 18 O.S. § 2013, 2019, 2019.1
[13] 60 O.S. § 7
[14] 16 O.S. § 1 and the Oklahoma Trust Act

property is listed on Exhibit A to the trust

document, the property still has to be transferred into the trust.

Reference to "trustee" only

A deed to "John Doe, Trustee" without stating the name of the trust is a transfer to John Doe individually.

The words "trustee" or "as trustee" are not enough to put a third party on notice that a trust exists.[15] In order for the third party to be put on notice, more evidence must be present. This additional evidence can be in the document itself (i.e., "John Doe, Trustee *of the John Doe Family Trust dated January 1, 1999*") or it can be in the form of other written evidence which is of record (i.e., an affidavit or a memorandum of trust).

The statute that provides which affidavits may relate specifically lists "names, . . . identity of parties, whether individual . . . or trust; . . . identity of trustees of trust, and their respective terms of service".[16] Consequently, if there is a deed into "John Doe, Trustee", and the grantee wishes to put third parties on notice that a trust exists, he or she may file an affidavit of record stating, for example, that he is John Doe, the trustee of the Doe Family Trust which was formed on January 1, 1998. This affidavit may also be filed by a beneficiary or anyone who has knowledge of the trust, as long as the affiant identifies his or her source of information.

A memorandum of trust can also be filed, but it can be executed only by the trustee. Oklahoma TES 3.2 points out that even if the person has an interest in the property, it does not diminish the value of the Affidavit. If nothing is filed of record putting third parties on notice of a Trust and John Doe, a single individual, executes a Deed to his son conveying all his right, title and interest in the property, then the property is conveyed, regardless of the fact that the original grantor may have thought he was deeding this to a Trust for the benefit of the beneficiaries as shown in the Trust. If a deed was filed of record into "John Doe, Trustee" and no other information is filed of record identifying the Trust and then John Doe dies, the property is part of his estate.

Final decrees

A final decree in a probate acts as a deed; it vests title to the property owned by the decedent into the designated heirs, beneficiaries or devisees as shown in the decree. To eliminate future title problems, it should be recorded in the county (or counties) where the property is located.

Many times the reason the final decree is not recorded in every county where the property is located is because of the sheer number of properties, especially when mineral interests are involved. Another problem is that the probate attorney is concerned with concluding the probate, not clearing title in all counties.

Section 711 of Title 58 of the Oklahoma probate statutes streamlines the recording process and controls fees by allowing the filing of a summary of the final decree in lieu of the full document. This summary must describe:
(1) the property by legal description,
(2) the name of the decedent in the probate proceedings,
(3) the court, case number and date the final decree or judgment was entered,
(4) the name and addresses of the party or parties now holding title to the property, and
(5) the county where the full final decree or judgment was entered.

If a final decree describes property or a mineral interest that the decedent did not own at the time of his or her death, it does not cloud title in and of itself.

[15] Under 60 O.S. § 156
[16] 16 O.S. § 83

Divorce decrees

A divorce decree acts as a deed if there is no other deed of record. The decree is recorded in each county where minerals or real property were owned or divided between the parties.

Divorce decrees not only terminate the marriage, but also allocate property and award title to one or the other spouse.[17]

TES 23.3 explains that judgments of the district court awarding real property to either litigant in a divorce action are effective to pass title to such property. It is not necessary that the decree contain language that it operates as a conveyance. The decree must be recorded in the office of the county clerk in the county where the land is located to give constructive notice of the transfer of title.

The comments under this standard state that for the purpose of marketability of title, any decree must clearly identify such real property and the property must be described with specificity. Identification of the real property by street address is not sufficient; an accurate legal description must be provided. Also, a divorce decree terminates any joint tenancy between the now ex-spouses, as well as removes the ex-spouse from a will.[18]

Caveat: While constructive notice is given by filing the judgment in the office of the county clerk where the property is located, see Comment to Title Standard 23.2E above as to the holding in *Watkins v. Watkins,* 922 F.2d 1513 (10th Cir. 1991) concerning the constructive notice effect of a judgment not filed in the office of the county clerk where the land is located.

The important part is the addition of this caveat. Constructive notice is given by filing the judgment with the county clerk where the property is located. The *Watkins v. Watkins* case noted in the caveat is what is disconcerting. Consider the following:

- John and Jane Doe are married and have their house in Tulsa County but also own oil and gas property in Creek County.
- John bought the property in Creek County, which is both surface and mineral interest, during their marriage and took title in the name of "John Doe, a married man, as his sole and separate property."
- Jane sues John for divorce in Tulsa County (county of residence).
- Divorce decree awards John the house in Tulsa and awards the Creek County property one-half (1/2) to John and one-half (1/2) to Jane.
- The divorce decree is *not* recorded in Creek County.

In the Creek County land records after the deed into John Doe is a quit claim deed from Jane Doe, a single woman, to her daughter, Sally Doe Jones. Since a divorce decree judgment acts as a deed in conveying property, and, furthermore, since the judgment must be recorded in the county where the land is located in order to give constructive notice, does taking a deed from John Doe, give title to all the surface and minerals he originally owned in Creek County or only half?

Because the deed from Jane Doe to Sally Doe Jones is of record, the division order analyst is under reasonable inquiry to determine who

[17] 12 O.S. § 181 and TES 23.3

[18] *Tiger v. Estate of Akers*, 554 P.2d 1213 (Okla. Ct. App. 1976)

these people are.[19] If the division order analyst asks John Doe – assuming he's truthful – he will say that she is his ex-wife. The division order analyst is then on notice that a divorce occurred and should obtain a copy of the divorce decree in order to verify who received which property interests.

However, if the same facts as above are true, but there is no deed from Jane Doe to Sally Doe Smith, only a lease from "John Doe, a single man" it is a more difficult situation because John Doe is the record owner, and John Doe executed the lease. However, because it is known that John Doe was married before, but he is now single, the division order analyst has inquiry responsibility to determine the facts. In both of these instances, the deed would cover only one-half even though Jane Doe (or, more correctly, her attorney) failed to record her divorce decree in Creek County.

Liens in divorce decrees

Liens in divorce decrees are liens on the real property of the debtor spouse and provide constructive notice.

An order for the payment of property division alimony in a divorce decree entered after September 1, 1991, whether payable in a single sum or periodically, is a lien against the real property of the person against whom the property division alimony is awarded ("the debtor spouse"), and it provides constructive notice to subsequent purchasers and lienors if:

1) The order states the amount of alimony as a definite sum, *and*

2) the order expressly provides for a lien on the debtor spouse's real property; *and either*
   a. the court's order providing for a lien is recorded in the office of the county clerk for the county in which the real property is situated, *or,*
   b. the debtor spouse acquired some or all of the interest in the real property that is subject to the lien via the divorce decree.

If the order was entered before September 1, 1991, TES 23.2 and the included Authorities apply.

The specific language used in the decree determines how long the liens last. This language may be as follows:

1) If the lien was payable in a single lump sum with no stated due date, it is extinguished five (5) years after the date of pronouncement of the lien by the court in a divorce case;

2) If the lien was payable in a single lump sum with a stated due date, the lien is extinguished five (5) years after the due date of the lump sum obligation as set out in the Divorce Decree;

3) If the lien was payable in installments, then the lien is incrementally extinguished as to each installment five (5) years after the due date of each installment, and the examiner shall disregard the lien, as extinguished, five (5) years after the due date of the final installment; and/or

4) If the lien was payable in a single lump sum which is due upon the occurrence of a designated event (e.g., sale of real property), then the lien is extinguished five (5) years after the designated event occurs. For constructive notice, evidence of the occurrence of the designated event must appear in the record.

[19] See TES 3.1

Enforceability of mortgages

Mortgages are no longer a valid encumbrance seven (7) years after their due date. If no due date is specified, they are not enforceable thirty (30) years after they were recorded.

A mortgage represents a lien on the property which cures the payment of the promissory note. If there is a mortgage against a piece of property which bears a due date for the final payoff of that mortgage, the note holder must foreclose the mortgage within a seven-year limitations period. This is helpful if the bank or financial institution is no longer in existence. If no due date is shown in the mortgage, then thirty (30) years must pass from the date the mortgage was recorded before the lien is unenforceable.

Estate tax liens

Estate tax liens cannot be enforced ten (10) years after the date of death of the decedent.

Although this principle seems self explanatory, it should be emphasized that the operative time is the date of death of the decedent, regardless of when the probate is filed, if ever. After 10 years, title acquired through a decedent is considered marketable as to the Oklahoma estate or transfer tax. An exception is recognized if, prior to the 10 years running, there was a tax warrant filed of record by the Oklahoma Tax Commission.

Indian land problems

Formerly allotted Indian lands can seriously impair and terminate title in Oklahoma. They must not be ignored.

Transfer-on-death deeds

Transfer-on-death deeds allow a grantor to convey his or her property to a grantee upon the grantor's death without a probate.

On November 1, 2008, a new Oklahoma Statute went into effect (58 O.S. §1253) titled the Nontestamentary Transfer of Property Act. Similar to a payable on death bank account, this new law allows a person to title real property in himself/herself and name a beneficiary who is to receive the property upon the owners death. No probate is necessary to make the title marketable.

The beneficiary on such a Deed need not be a signatory on the Deed and no consideration is necessary to validate the in-the-future conveyance.

The transfer-on-death deed is executed, acknowledged and recorded in the office of the county clerk in the county where the real estate is located, prior to the death of the owner. (See Appendix C in this chapter.) Important items to note about this instrument:

- The designation of the grantee beneficiary may be revoked at any time prior to death of the record owner.
- The revocation must be executed by the record owner, acknowledged and recorded in the county clerk's office where the land is located.
- Notice to the beneficiary or agreement of the beneficiary is not required.
- Payment of consideration by the beneficiary to the record title owner does not prevent the owner from moving the beneficiary from the deed.
- A transfer-on-death deed may be disclaimed by the beneficiary within nine months after the record owner dies. The disclaimer must also be filed in the county where the property is located.
- The beneficiary's ability to disclaim is waived if the beneficiary exercises

dominion over the property during the nine month period.

- Title to the property vests in the beneficiary at death of the record owner and is evidenced by filing an affidavit by the beneficiary (with a death certificate and an estate tax release attached if the beneficiary is not the spouse of record owner).

- If the beneficiary dies prior to the record owner and no alternate beneficiary is named in the deed, then the transfer shall lapse.

A joint tenant may utilize a transfer-on-death deed, but it only takes effect if that joint tenant survives all other joint tenants. The transfer-on-death deed does not sever the joint tenancy.

Homestead and trust problem

If both husband and wife deed all their property into a trust, and both are trustees, all conveyances of real property out of the trust must be executed by *both* trustees (i.e., both husband and wife), regardless of whether the trust says only one trustee need sign to effectuate a transfer.

The Oklahoma Constitution[20] and statute[21] give special protection to the homestead. No deed or mortgage is valid unless executed by both the husband and wife. This appears to cause problems when the homestead is conveyed to an express private trust. Some mortgage companies require the property to be conveyed out of the trust back to the husband and wife prior to refinancing, only to have them deed back to the trust after the refinancing was completed.

In this scenario, John and Sally Doe, husband and wife, convey all their property, including their homestead, to John Doe and Sally Doe, trustees of the Doe Family Trust dated January 1, 1996. The trust states that either trustee may act alone and all documents which require executions may be executed by only one of the trustees, and the signature of both is not necessary. Further, the Memorandum of Trust filed of record also clearly states that only one trustee is required for executions.

Since Oklahoma now recognizes that an express private trust is an entity capable of holding title to real property, it should appear obvious that the husband and wife have complied with the statutory requirements. They both signed the same deed that conveyed their homestead property to a legal entity. In addition, since only individuals can claim a homestead interest in property, it would also appear obvious that an express private trust cannot.

Furthermore, Oklahoma case law is clear that the homestead right is a personal right and can be waived.[22] The logical conclusion *should* be that if both spouses consented to deed their homestead property to a legal entity, and in the document that creates that legal entity, they both agreed that one person has authority to act alone, then the non-signing spouse or trustee has waived his or her claim to homestead rights in that instance.

If both spouses did not join in the creation of the express private trust and the deed is of the homestead to the trust, then the conveyance into the trust is void unless the deed into the trust has been of record for ten (10) years and no action has been instituted seeking to avoid, invalidate or cancel the deed. If the property is separate property owned by only one spouse, such deeds by either spouse without the joinder of the other is allowed.[23] But how does an examiner know if the property is homestead or not? The fact is the examiner has no way of knowing so he or she must

[20] Article 12, Section 2
[21] 16 O.S. § 4
[22] *Brooks v. Butler*, 87 P.2d 1092 (Okla. 1972)
[23] 16 O.S. § 13

treat every deed of real property in Oklahoma executed by a married person without their spouse's joinder as void. To correct this, the examiner must obtain a waiver of any homestead rights signed by both spouses. And, if such a document can be obtained, it is always better to obtain a corrective deed signed by both spouses.

Jurat and acknowledgement

A ***jurat*** ("subscribed and sworn before me") is not an acknowledgement and will prevent a deed or mortgage from being recorded (assuming the county clerk catches it).

A *jurat* is a sentence at the bottom of a document that simply says "subscribed and sworn before me" followed by the notary signature and seal. All it professes is that the person executing the document swore before the notary that what the document said was true. These are used in affidavits.

An *acknowledgement* is necessary for a deed or mortgage (or most any document) to be recorded. There are several forms of statutory acknowledgments in Oklahoma, including a short form, but all include the recitation that the notary knows the signer personally or has seen positive identification and further confirms that the person signing intends to convey or encumber the property.[24] People other than notaries are authorized to take acknowledgements in Oklahoma.[25]

Intestacy

If a spouse dies intestate survived by a spouse and one or more minor children, a legal guardian will need to be appointed by the court prior to the property being sold.

[24] 16 O.S. §§ 33, 34, 42, 95; 49 O.S. §§ 111-121; 60 O.S. § 178.11 and AG Opinion 70-345

[25] (16 O.S. § 35-39, 49 O.S. §§ 1-10; 72 O.S. §§ 52.1-56.3

The surviving parent is not automatically the legal guardian for purposes of selling real property inherited by the minor children. This is important to remember when taking leases from the heirs of intestate estates.

Trustees as grantors

Verify that the correct trustees (number of trustees and persons who are trustees) execute the document.

Unless the trust specifically allows the trustees to act alone, generally *all* trustees must sign every document under common law. The Oklahoma Trust Act modified the common law approach to provide that, where there are three or more trustees serving at the same time, authority may be exercised by a majority of the trustees.[26] The act[27] also provides that, where there are two or more trustees and one or more dies, the survivor may exercise the authority previously held by the trustees jointly, unless the trust provides otherwise. The act[28] also allows one co-trustee to give another co-trustee his or her power of attorney to act in his or her place.

Trust and estate tax release

Even if property is held in a trust, if one spouse dies, the division order analyst will still need to obtain an Estate Tax Release or Waiver Letter.

While transferring title to all of one's property into a trust will generally avoid probate, that is not always the blessing one would assume it would be for purposes of title. First, most trusts are revocable living trusts where the **settlors**, trustees and beneficiaries are usually all one and the same person retaining his or her right to freely amend or revoke the trust. In short, it is an illusory transfer. As such, the value of the

[26] 60 O.S. § 175.17A

[27] § 175.17B

[28] § 175.17C

property is included in the gross estate of the settlor when the settlor dies. This is true for both federal and state estate tax purposes. The Oklahoma statute[29] states that the value of the gross estate, used as a basis for

determination of the value of the net estate, is determined by including:

1) The value, at the time of the death of the decedent . . . of all property, real, personal, or mixed, whether tangible or intangible, in which the decedent had an interest, whether vested or contingent, within the jurisdiction of this state, . . . which shall pass in possession or enjoyment, present or future, by distribution, by statute, descent, devise, bequest, grant, deed, bargain, sale, gift or contract, to any person or persons, associations or corporation, in trust or otherwise, by testamentary disposition or by the laws of inheritance or succession of this or any other state or country, and including the value of the homestead.

2) The value of any real or personal property, including the homestead, passing by deed, grant bargain, sale or gift made in contemplation of death of the grantor, vendor, or donor, or intended to take effect in possession or enjoyment at or after his death. Any transfer made by the decedent of a material part of his estate within three (3) years prior to death, *without an equivalent in monetary consideration*, shall, unless shown to the contrary, be deemed to have been in contemplation of death, and such transfers shall, unless shown to the contrary, be deemed to have been in contemplation of death, and such transfers shall be included at the net value at the date of decedent's death. [Emphasis added]

The following set of facts will illustrate this:

1) John and Sally Doe, husband and wife, convey all their property to "John Doe and Sally Doe, Co-Trustees of the Doe Family Living Revocable Trust dated January 1, 1998."
2) The deed from the Does to the trust is filed of record.
3) John Doe dies February 1, 1999.

If the estate of a decedent passes to his or her spouse, no estate taxes are due.[30] The same result is obtained under federal law. Nevertheless, the title attorney should not rest in his or her inquiry.

Under the above facts, did the estate all pass to one spouse at the death of the other? How is an examiner to know? The property passes under the terms of the trust, but the trust document is not recorded. How does an examiner know if the surviving spouse is the sole beneficiary?

Assuming the same set of facts, but instead of John and Sally Doe acting as their own trustees, now the conveyance is to "The XYZ Bank as Trustee of the Doe Family Living Revocable Trust dated January 1, 1998." After the bank conveys title to a piece of property, does the title examiner have to inquire whether John and/or Sally Doe are deceased? Or, further, suppose the conveyance is to "The XYZ Bank as Trustee of the Tulsa Trust." Now the bank as trustee executes a deed to a third party. Should the title examiner inquire whether John and Sally Doe are still alive? This could easily be the Revocable Doe Family Trust since there is no requirement that the family name – or even "revocable" – be used in the name of the trust. When the bank, as trustee, conveys, should the examiner request a judgment search of the names John Doe and Sally Doe?

The *general rule* is: Absent any evidence to the contrary, an estate tax release should be requested where any revocable trust transfers title to real property where all the original

[29] 68 O.S. § 807

[30] 68 O.S. § 807(B)

individuals who conveyed the property into the trust in the original deed are not executing the deed out of the trust. If the examiner has made inquiry and determined that the original grantors are not deceased, the trustee should execute a recordable affidavit to this fact. As a matter of course, the attorney should file an estate tax return upon the death of the first spouse, even though the property is in trust. This could prevent future delays if it becomes necessary to sell the property at a time prior to the death of the second spouse.

Also note that TES 15.4 pertains to estate tax concerns of revocable trusts and includes a recording requirement as to the tax release when the property is held in trust and a deed is executed out of the trust by a trustee who is not a settlor. This can be avoided only if evidence is provided to the title examiner that the non-joining settlor died more than ten (10) years prior or that the non-joining settlor was, in fact, alive at the time of the conveyance.

It should also be obvious that there is no question that an estate tax release should be requested where the property was conveyed from a husband and wife into a trust, and the last surviving spouse has died, and the trustee is making conveyances out of the trust.

The Rebuttal Presumptions Statute

The division order analyst should not rely on the Rebuttal Presumptive Statute, but he or she should not ignore it either.

First, it is important to understand that the Rebuttable Presumptions Statute, found in Section 53 of Title 16, pertains to the evidentiary effect of recorded documents. In a nutshell, it says that it can be assumed that the facts are true in the documents that have been recorded. That is, the people who sign are who they say they are, they have the authority to do what they are doing, and what they say is true. (See Appendix D in this chapter for the complete text of the statute.)

While this sounds helpful, no language in the statutes protects the person who does rely on it. In other words, the statute does not provide a safety net for any person who relies on it. It is called a "*rebuttable* presumption" for a reason.

Appendix A: TES 7.2 – Marital Interest and Marketable Title.
Except as otherwise provided in Standard 7.1, no deed, mortgage or other conveyance by an individual grantor shall be approved as sufficient to vest marketable title in the grantee unless:

A. The body of the instrument contains the grantor's recitation to the effect that the individual grantor is unmarried; or

B. The individual grantor's spouse, identified as such in the body of the instrument, subscribes the instrument as a grantor; or

C. The grantee is the spouse of the individual grantor and that fact is recited by the grantor in the body of the instrument.

Comments:

1. There is no question that an instrument relating to the marital homestead in **VOID** unless both husband and wife subscribe it. *Grenard v. McMahan*, 441 P.2d 950 (Okla. 1968). It is also settled that husband and wife must execute the same instrument, as separately executed instruments will both be **VOID**. *Thomas v. James*, 84 Okla. 91, 202 P. 499 (1921). It is essential to make the distinction between a **valid** conveyance and a conveyance vesting **marketable title** when consulting this standard.

2. While 16 O.S. § 13 states that "The husband or wife may convey, mortgage or make any contract relating to any real estate, other than the homestead, belonging to him or her, as the case may be, without being joined by the other in such conveyance, mortgage or contract," joinder by husband and wife must be required in all cases due to the impossibility of ascertaining from the record whether the property was or was not homestead or whether the transaction is one of those specifically permitted by statute. *See* 16 O.S. §§ 4, 6 and 7 and kla. Const. Art. XII, O§ 2. A well-settled point is that one may not rely upon recitations, either in the instrument or in a separate Affidavit, to the effect that the property was not the homestead. Such a recitation by the grantor may be strong evidence when the issue is litigated, but it cannot be relied upon for the purpose of establishing marketability. *Hensley v. Fletcher*, 172 Okla. 19, 44 P.2d 63 (1935).

3. If an individual grantor is unmarried and the grantor's marital status is inadvertently omitted from an instrument, or if two grantors are married to each other and the grantors' marital status is inadvertently omitted from an instrument, a title examiner may rely on an Affidavit executed and recorded pursuant to 16 O.S. § 82 which recites that the individual grantor was unmarried or that the two grantors were married to each other at the date of such conveyance.

Caveat: These recitations may not be relied upon if, upon "proper inquiry" the purchaser could have determined otherwise. *Keel v. Jones*, 413 P.2d 549 (Okla. 1966).

4. A non-owner spouse may join in a conveyance as part of a special phrase placed after the habendum clause, yet be omitted from the grantor line of a deed, and still be considered a

grantor to satisfy paragraph B of this title standard. *Melton v. Sneed*, 188 Okla. 388, 109 P.2d 509 (1940).

Appendix B: TES 3.2 – Affidavits and Recitals

The new standard provides in relevant part:

A. Recorded Affidavits and recitals should cover the matter set forth in 16 O.S. § 83; they cannot substitute for a conveyance or probate of a will.
B. Affidavits and recitals should state facts rather than conclusions and should reveal the basis of the maker's knowledge. The value of an Affidavit or recital is not reduced if the maker is interested in the title.
Authority: 16 O.S. §§ 53, 82, 83.

Appendix C: Sample Transfer-on-Death Deed

_____ (name of owner) being of competent mind and having the legal capacity to execute this document, as owner transfers on death to _____ (name of beneficiary) as grantee beneficiary, the following described interest in real estate: (here insert description of the interest in real estate). THIS TRANSFER-ON-DEATH DEED IS REVOCABLE. IT DOES NOT TRANSFER ANY OWNERSHIP UNTIL THE DEATH OF THE OWNER. IT REVOKES ALL PRIOR BENEFICIARY DESIGNATIONS BY THIS OWNER FOR THIS INTEREST IN REAL ESTATE. THE GRANTOR HAS THE RIGHT TO WITHDRAW OR RESCIND THIS DEED AT ANY TIME. ANY BENEFICIARY NAMED IN THIS DEED IS HEREBY ADVISED THAT THIS DEED MAY BE WITHDRAWN OR RESCINDED WHETHER OR NOT MONEY OR ANY OTHER CONSIDERATION WAS PAID OR GIVEN.

THE STATE OF OKLAHOMA
COUNTY OF _____

Before me, on this day personally appeared _____, _____, and _____, the owner of the land described in this deed, and the witnesses, respectively, whose names are subscribed below in their respective capacities, and the owner of the land declared to me and to the witnesses in my presence that the deed is a revocable transfer-on-death of the real estate described therein, and the witnesses declared in the presence of the owner of the real estate and in my presence that the owner of the land declared to them that the deed is a revocable transfer-on-death of the real estate described therein and that the owner of the land wanted each of them to sign it as a witness, and that each witness did sign the same as witness in the presence of the owner of the land and in my presence.

_____
(name of owner)

_____
(witness)

_____
(witness)

Subscribed and acknowledged before me by _____, the owner of the land, and _____ and _____, witnesses, this ___ day of _____ (month), _____ (year).

_____
(signature of notary public)

(Seal)

My commission expires _____ (date).

Appendix D: Rebuttable Presumptive Statute

§ 53 Recorded Signed Documents – Rebuttable Presumptions

A. A recorded signed document relating to title to real estate creates a rebuttable presumption with respect to the title that:

1. The document is genuine and was executed as the voluntary act of the person purporting to execute it;
2. The person executing the document and the person on whose behalf it is executed are the persons they are purported to be and the person executing it was neither incompetent nor a minor at any relevant time;
3. Delivery occurred notwithstanding a lapse of time between dates on the document and the date of recording;
4. Any necessary consideration was given;
5. The grantee, transferee, or beneficiary of an interest created or claimed by the document acted in good faith at all relevant times up to and including the time of the recording;
6. A person purporting to act as an Attorney-in-Fact pursuant to a recorded power of attorney held the position he purported to hold and acted within the scope of his authority. It shall also be presumed that the principal was alive and was neither incompetent nor a minor at any relevant time;
7. A person purporting to act as:
    a. one of the officers listed in Section 93 of Title 16 of the Oklahoma Statutes on behalf of a corporation,
    b. a partner of a general partnership,
    c. a general partner of a limited partnership,
    d. a manager of a limited liability company,
    e. a trustee of a trust,
    f. any officer or member of the board of trustees of a religious corporation,
    g. a court-appointed trustee, receiver, personal representative, guardian, conservator, or other fiduciary, or
    h. an officer or member of any other entity held the position he purported to hold, acted within the scope of his authority (unless limitations of authority were previously filed of record and indexed against the property in question), and the authorization satisfied all requirements of law;
8. All entities that are parties to the document are in good standing in their jurisdiction of organization;
9. If the document purports to be executed pursuant to or to be a final determination in a judicial or administrative proceeding, or to be executed pursuant to a power of eminent domain, the court, official body, or condemnor was acting within its jurisdiction and all steps required for the execution of the title document were taken;
10. Recitals and other statements of fact in a conveyance are true if the matter stated was relevant to the purpose of the document;
11. Persons named in, signing, or acknowledging the document and persons named in, signing, or acknowledging another related document in a chain

of title are identical, if the persons appear in those conveyances under identical names, or under variants thereof, including inclusion, exclusion, or use of, a court-appointed trustee, receiver, personal representative, guardian, conservator, or other fiduciary, or

a. commonly recognized abbreviations, contractions, initials, or colloquial or other equivalents,
b. first or middle names or initials,
c. simple transpositions that produce substantially similar pronunciations,
d. articles or prepositions in names or titles,
e. descriptions of entities as corporations, companies or abbreviations or contractions of either, or
f. names suffixes, such as Senior or Junior, unless other information appears of record indicating that they are different persons; and

12. All other requirements for its execution, delivery, and validity have been satisfied.

Introduction

Initially, the entire area of the state of Oklahoma was set aside for Indian occupancy. In 1889, the western part of Oklahoma was opened to non-Indian settlers; title to most of those lands is derived from federal **patents**. Title to lands in eastern Oklahoma, in contrast, stems from allotments to individual tribal members pursuant to three general legislative schemes.

1. The treaties and statutes governing the lands of the Five Civilized Tribes, i.e., the Cherokee, Choctaw, Chickasaw, Creek and Seminole tribes;

2. The treaties and statutes governing the lands of the Osage Nation; and

3. The General Allotment Act which applies to all other tribes.

The legal basis for the federal government's control of Indian lands is found in the Constitution of the United States. The federal government has complete jurisdiction over Indian tribes and their lands pursuant to Article I of the Constitution of the United States:

The Congress shall have power . . . . to regulate commerce with foreign Nations and among the several States, and with Indian Tribes . . . .

From the formation of the United States, the federal government held fee title to Indian lands as "guardian" for the tribes, subject to the right and use of the tribes. The Oklahoma Enabling Act and the Supremacy Clause found in Article II of the Constitution of the United States protected this federal power when the state of Oklahoma was formed. The general theme of Oklahoma Indian titles is that the federal government imposed restrictions on alienation of Indian lands to protect the Indian allottees.

Indian titles necessitate attention to detail and research in the several treatises on Indian land law. (See Appendix A for research information.) Title examiners typically find that Indian Law is more difficult than any other area of their practice. The laws are complex, were frequently changed, and are not codified in the usual manner, which makes research difficult. Even a slight violation of an Indian restriction may invalidate a transaction.

Indian titles derived through The Five Civilized Tribes

The lands allotted to the Five Civilized Tribes are approximately the eastern half of Oklahoma with the exception of Osage County, which was allotted to the Osage Tribe, and a small area in northeast Oklahoma which was allotted to the Quapaws, Delawares and a few other tribes. The allotment scheme for the Five Civilized Tribes developed in the 1890s with the movement to create the state of Oklahoma out of Indian Territory.

The lands of the Five Civilized Tribes in Indian Territory were held as tribal domains, and, pursuant to treaties, tribal consent was necessary to include the lands within the territorial limits of a state. In 1893, the Dawes Commission was created to negotiate agreements with the tribes regarding their rights under the treaties and to dissolve the tribal domains by allocating the tribal lands in severalty to tribal members. In order to determine who was entitled to share in the tribal domains, the Dawes Commission compiled tribal rolls. The Indians were classified according to amount of Indian blood and age, and a roll book was published in 1906.

For the Five Civilized Tribes, the overall scheme of allotment of lands was to give each Indian an equal share of the tribal lands or monetary compensation. W. F. Semple describes these allotments in his book, *Oklahoma Indian Land Titles* (see Appendix B). The allotments were accompanied by restrictions as to alienability which evolved over a period of time as numerous acts were adopted amending the restrictions. The justification for the restricted Indian ownership of land was to allow the Indians time to adapt to a different culture and to prepare for competent business dealings.

An Oklahoma title attorney or land person needs familiarity with a minimum of thirteen Acts of Congress in connection with determining ownership of lands descending from an allotment of a member of the Five Civilized Tribes. In addition, there are numerous treaties between the tribes and the United States which are important. The applicable Acts of Congress are printed in the public laws, which are the Acts of Congress printed in chronological order and usually found in law libraries. The applicable acts are also published in W. F. Semple's treatise, *Oklahoma Indian Land Titles*. Appendix C includes a brief synopsis of the principal Acts of Congress dealing with restrictions on alienation by allottees of the Five Civilized Tribes.

The most important rule in dealing with Indian titles is that a purported conveyance in violation of alienation of restrictions is *void*. Therefore, it is important to understand the scheme of the alienation restrictions. An initial step is to determine whether the inception of the Indian title is from an individual allotment or from unallotted Indian lands.

In addition to allotting lands to individual tribal members, the treaties with the tribes reserved lands from allotment. Lands used for cemeteries, churches and schools were not allotted but were reserved as common properties. Lots in existing towns were sold at auction and patents from the applicable tribe issued to purchasers. Other unallotted lands were sold at public auction under rules promulgated by the Secretary of the Interior, and purchasers took fee simple title under Unallotted Land Deeds, which were approved by the Secretary of Interior and signed by the appropriate tribal authority.

Title derived through individual allotments is much more complicated than that of the unallotted lands. The restriction scheme for allotted lands includes several important considerations, discussed below.

Classification of the Indian by degree of Indian blood. Is the Indian a full-blood, half-blood, quarter-blood, intermarried white or freedman, i.e., a person who had formerly been a slave? The restriction scheme is more protective of tribal members with more Indian blood. When reviewing an Indian allotment, the patent will show the name of the tribe and the roll number of the allottee. The degree of blood of the allottee is determined by reference to the Dawes Commission roll. The rolls are available in the county law library or at the Bureau of Indian Affairs Office in Muskogee, Oklahoma.

Classification of the land as homestead or surplus. Each member of each tribe, except for the Choctaw and Chickasaw freedmen, received two allotments: a homestead allotment and a surplus allotment. The actual designation is shown on the patent. Choctaw and Chickasaw freedmen were allotted only surplus lands.

Age of the allottee. Whether the allottee has attained majority at the date of the conveyance may determine whether or not restrictions were removed by an Act of Congress. Under certain acts, a conveyance by a minor of allotted lands was prohibited. A convey-

ance by a guardian requires the determination that the guardian was appointed pursuant to proper authority and procedure.

Entity with approval authority. Does an Act of Congress delegate approval of the conveyance to the Oklahoma courts or to the Secretary of Interior? Was the proper approval obtained?

Whether Indian is original allottee or an heir of the allottee. The restriction scheme is different for an original allottee than for an heir of an allottee.

Date of conveyance. The date of the attempted conveyance is important to establish the scheme of restrictions imposed by the applicable act.

Whether lands were subject to taxation. If title descends from a tax deed, it must be determined that the lands were subject to taxation. If not, the tax sale and deeds are void, and title remains in the allottee.

Characteristically, the initial Indian instrument encountered when examining title is a sheet of Dawes Commission roll information for the allottee followed by an Allotment Patent designated either "Homestead" or "Surplus." Subsequently, a deed or, more typically, several deeds out of the allottee, are recorded and perhaps a quiet title action. Examination of these instruments in the context of the restrictions regarding alienation of allotted lands have created recurring legal issues for Oklahoma's title lawyers and oil and gas company land personnel. In an Indian conveyance, whether the instrument is a deed or oil and gas lease the allotment restrictions must be satisfied.

Restrictions affecting current conveyances, including oil and gas leases, apply to Indians of one-half or more blood. Restricted Indians of half-blood or more may convey their property if the Secretary of Interior or the district court removes restrictions. If the lands remain restricted, the restrictions are removed when the allottee dies, pursuant to the Act of August 4, 1947. Conveyances by an allottee's heirs or devisees of one-half or more Indian blood are exceptions, when the land was restricted in the hand of the person from whom the heir or devisee acquired title. In these situations, a conveyance requires removal of restrictions or approval of the district court after completion of the following procedures:

1. File petition for approval in the district court where the land is located and set hearing not less than ten days from the date of filing.

2. The judge signs a notice which describes the land and recites the consideration. This is published one time in a newspaper of general circulation in the county and notice is given to the Area Director's office at least ten days prior to the hearing. (Notice to the Area Director is required for the sale of an oil and gas lease, but not required for an agricultural lease.)

3. The grantor appears at the hearing unless he or she and the probate attorney consent otherwise.

4. The court must be satisfied that consideration is paid and that the conveyance is in the best interest of the Indian.

5. Evidence at the hearing must be transcribed and filed of record in the case.

6. The purchaser must pay all costs of the case.

7. Competitive bids may be taken at the hearing and the sale confirmed to the highest bidder.

After completing the court approval proceeding, the Indian is free to execute a commercial oil and gas lease or deed.

Tribal lands and Indian allottees whose restrictions have not been removed are leased under departmental forms of oil and gas leases. Forms for these leases and assignments are available from the Bureau of Indian Affairs at Muskogee, Oklahoma. A departmental lease cannot be assigned unless the Bureau of Indian Affairs approves. The provisions of these departmental leases do not die with the lessors/allottees but continue until the department relinquishes supervision. The Bureau of Indian Affairs in Muskogee will furnish a copy of departmental oil and gas leases and their status.

Probably the most common title opinion requirement in the area of Indian titles is for a judicial determination of heirship of a deceased allottee. Although an order approving a deed usually sets out information of heirship, the order is not a judicial finding as to heirship because the judge is merely acting in an administrative capacity as delegated by the federal government. To determine heirship of a deceased allottee, it is necessary to use one of the following methods:

1. Section 1 of the Act of June 14, 1918, where the procedure is essentially administrative and not judicial;
2. Decree of final distribution where an estate is administered in probate court; or
3. Quiet title or partition action in district court.

Land personnel may decide to waive requirements for determination of heirship based on business judgment, especially in reliance upon an Affidavit of Heirship or a Proof of Death and Heirship from the files of the Bureau of Indian Affairs in Muskogee.

To avoid expensive curative, if faced with a title requirement regarding Indian restrictions, always check with the Bureau of Indian Affairs Office to determine if Indian restrictions were removed from the subject land. The removal of restrictions may not be apparent to the examining attorney. In addition, do not assume that Oklahoma's Marketable Record Title Act[31] will cure the requirement. Generally the Marketable Record Title Act does not to apply to Indians of the Five Civilized Tribes.

Indian titles derived through the Osage Nation

The Osage Indians were moved from Kansas and located within the boundaries of present day Osage County by the Act of Congress of June 5, 1872, 17 Stat. 228. The lands were held as tribal domain until passage of the Act of Congress of June 28, 1906, 34 Stat. 539. Pursuant to that act, the surface of the lands was allotted to individual tribal members, and the oil, gas, coal and other minerals were reserved to the tribe.

Oil and gas leases were negotiated with the Bureau of Indian Affairs at Pawhuska and are either oil leases or gas leases or a combination oil and gas lease. An examination of the records of Osage County is not necessary because all records are located at the Bureau of Indian Affairs. All royalties are paid to the Bureau of Indian Affairs and then transferred to the Osage Tribe. Royalties are calculated at the highest posted price by the major

[31] OKLA. STAT. tit. 16, § 71

purchasers in Osage County, and the Bureau of Indian Affairs notifies lessees of the amount to remit. The income from this source is distributed to tribal members according to their *headrights* which is their *pro rata* share of the income. Upon the death of the original allottee, the headright is divided among the heirs.

The surface of the Osage Nation was allotted to individual tribal members by the Act of Congress of June 28, 1906. The homestead was **inalienable** and non-taxable. The surplus was inalienable for twenty-five years and non-taxable for three years or until a certificate of competency was issued. Inherited lands were **alienable** until passage of the Act of February 27, 1925, which made lands inherited by tribal members of one-half blood or more inalienable. The act of March 3, 1921, 42 Stat. 1249, removed restrictions as to adults of less than one-half blood.

Restricted Osage Indians may execute wills if the wills are approved by the Secretary of Interior. Oklahoma district courts have jurisdiction over estates of members of the Osage Nation.

Titles derived through the General Allotment Act

Unlike the restricted fee ownership allotment scheme of the Five Civilized Tribes, Indian allotments under the General Allotment Act (commonly referred to as the Dawes Act[32]) were made on the basis of trust-type ownership. Broadly speaking, the allottee has an equitable and present useable estate in land, but the legal title remains in the federal government and does not pass to the allottee or his heirs until the issuance of a fee patent. Tribes covered by the General Allotment Act include:

- Kiowa
- Comanche
- Apache (Kiowa-Apache)
- Wichita
- Caddo
- Delaware of Western Oklahoma
- Fort Sill Apache
- Cheyenne-Arapaho
- Kaw
- Pawnee
- Ponca
- Tonkawa
- Otoe-Missouria
- Eastern Shawnee
- Miami
- Seneca-Cayuga
- Peoria
- Wyandotte
- Quapaw
- Ottawa
- Modoc
- Absentee Shawnee
- Citizen Band Pottawatomie
- Iowa
- Kickapoo
- Sac and Fox

Working with lands allotted under the General Allotment Act requires examination of the records of the appropriate office of the Bureau of Indian Affairs. State recording statutes and curative acts have a limited effect on the rights of parties who could claim an interest in these lands. Unless restrictions are removed or federal law or regulation specifically refers to state law, federal law will control all aspects of ownership of these lands. Any contracts or conveyances made without the authority of federal law are void.

The general concept of the General Allotment Act was to divide tribal lands among eligible members of the tribes and to sell the excess lands. Trust patents were issued to individual allottees evidencing the right to use and occupancy of the premises with final title to

[32] 25 U.S.C. §§ 331-355

be issued at the end of the trust period. The early trust patents set out an initial trust period of 25 years, which have been extended pursuant to various executive orders up to the present time. The most recent extension was until January 1, 1994. Removal of restrictions and governmental trust supervision can be terminated in a variety of ways, including:

- competency determinations
- fee patents
- sales to non-trust status
- death of the allottee and the inheritance by non-Indians
- mortgages
- condemnations
- leasing
- easements

The Secretary of the Interior has broad powers in determining the effectiveness of wills and the heirship of a deceased allottee. (See Appendix C pertaining to Acts of Congress which dealt with the General Allotment Act.) Oklahoma state laws of descent and distribution are applied unless specifically otherwise provided by the Acts of Congress. Until such time that the land is no longer restricted, state courts have no jurisdiction. If the heirs of a deceased allottee were not determined during the trust period, and a trust patent has been withdrawn, a fee patent issued and the supervision of the government removed, the state district courts have jurisdiction to determine the heirs of the allottee.

Prior to June 25, 1910, there were no statutes which allowed determination of heirship. Pursuant to the Act of May 27, 1902, the Secretary of the Interior could approve conveyances of adults and minors of inherited land, and the approval of the deed constituted a practical determination of the heirs. The Act of June 25, 1910, allowed the determination of heirship by the Secretary of the Interior.[33] This grant of authority to the Secretary of the Interior is final in the absence of fraud, error of law, or gross mistake.

A record is kept in the Office of the Commissioner of Indian Affairs, Washington, D.C., of all determinations of heirship by the Department of the Interior. The local field office of the tribe to which the allottee belonged has information as to what determination was made by the Indian Office. Often, the information, including affidavits and other information, is conflicting. The Secretary of the Interior has the discretion to reopen a finding of heirship[34] .

Statutes and regulations control the leasing of allotted lands for oil and gas. (See Appendix D for the text of the Act of March 3, 1909, 25 U.S.C. § 396.) This Act states that the allottee may negotiate a lease if it is deemed advisable by the Secretary of Interior or the Superintendent of the Bureau of Indian Affairs Agency as the Secretary's authorized representative, subject to certain rules and regulations. If the allottee is deceased, however, and the heirs are not determined, or if some or all of the heirs are not located, the Secretary may not negotiate a lease but must offer the lease for bid. The Act of August 9, 1955, modifying the Act of March 3, 1909, provides for leasing by the Secretary if the allottee is deceased and the heirs have not been determined, or if determined, cannot be located. In order to lease, however, the Secretary must first give notice and advertise, and the lease is granted by competitive bidding. The regulations adopted under the Act of 1909 expand this to apply to all leases of allotted lands, not only those of heirs or unlocatables.

The 1938 Omnibus Leasing Act is the basic authority for leasing tribal lands. Many of the rules and regulations governing the leasing of

[33] 25 U.S.C.A. § 372
[34] 25 C.F.R. § 1011

tribal lands for oil and gas[35] are identical or substantially the same as those governing allotted lands; however, those few that differ can cause great problems. To avoid difficulties when dealing with tribal lands, the division order analyst needs to be aware of some general principles:

- Always determine the tribal officials which are authorized to act on behalf of the tribe with respect to the transaction. These differ among tribes.
- Although the Secretary of the Interior (or his or her authorized representative) may reject a lease, he or she cannot grant a lease on tribal lands of his or her own authority. The lease must be approved by the authorized tribal body.
- All leases must first be offered for competitive bid by advertisement in accordance with the regulations. Subject to this regulation, § 171.3 provides that leases may then be made through private negotiations. The title attorney must have evidence that the lease had first been advertised, such as the certified transcript of the prior advertised sale proceedings obtained from the Bureau of Indian Affairs agency having jurisdiction over the land.

Section 4 of the Omnibus Leasing Act makes all operations on Indian land under oil and gas leases covering Indian lands subject to rules and regulations promulgated by the Secretary of the Interior. The regulations[36] are administered under the direction of the Bureau of Land Management. If the lease or agreement refers to any other agencies or offices (Supervisor or Conservation Manager, United States Geological Survey, Department or Conservation Division, etc.), these references should now be interpreted to refer to the Bureau of Land Management or the Mineral Management Service as appropriate.

The Federal Oil and Gas Royalty Management Act of 1982 (codified in scattered sections of 30 U.S.C. (1982)) greatly expanded the realm of the Department of Interior in accounting for and monitoring production.[37] Operations may not be commenced on any tribal lease before it is approved by the Secretary of the Interior or his or her representative (usually the Superintendent of the appropriate Indian agency). After the lease has been approved, the lessee must obtain written permission from the Bureau of Land Management before commencing operations on the lease, and then the lessee must stay in compliance with all Bureau of Land Management regulations thereafter. If the lease covers allotted lands and not tribal lands, the regulations are very similar. The Department of Interior has long held that failure to put leased premises under production in paying quantities during the primary term results in the termination of the lease by its own terms. , However, case law has held, based on Oklahoma law, that a well commenced during a primary term of an allotted lease with a standard **habendum clause** would extend the lease for a period sufficient to complete the well.[38] Suffice it to say that no extension of the primary term of tribal leases beyond the ten-year statutory limit would be advisable.

All documents transferring any interest in or modifying the terms of the tribal or allotted oil and gas lease must be on forms prescribed by the Secretary of the Interior and must bear the Secretary's approval. Assignments of overriding royalties need not be filed for approval or even made apparent to the Superintendent. Assignments of tribal leases issued under the Omnibus Leasing Act of 1938 can only be of either the entire interest or of a partial (undivided) interest in the whole lease.

[35] 25 C.F.R. Part 171 (UU 171.1 – 171.30)
[36] found at 43 C.F.R. Part 3160

[37] See 43 C.F.R. Part 3160 and 30 C.F.R. Parts 228 and 229 (1989)
[38] *Moncrief v. Pazotex Petroleum Co.,* 280 F.2d 235 (10th Cir. 1960)

There has always been some question whether a lessee may assign a divided interest in a tribal lease because in some instances they have been approved and in other instances they have been rejected. Recent forms usually provide if a lease is divided by the assignment of an entire interest in any part, each part is considered a separate lease.

All assignments and conveyances of leasehold interests (other than overrides) must be filed with the superintendent within 30 days of execution. If a document is filed after this time but nonetheless is approved, this is not deemed a title defect. In many instances, where a prior assignment has not been approved, companies will use an assignment of operating rights as a document of transfer of an interest in the oil and gas lease. Under the regulations, assignments of operating rights must be approved in order to be effective under the applicable regulations; however, a 1956 Oklahoma court[39] has indicated that the assignment of operating rights may be enforced between the parties regardless of whether approval had been granted. Because many companies do not seek approval of the assignment of operating rights, it is very important to review company files as well as Bureau of Indian Affairs and county records in determining title.

Interesting cases under the General Allotment Act

***Estoril Producing Corporation v. Murdock*, 822 P.2d 129 (Okla. Ct. App. 1991).** Kah-Kah-to-the-Quah was a restricted Mexican Kickapoo Indian who received an allotment of 80 acres which was held in trust by the United States. On October 20, 1927, Mr. Quah executed a Warranty Deed to the C.R.I.&P. Railroad. However, the deed does not show the approval by the Secretary of the Interior, as required by the General Allotment Act.

On October 5, 1980, the heirs of Kah-Kah-to-the-Quah executed an oil and gas lease to defendants. The defendants claimed title through a 1986 oil and gas lease executed by the successors of the railroad.

The appeals court stated that the three basic requirements of the Act are:

1. The conveyance must be in such terms and conditions and under such rules and regulations as the Secretary may prescribe;

2. The conveyance must be under the supervision of the Commissioner of Indian Affairs; and

3. Approval of the conveyance must be made by the Secretary of Interior.

The warranty deed, on its face, fails to evidence that these three requirements were met. Since there was no approval, the deed is void. Because the deed is void, the oil and gas lease from the successors of the railroad is also void.

***Cheyenne-Arapaho Tribes of Oklahoma vs. United States*, 966 F.2d 583 (10th Cir. 1992).** The Cheyenne-Arapaho Tribes executed six oil and gas leases, four with Woods Petroleum in May of 1976, and two with Reading & Bates in February of 1980. All leases were for a term of five years plus term of production and all were approved by the Area Superintendent.

In April, 1981, Reading & Bates and Woods sought to communitize these leases. The tribe refused to approve the communitization agreements on the four leases that were expiring in 1981 without renegotiation, which the lessees refused to do. The proposed communitization agreement was then

[39] *Cleary v. Sewel*, 299 P.2d 524 (Okla. 1956)

submitted to the area director of the Anadarko Office of the Bureau of Indian Affairs and was approved. The tribe appealed, but the area director's decision was affirmed. The tribe sued in federal court, which ruled that the lack of tribal consent did not invalidate communitization agreements but held that the area director had breached his fiduciary responsibility by approving the agreements without studying the economic conditions prevailing at the time. Thus, the 1981 leases expired.

The Tenth Circuit agreed and concluded that the Secretary's position as a trustee over tribal lands conveys with it fiduciary responsibilities and thus must consider the economic interests of Indian lessors and has a duty to maximize lease revenues.

The record revealed that the area director did not consider any evidence of the market value and marketability of a new lease. (The value of leases in the Deep Anadarko Basin had risen astronomically in the 1980s.) The Tenth Circuit concluded that the Secretary and his delegates' actions were an "arbitrary and capricious abuse of discretion" and that the communitization agreements were not valid and that any leases upon which drilling had not commenced by May 10, 1981 had expired as of that date.

Appendix A: Useful Research Materials about Oklahoma Indian Land Titles

Books and Articles.

Semple, W. F., ***Oklahoma Indian Land Titles Annotated***, Thomas Law Book Company (1952), (Supp. 1977). This book is out of print but is available at the Tulsa County Law Library, the University of Tulsa Law Library and the University of Oklahoma Law Library.

Mills, Lawrence, ***Oklahoma Indian Land Laws***, Thomas Law Book Co. (1924) (Supp. Lawyers Publishing Co., 1947). This book is out of print but is available at the Tulsa County Law Library, the University of Tulsa Law Library and the University of Oklahoma Law Library.

General Allotment Act, 25 U.S.C.A. § 331, et seq. (1983).

25 C.F.R. and 43 C.F.R., generally.

Cohen, Felix, U. S. Department of Interior, ***Federal Indian Law***, (1958). This is a general treatise with an update by Rennard Strickland. It is available through the governmental printing office. It is particularly good for tribal matters. This book is also available at the University of Tulsa Law Library and the University of Oklahoma Law Library.

Rarick, Joseph F., ***Oklahoma Indian Land Titles***, University of Oklahoma (1982). This material can be viewed on the University of Oklahoma website at http:/thorpe.ou.edu/treatises.html.

Rarick, Joseph F., ***Cases and Materials on Problems in Lands Allotted to American Indians***, University of Oklahoma (1982). This material can be viewed on the University of Oklahoma website at http:/thorpe.ou.edu/treatises.html.

Rolls of the Dawes Commission. This material is available at the Rudisill North Regional Branch of the Tulsa County Library, the University of Tulsa Law Library and the University of Oklahoma Law Library.

Withington, W.R., "Land Titles In Oklahoma Under The General Allotment Act." 30 O.B.J. 2320 (1960).

Withington, W.R., "Kickapoo Titles in Oklahoma," 23 O.B.J. 1751 (1952).

Sulllivan, Alan L., "Minimizing The Double Tax Burden On Oil And Gas Production In Indian Country." 36 Rocky Mtn. Min. L. Inst. 17 (1990).

Online Resources.

Indian Law Web Site
http://www.indianlaw.org

American Indian Law Review
http://hamilton.law.ou.edu/lawrevs/ailr

National Congress of American Indians
http://www.ncai.org

Bureau of Indian Affairs
http://www.doi.gov/bureau-indian-affairs.html
http://www.the13thregion.com/bia.htm

University of Oklahoma Law Center – Native American Legal Resources
http://www.law.ou.edu/indian/
http://thorpe.ou.edu/treatises.html

Tribal Governments on the Internet
http://www.piperinfo.com/state/
[will redirect to] http://www.statelocalgov.net/index.cfm

Indian Land Working Group (General Allotment Act)
http://www.csusm.edu/nadp

Oklahoma Indian Affairs Commission
http://www.oiac.state.ok.us/tgo.html

Oklahoma Tribes and Officials
http://www.yvwiiusdinvnohii.net/OKTribes.htm

Appendix B: Allotment of Indian Lands

The allottees included:

- 3,119 Seminoles with average allotments of 120 acres, 40 acres of which were classified as homestead;
- 18,712 Creeks, including 6,807 freedmen, with allotments of 160 acres, 40 acres of which were classified as homestead;
- 40,196 Cherokees, including 4,924 freedmen, with average allotments of 110 acres, 40 acres of which were classified as homestead;
- 27,021 Choctaws and Chickasaws which average allotments of 320 acres, 160 acres of which were classified as homestead; and
- 10,657 Choctaw and Chickasaw freedmen to whom an average of 40 acres was allotted.

Source: *Oklahoma Indian Land Titles*

Appendix C:
Summary of Primary Acts of Congress Dealing with Restrictions on Alienation involving The Five Civilized Tribes

ACT OF APRIL 21, 1904, 33 Stat. 189: This Act removed restrictions upon the surplus lands of whites and freedmen of majority age and provided that the Secretary of the Interior could remove restrictions as to other surplus lands of majority age owners if the removal of the restriction was in the best interest of the allottee.

ACT OF APRIL 28, 1904, 33 Stat. 573: This Act applied Arkansas law to Indian Territory and gave the district courts jurisdiction over estates of decedents and guardianships of allottees.

ACT OF APRIL 26, 1906, 34 Stat. 137: This Act provided that all patents and conveyance instruments affecting allotted lands shall be recorded in the office of the Commissioner of the Five Civilized Tribes and when recorded shall convey legal title. The Act also provided that no full-blood shall sell or encumber his allotted lands for a period of twenty-five years unless the restrictions are removed. The Act exempted allotted lands from taxes as long as title remained in the original allottee and remained restricted and contained a provision authorizing Indians of the Five Civilized Tribes to make wills.

ACT OF MAY 27, 1908, 35 Stat. 312: This Act sets out the basic alienation scheme for allotted lands. The Act freed all lands of intermarried whites, freedmen and mixed bloods of less than half blood, including minors, from all restrictions. The surplus lands of mix-bloods of half blood or more and less than three-quarter blood were freed from restrictions and the homestead lands could be sold or encumbered if the Secretary of Interior removed restrictions. Lands of an allottee having more than three-quarters Indian blood were left fully restricted. An additional provision was that the death of an allottee removed all restrictions upon alienation except, as to full-blood heirs, the court having jurisdiction of the settlement of the estate of the deceased allottee must approve a conveyance by the heir.

ACT OF JUNE 14, 1918, 40 Stat. 606, 25 USCA 375: This Act allowed the probate courts of the State of Oklahoma to determine the heirship of any deceased allottee of the Five Civilized Tribes who died leaving restricted heirs. The Act also provided that the lands of full-bloods were made subject to Oklahoma partition laws.

ACT OF AUGUST 24, 1922, 42 Stat. 831: This Act validated approval of deeds by the Secretary of Interior and any prior order issued removing restrictions except those procured through fraud or duress.

ACT OF APRIL 12, 1926, 44 Stat. 239: This Act, often called the "Hastings Act," provided that if a member of the Five Civilized Tribes of one-half or more Indian blood should die leaving children surviving born since March 4, 1906, the homestead of such deceased allottee remained inalienable unless restrictions were removed by the Secretary of the Interior. The provision was adopted to support the so-called "afterborn" children. Section 3 of the Act confers jurisdiction upon the courts of Oklahoma to try title to land in which the allottees of the Five Civilized Tribes or their heirs claim an interest as long as written notice of suit is served upon the Superintendent for the Five Civilized Tribes (now Area Director) who has

twenty days to remove the case to the federal courts. The Act also provided that Oklahoma statutes of limitation apply against all restricted Indians of the Five Civilized Tribes.

ACT OF MAY 10, 1928, 45 Stat. 495: This Act extended the restrictions against alienation for twenty-five years from April 26, 1931, and gave the Secretary of the Interior authority to remove the restrictions upon the application of the restricted Indian. The provisions protecting afterborns were deleted. The Act applied Oklahoma's gross production taxes to all minerals produced from restricted allotted lands. The Act also limited the tax exemption of each restricted Indian to 160 acres.

ACT OF JANUARY 27, 1933, 47 Stat. 777: This Act restricted tax exempt lands inherited after January 27, 1933, by heirs and/or devisees of the half-blood Indian. The Act provided that approval of conveyances must be made in open court after notice in accord with the rules of procedure for probate matters adopted by the Supreme Court of Oklahoma in June 1914.

ACT OF JUNE 26, 1936, 49 Stat. 1967, 25 USCA 501: This Act, known as the Oklahoma Welfare Act, provided that if restricted Indian land was sold, the Secretary of the Interior had a preferential right to purchase the land for any other Indian.

ACT OF JULY 2, 1945, 59 Stat. 313: This was a curative act which validated certain conveyances of lands that had been purchased for an Indian and which validated judgments in partition cases from June 14, 1918, to the date of the Act where the United States was not made a party. The Act also provided that all lands purchased by the Secretary for an Indian would be restricted. (Deeds to these purchased lands contain elaborate statements setting forth the requirements for sale and are called "Carney Lacher" deeds.)

ACT OF AUGUST 4, 1947, 61 Stat. 732: This Act provided that the death of a restricted allottee removed all restrictions from his lands except if the restricted land passed to an Indian heir or devisee of one-half or more Indian blood, a conveyance, including an oil and gas or mineral lease, required court approval. Notice must be given to the Area Director of all conveyances so that he may purchase the land under the Oklahoma Welfare Act. The Act also subjected all restricted lands of the Five Civilized Tribes to the oil and gas conservation laws of Oklahoma including orders of the Oklahoma Corporation Commission if approved by the Secretary of the Interior.

ACT OF AUGUST 11, 1955, 69 Stat. 666: This Act extended the period of restriction on lands belonging to Indians of the Five Civilized Tribes and set out methods for removing restrictions which are not covered by the Act of 1947.

Summary of Primary Acts of Congress Relating to the Osage Nation

ACT OF JUNE 28, 1906, FOR DIVISION OF LANDS AND FUNDS OF OSAGE INDIANS AND FOR OTHER PURPOSES, 34 Stat. 539: This is the basic Act for the allotment of the surface to the members of the Osage Tribe and the reservation of the coal, oil, gas and other minerals to the tribe.

ACT OF MARCH 3, 1921, 41 Stat. 1249: This Act reserved coal, oil, gas and other minerals to the tribe for 25 additional years.

ACT OF FEBRUARY 27, 1925, 43 Stat. 1008: This Act stated that Osage Indians of one-half blood or more were restricted and that only heirs of Indian blood could inherit from those who were one-half or more Indian blood. This Act did not apply to spouses who were under existing marriages as of the date of enactment.

ACT OF MARCH 2, 1929, 45 Stat. 1478: This Act applied restrictions to children born after July 1, 1907.

ACT OF JULY 25, 1947, 61 Stat. 459: This Act granted the authority to determine the bonus value of any tract offered for lease to the Osage tribal council.

ACT OF FEBRUARY 5, 1948, 62 Stat. 18: This Act declared that the Secretary of the Interior was to issue certificates of competency to all Osage Indians of less than one-half blood and who are 21 years of age or older.

Summary of Primary Acts of Congress Relating to Indian Allotments Under the General Allotment Act

GENERAL ALLOTMENT ACT OF FEBRUARY 8, 1887, 24 Stat. 388: This Act provided for the issuance of trust patents to individual Indian allottees which evidenced their right to the use and occupancy of a certain tract of land with a fee patent to be issued at the end of the trust period. The initial trust period was 25 years. Any conveyance of these lands without approval was declared absolutely null and void.

Numerous allotment agreements between the United States and individual tribes from March 3, 1891, to March 2, 1895. (See Semple, *Oklahoma Indian Land Titles*, Appendix Part III, pp. 862-915.)

ACT OF MAY 27, 1902, 32 Stat. 275: This Act sets out the basic alienation scheme for allotted lands. Adult heirs of deceased Indians who held restricted lands at the time of their death may sell or convey the inherited lands. If the heir was a minor, the interest could be sold only by a guardian duly appointed by the proper court and the sale had to be approved by the Secretary of Interior. Such sold lands were then subject to taxation.

ACT OF JUNE 21, 1906, 34 Stat. 327: This Act exempted allotted lands from satisfaction of any debt prior to issuance of the final patent in fee.

ACT OF MARCH 1, 1907, 34 Stat. 1018: This Act pertained to the sale of allotments of noncompetent Indians.

ACT OF JUNE 25, 1910, 36 Stat. 855: This Act provided that the Secretary of the Interior had the exclusive jurisdiction for determining the heirs of an Indian with land whose trust period had not expired and who did not have a fee simple patent on the property. The Secretary was authorized to issue certificates of competency upon application to any Indian or his heirs at his discretion and such certificates would have the effect of removing the restrictions. (See Act of April 30, 1934.)

ACT OF FEBRUARY 14, 1913, 37 Stat. 678: This Act granted Indians over age 21 with allotments held in trust the right to dispose of the property by will. The will had to have been approved by the Secretary of the Interior. Approval could be granted even after the death of the testator.

Appendix D: Act of March 3, 1909, 25 U.S.C. § 396.)

All lands allotted to Indians in severalty, except allotments made to members of the Five Civilized Tribes and Osage Indians in Oklahoma, may by said allottee be leased for mining purposes for any term of years as may be deemed advisable by the Secretary of the Interior; and the Secretary of Interior is authorized to perform any and all acts and make such rules and regulations as may be necessary for the purpose of carrying the provision of this section into full force and effect: Provided, that if the said allottee is deceased and the heirs to or devisees of any interest in the allotment have not been determined, or, if determined, some or all of them cannot be located, the Secretary of the Interior may offer for sale leases for mining purposes to the highest responsible qualified bidder, at public auction, or on sealed bids, after notice and advertisement, upon such terms and conditions as the Secretary of the Interior may prescribe. The Secretary of the Interior shall have the right to reject all bids whenever in his judgment the interests of the Indians will be served by so doing, and to re-advertise such lease for sale.

Appendix E: Comparison of the Three Major Groups of Oklahoma Indian Tribes

	Five Civilized Tribes	**Osage Tribe**	**General Allotment Act**
Allotment	Allotment Patent • homestead • surplus	Generally the same as Five Civilized Tribes	Trust Patent, followed by Fee Simple Patent
Ability to Alienate Lands	Restrictions depend on • age • degree of Indian blood • homestead/surplus classification • method by which land was acquired	Restrictions depend on • age • degree of Indian blood • homestead/surplus classification • method by which land was acquired	Restrictions run with the land until removed
	Must look to statutes at the time of alienation • absolute prohibition • removal by Secretary of Interior • court approval	Must look to statutes at the time of alienation • removal by Secretary of Interior • Certificate of Competency issued by the Secretary of Interior	Restrictions may be removed by the Secretary of Interior • Fee Simple Patent • Certificate of Competency
Successor and Heirship: **Laws of descent and distribution**	• Tribal law until 1904 • Arkansas law 1904-1907 • Oklahoma law after 1907	Oklahoma law	Oklahoma law

Successor and Heirship: **Jurisdiction to determine heirs**	Various county and district courts; required notice to the Secretary of Interior	County courts under Act of April18, 1912	Secretary of Interior
Successor and Heirship: **Devise**	Devisable after 1906 Exception: full-blood wills had to be approved	Devisable after 1912 by competent adult, subject to Secretary of Interior approval of will before or after death	Devisable by will, subject to Secretary of Interior approval of will before or after death
Judicial Proceedings Affecting Restricted Lands	Notice of Pendency of Action must be served on Area Director	Government is a necessary party; no general consent to suit	Government is a necessary party; no general consent to suit

CHAPTER 14: OKLAHOMA

CHAPTER 14 Part 3: SENATE BILL 168

Introduction

In 1963, the Oklahoma Supreme Court handed down the "Blanchard" Decision[40] . This decision caused the "Blanchardizing" of one-eighth of all production from a unitized area. Under this decision, royalty owners received one-eighth of everyone's proceeds, not just one-eighth of the price for which their lessee sold his or her gas.

In 1985, the Oklahoma legislature enacted Senate Bill 160, which attempted to Blanchardize the excess royalty (i.e., royalty in excess of the normal one-eighth). However, certain pipeline companies immediately filed actions questioning the constitutionality of the legislation. All phases of the industry were in a quandary as to whether to comply with the new legislation or continue to pay under the Blanchard scheme. Companies asked their title examiners to break out the excess royalties while they internally tried to decide how to pay. It was safe to say that there was no consensus other than that something needed to be done.

A panel was assembled consisting of seventeen persons – lawyers, legislators, producers, royalty owners, pipeline representatives which met between the 1990 and 1991 legislative sessions. Senate Bill 168 was the result. Senate Bill 168 is codified as Oklahoma Statute, title 52, §§570.1 570.15 and 581.1 581.10. Sections 1 through 15 of the bill are now the Production Revenue Standards Act (PRSA), which became effective July 1, 1993. The statute also includes the Natural Gas Market Sharing Act (NGMSA), which eliminated the "Sweetheart Gas Bill". This act requires a contract working interest owner (the "Designated Marketer") to ratably share gas production and the resulting revenues with the non-contracted working interest owners in the same well who elect to share and who meet certain of the Act's requirements. The NGMSA became effective on September 1, 1992.

Production Revenue Standards Act definitions

To understand this Production Revenue Standards Act (PRSA), it is necessary to understand the definitions contained in it. All are in § 507.2 of the PRSA, but a select few are described here.

Owner. A person or governmental entity with a legal interest in the mineral acreage under a well which entitles that person or entity to oil or gas production or the proceeds or revenues from it.

Producing Owner. An owner entitled to produce who, during a given month, produces oil or gas for its own account or the account of subsequently created interests as they burden its interest.

Proportionate Production Interest (PPI). The interest in production which a working interest owner is entitled to produce in order to adjust for shifting of royalty burdens among working interest owners under the royalty payment provisions of this act. It is equal to the quotient of:

1. the sum of that working interest owner's net revenue interests plus the net revenue interests of any subsequently created inter-ests as they burden the owner's working interest, and

[40] *Shell Oil Co. v. Oklahoma Corporation Commission*, 389 P.2d 951 (Okla. 1963)

2. the remainder of one (1) less the royalty share

Proportionate Royalty Share (PRS). The percentage of the royalty share owned by a royalty interest owner calculated by dividing the owner's royalty interest in a well by the royalty share.

Royalty Interest in a Well (RIW). An owner's royalty interest multiplied by the quotient of:

1. the gross mineral acres under the well attributable to such interest, and
2. the total mineral acres under the well.

Royalty Proceeds. The share of proceeds or other revenue derived from or attributable to any production of oil and gas attributable to the royalty share. It does not include payments of bonus, delay rentals, shut-in royalties or any additional royalty payable to the Commissioners of the Land Office or other governmental entity, pursuant to and valued according to the terms of its oil and gas lease, which is calculated separately from the royalty portion of actual proceeds from the sale of oil or gas.

Royalty Share (RS). The percentage of the well equal to the sum of all royalty interests in a well;

Subsequently Created Interest. Any interest carved from a working interest other than a royalty interest. In addition to the royalty interest contained in a lease, a nonparticipatory interest created by a working interest owner for the benefit of a mineral interest owner in excess of a one-eighth (1/8) royalty interest may, by separate agreement other than the oil and gas lease, be a subsequently created interest. It cannot thereby be communitized under the terms of the Production Revenue Standards Act, only if there is clear and unambiguous language expressing that intent in the creating document. The additional royalty payable to the Commissioners of the Land Office or other governmental entity, pursuant to and valued according to the terms of its oil and gas lease, which is calculated separately from the royalty portion of actual proceeds from the sale of oil or gas is also a subsequently created interest and thereby is not communitized under the Production Revenue Standards Act.

Working Interest. The interest in a well entitling the owner to drill for and produce oil and gas, including but not limited to the interest of a participating mineral owner to the extent set forth in Section 87.1 of Title 52 of the Oklahoma Statutes.

The PRSA applies to all owners and to all producing wells, regardless of the date pooled, drilled or the date of the underlying leases.

Communitization of royalty

Section 570.4 provides that each month every royalty owner shares in all the proceeds derived from the sale of gas production to the extent of the owner's royalty interest in the well.

Each producing owner pays the operator the royalty share of its gas sales proceeds, valued according to the producing owner's lease terms or the Corporation Commission force pooling order, from all gas produced from the well by the owner during that month. The operator is then required to pay each royalty interest owner in that well according to the

royalty interest owner's proportionate royalty share.[41] Section 570.12 then instructs the

operator what information is to be included with that payment to the royalty owner.

Commissioners of the Land Office Leases

The additional value due the Commissioners of the Land Office (CLO) under their lease is *not* communitized under the Act. It is treated as a subsequently created interest. Similarly, restricted Indian leases (BIA, BLM) are *not* communitized under the Act at all. For an example of how this works, see the last two examples in the Calculations and Examples section of this paper.

If an owner, including the CLO, takes his or her royalty gas in kind, it is considered consumption of gas from a well by the royalty interest owner and is deemed production by the working interest owner burden by the CLO lease. The accounting is based on the average price, weighted by volume for gas sold by that working interest owner for that month. If the working interest owner does not sell that month, then it becomes the average price weighted by volume for gas sold by all the producing owners during that month.

Interest on proceeds

Any portion of the proceeds not paid within the applicable time (which starts six (6) months from the date of the first production) earns interest at the rate of 12% *per annum* compounded annually, calculated from the end of the month in which the production is sold until the day paid.

If an interest owner is not paid because his or her title is not marketable, the interest is 6% *per annum* compounded annually and calculated from the end of the month in which production is sold until the time the title becomes marketable.

Balancing

Under the PRSA, royalty owners should not get out of balance on a well. The Act did not address what happens if the royalty owners were out of balance when the Act became effective. Most of those problems have been resolved at this time. However, the PRSA did not require balancing at the time the Act became effective.[42]

Application of the PRSA

Section 570.3 states:

> *The Production Revenue Standards Act shall apply to all owners and shall apply to all producing wells, regardless of the date pooled, drilled or of the date of the underlying leases; provided, however, that Sections 4, 5, 6 7 and 8 of this act shall not apply to wells in common sources of supply under unitized management pursuant to Section 287.1 of Title 52 of the Oklahoma Statutes or where royalty remittance is otherwise provided by written agreement among all owners in a well.*

Especially important is the last phrase above "or where royalty remittance is otherwise provided by written agreement among all owners in a well." This language allows the owners of interests in any well to remove themselves from the operation of the PRSA. Consequently, there are no PPI calculations

[41] Section 570.4.B

[42] See § 570.7B

and no SCI tabulations. These companies require everyone to sign an agreement, usually as part of their division orders, that they agree to remove themselves from the effects of the Act. Otherwise, the operator states that he or she will charge the maximum overhead charge per month allowed to calculate and distribute proceeds. Most times the parties agree and remove themselves from the Act.

When are payments due

Section 570.10 sets up a detailed scheme of when payments are due. The general rule is: proceeds are payable commencing not later than six (6) months after the date of first sales and thereafter not later than the last day of the second succeeding month after the end of the month in which the production was sold.[43]

- The purchaser and selling working interest owner are responsible for paying the royalty within two (2) months of sale.
- If proceeds are less than $25, they can be paid semi-annually.[44]

If the operator distributes the royalty under § 570.4.B, a three (3) month rule applies to gas production proceeds. This extra month allows for the extra step in the distribution process.

There is not a section of the PRSA that explains how to treat ONRR formerly MMS/BIA/Indian leases. No cases have been heard on this issue. Because the lessee is included in the PRSA computations, it is possible that the lessee will not receive sufficient proceeds which can result in out of pocket royalties at the time the royalties are due.

Federal lands and restricted Indian leases

Since states cannot exercise jurisdiction over federal entities, it follows that the State of Oklahoma does not have jurisdiction over the Office of Natural Resources Revenue (ONRR) formerly known as Minerals Management Service (MMS) or Indian lands located within the state. This is the reason that Indian lands cannot be force pooled but must be included in a unit, if at all, under a communitization agreement. For the same reason, the ONRR, BIA or restricted Indian mineral interest is not communitized into the royalty pool since such federal entities do not have to submit to state enforced statutory payment plans.

The effects of this are:

- ONRR/formerly MMS/BIA/Indian Interest is valued based on terms of the lease and what the lessee recoups from its share of production.
- The ONRR/MMS/BIA/Indian royalty is excluded from the royalty pool.
- The ONRR/ MMS/BIA/Indian Inter-est is *excluded* from RS and PRS computation.

Natural Gas Market Sharing Act background

[43] § 570.10.B.1
[44] § 570.10.B.3

In the early 1980s, the biggest problem facing gas producers was finding someone to purchase their gas from their newly drilled wells. The general scheme up until this time was that the operator of the well entered into a sales contract. The non-operators in the well then either ratified the operator's contract or the operator sold the uncontracted owners' gas under his or her contract and disbursed the proceeds directly to the interest owners.

Through the late 1970s, gas prices were regulated. Since prices did not vary from contract to contract, it did not really matter who purchased the gas as long as the operator found someone who would. However, when natural gas prices were deregulated and the "gas bubble" formed in the early 1980s, gas purchasers had more gas than they wanted. Purchasers began strictly enforcing the quantity and dedication provisions of their contracts, especially new contracts that had higher priced gas payments. This left some producers without a market for their gas.

A panel of panicked producers convinced the Oklahoma legislature to enact what became known as the "Sweetheart Gas Act". However, capitalism continued on its course, and new purchasers appeared to fill the gap previously held only by the traditional pipeline purchasers thus effectively curing the problems which spawned the Sweetheart Gas Act legislation. Disputes then arose concerning the sharing of revenues under the new out-of-date high price gas contracts. The Sweetheart Gas Act did not address this kind of problem. Instead the bill was designed to force those producers, primarily perceived as the major oil companies, to share those contract rights with smaller producers who did not have the leverage or the clout to obtain such contracts. However, market realities did not change: Under-produced owners were still out of balance with over-produced owners. The Sweetheart Gas Bill proved to be insufficient for the growing needs of the industry.

Working interest owners began to dispose of whatever production was available on the spot market. The centralized control traditionally enjoyed by the operator or first purchaser was lost. The resulting confusion culminated in the enactment of SB 160 (Blanchard) in 1985. This legislation was immediately disfavored because it made the first purchaser liable for all royalty payments.

Natural gas market sharing act definitions.

To understand this Natural Gas Market Sharing Act (NGMSA), it is necessary to understand the definitions contained in it.

Designated marketer. The operator of the well or a producing owner substituted for the operator as provided in Section 22 of this act.

Electing owner. Any owner who elects to produce and market his or her share of production pursuant to the provisions of this act

Nonexempt sales. Those gas sales which are subject to the provisions of this act and do not qualify for exemptions as set forth in Section 21 of this act.

Overproduced owner. An owner who has produced and sold a volume of gas in excess of his or her working interest percentage of cumulative sales from a well.

Owner. A person or persons who own a working interest in a well.

Producing owner. An owner who produces

and sells gas from a well for its own account.

Working interest. The interest in a well, calculated prior to deduction for royalty, overriding royalty and other non-cost-bearing interests burdening production, entitling the owner to drill for and produce oil and gas, including the interest of a participating mineral owner to the extent set forth in Section 87.1 of Title 52 of the Oklahoma Statutes.

Calculations and Examples

Sample Calculation 1 – No Overriding Royalty Interests.

640 Acre Section

W/2	E/2
A	B
1/8 Royalty	1/4 Royalty

Step 1: Identify Parties

AR = Royalty Interest Owner in Tract A
AW = Working Interest Owner in Tract A
BR = Royalty Interest Owner in Tract B
BW = Working Interest Owner in Tract B

Step 2: Identify the Royalty Interest

AR = 1/8 .125
BR = 1/4 .250

Step 3: Calculate the RIW (Royalty Interest in the Well)

AR = 1/8 x 320/640 = 1/16 .125 x .5 = .0625
BR = 1/4 x 320/640 = 1/8 .25 x .5 = .125

Step 4: Calculate the RS (Royalty Share)

[This is the weighted average Royalty for the whole unit]
RS = Sum of all RIW's in Unit:

1/16 + 1/8 = 3/16 .0625 + .125 = .1875

Step 5: Calculate the PRS (Proportionate Royalty Share)

RIW/RS

AR	=	1/16	÷	3/16 =	1/3	.0625/.1875	=	.333
BR	=	1/8	÷	3/16 =	2/3	.125/.1875		.667
								1.000

Step 6: Calculate WIW (Working Interest in the Well)

- *Note: WIW is not defined in the Statute (§ 507.2)*
- *This is necessary for the PPI formula*

AW	=	7/8	x	320/640	=	7/16	.875 x .5	=	.4375*
BW	=	3/4	x	320/640	=	3/8	.75 x .5	=	.3750*

---

* This is what is described as the "Working Interest Owners' Net Revenue Interest" in § 570.2(4).

Step 7: Calculate WS (Working Share)

- Note: WS is not a defined term
- This is the total of all the WIWs
- This is part of the PPI formula

7/16 + 3/8(=6/16) = 13/16 .4375 + .375 = .8125

Note: The WS + RS always equals 1.000. Stated another way, 1 – WS = RS.

Step 8: Calculate the PPI (Proportionate Royalty Share)

Remember: The PPI is the interest in proceeds that a Working Interest Owner is entitled to in order to adjust for the shifting of the royalty burdens among the Working Interest Owners.

In this example, even though the AW Lessee has a lease with only a 1/8 royalty burden, AW has to pay 3/16 in royalties out. So, to balance this out, AW will receive a larger share of the Net Revenue Interest.

AW	=	7/8	÷	13/16	=	7/13	.4375	÷	.8125	= .53846154
BW	=	6/16	÷	13/16	=	6/13	.3750	÷	.8125	= .46153846

Step 9: Calculating Proceeds

Assume sales of 1000 mcf

AW contracts to sell at $5.00
BW contracts to sell at $10.00
What does each lessee pay towards his royalty owner?

a) Calculate AW's contribution:

1000 [Total Sales] x .53846154 [PPI]	=	$ 538.46
	x	5.00
		2692.30
Remember: RS is the weighted average for the whole unit	x	.1875 [RS]
		$ 504.81

b) Calculate BW's contribution:

1000 [Total Sales] x .46153846 [PPI]	=	$ 461.54
	x	10.00
		4615.40
	x	.1875 [RS]
		$ 865.39

c) TOTAL: $504.81 + $865.39 = $1370.20

Step 10: Royalty Owners' Share

AR had a PRS of 1/3 (See Step 5)
BR had a PRS of 2/3 (See Step 5)

So:

Total in Royalty Pool = $504.81 (from AW) + $865.39 (from BW) = $1370.20

AR = $1370.20 x 1/3	=	$ 456.73
BR = $1370.20 x 2/3	=	$ 913.47
		$1370.20

Step 11: What this would look like in a title opinion:

ROYALTY

Tract	Owner	Acres	Royalty	PRS	RIW/NRI
W/2	AR	320	1/8	.3333333	.0625000
E/2	BR	320	1/4	.6666667	.1250000
				1.0000000 (RS)	.18750000

LEASEHOLD

Tract	Owner	Acres	GWI	Revenue Interest	WIW	PPI	NRI
W/2	AW	320	.5000	7/8	.4375000	.5384615	.4375000
E/2	BW	320	.5000	3/4	.3750000	.4615385	.3750000
			1.0000		.8125000	1.0000000	.8125000

RECAP

Total Unit Royalty Interest:	.1875000
Total Unit Working Interest:	.8125000
	1.0000000

Sample Calculation 2: Subsequently Created Interests ("SCI")
a/k/a Overriding Royalty Interests

320 Acres 1 AR – 1/8 (AS – 1/16 ORRI) BR – 3/16	
160 Acres 2 CR – 15	160 Acres 3 DR – 1/4

A's Lease covers 1/2 Tract
B's Lease covers 1/2 Tract

Step 1: Identify Parties

AR = RIO under 1/2 of Tract 1
AW = WIO under 1/2 of Tract 1
AS = SCIO under 1/2 of Tract 1
BR = RIO under 1/2 of Tract 1
BW = WIO under 1/2 of Tract 1
CR = RIO under Tract 2
CW = WIO under Tract 2
DR = RIO under Tract 3
DW = WIO under Tract 3

AR = 1/8 x 320/640 x 1/2
BR = 3/16 x 320/640 x 1/2
CR = 1/5 x 160/640
DR = 1/4 x 160/640

Step 2: Calculate Royalty Interest

AR	=	1/8	.125
BR	=	3/16	.1875
CR	=	1/5	.20
DR	=	1/4	.25

Step 3: Calculate RIW

AR	1/8 x 1/2 x 320/640 = 1/32	.125 x .5 x .5 = .03125
BR	3/16 x 1/2 x 320/640 = 3/64	.1875 x .5 x .5 = .046875
CR	1/5 x 160/640 = 1/20	.2 x .25 = .050000
DR	1/4 x 160/640 = 1/16	.25 x .25 = .062500

Step 4: Calculate Royalty Share (RS)
(Sum of all RIWs)

1/32 + 3/64 + 1/20 +1/16 = 10/320 + 15/320 + 16/320 + 20/320 = 61/320
.03125 + .046875 + .05 + .0625 = .190625

Step 5: Calculate Proportionate Royalty Share (PRS)
RIW ÷ RS

AR	=	10/320 ÷ 61/320	=	10/61	.03125/.190625	=	.16393443
BR	=	15/320 ÷ 61/320	=	15/61	.046875/.190625	=	.24590164
CR	=	16/320 ÷ 61/320	=	16/61	.05/.190625	=	.26229508
DR	=	20/320 ÷ 61/320	=	20/61	.0625/.190625	=	.32786885
		TOTAL:		61/61			1.00000000

Step 6: Calculate Working Interest in a Well (WIW)

AW	7/8 x 1/2 x 320/640	=	7/32	.875 x .5 x .5	=	.218750
BW	13/16 x 1/2 x 320/640	=	13/64	.8125 x .5 x .5	=	.203625
CW	4/5 x 160/640	=	4/20	.8 x .25	=	.200000
DW	3/4 x 160/640	=	3/16	.75 x .25	=	.187500
	TOTAL:					.809375

Step 7: Calculate Working Share ("WS")
[1-RS] (Sum of all the WIW)

7/32 + 13/64 + 4/20 + 3/16 = 259/320 .21875 + .203125 + .20 + .1875 = **.809375**

70/320 + 65/320 + 64/320 + 60/320 = 259/320

[1 – RS]

Step 8: Calculate PPI
(WIW ÷ WS)

					PPI
AW	=	7/32	70/259	.21875	.27027027
		79/320 ÷ 259/320		**.809375**	
BW	=	13/64	65/259	.203125	.25096525
		65/320 ÷ 259/320		**.809375**	

CW	=	4/20 64/320 ÷ 259/320	64/259	.20 **.809375**	.24710425
DW	=	3/16 60/640 ÷ 259/320	60/259	.1875 **.809375**	.23166023
					1.00000000

Do *not* subtract ORRI for PPI computation! SCIO will be paid solely out of that owner's (that created it) PPI.

Step 9A: How this would look in a basic division order title opinion

All of Section 5-5N-5W, Ralph County, Oklahoma
Containing 640 acres, more or less

Unit Summary
All of Section 5-5N-5W, Ralph County, Oklahoma
Containing 640 acres, more or less

ROYALTY INTEREST:

Tract	Royalty Owner	PRS	(RIW) NRI
I	AR	.16393443	.03125000
I	BR	.24590163	.04687500
II	CR	.26229508	.05000000
III	DR	.32786886	.06250000
		1.00000000	**.19062500** [RS]

WORKING INTEREST:

Tract	Working Interest Owner	Acreage	GWI	WIW	PPI	NRI
I	AW	160.00000	.25000000	.21875000	.27027027	.20312500
I	BW	160.00000	.25000000	.20312500	.25096525	.20312500
II	CW	160.00000	.25000000	.20000000	.24710425 24710425	.20000000
III	DW	160.00000	.25000000	.18750000	.23166023	.18750000
		640.00000	1.00000000	.80937500	1.00000000	**.79375000**

OVERRIDING ROYALTY INTEREST:

Tract	Overriding Royalty Owner	SCIO-Factor	NRI
	AS (ORRI)=NRI/PPI	.015625/.27027027	**.01562500**
	ORRI's WIO's PPI	.0578125	

TOTAL UNIT ROYALTY INTEREST	**.19062500**
TOTAL UNIT WORKING INTEREST	**.79375000**
TOTAL UNIT OVERRIDING ROYALTY INTEREST	**.01562500**
	1.00000000

TRACT 1

N/2

Acreage Content: 320 Unit Participation: .50000000

ROYALTY OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
A	AR	160.00000	1/2 x 1/8 x 320/640 =	.03125000
B	BR	160.00000	1/2 x 3/16 x 320/640 =	.04687500
		320.00000		.07812500

WORKING INTEREST OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
A	AW	160.00000	1/2 x 7/8 x 320/640 less 1/2 x 1/16 x 320/640	.21875000 - .01562500 .20312500
B	BW	160.00000	1/2 X 13/16 X 320/640 =	.20312500
		320.00000		.40625000

OVERRIDING ROYALTY INTEREST OWNERSHIP:

Lease	Owner	Fractional Interest	Net Revenue
A	AS	1/2 x 1/16 x 320/640 =	.01562500

TRACT 2

SW/4

Acreage Content: 160 Unit Participation: .25000000

ROYALTY OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
C	CR	160.00000	100% x 1/5 x 160/640 =	.05000000

WORKING INTEREST OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
C	CW	160.00000	100% x 4/5 x 160/640 =	.20000000

TRACT 3

SE/4

Acreage Content: 160 Unit Participation: .25000000

ROYALTY OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
D	DR	160.00000	100% x 1/4 x 160/640 =	.06250000

WORKING INTEREST OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
D	DW	160.00000	100% x 3/4 x	.18750000

160/640 =

Step 9B: How This Would Look in a Basic Division Order Title Opinion Where Someone Has Gone Non-Consent

All of Section 5-5N-5W, Ralph County, Oklahoma
Containing 640 acres, more or less

Non-Consent Unit Summary
All of Section 5-5N-5W, Ralph County, Oklahoma
containing 640 acres, more or less

ROYALTY INTEREST:

Tract	Royalty Owner	PRS	(RIW) NRI
1	AR	.16393443	.03125000
1	BR	.24590163	.04687500
2	CR	.26229508	.05000000
3	DR	.32786886	.06250000
		1.00000000	**.19062500** [RS]

WORKING INTEREST:

Tract	Working Interest Owner	Acreage	GWI	WIW	PPI	NRI
1	AW	213.33333	.33333333	.28645833	.35392535	.27083333
1	BW	-0-	-0-	-0-	-0-	-0-
1 and 2	CW	213.33333	.33333333 .25000000	.26770833 26770833	.33075933	.26770833
1 and 3	DW	213.33334	.33333334	.25520834	.31531532	.25520834
		640.00000	1.00000000	.80937500	1.00000000	**.79375000**

OVERRIDING ROYALTY INTEREST:

Tract	Overriding Royalty Owner	SCIO-Factor	NRI
1	AS .015625/.35392535 AS's NRI/AW's PPI	.0441477	**.01562500**

[**Note**: Share nonconsent interest *not* on PPI but on the gross interest]

TOTAL UNIT ROYALTY INTEREST	**.19062500**
TOTAL UNIT WORKING INTEREST	**.79375000**
TOTAL UNIT OVERRIDING ROYALTY INTEREST	**.01562500**
	1.00000000

TRACT 1

N/2

Acreage Content: 320 Unit Participation: .50000000

ROYALTY OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
A	AR	160.00000	1/2 x 1/8 x 320/640 =	.03125000
B	BR	160.00000	1/2 x 3/16 x 320/640 =	.04687500
		320.00000		.07812500

WORKING INTEREST OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
A	AW	160.00000	1/2 x 7/8 x 320/640	.21875000
			less 1/2 x 1/16 x 320/640	- .01562500
				.20312500
	▪	53.33333	ORRI =	
			1/3 x 1/2 x 13/16 x 320/640 =	.06770833
B	AW	213.33333		.27083333
	Total			

B	CW	53.33333	1/3 x 1/2 x 13/16 x 320/640 =	.06770833
B	DW	53.33334	1/3 x 1/2 x 13/16 x 320/640 =	.06770834
		320.00000		.40625000

OVERRIDING ROYALTY INTEREST OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
A	AS		1/2 x 1/16 x 320/640 =	.01562500

TRACT 2

SW/4

Acreage Content: 160 Unit Participation: .25000000

ROYALTY OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
C	CR	160.00000	100% x 1/5 x 160/640 =	.05000000

WORKING INTEREST OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
C	CW	160.00000	100% x 4/5 x 160/640 =	.20000000

TRACT 3

SE/4

Acreage Content: 160 Unit Participation: .25000000

ROYALTY OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
D	DR	160.00000	100% x 1/4 x 160/640 =	.06250000

WORKING INTEREST OWNERSHIP:

Lease	Owner	Net Acres	Fractional Interest	Net Revenue
D	DW	160.00000	100% x 3/4 x 160/640 =	.18750000

Sample Calculation 3: ONRR/formerly MMS Interest and ORRIs

AR owns 320 acres
BR owns 200 acres
ONRR owns 80 acres
CR owns 40 acres
640 acres

AR leases to AW with a 3/16 royalty.
BR leases to BW with a 1/8 royalty.
ONRR leases to CW with a 1/4 royalty.
CR leases to CW with a 3/16 royalty.

BW grants a 1/16 ORRI (of 8/8) to Bob.
CW grants a 1/8 ORRI (of 8/8) to Chuck.

Mineral/ Royalty Owner	Acreage	Royalty	Royalty Fraction	Royalty Revenue Interest	RIW
AR	320/640 x	3/16 =	3/32	.0937500	.0937500
BR	200/640 x	1/8 =	5/128	.0390625	.0390625
ONRR	80/640 x	1/4 =	1/32	.0312500*	.0000000**
CR	40/640 x	3/16 =	3/256	.0117188	.0117188
				.1757813	.1445313 (RS)

* This is shown here only to reflect the ONRR /MMS' royalty in the unit.

** The ONRR is excluded from the Royalty in Well and Royalty Share calculation.

PRS = Used to divided the communitized royalty pool and is the percentage of the Royalty Share (RS) owned by each Royalty Interest Owner (RIO).

PRS = RIW/RS

Mineral/Royalty Owner	RIW/RS	PRS
AR	.0937500/.1445313 =	.6486484
BR	.0390625/.1445313 =	.2702704
ONRR	0/0 =	.0000000
CR	.0117188/.1445313 =	.0810812
		1.0000000

ORRI Calculations

ORRIs are now called Subsequently Created Interests ("SCI"). Not only does SCI include overriding royalty interests, but it also includes production payments and "extra" payments (added value payments) as found in Commissioners of the Land Office leases. SCIs are interests created by contract/agreement other than the oil and gas lease.

ORRI Owner	Fractional Interest	Decimal Interest
Bob	1/16 x 8/8 x 200/640	.0195313
Chuck	1/8 x 8/8 x 40/640	.0078125
		.0273438 (Total SCI)

Leasehold Calculations

Gross working interest less royalty burdens less SCI equal NRI

Leasehold Owner	GWI	Royalty Burden	SCI	NRI
AW	(320/640)	.0937500 -	.0000000 =	.4062500
BW	(200/640)	.0390625 -	.0195313 =	.2539063
MW	(80/640) .1250 -	.0312500 -	.0000000 =	.0937500
CW	(40/640) .0625 -	.0117188 -	.0078125 =	.0429688
	1.0000 -	.1757819 -	.0273438 =	.7968750

PPI (Proportionate Production Interest)

The Proportionate Production Interest ("PPI") is the amount that the leasehold owner is entitled to receive of the gas production/proceeds. This shifts the Royalty burdens to make sure the Royalty Interest Owners stay in balance. This calculation takes the NRI and adds back in any SCI then divides it by the RS to get the PPI.

NRI + SCI/1 – RS = PPI
[1-.145313 = .8554688]

Leasehold Owner	NRI	SCI	1-RS	PPI
AW	.4062500 +	.0000000	.8554688 =	.4748859
BW	.2539063 +	.0195313 ÷	.8554688 =	.3196347
MW	.0937500 +	.0312500*	.8554688 =	.1461187
CW	.0429688 +	.0078125 ÷	.8554688 =	.0593607
	.7968750 +	.0585938 ÷	.8554688 =	1.0000000

* The ONRR Royalty interest is treated as a SCI for PPI calculations and burdens *only* the lease that created it.

CHAPTER 15: LOUISIANA SUCCESSION AND UNIQUE LAWS

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Edited by Linda Barry

Introduction

In the laws and rules effecting Louisiana oil and gas properties are unique. So the division order analyst who works Louisiana should become familiar with Louisiana's unique terms and laws.

Successions

A Succession is a legal procedure in which the court places the heirs and/or devisees of an estate in possession of property. The court order which accomplishes the transfer of both personal and real property to the heirs and/or devisees is known as a **Judgment of Possession**. This order usually has a description of the property and the manner in which it should be distributed. A Judgment of Possession can be issued regardless of whether the deceased party died testate or intestate, so long as the court is satisfied that all debts and taxes have been satisfied.

General principles of intestate succession

If a person dies without a will or if the will is void, that person's estate is distributed in accordance with the rules of intestate succession.

In order to be called as an heir to an intestate succession, a person must be a descendant, ascendant or collateral, by blood or adoption, or be a surviving spouse not judicially separated from the deceased.[1]

Descendants are children, grandchildren, great-grandchildren, and so forth. Ascendants are parents, grandparents, great-grandparents, and so forth. Collaterals are relatives who do not descend from one another but share a common ancestor, such as siblings, aunts and uncles, and cousins.

Generally, the nearest relative is called to the succession. The unit of measurement is the *generation* and each generation is a degree. Thus, a father is related to a child in the first degree and to his grandchild in the second degree.

The line of relationship is either direct or collateral. The direct line is either ascending or descending. In the direct line, the number of degrees is equal to the number of generations between the relative and the deceased. In the collateral line, the number of degrees is equal to the number of generations between the relative and the common ancestor, plus the number of generations between the common ancestor and the deceased. Thus, an uncle and nephew are related in the third degree, while first cousins are related in the fourth degree.

Doctrine of representation

Representation is defined as a fiction of law, intended to put the representative in the place, degree and rights of the person represented.[2] Representation occurs as a matter of law in intestate successions.

Representation takes place *ad infinitum* with respect to descendants of the deceased.[3] For example, a father of two children dies intestate, survived by one child and predeceased by the other. The predeceased child is survived by two children. According to the doctrine of representation, the two grandchildren represent the predeceased child's share, and the estate is inherited one-

[1] La. C.C. art. 880.

[2] La. C.C. art. 881

[3] La. C.C. art. 882

half by the surviving child and the other one-half is inherited by the two grandchildren, in equal proportions, through representation of the predeceased child.

Representation also operates in favor of descendants of predeceased brothers and sisters of the deceased.[4] For example, a person dies intestate, survived by no descendants and no parents, but is survived by a brother and two children of a predeceased sister. According to the doctrine of representation, the two children of the predeceased sister represent the predeceased sister's share, and the estate is inherited one-half by the brother and the other half is inherited by the two children of the predeceased sister, in equal proportions, through representation of the predeceased sister.

Representation never takes place in favor of ascendants.[5]

Only deceased persons can be represented.[6]

For example, a father of two children dies intestate, survived by both children. One child renounces his share of the succession. The children of the child who renounces are not allowed to step in and take his share. The other child of the deceased will be called to take the share of the child who renounces.

Devolution of community property

Property acquired during a marriage is presumed community property, but either spouse may rebut this presumption.[7] Each spouse owns an undivided half interest in the community property.[8]

Community property comprises:

- Property acquired during the existence of the legal regime through the effort, skill or industry of either spouse;
- Property acquired with community things, or with community and separate things when the value of the separate things is inconsequential in comparison with the value of the community things used to acquire the thing;
- Property donated to the spouses jointly;
- Natural and civil fruits of community property;
- Damages awarded for loss or injury to a thing belonging to the community;
- Natural and civil fruits of separate property, and minerals produced from separate property, including bonuses, delay rentals, shut-in payments and royalties revenues from mineral leases covering separate interests, unless spouse executes declaration reserving fruits as his separate property made in an authentic act or in an act under private signature duly acknowledged;
- Transfer by a spouse to the other spouse of a one-half (1/2) interest in separate property with stipulation that it will be community; and
- All other property not classified as separate.[9]

Rules of intestacy of community property for deaths after January 1, 1982

If the deceased leaves descendants, the deceased's share of the community is inherited

[4] La. C.C. art. 884
[5] La. C.C. art. 883.

[6] La. C.C. art. 886

[7] La. C.C. art. 2340
[8] La. C.C. art. 2336
[9] La. C.C. arts. 2338, 2339 and 2343.1

by his descendants, subject to the **usufruct (life estate)** of the surviving spouse. The descendants succeed in equal proportions and by head if they are all in the same degree. They take by roots if all or some succeed by representation. The usufruct of the surviving spouse terminates at death or remarriage and the property will pass to the **naked owners (remaindermen)**.[10]

For example, a husband dies intestate, survived by his spouse, one child and two children of a predeceased child. The husband's share of the community property is inherited one-half by the surviving child, and the other half is inherited by the two grandchildren, in equal proportions, through representation of the predeceased child. The surviving spouse retains her share of the community and acquires the usufruct of her husband's share of the community property until her death or remarriage.

However, if the deceased leaves no descendants, the deceased's share of the community is inherited in full by the surviving spouse.[11]

Rules of intestacy of community property for deaths prior to January 1, 1982

The primary differences between the present law and the prior law are as follows:

The usufruct of the surviving spouse affected only community property inherited by issue of the marriage.[12]

Former Article 915 governed the situation where the deceased was survived by no descendants. This article was amended numerous times with the rights of the surviving spouse being elevated in each instance. By Act 160 of 1920, it became settled that the deceased's share of the community was divided into two parts when there was no issue, one for the deceased's father and mother, or the survivor of them, and the other for the surviving spouse. The surviving spouse inherited the deceased's share of the community in full only when the deceased was survived by no descendants and was predeceased by both parents. This change was incorporated in subsequent amendments to this former Civil Code article.

Devolution of separate property

Separate property is property exclusively owned by a person. Separate property comprises:

- property acquired by a spouse prior to the establishment of a community property regime;
- property acquired by a spouse with separate things, or with separate and community things when the value of the community things is inconsequential in comparison with the value of the separate things used to acquire the thing;
- property acquired by a spouse by inheritance or donation to him or her individually;
- damages awarded to a spouse in an action for breach of contract against the other spouse or for the loss sustained as a result of fraud or bad faith in the management of community property by the other spouse;
- damages due to personal injuries, or damages awarded to a spouse in connection with the management of his or her separate property;

[10] La. C.C. arts. 888 and 890.

[11] La. C.C. art. 889

[12] Former La. C.C. art. 916

• things acquired by a spouse as a result of the voluntary partition of the community property during the existence of the community property regime;
• fruits of separate property if a declaration is executed; and
• donation by a spouse to the other spouse of his or her interest in the community property.[13]

Rules of intestacy of separate property for deaths after January 1, 1982

If the deceased leaves descendants, the deceased's separate property is inherited in full by his descendants.[14] As with community property, they take in equal portions and by heads if they are in the same degree. They take by roots if all or some of them succeed by representation.

If the deceased leaves no descendants, but is survived by a father, mother, or both, and by brothers or sisters, or descendants from them, the brothers and sisters, or their descendants, inherit the separate property of the deceased, subject to a usufruct in favor of the parent or parents.[15]

If the deceased leaves no descendants and is predeceased by his parents, his brothers and sisters, or descendants from them, inherit the separate property of the deceased in full ownership.[16] If the deceased leaves no descendants and leaves no brothers and sisters, or descendants from them, the deceased's parent or parents inherit the separate property of the deceased in full ownership.[17]

The surviving spouse inherits the separate property of the deceased only when the deceased leaves no descendants, no parents, and no brothers or sisters, or descendants from them.[18]

If the deceased leaves none of the above types of heirs, the separate property of the deceased is inherited by the nearest ascendants. If the ascendants in the paternal and maternal lines are in the same degree, the property is divided into two equal shares, one share for the paternal line and the other share for the maternal. The ascendants in each line share by heads. If there is in the nearest degree but one ascendant in the two lines, such ascendant excludes the more remote ascendants.[19]

If none of the above types of heirs exist, the separate property is inherited by the nearest collateral relations. If there are several in the same degree, they succeed equally and by heads.[20]

In default of all of the above, the estate belongs to the State of Louisiana.[21]

Rules of Intestacy of Separate Property for Deaths prior to January 1, 1982

The primary differences between the present law and the prior law are as follows:

[13] La. C.C. arts. 2341, 2343 and 2344
[14] La. C.C. art. 888
[15] La. C.C. art. 891
[16] La. C.C. art. 892
[17] La. C.C. art. 892
[18] La. C.C. art. 894
[19] La. C.C. art. 895
[20] La. C.C. art. 896
[21] La. C.C. art. 902

The surviving spouse is not called as an heir to separate property unless the deceased is not survived by any descendants, ascendants or collaterals.

If the deceased is survived by his parents and by brothers and sisters, or the descendants from them, the succession is divided into two portions, one-half going to the mother and father and the other half going to the brothers and sisters, or the descendants from them. However, should only one parent be alive, the surviving parent takes only one-fourth and the brothers and sisters, or the descendants from them, take the other three-fourths.

Special rules and exceptions

Brothers and sisters related by half-blood.

A full brother or sister is one with both parents in common with the deceased. A half brother or half sister has only one parent in common with the deceased. If brothers and sisters of the deceased are called to take his succession, and the deceased is survived by full brothers and sisters and by half-brothers and half-sisters, the property is divided into two equal shares, one share for the maternal line and the other share for the paternal line. Full brothers and sisters take in both lines. Half-brothers and half-sisters take only in the parental line in common with the deceased. Each line's share is equally divided among the siblings in the line.[22]

Right of inheritance of immovable property. Ascendants inherit immovables donated by them to their descendants who die without posterity when these immovables are found in the succession.[23] However, the ascendants take these immovables subject to any mortgages created by the **donee**.[24]

General principles of usufruct

The usufruct is defined as a real right of limited duration over the property of another. The features of the right vary with the nature of the things subject to it.[25] Former Article 533 defined the usufruct as the right of enjoyment of a thing belonging to another with the right to use the thing so as to derive all profits and possible advantages from it.

The person who has the usufruct is called the *usufructuary*, and the person who owns the property subject to the usufruct is called the *naked owner*.

If the usufruct is of a consumable such as money or royalties, the usufructuary is treated as owner and may consume the property as he or she sees fit. At termination of the usufruct, the usufructuary is bound to pay the naked owner the value of the consumable at the commencement of the usufruct or deliver to the naked owner things of the same quantity and quality.[26]

If the usufruct is of a nonconsumable, such as land, houses, shares of stock, furniture or vehicles, the usufructuary has the right to possess them and to derive all profits and advantages that they may produce. The usufructuary is bound to use them as a prudent administrator in order to preserve their substance and, at the termination of the

[22] La. C.C. art. 893
[23] La. C.C. art. 897
[24] La. C.C. art. 898
[25] La. C.C. art. 535
[26] La. C.C. art. 538

usufruct, to deliver them to the naked owner.[27]

Legal usufruct of the surviving spouse

The surviving spouse acquires by operation of law the usufruct of the deceased's share of the community when the deceased dies intestate and is survived by descendants.[28] This usufruct terminates upon the death or remarriage of the surviving spouse.

Under the present law, the usufruct affects the community property inherited by all descendants of the deceased. However, prior to January 1, 1982, the usufruct affected only the community property inherited by issue of the marriage between the deceased and the surviving spouse. The legal usufruct does not affect any separate property of the deceased.

Testamentary usufruct

Article 1499 of the Civil Code, adopted by Acts 1996, No. 77, §1, provides that a testator, in his or her will, may grant his or her spouse, as usufructuary, the following:

- the usufruct over all of his property, both separate and community, including the forced portion;
- the power to dispose of nonconsumables without the consent of the naked owners; and
- the usufruct is for life unless a shorter period is expressly designated.

Usufruct of minerals

The Mineral Code makes a distinction between the usufruct of land and the usufruct of a mineral right. The usufruct of land refers to the situation in which title to the mineral rights is part of the ownership of the land itself. The usufruct of mineral rights refers to the situation in which the ownership of the mineral rights is segregated from the ownership of the land, such as the usufruct of a mineral servitude, mineral lease or mineral royalty.

The surviving spouse, as the usufructuary of land, whether legal or testamentary (conventional), is entitled to the use and enjoyment of the landowner's rights in the minerals, unless there is a provision to the contrary in the will creating the usufruct. However, the surviving spouse, as usufructuary, may not execute a mineral lease without the consent of the naked owners.[29]

Prior to legislative amendment, La. R.S. 31:190, the surviving spouse, as the usufructuary of the land, was entitled only to the use and enjoyment of the landowner's rights in minerals as to mines or quarries actually worked at the time the usufruct was created, the so-called "open mine doctrine." As applied to oil and gas, this principle means that if, at the time the usufruct is created, there are minerals being produced, or shown by a surface production test to be capable of production in paying quantities, the usufructuary is entitled to the use and enjoyment of the landowner's rights in minerals as to all pools penetrated by the well or wells in question.[30]

The surviving spouse, as the usufructuary of a mineral right, is entitled to all of the benefits of use and enjoyment that would accrue to

[27] La. C.C. art. 539

[28] La. C.C. art. 890

[29] La. R.S. 31:190, as amended by Acts 1986, No. 245, §1, effective August 30, 1986.

[30] La. R.S. 31:191

him or her as if he or she were the owner of the right. He or she may use the right according to its nature for the duration of the usufruct.[31] A usufructuary of a mineral servitude or other executive interest may grant a mineral lease that extends beyond the term of the usufruct and bind the naked owner of the servitude.[32]

General principles of testate succession

Donation *mortis causa* (in anticipation of approaching death) is a donation which takes effect on the death of the donor and by which the donor disposes of some or all of his property.[33] In order for this kind of donation to be valid, it must be contained in a form of last will and testament recognized by law.[34] The person who makes a will is called the **testator**.

Capacity of the testator to make a will must exist at the time the testator executes the will.[35] Everyone is presumed to have capacity.[36]

Capacity to receive under a will must exist at the time of death of the testator.[37] A legatee has capacity if he or she is in existence at the time of death of the testator. So, in order for an unborn child to receive under a will, the child must be conceived at the time of death of the testator and the child must be subsequently born alive.[38] A minor under the age of 16 does not have capacity to make a will, except in favor of his or her spouse or children.[39]

To have capacity to make a will, "a person must also be able to comprehend generally the nature and consequences of the disposition that he is making."[40] This test, enacted in 1991, purposefully rejects the phrase "of sound mind" contained in the prior article. It is intended to avoid prior jurisprudence regarding the usage of that phrase.

A will is invalid if (1) it was the result of fraud or duress,[41] or (2) it was procured through undue influence.[42]

All wills must be in writing. Louisiana law previously divided wills into four principal types:

- Olographic[43]
- Mystic or sealed[44]
- Nuncupative or open[45]
- Statutory[46]

Under the new legislation, the only two forms of testaments are the olographic (same as original olographic form) and the notarial (essentially identical to the statutory testament).[47] However, any will executed prior to January 1, 1998 that was valid under the law and jurisprudence prior to that date, when

[31] La. R.S. 31:193
[32] La. R.S. 31:118
[33] La. C.C. art. 1469
[34] La. C.C. art. 1570
[35] La. C.C. art. 1471
[36] La. C.C. art. 1470
[37] La. C.C. art. 1472
[38] La. C.C. art. 1474
[39] La. C.C. art. 1476
[40] La. C.C. art. 1477
[41] La. C.C. art. 1478
[42] La. C.C. art. 1479
[43] Former La. C.C. art. 1588
[44] Former La. C.C. arts. 1584-1587
[45] Former La. C.C. arts. 1577-1583
[46] Former La. R.S. 9:2442-2444
[47] La. C. C. art. 1574, Acts 1997, No. 1421, §1, effective July 1, 1999

executed, is not invalidated by the passage of the new statutes.

Interdiction

This term refers to the status of a person who has lost control of his/her own interests, usually by way of insanity or who is put under control of a guardian by a court of law.

Ownership of Surface and Minerals

In Louisiana, ownership of surface and minerals cannot be separated. Upon casual review of a title opinion, one might note that the examining attorney has set out a surface ownership and mineral/royalty ownership, which may or may not be the same.

Let's say for example that the title opinion shows Owner A as surface owner and Owners A, B, and C as owners of the mineral rights. You have a situation where Owner A has conveyed a mineral servitude to Owners B and C. A **Servitude** is merely the right to use something belonging to someone else. In this example Owner A has conveyed out just a portion of his rights, but you could have a case where Owners B and C would have been conveyed a servitude on all of the minerals with the right to lease and receive royalty.

Under Louisiana law, the servitude is good for only ten (10) years, if not used. At the end of a ten (10) year period the mineral rights as granted by the servitude will revert back to the then surface owner in the event of non-use. This reverting back of mineral rights is called **prescription** of non-use, or as the layman would say, *the use it or lose it* principle. There are a number of situations that will interrupt prescription, the most common being the establishment of production.

Let's look at some examples to illustrate this law. Owner A grants a mineral servitude to Owners B and C on June 1, 1988 and then Owners B and C as lessors give a lease to AAA Oil Company on July 1, 1988 and AAA as lessee drills and completes a well on August 1, 1988. This well produces until March 31, 1990 at which time the well is plugged and abandoned. When will the minerals prescribe? The answer to that question is March 31, 2000 unless the minerals are put to use in the ten (10) year period beginning April 1, 1990. It should be pointed out that the drilling and completion of a well as a dry hole will interrupt prescription.

Prescription can also be interrupted by pooling or unitizing, in which case if AAA had drilled on offset tracts they would have to pool or unitize the Owner B and C tract before June 1, 1998 or take a protection lease from Owner A, to whom the minerals would prescribe, if pooling and unitization occurred after June 1, 1998. In our example, we are assuming the primary term of the Owner B and C lease runs for a period of at least ten (10) years.

In a prescription problem involving two (2) non-contiguous tracts that were treated as a single servitude. Needless to say two (2) non-contiguous tracts cannot be treated as one servitude. My company had taken a lease from the same owners in Sections 27 and 21 on a prospect in Lincoln Parish. A well was completed and production established with the Section 21 portion of the lease included in a Unit. Eleven (11) years later, a well was completed with the Section 27 portion of the lease serving as the drillsite. The Landman advised the title analyst to pay royalties on the Section 27 acreage to the same owners as royalty was being paid to in the Section 21 acreage. In summary, we paid the wrong owners and did not realize our error until a demand was made by the Section 27 owner. The minerals in Section 27 had prescribed to the surface owner.

Unitization

Louisiana is a forced-pooling state, with laws providing for the unitization of acreage with the intent of conservation and proper drainage of reservoirs. The proper governmental authority for administration of the laws of unitization is the Department of Conservation. This body issues orders establishing units, the boundaries thereof, the density of wells, and designates wells to serve the units. The types of unitization are as follows:

Commissioner's Unit — A unit defined and approved by the Louisiana Department of Conservation after a hearing before parties with an interest in the area being unitized. The interested parties are notified in writing of the hearing, the date, the time and its location. Mineral owners, royalty owners and working interest owners have the opportunity to testify with geological and engineering data as to the size of the reservoir being drained by one or more wells that will serve the unit. The Conservation Commission will then approve the unit size and configuration based on testimony and evidence as to the reservoir for the zone being drained. The Conservation Commission also designates the unit well and possibly an alternate well to serve the unit. A well can be an alternate well for a unit and the unit well for another overlapping unit at a different level. In the Conservation Commission order, the operator of the unit is also designated. The operator then has the unit surveyed and tract participation is determined by the percentage the tract acreage bears to the total unit acreage. The tract factor can also be determined as the acre feet of oil and gas, which combines the acreage and reserve factors, determined by engineers and approved by the Commission.

Declared Unit — The size and configuration of this unit is determined by the operator and approved by the Conservation Commission.

Voluntary Unit — The size and configuration of this unit is determined by the operator and royalty owner(s).

Fieldwide Unit — This is usually a unit comprising a large number of acres or an entire field requiring approval by 75% of all owners and the Conservation Commission.

In the case of declared, voluntary, and fieldwide units, the operator has a survey plat prepared by a licensed surveyor. Declared and voluntary units usually have the tract participation calculated on an acreage basis, while fieldwide unit tract participation is usually calculated on an acre feet basis.

As discussed previously, unitization can have an effect on prescription. Unitization can also have an effect on lease administration, the most obvious effect being whether a lease is included in a producing unit before the end of its primary term. Another effect of unitization on lease maintenance is cases where leases contain a Pugh Clause, also known in Texas as a Freestone Rider. This type of clause provides that during the primary term of a lease, the portion of a lease outside of a producing unit cannot be held by production from a portion of the lease participating in a unit, but must be held by a rental payment as provided in the lease.

Conveyances

The term mineral rights as used in Louisiana refers to the rights in minerals by the surface owners, servitude owners, working interest owners and owners of royalty, overriding royalty, and non-participating royalty. These rights are conveyed by instruments known as Act of Sale,

Act of Donation, Assignments and Sublease. A mineral or royalty is usually conveyed by an Act of Sale or Donation. The Act of Donation is used in cases where no money consideration is involved, much as a Quit Claim Deed is used in other states. The working interest is conveyed by assignment or sublease. The overriding royalty is usually conveyed by an assignment.

CHAPTER 16: HOT TITLE CURATIVE ISSUES FACING PENNSYLVANIA OIL AND GAS OPERATORS

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Pennsylvania Dormant Oil and Gas Act:[1]

Purpose. The Pennsylvania Dormant Oil and Gas Act[2] was enacted as a title curative mechanism to facilitate the development of subsurface properties. The Act attempts to reduce the problems caused by fragmented and unknown or unlocatable owners of oil and gas. The purpose of this Act is *not* to vest the surface owner with title to oil and gas interests that have been severed from the surface estate. Also, the Act specifically excludes coalbed methane gas.

Petition to the court and standing under the Act. Under the Dormant Oil and Gas Act, anyone who has an interest in fee, by lease, royalty or by ownership of correlative rights in the oil and gas underlying a property is permitted to petition the court in the county where the property is located to declare a trust in favor of the unknown or unlocatable owners of oil and gas. To have standing to petition the court, an oil and gas operator must have a lease with at least one fractional owner of the oil and gas underlying the property. If all the oil and gas owners are unknown and no one can be located having an interest in the oil and gas via a valid conveyance, or lease of an interest in the property then no one has standing to petition the court to declare a trust and the oil and gas remains dormant.

Diligent Efforts to Locate Unknown Owners and Service of Process.
The Dormant Oil and Gas Act does not specify the nature or extent of the search to attempt to locate the unknown owner(s). However, the Pennsylvania Rules of Civil Procedure, Rule 430 sets forth good-faith special service requirements for service for unknown persons. A "good-faith" or "diligent" effort may require an heirs and assigns search of the records on file in the county in which the property is located. An affidavit of good faith investigation should be completed, setting out the efforts used to locate persons with interest in the oil and gas. Additionally, the Act does not address service of process. By default, Pa. Rule of Civil Procedure, Rule 430 applies. A motion for special service by publication may be warranted.

Petitioner's Requirements. The Act and Rules of Civil Procedure place requirements on the Petitioner. The Petitioner must make a diligent effort to locate the owner(s) or claimant(s) of the oil and gas, and must have been unable to locate the identity of one or more of the owners or claimants of the oil and gas. The Petitioner must then request the appointment of a trustee in the best interest of all the unknown owners of an interest in the oil and gas.

Appointment of Trustee. To be eligible for appointment as a trustee under the Act, the trustee must be a financial institution authorized to do business in the Commonwealth of Pennsylvania. The Petitioner should contact the financial institution prior to filing of the petition in order to get consent from the institution.

Administration and Duration of Trust. The administration of the created trust must be in accordance with Title 20 of the Pennsylvania Consolidated Statutes. An actual trust agreement is recommended. All payments of bonuses, rental payments, royalties, and other income is paid to the trustee by the operator until the trust is terminated and notice of its termination is given by the trustee to the oil and gas operator. The trustee must distribute monies held in trust as owners become known. The trust will remain in force until all unknown owner(s) of oil and gas have been identified. Proceeds held in the trust are subject to escheat laws at five years. How-

[1] Bradley J. Martineau, *Pennsylvania's Dormant Oil and Gas Act: Another Statutory Solution for the Problem of Unknown Oil and Gas Owners*, LANDMAN, July/August 2007

[2] 58 P.S. §701.1 *et. seq.*

ever, the Act does not address what will happen to the trust after the proceeds are escheated to the Commonwealth.

Liability of Operator. Any lessee or other person who pays bonuses, rental payments, royalties or other income due to unknown owners to a trustee is not liable for further claims by unknown owners. However, any lessee or other person who fails to pay the trust within six (6) months of the due date is liable for all attorney fees and court costs of collection, with interest.

Future of the Act. There has been discussion in the Pennsylvania Legislature about possible amendments to the Pennsylvania Dormant Oil and Gas Act. In particular, the Act as it currently stands does not address the situation where one person owns the oil and gas, but cannot be located. In this scenario, the oil and gas in and under the property still remains dormant.

Miscellaneous title and curative issues

Memoranda of Leases. Many oil and gas lessors will file a Memorandum of Lease in lieu of recording an oil and gas lease. In Pennsylvania, statute 21 P.S. § 405 sets forth what a Memorandum of Lease must include. All persons who are parties to the oil and gas lease must execute the Memorandum of Lease. The provisions that must be included in a Memorandum are:

- Name of the Lessor;
- Name of the Lessee;
- Addresses, if any, set forth in the lease as addresses of the Lessor and Lessee;
- Reference to the date of the lease;
- Description of the leasehold premises;
- Date of commencement of the term of the lease, if a fixed date, and if not, the full provision or provisions that determine the date of commencement;
- Term of the lease;
- If the lease has a right of extension or renewal, the date of expiration of the final period for which this right is given;
- If the lease has a right of purchase of or refusal on the leasehold premises or any part of it, a statement of the term during which this right is exercisable.

It is important to be sure that the information reported on the Memorandum of Lease corresponds with the information reported on the "unrecorded" oil and gas lease. Common discrepancies between the Memorandum of Lease and the "unrecorded" lease include (1) acreage discrepancies, (2) drilling rights vs. non-drilling rights, and (3) tax parcel number discrepancies.

Royalty Provisions. In Pennsylvania, oil and gas royalties under an oil and gas lease are governed by 58 P.S. § 33, which requires the lessor be paid a minimum one-eighth (1/8) royalty of all oil, natural gas or gas of other designations removed or recovered from the subject premises. Recently, many lessors have been filing lawsuits claiming that if a lessee deducts costs prior to calculating the one-eighth (1/8) royalty, the statute is violated, even if the oil and gas lease expressly permits the deduction of post-production costs. This litigation is still pending as the Pennsylvania Supreme Court is reviewing the issue.

Minerals vs. Oil and Gas. Prevailing Pennsylvania law holds that the word "minerals" alone is insufficient in and of itself to include oil and gas. However, this is a rebuttable presumption as courts have gone against the general rule by showing clear, convincing evidence that the parties' intent at the time of the conveyance was to convey the oil and gas as part of the conveyance of minerals.[3]

[3] *See Silver v. Bush*, 62 A. 832 (Pa. 1906); *Highland v. Commonwealth*, 161 A.2d 390 (Pa. 1960)

Adverse Possession. An **adverse possession** theory may be asserted when an oil and gas lease is signed by the wrong oil and gas owner. This is a fact-specific determination as to whether an owner has acquired title by adverse possession. In Pennsylvania the possession must be adverse for a period of 21 years. Generally, in order to establish title by adverse possession, the possession of the property must be actual, continuous, exclusive, visible, notorious, distinct, and hostile for a period of 21 years.

For example, an adverse possession theory was used to establish fee title to the oil and gas for an oil and gas operator who was operating on the premises for oil and gas for a period longer than 21 years, although he did not have record title to the oil and gas. The operator drilled wells on the premises, had records for the sale of oil from the wells, and also had witnesses who testified to assisting him with the wells. Furthermore, there was no indication of anyone else displaying ownership to the oil and gas. The court found that he satisfied the adverse possession requirements and ordered that he had possession of the oil and gas in and under the premises.[4]

Marital Interests. Pennsylvania is not a community property state. Property acquired during the marriage is "marital property".[5] The appreciation of "separate" property that accrues during the marriage could also be considered "marital property".[6] If a divorce or separation occurs, each spouse's interest and/or marital interest in the oil and gas must be determined. As a matter of practice and an abundance of caution, both spouses should execute an oil and gas lease if record title is in only one spouse's name.

Tax / Sheriff's / Treasurer's Deeds. There are numerous statutory requirements to comply with when executing a Tax/ Sheriff's/ Treasurer's Sale of property, and it is often impossible to be sure that all of the requirements were satisfied from the documents of record.[7] A Quiet Title Action is recommended to clear any cloud on the title as a result of a Tax/Sheriff's/Treasurer's Sale. An oil and gas operator may decide, however, to take a reasonable business risk and waive a Quiet Title Action based on the amount of time that has elapsed since the Tax/Sheriff's/ Treasurer's Sale and if the subsequent chain of title is unbroken.

Cemeteries. As to who owns **fee simple title** to a cemetery plot, the law is well settled in Pennsylvania: the grantor retains fee simple title to the plot, and the grantee receives only a privilege/easement/license to use the plot for burial purposes. Thus, the grantor of the cemetery plots retains the oil and gas.[8]

Roadways and Highways. As to who owns fee simple title to the oil and gas in and under roadways and highways in Pennsylvania, the law is not clear.

In Pennsylvania, prior to 1937, the instrument conveying the roadway/highway to the Commonwealth or a political subdivision of the Commonwealth controlled in the determination as to whether fee simple title was conveyed or an easement or right of way for the limited purpose of a highway or roadway. If the conveyance is deemed an actual deed that conveyed all right, title and interest to a portion or a strip of a piece of property, then the oil and gas, if not previously severed or conveyed, would also be conveyed by that

[4] *Morrison v. Coleman*, Pa. D. & C.3d 333 (1988)

[5] 23 Pa. C.S.A. § 3501

[6] 23 Pa. C.S.A. § 3501

[7] *See* 72 P.S. § 5860.101, *et seq.*; 42 Pa. C.S.A. § 8101, *et seq.*; Pa. R.C.P. § 3101, *et seq.*

[8] *See Petition of First Trinity Evangelical Lutheran Church*, 251 A.2d 685 (Pa. Super. 1969)

instrument. On the other hand, if the instrument is deemed to have only conveyed an easement or right of way for the express purpose of a highway or roadway, then that instrument would not have conveyed the oil and gas to the Commonwealth or the political subdivision of the Commonwealth.

In 1937, the Pennsylvania Legislature passed two statutes, 53 P.S. §§ 1171 and 1172, which provide that "any city, county, school district, or other municipality shall have power . . . to acquire title in fee simple to any real estate to which such municipality shall have previously acquired a lesser estate in any manner . . . ." The statutes further provide that as long as the municipality has been using or holding the property for a period of not less than 10 years, the municipality can acquire fee simple title by following the statutes' requirements.

It is unclear, however, whether 53 P.S. §§ 1171 and 1172 apply to properties acquired by the Commonwealth. In other words, what is unclear from the statutes is whether the Commonwealth itself has these rights under the statutes. Moreover, if the Commonwealth does not have these rights, it could get these rights if the statutes were amended at any time in the future to give them these rights. Although it does not seem that the statutes are used that often by cities, counties, school districts or other municipalities, the statutes, nevertheless, are significant as they give the governmental entities the *unilateral* power to convert a lesser estate into fee simple title after the lesser estate has been used for a public purpose for more than ten years.

Also, subsequent eminent domain statutes do not specify what interest the Commonwealth requires in such instruments. The declaration of taking (or a deed in lieu of condemnation) should recite the nature of the interest conveyed in it. However, these condemnation instruments do not always clearly state what interest is being conveyed or condemned, thus leaving a cloud on the title.

If the instrument that transfers title to the Commonwealth or a political subdivision of the Commonwealth (i.e., deeds or declarations of condemnation/appropriation) contains a statement of or reference to the nature of the title acquired by the Commonwealth or the political subdivision of the Commonwealth, this conveyance and statement will be controlling as to the title acquired pursuant to the Eminent Domain Code. If there is no statement of or reference to the nature of the title acquired in the document, then a gray area exists, thus leaving a cloud on the title.

Railroads. As to the issue of who owns the oil and gas in and under a railroad, the law in Pennsylvania is also unclear.

In construing an instrument by which a railroad was conveyed a strip of land to be used for railroad purposes, the primary objective in determining whether the instrument conveyed fee simple title, a right of way or a conditional fee is to ascertain and effectuate the parties' intention. The distinction is critical as it determines who owns the oil and gas in and under the railroad. The courts have considered many factors in deciding the parties' intent, including the consideration paid and the language of the instrument itself. However, the courts' decisions vary on whether an instrument conveying a strip of land for railroad purposes conveyed fee simple title or a right of way, since the parties' intent is unique to each instrument. Moreover, it is often difficult to definitively ascertain the parties' intent from often very old instruments, thus making it uncertain whether these instruments conveyed fee simple title or just a right of way, thus leaving a cloud on the title.[9]

[9] *See Brookbank v. Benedum-Trees Oil Co.*, 131 A.2d 103 (Pa. 1957)

Curative Options for Roadways, Highways, and Railroads. If there is a cloud on the title as to who owns the oil and gas in and under a roadway, highway, or railroad, there are several options as to curative measures to resolve the cloud on the title. One option is to obtain a Quit Claim Deed from the Commonwealth/political subdivision/railroad to the current oil and gas owner, relinquishing any and all interest it may have in the oil and gas. Another option is to file a Quiet Title Action asking the court to declare who owns the oil and gas. Alternatively, an oil and gas lease could be obtained from both the purported oil and gas owners and also the Common-wealth/political subdivision/ railroad. Finally, all oil and gas operations on or under the roadway, highway, or railroad could be avoided.

As with any oil and gas title, an oil and gas operator should always consult with a competent attorney about the status of the title before conducting any oil and gas on a property.

CHAPTER 17: ROCKIES (FEDERAL UNITS) DIVISION ORDER OVERVIEW

Introduction

Division order work in the Rocky Mountain states presents a unique set of challenges to the analyst. Because of the wide open spaces and historically sparse population, the blend of mineral ownership between fee, federal and state is much more dominated by federal acreage than in any other area with the exception of offshore and Alaska. This blend creates several different considerations in analyzing properties. This chapter discusses these important considerations.

Administration of federal lands

Administration by the government of federal lands is split into certain entities of the Department of the Interior. The Bureau of Land Management oversees leasing, surface use, and development of the minerals owned by the United States, with the exception of US forest lands (administered by the U.S. Forest Service). The Minerals Revenue Management Program, under the Office of Natural Resources Revenue formerly known as the Minerals Management Service, accounts for the revenues from oil and gas. Interaction between industry, the BLM, and the Office Of Natural Resources Revenue, (ONRR) formerly known as MMS is specified in detail in the Code of Federal Regulations, mostly under 30 CFR and 43 CFR.

As may be expected, forms, procedures, and waiting will characterize dealings with the government. The waiting in particular has a direct impact on workloads, as will be discussed later. The individual state or regional BLM offices are allowed their own procedures in some situations; they also and have their own workloads and timing, so it must be remembered with which agency the interaction is taking place and what quirks accompany those dealings. On the other hand, there is a consistency in federal transactions that is lacking in fee ownership situations. Once the particulars are learned, working federal lands is a simpler process than might be expected.

Federal leases

Leasing by the BLM is accomplished by what is essentially a closed-bid auction. That is, the BLM will release a group of tracts to lease, and then set a date for the auction. Each lease will go to the highest qualified bidder. Anyone can apply to bid, so quite often there are assignments to exploration companies from individual lessees that reserve overriding royalty interests.

The terms of federal leases are governed and sometimes overridden by the BLM's regulations. The royalty rate can vary depending on the area, industry standard, whether the acreage is within a known geological structure, and, in the case of sliding scale royalties, by product or by volume produced. Sliding scale royalties range higher as the volume of oil produced on a daily basis (bopd) increases. The volumes and associated royalties are identified on an Exhibit "B" attached to the lease. The royalty for gas in these cases is determined by applying one of two percentages based on volume produced.

The last couple of decades have seen a growing concern by the ONRR/MMS (and other royalty owners) about the pricing of the products sold on which they are paid royalties. This concern developed partly because of the sale of products by a producer to an affiliated marketing company. The concern was that the royalty owner should receive payment based on a fair price for the product, not based on some reduced price received by the producer. On the one hand, marketers argue that the risk taken by the marketers justifies paying a more fixed price to the producer and its royalty owners. On the other hand, the royalty owners want to ensure that they are not being paid an unfairly low price by the

producers. After many lawsuits and negotiations, new ONRR/MMS regulations govern the price that must be followed.

Similarly, much attention has been given to the deductions from royalty payments that are taken. When a product is produced from a well, various costs are incurred in getting that product to a point and in a condition that it can actually be sold. For example, gas may need to be gathered from various wells, dehydrated, compressed, processed for H2S (hydrogen sulfide - a poisonous gas sometimes produced with natural gas), processed to extract liquids that are salable, and transported to the various plants or sale points. Each of these processes has a cost associated with it, and the question is whether the royalty owner should bear any or all of these costs.

Some leases attempt to address this issue, but interpretation of the language, even by the courts, frequently causes problems. . Several producers have entered into settlement agreements with fee royalty owners over a large area, perhaps all of their fee owners in a given state, in order to define exactly which costs may or may not be charged to the royalty owner. The ONRR/MMS has likewise defined in the regulations which costs may be deducted. As a general rule, gathering costs may be deducted from ONRR/MMS royalties, but there are many exceptions to this rule. Knowing the area and communicating with appropriate ONRR/MMS contacts regularly will prevent mispaying royalties and being subject to penalties and/or interest. This might appear to be an accounting issue, but many revenue and land systems require some sort of input from division order or lease personnel related to deducts in order to pay properly.

Another issue addressed in BLM leases and regulations is that of compensatory royalties. There are the same issues with fee leases, but in this case, a whole bureaucracy keeps track of such things. If a well is drilled too close to a lease line, or if the reservoir does not cooperate and conform to state spacing rules, drainage of oil or gas from a lease not included in the spacing unit may cause damage. If the BLM determines that a federal lease is being drained, then compensatory royalties will be due. These are lease payments payable by the operator of the offending well, regardless of whether the lessee is participating in the well or not. Payments are calculated based on production from the well and the theoretical percentage of production that the lease is due.

Wells on or near federal leases

"Doc" Emmett Brown: Marty, you're not thinking fourth dimensionally!
Back to the Future Part III

Any well that is drilled on or near a federal lease is initially considered a lease well (unless it is drilled within an approved producing unit of some kind). That is, royalties are payable only to the lessor of the lease on which the well is drilled. If the state spacing requires a larger spacing unit than the lease itself, or if the configuration of the spacing unit would include another lease, some form of pooling is needed. Any time that there is a federal lease contributing more than 10% of a spacing unit, a communitization agreement must be submitted for approval to the BLM.

A communitization agreement is a single-well pooling of leases that combines a federal lease with any other kind of lease, whether it is another federal lease, a state lease or a fee lease. The BLM and the ONRR/MMS must approve the communitization agreement before any royalty payment may be made on a pooled basis. This is where the initial lease well designation becomes important. If the well is drilled on a federal lease, the ONRR/MMS will initially expect 100% of the royalty to be reported to them. On the other

hand, if the well is not drilled on a federal lease, but it is anticipated that there will be a communitization agreement to pool the federal lease, the ONRR/MMS will refuse to accept any payment on that well until the communitization agreement is approved.

One of the critical skills necessary for working the Rockies is the ability to think fourth-dimensionally. In this case, the fourth dimension is time. Because of this, the Rockies analyst must be able to not only answer the question of ownership in a well, but also when that ownership began. Was it before or after the communitization agreement was approved? This will be discussed in more detail later in the chapter.

For a communitization agreement well, two divisions of interests (DOI) will need to be set up. The first will show the lessor of the drillsite lease receiving 100% of the royalty, and this DOI will be used until the communitization agreement is approved. The second DOI will not be used until notice of the BLM's approval of the communitization agreement is received. This DOI will show all of the royalty owners covered by the communitization agreement with each reflecting its proportionate share of the royalty. When approval of the communitization agreement is received, Revenue Accounting will need to be notified to begin using the second DOI, *and* to rebook all revenues associated with the well from the first DOI to the second, effective back to first sales. There are no shortcuts to this process. It is a cost of doing business with the federal government.

Several questions are raised with this treatment of revenues. Royalties and overrides burdening the drillsite lease must be assessed for risk to the company. These owners could be tremendously overpaid by the time that a communitization agreement is approved. Keep in mind that they will receive revenues as if their lease is the only lease in the spacing unit until the communitization agreement is approved, at which time their interests will be proportionately reduced on a retroactive basis. As a prudent operator, your company must pay the entire royalty to show good faith. There is not much that can be done with the royalties, but a discussion with management might yield some methods to protect the company from exposure in the case of overrides. Knowing the owners and how well they would be able to bear recoupment is critical in this situation. Keep in mind also that the whole revenue process is involved in this situation. For example, *ad valorem* and production taxes are accrued based on whether a royalty owner is tax-exempt or not. So these taxes will either be over-accrued or under-accrued and will need to be reconciled after the fact.

There is better news with regard to the working interest ownership in a communitization agreement. The partners in such a well will often negotiate a joint operating agreement (JOA) or a working interest pooling agreement that will establish a drillblock that is similar to the proposed communitization agreement. Working interests can then be set up that will match the anticipated interests in the approved communitization agreement. This greatly reduces the probability of rebilling and rebooking working interest revenues and reduces the operator's exposure. Even if the BLM alters the proposed communitization agreement which it will do on occasion, the alterations will most likely be minimal and the associated adjustments fairly slight.

By way of example, here is a typical well that will need to be communitized: The state spacing for the formation completed is 640 acres. The well is drilled in the NE/4 SW/4 of the section, and per the state spacing, the section is the spacing unit. Two leases comprise the spacing unit, a federal lease covering the W/2 and a fee lease covering the E/2.

Federal exploratory units

Another way to preserve leases, spread risk and develop an area is by use of an *exploratory unit*. The BLM allows huge units, some up to 50,000 acres, to be formed by exploration and production companies that yield several benefits. An exploratory unit has a primary term of five years. Drilling anywhere on the unit over the expiration date and then continuously drilling within a specified number of days will extend the term of the unit another five years, and then another year, for a total possible term of eleven years. Once the unit expires, it will contract to the boundaries of its participating areas. Ownership in the contracted unit is based on ownership within each of the surviving participating areas. If there are no wells capable of producing in paying quantities as defined in the unit agreement, the unit will terminate.

Lease extension is one of the primary benefits of an exploratory unit. Leases throughout the unit are extended by activity anywhere in the unit, so long as they are properly maintained with rental or royalty payments. Upon contraction or termination of the unit, each lease that is excluded will be extended by an additional two years. The term *twelfth year rentals* applies to the rental payments made after the eleventh year of an exploratory unit.

Any leaseholder can refuse to join in a federal exploratory unit. This uncommitted tract can create a "hole" in the unit from which no ownership is derived and to which no production is allocated. To preserve such a lease, the leaseholder would have to drill a well, which would be a lease well with no connection to any participating areas in the unit. Production would be allocated 100% to the lease and its owners.

When a well is drilled and completed within the unit and is determined to produce in paying quantities (a unit well), a proposed participating area is sent to the BLM. In terms of size, the acreage included in the participating area will conform to state spacing requirements. The configuration of the acreage, how-ever, will conform to BLM regulations. This usually means employing the circle-tangent method. This method involves creating a virtual circle around the well, with the well at the center of the circle. The size of the circle is such that its area will equal the spacing acreage. Generally, any 40-acre quarter-quarter section (or other fractional section as designated by the BLM) that is at least 50% included in the circle will be included in the participating area.

It should be noted that the BLM may take some time to determine whether a well is a unit well (producing in commercial or paying quantities) or a lease well. They may wish to observe several months' worth of production in order to make the determination. After the paying well determination, the participating area proposal is submitted for approval, which may take another few months. Fourth-dimensional thinking once more comes into play. As a lease well, the burdens are going to be different than a participating area well. So between first production of the well and approval of the participating area, royalties and overriding royalties will be paid on a lease basis. After participating area approval, royalties will be paid on a participating area basis, retroactive to the date of first production. Again, this will create a probably substantial overpayment to the drillsite lease owner. Hopefully, the working interests have been previously pooled and accurately forecast. Otherwise, large cost adjustments will be required in addition to the revenue adjustments.

Do not yield to anyone who would pressure to have a division of interest for royalties and overrides based on projected participating area interests set up. Copies of participating area or communitization agreement proposals may be received or there may be reasonable

ideas about the configuration of a participating area or communitization agreement, but only an approval letter from the BLM should be used as a basis for setting up participating area or communitization agreement ownership for a well.

Exhibits to the approval letter will include a list of the leases covered and a map of the approved participating area or communitization agreement, as well as some of the calculations needed. The approval legitimizes the pooling of federal leases, and nothing else will. This is not only industry standard for the setup of participating areas and communitization agreements, but it will save unnecessary work. As soon as a proposal is relied upon, the BLM will likely change the proposed configuration of the participating area and DOIs will have to be corrected. Furthermore, the ONRR/MMS will refuse to accept any royalties that are paid without benefit of approved pooling, in those situations where the federal lease is not the drillsite. Likewise, the ONRR/MMS will insist on payment of the full, undiluted royalty in cases where a federal lease is the drillsite.

A second well drilled in the exploratory unit that is determined to be a paying well will result either in a second participating area or in the first revision to the initial participating area. If the well is close enough to the original well, the first revision to the initial participating area will be approved. The first revision acreage and configuration will again be determined by the circle-tangent method. In this example, there will be a 640-acre circle drawn around the second well. Then two tangents will be drawn between the circle for the second well and the circle for the first well. (See Appendix for illustration) Any 40-acre quarter-quarter section that is at least 50% included in either of the circles or the tangent will be included in the first revision.

All of the same processes apply to the second well that apply to the first. The royalties for the second well are treated as if it is a lease well until approval of the first revision. The well is evaluated for commercial capabilities, and the participating area revision proposal is sent to the BLM. Upon approval, the first revision will be effective with first production from the second well. This means that any subsequent adjustments done to costs or revenues from the first well will be dependent on the time period of the adjustment. Any adjustments or corrections done for periods prior to the date of first production of the second well will be calculated with initial participating area ownership. Adjustments done for periods after first production of the second well will be calculated with first revision ownership. Fourth-dimensional thinking becomes more critical with each well drilled. If the first participating area was not have been approved before the second well is drilled, it is fairly likely that two or more lease wells may exist at the same time. As more wells are drilled as allowed by the continuous drilling clause of the unit agreement, numerous lease wells and participating area revisions may end up being juggled all at once. The ONRR/MMS allots ninety days from approval to process each change and report the proper revenues.

A second well that is too far away from the initial well will have its own participating area established in the same way as the participating area for the first well was determined. The second participating area will become the initial participating area "B", while the first participating area is known as participating area "A". Once each participating area has been revised and expanded a few times, the boundaries may come close enough to each other to merge the two participating areas into one. This merged participating area will be called the Initial Consolidated PA "A-B". The consolidated participating area will then undergo revisions as more wells are drilled. Each revision will follow the process described above. Participating area "A-C-D-E-F" could well be the result. After all of the

permutations have been worked through, the unit will be contracted to the existing participating areas. Leases will receive their final unit-related extensions and the final unit DOI can be set up.

It is a mistake to think that the unit will finally not have to be dealt with again. Especially during times of good prices, every feasible measure will be undertaken to optimize production from the unit. Quite often this will mean continued drilling until the full extent of the reservoir is defined and also infill drilling to maximize recovery of reserves. That in turn will lead to situations in which the unit DOI will be used to partially determine ownership of a well that overlaps the boundaries of the contracted unit. Ultimately the establishment of a secondary or tertiary recovery unit may be in order.

First, however, no discussion of fourth-dimensional thinking can be complete without some consideration for the third dimension: depth. Each participating area that is formed within the unit will be depth-restricted to the formation from which it produces. The name for a participating area will typically include the formation name, as in the Cathedral Buttes Unit Frontier PA "B" Fourth Revision. Note that each of the dimensions discussed so far in this chapter is represented in the participating area name: Cathedral Buttes Unit and PA "B" define the height and width on a horizontal plane (legal description), Frontier defines the vertical depth and the fourth revision further defines the legal and adds the time dimension.

It is not uncommon that one tract of land will have production allocated to it from two or three participating areas representing different producing formations. Each participating area will have its own boundaries and ownership, and each will have had its own history of expansion. When the unit contracts to the participating areas, only the designated participating area formations retain unitized ownership. If a new well is completed in a participating area formation, it will have the same ownership as the participating area (unless it is near the border of the participating area – more later). Any other depth retains its lease-level ownership. If a lease does not have a vertical Pugh clause, or a state statute does not impute one, then the lease is held by unit so long as a participating area produces. Any wells within the contracted unit that are completed in a non-participating area formation will be treated as lease wells subject to the terms of the UA and Unit Operating Agreements (UOA). Keep in mind that a unit contraction is subject to third-dimensional thinking – that is, it may be depth-restricted differently in each tract, depending on the terms of the leases involved or the statutes of the state.

Working interest owner agreements

This presents another aspect of units that is also subject to fourth-dimensional thinking. Unit and UOAs are perpetuated beyond their primary term as their associated leases are, by production. If there are JOAs in effect when the UOA is initiated, then the terms of those JOAs are carried forward unless they are specifically modified by the UOA. Likewise, if there are JOAs created subsequent to the UOA covering lands or formations that may partially fall under the UOA, the terms of the UOA will govern the unit lands unless they are specifically modified by the JOA. This can have a substantial impact on the DOA in calculating working interest ownership and in setting up burden links and distributing burdens. The hierarchy of priority for overlapping agreements begins in the fourth dimension with the oldest agreement. Again, its terms retain priority until specifically overridden by a subsequent operating agreement.

This is a more important issue than might be expected. There are many examples of inaccurate title opinions being based on incom-

plete information because of a missing underlying operating agreement. This problem is exacerbated by the fact the operating agreements are not generally recorded, so if the party requesting the opinion does not supply a complete inventory of unrecorded agreements, working interest ownership may not be accurately calculated.

By way of an actual example, consider a 40-acre fee tract in a 2,500-acre contracted participating area. A well was drilled in Section 3 containing the tract prior to the formation of the unit. Spaced 640 acres, the well was governed by a JOA that specified a 75/25 split throughout the section between two companies, essentially pooling the working interests. Two leases made up the section, one covering three-fourths of it and the other covering the SE/4. As the participating area developed, the NW/4 NW/4 was added to the PA. Since there was nothing in the UOA to overturn the ownership designated in the JOA, the 40 acres was split 75/25 between the two companies.

In preparing the title opinion, however, the operator of the unit failed to supply a copy of the JOA to the attorney. The attorney allocated the entire 40-acre tract to the owner of the ¾ lease, instead of splitting it between the two companies. The ownership was calculated incorrectly, and the operator even acted on the erroneous title for several years before a DOA raised the question and notified the operator, who corrected the ownership.

Obviously the key to knowing whether an agreement applies to a well or unit is to ***read the document***. This is so fundamental to good title analysis that it almost goes without saying. Almost, but not quite. We work in an age of instant results, and many analysts feel pressure to skip such basic steps in order to meet personal or departmental goals. Ultimately, however, each analyst is responsible for the accuracy of the ownership setup. Do what it takes to keep goals realistic, but *take the time* to know each piece of the puzzle.

Aside from working interest ownership, another facet of operating agreements that affects setup is that of royalty distribution. In the Rockies, any time a large unit is established, there is a very good chance that federal leases are involved. Royalty reporting rules are very strict with the ONRR/MMS, and this leads to a general reluctance on the part of producers to report any federal royalties but their own. As a result, operating agreements are often composed in such a way as to ensure that each producer is responsible for its own royalty distribution in cases where the producer is taking its product in-kind. At the same time, no producer is willing to have its net revenue interest compromised. It is a simple concept, but the devil can be in the details.

One such situation can be illustrated by the immediately preceding example of a JOA pooling the working interests in Section 3 in which there is a 75/25 split between the leases. For this instance, the assumption will be made that the SE/4 is covered by a BLM lease. Each of the two working interest owners is taking its gas in-kind. Company A takes its 75% of the gas, but then question is raised as to which royalty owners to pay. In a normal situation (normal being defined as anywhere outside the states of Oklahoma and Arkansas), the producer would pay all royalties since the section is pooled 75/25, and the producer has virtual ownership in both leases. In this case, however, the producers had decided that they wanted each to be responsible only for its own royalties and had composed the JOA in such a way as to accomplish that. These terms are fairly common in southern Wyoming.

Terms were included in the JOA that allocated 15% of any product taken in-kind as

the royalty share. Net Revenue for marketing purposes was 85%. So each party was allocated 85% of its working interest, plus 15% of the same acreage as the spacing unit, Company A was allocated 85% x 75% plus 15% x 75%, for a total of 75%.

Simple and normal. Company A's lease had a 12.5% royalty, so it paid 12.5% x 75% to its royalty owner(s) and retained the extra 2.5% of the royalty share as the balance of its net revenue interest, a total of 87.5% x 75%. Company B's federal lease had 15% in total burdens, so it was responsible to pay the ONRR/MMS for its own lease at 12.5% x 25%, plus 2.5% x 25% in overrides. Company B's net revenue interest was then apportioned its proper 85% x 25%.

For a more complicated example, let us presume that the JOA or Working Interest Pooling Agreement (the governing agreement) covered two sections instead of one. Spacing for any well is still 640 acres, and the terms of the agreement are the same as above. One of the sections is Section 7, with a 75/25 split between two working interest owners as above, with each working interest owner holding a separate lease. Section 6 is covered by one federal lease that is owned 100% by Company C. So the working interests for a well anywhere in the two sections are as follows:

Company A	37.5%
Company B	12.5%
Company C	50.0%
	100%

Again, the terms of the governing Agreement are identical to the one above, with a 15% royalty share allocated to the working interest owner(s) contributing the tract.
If the well is located in Section 7, and the spacing unit covers all of Section 7, the allocation of revenues would be calculated as follows:

Company A - 37.5% x 85% (0.328125)
+ 75% x 15% (0.1125) =
0.43125000

Company B - 12.5% x 85% (0.10625)
+ 25% x 15% (0.0375) =
0.14375000

Company C - 50.0% x 85% =
0.42500000
1.00000000

The royalty share (15%) is split between the two contributors of leases to the spacing unit. Companies A & B supplied the leases in Section 7, and so they are allocated the entire royalty share in the 75/25 ratio in which the leases cover Section 7. Company C has not contributed any leases to the spacing unit (Section 7), and so it is not allocated any of the royalty share. By virtue of the governing Agreement, however, Company C is entitled to a 50% working interest in the well, and so it is allocated the working interest share (85%) of its 50% WI.

Since the spacing unit is Section 7, there is no allocation of production to Section 6. The royalties and overrides that burden the Section 6 lease do not receive any revenues from the Section 7 well, since they are not within the spacing unit. Company C is only involved in the Section 7 well because of the governing agreement that pools only working interests.

There is a disparity above that causes many analysts or their managers concern. Look again at the two sets of numbers for this well. The working interest s are:

Company A	37.5%
Company B	12.5%
Company C	50.0%

The revenue allocations are:

Company A	0.43125000

Company B 0.14375000
Company C 0.42500000

What causes many companies and/or systems headaches is that the working interests, or the billings, do not match the revenue allocations, or the marketing share. Many analysts (or managers or systems) are programmed that these must match. This situation is very similar to those under Oklahoma Senate Bill 168 and its counterpart in Arkansas. The marketable share is not the same as the joint interest billing of each working interest owner. Note that while Company A is billed 37.5% of the costs of the well, it is allocated 43.125% of the production from the well. On the other hand, Company C pays 50% of the costs of the well, but is only allocated 42.5% of the production. That hardly seems fair.

This is both correct and deliberate on the part of those who negotiated the agreement. Remember that in the Rockies, where federal lands predominate, there is frequently some sort of agreed arrangement to have each company pay and report its own ONRR/MMS royalties. The arrangement may not be exactly as outlined here, but it is something that the Rockies analyst must look for, or perhaps even insist upon, when analyzing a property. One of the fundamentals of the profession is to ***read the documents***, and this is one more reason to do so.

The DOI for each company would be set up as follows:

Company A:
ONRR: 75% x 12.5% = .09375000
Co A: 37.5% x 85% +75% x 2.5%= .33750000
.43125000

Company B:
ONRR: 25% x 12.5% = .03125000
Co B: 12.5% x 85% + 25% x 2.5% =.11250000
.14375000

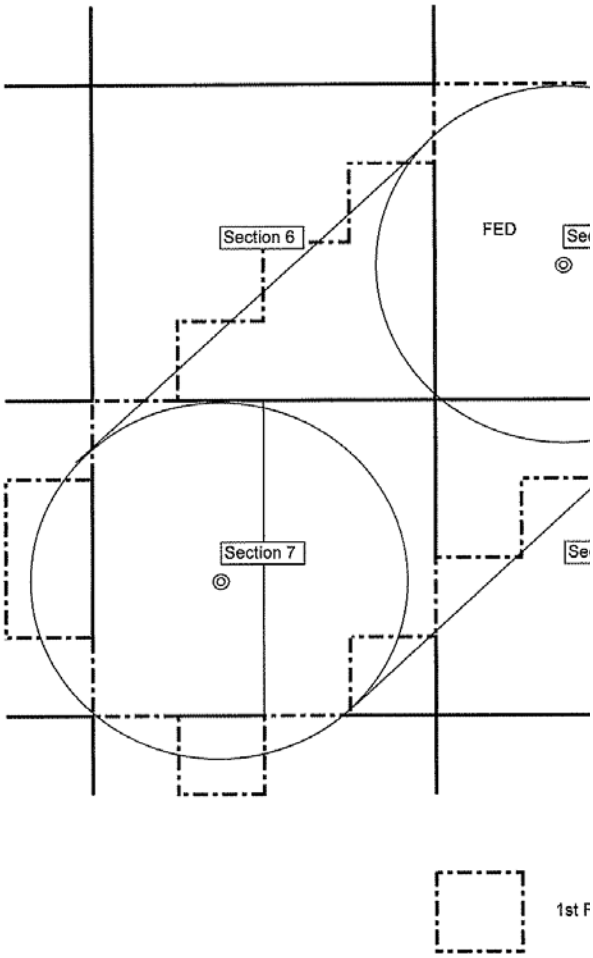
Company C:
Co C: - 50.0% x 85% = 0.42500000

0.42500000
1.00000000

In the cases of Companies A and B, the balance of the royalty share after payment of royalties reverts to the working interest owner as net revenue. If there were overrides to pay, they would be paid out of that balance, or if greater, out of the working interest owner's net revenue interest. It is up to the negotiators of the agreement to preserve the net revenue interest of their respective companies, and this is done by accurately calculating what the royalty share should be and reaching an appropriate deal. Companies A and B did have a higher net revenue interest than they would normally be due, but the opposite would be true for a well in Section 6. On the whole, for the entirety of the agreement, each company's net revenue interest is preserved fairly well.

Imagine combining all of these elements that have been discussed—lease wells, formation and expansion of the initial and subsequent participating areas, fourth-dimensional thinking with regard to ownership and to agreement terms, individual wells drilled outside participating areas or a contracted unit, communitization agreements that overlap unit agreements, unusual revenue distribution terms—into one unit with its associated wells, and the complexity of the Rockies will begin to be appreciated. Even a division of interest with relatively few owners can become a challenge of great magnitude.

Appendix



CHAPTER 18: HOW A FEDERAL UNIT IS FORMED

Richard Champion

This paper was first published in Federal Onshore Oil & Gas Pooling &Unitization Special Institute (Rocky Mountain Mineral Law Foundation. 2006), and is reprinted by permission.

Forming the unit

Why should we go to the time and expense to form a federal unit and to deal with all the additional rules and regulations and thereby create another level of federal paperwork!

To unitize or not is a question that should be asked and definitively answered prior to drilling any exploratory well. The answer will largely be determined by the type of lease (either fee, state, or federal) and the rules and regulations of the state in which the well is to be drilled. This paper does not cover the effect of unitization in each state but deals only with federal exploratory units involving areas where an operator holds predominantly federal leases.

State regulatory powers

Oil and gas operations in the Rocky Mountain states are primarily governed by each state's oil and gas conservation act, and the rules and regulations promulgated by the designated regulatory agency. Each conservation act empowers the designated regulatory agency to regulate the spacing of wells. Other purposes of the agency's mission are (1) to protect the correlative rights of the owners in a common source of supply of oil and gas – to the end that each may obtain a fair share of production, (2) to encourage the efficient development of natural resources, (3) to protect public and private interests against both physical and economic waste, (4) to provide for the development of an oil and gas pool in such a manner as to maximize ultimate recovery, and (5) to encourage voluntary agreements for assisted recovery operations for the benefit of the public as well as for the owners of the oil and gas rights. Spacing, pooling and unitization are also measures addressed in the laws and regulations of the states and are intended to assist in accomplishing these purposes.

As a part of its rules and regulations, the regulatory agency of each state has adopted a rule regulating the location of wells. The rule usually will prohibit the drilling of a well closer than a stated distance to a lease line, a property line, or a surveyed governmental subdivision line. In addition, the rule will establish a minimum distance between wells drilled to a common source of supply.

Pooling or communitization

After an operator determines the legal location of the proposed exploration well, he or she may find that there are undivided or divided lessor or lessee interests within the spacing pattern. If this is the case, it will then be necessary to pool those interests to provide for the sharing of production and possibly the costs for the permitted well.

Pooling may be accomplished either voluntarily by agreement of the parties or involuntarily by order of the state regulatory agency after application, notice and hearing. The majority of fee leases contain a pooling provision, and ordinarily, pooling may be accomplished by the lessee filing a declaration of pooling pursuant to that provision in the oil and gas lease. This declaration must be filed in the appropriate county records. If one or more of the leases involved does not permit pooling by declaration, a pooling agreement may be entered into between the parties concerned.

Although most fee lease forms in use in the Rocky Mountains contain a pooling clause, particular attention should be paid to the form to be used in areas where fee lands are interspersed with federal lands. It is important that this form contain a unitization provision.

Some of the forms in general circulation in the Rocky Mountains use a clause similar to that upheld in the lessee's favor in *Phillips Petroleum Co. v. Peterson*,[1] a Utah case. In that case, the U.S. Court of Appeals held that the

[1] Phillips Petroleum Co. v. Peterson, 218 F.2d 926 (10th Cir. 1954).

unitization clause in question did not affect cross-transfers of royalty interests and even had it done so, did not violate the Rule Against Perpetuities. The Court also upheld the validity of the principal-agent relationship that established Phillips had the right and power to commit the lessor's interest to a unit approved by the United States Geological Survey and the State of Utah.

Many times the landowner will insist that the unitization clause be stricken, but if possible, it is strongly recommended that a version of the clause similar to the court-tested version be used. The clause at issue in *Phillips Petroleum* reads as follows:

> Lessee shall have the right to unitize all or any part of the above described lands with other lands in the same general area by entering into a Unit Agreement setting forth a plan of development or operation approved by the Secretary of the Interior, or other officer or representative of the United States having authority to approve such Unit Agreements, and, from time to time, with like approval, to modify, change or terminate any such agreement. In any of such events, the terms, conditions and provisions of this lease shall be deemed modified to conform to the terms, conditions and provisions of such approved Unit Agreement, and all drilling and development requirements of this lease, express or implied, shall be satisfied by compliance with the drilling and development requirements of such agreement, and this lease shall not terminate or expire during the life of such agreement except as may be otherwise provided in said agreement. In the event that said above described lands, or any part thereof, shall hereafter be operated under any such Unit Agreement whereby the production thereunder is allocated to different portions of the land covered by said agreement, then the production allocated to any particular tract of land pursuant to such agreement shall, for the purpose of computing royalties, be regarded as having been produced from the particular tract of land to which it is allocated and not from any other tract of land and any royalty payments on such production to be made hereunder shall be based solely upon the production so allocated. Nothing herein contained shall authorize or affect any transfer of any title to any leasehold, royalty or other interest unitized pursuant hereto. Lessee's execution of such Unit Agreement shall be binding as to both lessor and lessee and their respective interests. Lessee, following such execution, shall furnish lessor with a copy of such Unit Agreement by mail to lessor's last known address as shown by lessee's records and shall give lessor written notice of approval of the same in the same manner within a reasonable time after lessee is notified of such approval.

If federal leases are involved, pooling must be accomplished by means of a communitization agreement. Communitization agreements are authorized by federal regulation:

> When a lease or a portion thereof cannot be independently developed and operated in conformity with an established well-spacing or well-development program, the authorized officer may approve communitization or drilling agreements for such lands with other lands, whether or not owned by the United States, upon a determination that it is in the public interest. Operations or production under such an agreement shall be deemed to be operations or production as to each lease committed thereto.[2]

While pooling or communitizing leasehold of up to 640 acres is a common practice, the explorationist should seriously consider the greater benefits of federal unitization when the pooled area covers an entire oil and gas field involving at least 10% or more federal leasehold.

Federal unitization

The BLM Handbook explains the rationale for federal unitization as:

> The objective of unitization is to proceed with a program that will adequately and timely explore and develop all committed lands within the unit area without regard to internal ownership boundaries. Exploratory units normally embrace a prospective area that has been delineated on the basis of geological and/or geophysical inference. Exploratory unit agreements normally encompass all oil and gas interests in all formations within the unit area and provide for the allocation of unitized production to the committed lands reasonably proven to be productive of unitized substances in paying quantities on the basis of the surface acreage included within the controlling participating area. By effectively eliminating internal property boundaries within the unit area, unitization permits the most efficient and cost-effective means of developing the underlying oil and gas resources.
>
> The BLM will approve the commitment of federal lands to a unit agreement in the interest of conserving the natural resources, when it is determined to be necessary or advisable in the public interest. When such a determination is made and federal lands are committed to the unit, the authorized officer has a responsibility to ensure that unit development proceeds in a way that continues to serve the public interest, regardless of whether the federal lands comprise only a small fraction or a major part of the unit area.[3]

Unitization in its simplest form means pooling the lessee's and lessor's interests within a given area and sharing the risks and the possible benefits of exploration and development.

There are two types of federal units: exploratory units and secondary recovery

[2] 43 C.F.R. Part 3105.2-2.

[3] Draft *BLM Manual*, Section 3180-1-Unitization (Exploratory), p. 2-60.

units. An exploratory unit is one that is formed prior to drilling the first well in the unit. A secondary recovery unit or enhanced recovery unit is usually formed after the field or unit area is fully developed in order to maximize ultimate recovery from the field by some method of assisted recovery.

The federal government has been the pioneer in fostering unitization. In 1930 Congress passed a temporary act authorizing unitization of federal lands. In the early part of 1931, a permanent act was passed. The act has been amended several times, as have the regulations. The present authority for federal unitization is found in the Mineral Leasing Act, and 43 CFR Part 3180 addresses unit agreements.

Early in the history of the Act, there was strong opposition to the idea of unitization. However, today unitization is almost universally recognized as the keystone to conservation of our natural resources.

The federal form of Unit Agreement must be used to form a federal exploratory unit.[4] The outline of the proposed unit is described in the Definitions Section of 43 C.F.R. Subpart 3180 – Onshore Oil and Gas Unit Agreements as:

> *Unit Area.* The area described in an agreement as constituting the land logically subject to exploration and/or development under such agreement.[5]

The size of the unit area is determined by the geologic feature but is generally limited to 25,000 acres for a one well commitment. If the prospect is larger than 25,000 acres, additional well commitment(s) may be required for each additional 10,000 to 15,000 acres.

The procedure for initiating the formation of a federal exploratory unit and eventual final approval by the Bureau of Land Management will not be discussed here since many excellent papers have previously been written on the subject.[6]

Why unitize

The purpose of unitization is to conserve natural resources, prevent waste, and secure other benefits obtainable only through exploration, development and operations under a unified plan. Ideally, this is the objective of every conscientious explorationist. The explorationist may expect other benefits from operations under a federal exploratory unit.

Easier to obtain support. If a unit is proposed, the unit proponent may be able to solicit farmouts, acreage contributions and dry hole money from other working interest owners within the unit area. This support will come for a variety of reasons: leaseholders

[4] 43 C.F.R. Part 3186.1.

[5] 43 C.F.R. Part 3180.0-5.

[6] *See* D.O. Churchill, "Federal Unitization," *Proceedings of the Twenty-First Annual Rocky Mountain Mineral Law Institute* (Rocky Mt. Min. L. Fdn); Gilbert L. Kutchins, "Federal Unit," presented before the Public Lands Committee Interstate Oil Compact Commission Annual Meeting (1975); Laura Lindley, "The Life Cycle of a Federal Unit," *Onshore Pooling & Unitization* (Rocky Mt. Min. L. Fdn. 1997); Neal Brecheisen, "Forming the Unit: The Area and Depth (Designation) Meeting," *Onshore Pooling & Unitization* (Rocky Mt. Min. L. Fdn. 1997); William J. Norton II, "Forming the Unit: Final Approval of Exploratory Unit Agreements," *Onshore Pooling & Unitization*, (Rocky Mt. Min. L. Fdn. 1997); Draft BLM Manual Section 3180-Unitization (Exploratory), *available at* http://www.co.blm.gov/oilandgas/unit_man.htm.

who are anxious to delay lease expirations, working interest owners who wish to avoid including their leasehold in the determination of federal chargeability, or others who are unwilling to bear the cost of exploration alone. After the BLM approves the unit, the unit area becomes, in many ways, one large lease.

Limiting offset obligations. If the unit proponent were to drill a discovery exploratory well without the benefit of unitization, he or she would likely be exposed to offset well obligations, either his or her own or those of other working interest owners. In a federal unit, the offset obligation is limited after discovery of oil or gas in paying quantities (defined below). Additional wells must be drilled in accordance with a Plan of Development approved by the BLM, except those which may be necessary to afford protection against operations not subject to the Unit Agreement. The implied covenant to develop leased property is superseded by specific provisions of the Unit Agreement concerning development.

The model form Unit Agreement provides:

> PLAN OF FURTHER DEVELOPMENT AND OPERATION. Within 6 months after completion of a well capable of producing unitized substances in paying quantities, Operator shall submit for the approval of the AO an acceptable plan of development and operation for the unitized land which, when approved by the AO, shall constitute the further drilling and development obligation of the Unit Operator under this agreement for the period specified therein.[7]

Before the expiration of any existing plan, an additional plan for a specified period must be submitted.

Any plan submitted must provide for exploration of the unitized area and for diligent drilling necessary to determine the area or areas capable of producing in paying quantities in each and every productive formation. Each plan must specify the number and location of any wells to be drilled, the order and time for this drilling, and to the extent practicable, the operating practices regarded as necessary and advisable for proper conservation of the oil and gas resources. Any plan may be modified or supplemented whenever necessary to meet changed conditions or to protect the interest of all parties to the Unit Agreement.

Extension of leases. Generally, all fee and state leases which cover interests that are committed to the unit are extended for the life of the unit. Most federal leases are not extended unless production is obtained in paying quantities in the unit prior to the expiration of the term of the lease. However, if a unit well, no matter where located within the unit area, is drilling over the initial expiration date of the federal lease, the lease or leases will be extended for a period of two years and as long after as oil or gas is produced. Drilling and producing operations under the unit are deemed to be performed upon and for the benefit of each and every tract of unitized lands.

The regulations governing lease extensions are specific and must be carefully followed. A federal lease may receive only one extension by drilling. A lease extension resulting from segregation from a unit or a lease extension resulting from a unit termination are considered extensions by drilling. A careful reading

[7] 43 C.F.R. Part 3186.1.

of *BLM handbook H-3107-1 Continuation, Extension, or Renewal of Leases* is a must.

Sharing production and costs. If there is more than one working interest owner, the owners enter into a Unit Operating Agreement. The Unit Operating Agreement must provide the basis for sharing of costs and production from the unit wells. It is not necessary that the basis of sharing by the working interest owners be the same as the basis provided for in the Unit Agreement. However, the Unit Operating Agreement may not alter or modify the terms and provisions of the Unit Agreement. In the event of any conflict between the Unit Agreement and the Unit Operating Agreement, the Unit Agreement must control. The Unit Agreement also determines the rights of the royalty owners. The permissible allocated are described below:

> *In short, royalties on committed tracts are paid based on the percentage of production allocated to that tract. The working interest share, however, may be divided in any manner the parties agree, as set forth in the unit operating agreement.*[8]

The Unit Operating Agreement also sets forth the unit operator's powers, rights, duties, obligations and limitations, and the basis for voting control in the conduct of operations. In addition, the usual provisions found in most operating agreements (such as the AAPL Form 610) are covered.

Upon the completion of the discovery well as a well capable of producing oil or gas in paying quantities, the sharing of costs and benefits is dependent upon the participating areas which may be established from time to time. Paying quantities is defined in the unit agreement as, quantities sufficient to repay the cost of drilling, completing, and producing operations, with a reasonable profit.[9] The only land that can be included in a participating area or areas is that land reasonably proved to be productive of producing oil or gas in paying quantities. The amount of acreage included in the participating area depends upon the geological and reservoir data from the well(s). The initial participating area can cover as few as 40 acres or it can be as large an area as the operator can demonstrate to the BLM is reasonably proved to be productive. The effective date of the initial participating area is usually the date the well was completed.

All production from a given participating area is deemed to be produced equally from all portions of that participating area. In other words, the total production from the participating area is divided by the interests of the parties affected by the participating area and a percentage is allocated to each lease or a portion thereof within that participating area. This is true regardless of where the well is located within the participating area. The production so allocated is used as the basis for settlement with royalty owners just as though there were no unit.

When additional paying wells are completed in the formation for which the participating area has been established, the participating area is revised and enlarged. The amount of acreage added to the participating area depends upon the geological data and engineering information derived from the well or wells which cause the revision.

Relief from acreage limitation. Any company, association or person actively exploring for oil and gas in any of the Rocky Mountain states on federal lands should be patently aware of the limit on the number of acres any party may hold under federal leases

[8] *See* Lindley, *supra* note 6 at 14-26.

[9] 43 C.F.R. Part 3186.1.

at one time in any given state. Present federal law provides that:

> *No person or entity shall take, hold, own or control more than 246,080 acres of federal oil and gas leases in any one State at any one time. No more than 200,000 acres of such acres may be held under option.*[10]

The State of Alaska is an exception and the limitation is separately defined.

While there are several other means to exclude acreage from the chargeability calculation, it should be noted that federal leasehold committed to a unit agreement is not included in the limitation determining whether or not a leaseholder has exceeded the statu-tory limit. As long as a federal leasehold is committed to a unit, it will not be counted in the limitation. When it is eliminated from the unit by contraction of the unit area or termination of the unit agreement, the federal leasehold may become subject to the limitation. The Energy Policy Act of 2005, Sec 352. Oil and Gas Lease Acreage Limitations, amended Section 27(d)(1) of the Mineral Leasing Act (30 U.S.C. § 184(d)(1)) as follows:

> *. . . by inserting after "acreage held in special tar sand areas" the following: "and acreage under any lease any portion of which has been committed to a federally approved unit or cooperative plan or communitization agreement for which royalty (including compensatory royalty or royalty in-kind) was paid in the preceding calendar year.*

This wording appears to indicate that leases eliminated from a producing unit, through contraction may not become immediately chargeable.

Extension of leases by termination of unit. In the event the initial exploratory well drilled in the unit area is a dry hole, the unit agreement provides that the unit operator must continue drilling one well at a time, allowing not more than six months between completion of one well and the beginning of the next well, until a well capable of producing oil or gas in paying quantities is completed. The unit agreement will automatically terminate if the unit operator fails to commence any such well within the time allowed, including any approved extension of time.

If the first well has been completed as a dry hole, the unit may be terminated by not less than 75% (on a surface acreage basis) of the committed working interest owners with the approval of the BLM.

If there are any federal leases within the unit area with expiration dates prior to the next well commencement date, the unit operator can voluntarily, with approval of at least 75% of the working interest owners, request voluntary termination of the unit agreement, effective as of a date just prior to the date of the expiring lease or leases. If the request for termination is approved, all federal leases in effect at the effective date of the termination will continue in effect for the original term of the lease, or for two years after the termination, whichever is the longer, and so long thereafter as oil or gas is produced in paying quantities.[11]

In areas of multiple, complicated ownership, such as the Powder River Basin in Wyoming, the formation of units, the drilling of dry holes and the subsequent termination of units

[10] 43 C.F.R. Part 3101.2-1.

[11] 43 C.F.R. Part 3107.4.

have perpetuated federal leases up to eight years beyond their initial expiration date, with no production associated to those individual leases. If appropriately used, voluntary unit termination is a powerful option for the explorationist (who continues to drill dry holes) for lease retention.

Minimize surface disturbance. Development of a non-unitized field with multiple leasehold owners generally results in each separate lease being drilled without regard to optimum operating practices. Separate storage facilities might be constructed for each lease. Separate gathering lines, roads, rights of way and trucking activity might be required, resulting in inefficiencies and increased costs.

Unitization eliminates such duplication of these facilities. Storage tanks can be centralized. The use of roads, rights of way, gathering line requirements and pipeline needs can be minimized. This will reduce the surface disturbance on the land, especially desirable in areas of sensitive environmental concerns.

Increase ultimate recovery. One of the results of operations without the benefit of unitization is the inherent desire of each landowner and leaseholder to produce and retain all the oil and gas produced from his or her land, whether the production was originally under that land or adjoining land. Competing efforts by each operator to produce rapidly and to drain adjoining lands tend to reduce, rather than increase, the maximum ultimate recovery from a field.

Unitization consolidates separately owned interests for the purpose of developing and operating the interests as a unit, as demanded by the nature of the reservoir. The allocation among the interest owners is on an equitable basis and correlative rights are protected. More orderly development and operations are allowed. In a federal unit, lease lines lose their identity. The operator is not subject to the well spacing patterns from the state regulatory agency. Proper spacing based on geologic and reservoir data prevents waste and increases ultimate recovery. Producing at the maximum efficient rate saves reservoir pressure and minimizes waste of reservoir energy. Wasteful competitive practices are eliminated.

Secondary recovery. The standard form of the unit operating agreement has a provision pertaining to secondary recovery and pressure maintenance. The unit operator is not permitted to undertake any program of secondary recovery or pressure maintenance without first obtaining the consent of the parties. Customarily, the consent required varies from 80 percent to 90 percent of the committed working interests on an acreage basis in the participating area affected by such program.

Secondary recovery without unitization would be nearly impossible because of the necessity to move oil or gas across lease lines for greater use of reservoir pressures and ultimate recovery. The time needed to negotiate a participation formula for allocation of costs and production under secondary recovery operations should be considerably shortened because of this provision in the exploratory unit operating agreement. Pressure maintenance and fluid or gas injection programs may be commenced prior to primary depletion, resulting in greater ultimate recovery.

The parameters most commonly used in determining secondary recovery participation are acre feet, cumulative production, current production, original oil in place, and remaining primary production. The ideal objective in secondary recovery is to establish that each owner's share of production from the unit is in exact proportion to the contribution which he or she makes to the unit. Since negotiation to obtain the ideal objective may take a time, it is indeed fortunate that the exploratory unit is maintaining orderly development pending these negotiations.

Conclusion: to unitize or not

The explorationist has a difficult task. He or she must preserve his or her leasehold asset base from imminent expiration to the extent possible and must do so in a cost effective manner. Dealing with federal lease rules and regulations can be exhausting; however the benefits often outweigh the hurdles. Some of the benefits to be derived from such units are:

- Conservation of Natural Resources.
- Orderly development. Drilling only the wells necessary, and at the best locations to efficiently drain the reservoir.
- Spreading the risks and costs among several owners.
- Minimizing damage to the environment.
- Maximizing administrative efficiency through delegation to one operator.
- Relief from federal acreage limitation.
- Extensions of leases by timely drilling or discovery of a well in paying quantities.
- Ease of institution of secondary recovery operations or pressure maintenance when needed.
- Increasing ultimate recovery.
- Providing a better rate of return on an investment.

As John Paul Getty said, "Get up early. Work hard. Find oil." The explorationist can't find oil without the leasehold assets. Experience teaches that when federal lands are involved on a geological prospect, the formation of an exploratory unit prior to drilling often provides the greatest reward and protection for the leasehold assets. So, is it worth the additional rules and regulations and another level of federal paperwork? The opportunities provided by the investment of unitization should pay out many times.

CHAPTER 19: MICHIGAN OIL AND GAS TITLE

Jeffrey A. Smetzer, CPL

Spacing Orders

The State of Michigan has established 40-acre spacing (quarter-quarter) for all wells in Michigan.[1] However, the state allows numerous exceptions to this general spacing rule. These exceptions are explained in detail on the state's Department of Environmental Quality website.[2] The website lists "Antrim Spacing, Niagaran Spacing, Trenton-Black River Formation Spacing and Glenwood and below Spacing" that can be printed. There are more spacing orders than these; the Michigan Department of Environmental Quality (MDEQ) can provide them with the township and formations. **Note:** The division order analyst should get *all* of the orders covering the targeted geographical area (all formations) to be prepared in case the company wants to plug back a deeper try.

The state has numerous spacing orders for various formations (and depths). The size of the spaced units has changed over time. For instance, the Antrim Shale was originally spaced at one well per 40 acres. However, five sections of land in T30N, R3W were spaced at one well per 160 acres in 1983. In 1994 the state issued a new spacing order for Antrim Shale wells at one well per 80 acres. At that time, the state also set up a Uniform Spacing Pattern (USP) for Antrim Shale wells. This allowed for pooling several hundred acres into a single production unit. It also permitted drilling up to a density of one well per 80 acres anywhere within the USP. The wells cannot be closer than 1,320' or closer than 330' to the boundary of the USP. This was done to allow for more flexibility in locating wells on the surface in order to avoid wetlands, ravines and other surface features without a hearing (to request an exception).

[1] Natural Resources and Environmental Production Act, Administrative Rules, Part 615, P.A. 451 1994, as amended

[2] www.michigan.gov/deq Use "spacing orders" for search term.

State leases

The lessee needs a performance bond according to the number of acres under lease. The minimum amount is $2,000.00, but that amount is subject to change, so the division order analyst needs to verify the amount in each case.

Typically companies will put up a $2,000.00 (or more) Certificate of Deposit in the name of the State of Michigan. This allows the company the option of being paid the interest. After the division order analyst notifies the state that the interest should be paid to the company, the bank holding the CD pays the state, which in turn pays the lessee (the company) annually.

Michigan requires a form assignment for state leases. (This form is current as of August 1, 2008.) A fee is also charged for approval of state assignments; the Department of Environmental Quality can provide the appropriate fee schedule. **Note:** Michigan changes their assignment forms frequently, so it is best to contact them when making an assignment to be sure the form is current.

A full assignment in Michigan means the assignee has the obligation for performance under the lease. In that case, the assignee needs a lease bond for approval of the assignment.

Pooling and Unitization

State Leases. The current state lease form, available online, allows the operator to pool the lease into a spaced unit, but not larger. The operator will have to ratify or sign the pooling agreement if the lease is involved in a production unit that is larger than a spaced unit.

Note: The state has changed the lease form over time, so the division order analyst must carefully review the most current state lease form to clarify the company's rights and/or obligations. It is best to contact the state to ask them about any unclear lease provision Michigan is very particular about how certain clauses in the state lease are interpreted; they also require certain language in any pooling or unitization agreement that they will be a party to.

Private leases. Leases are pooled, not lands. The leases describe the lands that are pooled, and the pooling or unitization agreement describes the area being pooled.

Unitization agreement maps identify areas of land that parties with interests in them are bound, by agreement, to share investment costs and revenues generated from the production of oil and natural gas within the defined boundary. A unit may be created by convention or by order of the State's Supervisor of Wells. A unit formed by order of the State's Supervisor of Wells is called a 'compulsory pooled unit.'

For example, this map identifies the Antrim unitization units in Alpena County, Michigan. It shows the well locations and the boundaries of the unitized areas. Antrim units are so named to reflect production from the Antrim Shale geologic formation.

Shut in wells.

Older private leases in Michigan almost never have a shut in provision for oil wells. The lessee can shut in a gas well and make shut-in payments to extend the lease, but this is not true for oil wells. The division order analyst should check the lease form prior to shutting in a well to see if it is classified by the state as an oil well, a gas well, or a gas well that produces oil. This information must be confirmed by both the Michigan Public Service Commission (MPSC) and the Michigan Department of Environmental Quality. If the well is officially classified as an oil well under most of the old lease forms, it cannot be shut in. The lease usually allows between 60 and 120 days to rework or redrill the well and then put it back into production. While it may be possible to use a *force majeure* situation, such as Frost laws, that is only a short term possibility. The division order analyst should contact his or her legal department about possible options to avoid losing the lease and, consequently, the well.

Compulsory pooling

An unleased interest within a spaced unit (or within a unitized area in an Antrim Shale unit or USP) is subject to compulsory pooling upon a request to the MDEQ. However, a well cannot be drilled on an unleased interest, even if the request for compulsory pooling has been successful. The state has specific notice provisions for a hearing; a Michigan title attorney should review those provisions. Generally the division order analyst documents any attempts to buy a lease from the holdout party. **Note:** Since landowners often attend these hearings and may complain about alleged abusive treatment by the landman attempting to acquire the lease, diplomacy is crucial.

The division order analyst must file an affidavit regarding contacts with the holdout party when requesting a hearing. A specific notification process requires filing an affidavit enumerating the parties notified for the hearing. It will typically take six to 12 months after the initial request for the state to issue the final order.

As part of the final order, a 30-day time period runs for the party being compulsory pooled to respond to an election. The election choices are to either join the unit voluntarily by signing a lease or do nothing and be considered pooled. If the landowner does not want to join the unit, the state

awards him or her one-eighth royalty (to be paid immediately with the other royalty owners). The operator will receive a contribution from the party for costs of drilling, completion, and operational costs until the operator recovers his or her proportionate share of the costs, plus a penalty for the risk of a dry hole. **Note:** A penalty is not awarded in every case.

Many operators have had to go through the compulsory pooling process at one time or another in order to complete the leasing in their spaced unit prior to drilling. The state will not issue a drilling permit until all of the interests are leased or compulsory pooled.

Division orders and revenue

Division Orders. The State of Michigan will *not* sign division orders. You can mail a division order to the state so they can glean the information for set-up, but they will not sign them. They will send you a letter confirming that they agree with the calculation. It is sufficient to send them a letter with the well name, unit description, owner number, calculation and interest, and so forth. They will respond in writing with their agreement and with the request to pay them according to the terms of the lease.

Michigan Dormant Mineral Act

The State of Michigan passed the Dormant Mineral Act in 1963. This was done because parties that reserved oil, gas, and mineral rights over the years were impossible to locate along with their heirs. This naturally prevented the producers from drilling wells since they could not lease the entire interest within a production unit. The act is actually a dormant oil and gas act and did not originally cover hard minerals such as coal, sand, and gravel.

It included a provision that if there were no activity on a severed mineral tract in a 20- year period, the oil and gas went dormant (suspended or inactive) and reverted to the surface owner. The owner of a severed mineral tract can perform several activities that toll the 20-year period, such as leasing the property, competing a sale, mortgage or transfer of interest of record, or reserving or claiming the interest. Off-the-record activity, such as filing for a drilling permit, withdrawing oil and gas, or storing gas underground would accomplish the same purpose.

The mineral owner can also simply file an affidavit entitled *Claim of Interest* and describe the land on which he or she wishes to toll the oil and gas interest. This act was amended in 2006 and 2007 to include a new provision regarding severed oil and gas interests. The amendments allow for the severed oil and gas interest owner to toll his or her severed interest every 20 years, preventing a tax foreclosure. Filing a claim of interest is required even if a lease or tract is active and is held by production and the severed mineral owner is receiving royalty payments.

Tax foreclosures on severed minerals

Several years ago, the state of Michigan took the position that if a surface owner failed to pay the real estate taxes and the state foreclosed, the state would take the oil, gas and mineral rights and extinguish the existing oil and gas lease (even if it was paying royalty). The state would then demand that the lessee/operator buy a lease from them (for a higher royalty rate) and pay them.

This policy was based on the theory that the severed mineral owner should have kept track of the delinquent tax payments and foreclosure proceedings by a surface owner, even though many severed mineral owners lived several states away from Michigan, and the surface may have been subdivided into hundreds of lots. The state claimed that the newspaper notice was sufficient notice for a severed mineral owner to pay the surface

owner's taxes to preserve their interest. Later, the state changed the way tax foreclosures were done and the Antrim County Treasurer, Sherrie Comben, sued the state over this in the now-famous *Comben v. State* lawsuit. The Circuit ruled that the State of Michigan had stolen the oil, gas, and mineral interests through this bogus notice concept and that they had to give those rights back along with any royalty they were paid.

When this case reached the Michigan Supreme Court, they vacated the decision for technical reasons. However, at the same time a class action suit, *Blackstone v. State*, sought damages through the state theft of private property without the opportunity for a hearing. That suit was settled; the state now takes the position that for any tax foreclosures that took place after 1976, they would reassign the oil, gas, and minerals to the severed owner, with a few caveats like making certain the interest was not dormant. The state will, not, however, litigate suits regarding tax foreclosure sales prior to 1976 because of statute of limitations.

When the state found out that the courts were in the process of making them give the oil, gas, and mineral rights back to the severed mineral owners, it attempted to remedy this matter by amending the Dormant Mineral Act discussed above. It is still unclear to the title attorneys whether or not the lessee can simply file a notice regarding their leases every 20 years so that they won't have to risk losing a lease because of a tax foreclosure sale.

An oil and gas lease purchased at a state lease sale must be reviewed by an attorney who will provide a title opinion that clarifies whether the leased tract was pre- or post-1976 tax foreclosure property or a fee purchase. If it is a fee purchase the state will issue the lease. If there is a question about whether there were severed minerals and a subsequent tax foreclosure (especially after 1976), the lease may not be issued. If it is eventually determined that the state did not have ownership of the oil, gas and minerals they leased, they will return the money and not issue the lease.

Leasing trusts

Conveyances into and out of a trust. A deed or conveyance of a real or leasehold interest into a trust is carried out just like any conveyance instrument. The grantee in such a conveyance is "John Doe, Trustee of the John Doe Revocable Trust, dated Month XX, 20XX" or "John Doe and Susan Roe, Co-Trustees of the Burton J. Doe Family Trust dated Month XX, 19XX".

Likewise, if the trust is a grantor, it should be set up as "John Doe, Trustee of the John Doe Revocable Trust dated Month XX, 20XX" or "John Doe and Susan Roe, Co-Trustees of the Burton J. Doe Family Trust dated Month XX, 19XX".

The Certificate of Trust Existence is Michigan Land Title Standard 8.3. It is essentially an affidavit; it can be requested from the party that is executing a division order to verify they are the authorized party.

Titles

Married women can hold title in their own names, and it is their sole and separate property. That is, Jane Doe (whether or not she is married) can buy and sell real property, including oil, gas and mineral interests; if she is married, her husband does not need to execute a sale or transfer. The woman's marital status does not need to be listed.

Married men need to have their wives execute a sale or transfer because the wife has a dower interest in the property unless she is a voluntary non-resident of the state. If a man is listed on an instrument his marital status must be indicated, or the Register of Deeds will not record the instrument. However, if a married man is a lessee, he can technically sell

the interest without the wife signing because Michigan courts look at this as personal and not real property. However, as a precaution, the wives of married men should sign a division order, a mineral deed, or a royalty conveyance instrument to obtain a release of a potential dower interest.

Title can be held as:

- *joint tenants*, with full rights of survivorship
- *tenants by entireties*, similar to a joint tenancy with full rights of survivorship; used for married couples. Stating "John Doe and Mary Doe, husband and wife" designates tenants by entireties.
- *tenants in common*, assumed automatically if it is not indicated that the parties are joint tenants. The parties listed each have an undivided interest. For example, if there are three parties listed as grantee, they would each have an undivided one-third interest. The instrument would state "John Doe, a married man, James Roe, a single man, and Mary Smith".

Post-production costs

State lease forms and post-production costs. Over 10 years ago, the State of Michigan modified their lease form, so the division order analyst needs to review the specific language in the lease in question.

Private lease forms and post-production costs. A private lease will include a definition of post-production costs. This statutorily-required language ensures that the lessor understands post-production cost deductions from his or her royalty check.

Post-production costs are primarily used for natural gas in Michigan and specifically for the more than 10,000 Antrim Shale gas wells drilled in northern Michigan. Since gas in Michigan is usually not purchased at the wellhead, the producer will calculate or deduct the transportation and treating rates between the well head and the point of sale. The point of sale for almost all of the Antrim Shale gas produced in northern Michigan is at the tailgate of a Merit Energy plant in Kalkaska, Michigan.

There are numerous lateral pipe-lines with charges along with main transportation pipelines. The prices of these pipelines for transportation only are regulated by the Michigan Public Service Commission. The MPSC has a public hearing on the rate to be charged and sets or approves the final rates. The rates on laterals run from 1 cent per mcf to 12 cents per mcf. Any midstream treating that takes place, such as carbon dioxide removal from the gas, is done by midstream treating plants such as DCP Midstream, Merit Energy or Michcon Gathering; those treating rates are not publicly regulated. Those rates run from 10 cents to 11.1 cents per mcf.

Incidentally, gas is sold in dekatherms at 14.65 PSI, so the accounting staff needs to ensure that the pressure differential is standardized between the charges so volumes tie back to nominations, sales, or transportation and treating volumes.

Note: Oil and natural gas liquids in Michigan are typically priced at the wellhead, so post-production costs usually do not come into play – just the net price.

Riparian rights

Because Michigan has a lot of inland lakes, the parties that own land along the shore line have rights that extend to the centerline of the adjoining lake. Some leases actually include or list the riparian rights in the granting clause. A division order title opinion will request a map of any lands which involve lakes to determine if there are any uplands that could have riparian interest into the production unit. A surveyor will map the land descriptions and extend the property lines to the center thread line of the lake. This acreage can be a substantial amount of land and will be

included in the production unit denominator on the Division of Interest. Almost every DOTO will require signatures on all of the division orders that involve lands with riparian rights prior to releasing them for payment in the event that someone complains about the acreage calculation from a riparian map. Other attorneys take the position that only a court can affirm the acreage attributable to the riparian calculation or acreage but most companies do not go to that cost or expense.

Descent and distribution in Michigan

The intestate provisions of the state have become very complicated. If a party dies intestate, the succession is very fact specific but typically involves the surviving spouse and children. Among the complicating factors are residency, amount or size of the estate, some cost of living allowance for the surviving spouse, and some property exemptions. Since the issues involved are so complicated, it is best to contact a Michigan title attorney to work through the rights and responsibilities. The surviving spouse should contact an attorney to open a probate on the decedent and let that attorney work through all the legal and notice issues.

When a party dies testate, an attorney should probate the will. Naturally the probate court will follow the outline in the will.

Escheatment of royalty payments

The state does have escheatment rules under Uniform Unclaimed Property Act. However, prior to escheating royalty to the state, the division order analyst should conduct a thorough investigation to locate any siblings or other heirs in a production unit that may have known the missing party. A Michigan attorney can determine the current status of escheating royalty when the owner cannot be found in order to receive payment.

Note: The website for the Michigan Department of Environmental Quality has many valuable resources available for the division order analyst. The "Who does what list" is especially helpful.

Chapter 20: Fundamentals of Federal OCS Title

Lisa Shelton Jaubert

Introduction

In scientific terms, "continental shelf" refers to the submerged extension of a continent, and, with respect to the United States, is comprised of the submerged lands surrounding the entire continental United States as well as Alaska. By international convention, the outer continental shelf has been defined as "those submerged offshore areas lying seaward of the territorial lands of the adjacent country out to a water depth of at least 200 meters (656 feet) and extending beyond that to depths where there exists the likelihood of minerals exploitation of natural resources." And, also by international agreement, countries retain the right to explore and exploit the resources to be found on their respective outer continental shelves.

The United States has asserted jurisdiction over its outer continental shelf pursuant to a pair of laws enacted in 1953 - the Submerged Lands Act,[1] and the Outer Continental Shelf Lands Act, (as amended, "OCSLA").[2] The Submerged Lands Act grants certain offshore lands to the coastal states, and reaffirms that the submerged lands (and associated natural resources) extending beyond those granted to the states are under the jurisdiction of the federal government for the benefit of the entire nation. OCSLA further reaffirms this division and establishes the legal framework for the leasing, exploration, development and production of hydrocarbons on the portions of the United States' outer continental shelf under federal jurisdiction.

While there were early disputes between several of the states and the federal government about the boundary between their respective spheres of jurisdiction over the United States' outer continental shelf, these were eventually resolved, and the delineation has now been well established. The term *OCS* as used throughout the following discussion refers to those portions of the United States' outer continental shelf under exclusive federal control and may be understood to be the same as the defined term "outer Continental Shelf" found in OCSLA, i.e., "all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in Section 2 of the Act [being the lands granted to the coastal states by the Submerged Lands Act] and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control."[3]

The OCS

OCSLA delegates to the Department of the Interior (DOI) primary responsibility for managing the OCS; these responsibilities have been further delegated to the Bureau of Ocean Energy Management (BOE) and to the Office of Natural Resources Revenue (ONRR) and to the Bureau of Safety and Enviroment (BSEE) all formerly know as the Minerals Management Service (MMS), and all are agencies of the DOI. For administrative ease, BOE/MMS has divided the OCS into four regions: Atlantic, Gulf of Mexico, Pacific, and Alaska. Only three of these regions, the Gulf of Mexico, Pacific, and Alaska regions, have existing hydrocarbon production. In the Atlantic region, there is no current oil and gas production, although 10 oil and gas lease sales were held during 1976 and 1983. Forty-seven exploratory wells were drilled, and although five of the wells, located offshore New Jersey, had hydrocarbon discoveries, all five were abandoned as non-commercial. While alternative energy uses of the OCS are now being investigated and pursued in all four regions, oil and gas remain the principal OCS resources being exploited at this time; they are the focus of this discussion.

[1] 43 U.S.C. §1301, *et seq.*
[2] 43 U.S.C. §1331, *et seq.*
[3] 43 U.S.C. §1331(a).

Although the BOE/MMS is the federal agency with principal responsibility for the OCS, several other federal agencies (such as the Coast Guard, the EPA, etc.) oversee activities on or related to the use and exploitation of OCS resources. Accordingly, the laws, rules, and regulations of these other governmental authorities must be considered along with those of the BOE/MMS.

Furthermore, administrative procedures and policies can vary from region to region. Of the three OCS regions with hydrocarbon production, the Gulf of Mexico region is the most prolific. As a result, it is also the region with the most established policies and procedures relative to oil and gas leasing and exploration, development and production activities, although all regions have unique procedures which must be followed. And, these many sources of laws, regulations, procedures, and policies change with some frequency. It is, therefore, necessary to monitor the many applicable and changing legal requirements over the often long life of an OCS lease.

Leasing on the OCS

Within each region, the OCS is further divided into planning areas, and each planning area is further subdivided into tracts referred to as *blocks* – a block being a numbered area in an OCS planning area with a specific identifying number, corresponding latitude and longitude coordinates and generally not exceeding 5,760 acres. The Bureau of Ocean Energy Management (BOEM or BOE) maintains leasing maps and official protraction diagrams identifying these blocks. And, the rights to explore, develop, and produce hydrocarbons from these OCS blocks are granted to private persons (whether natural persons or public or private legal entities) through a public lease sale process.

OCSLA requires the Secretary of the Interior to prepare and maintain an oil and gas leasing program to implement the policies of OCSLA. The leasing program consists of a series of five-year schedules of proposed lease sales, by region, and a sale cannot be held unless it has been included in an approved five-year OCS lease sale schedule. At various times, lease sales in certain of the regions, as well as in specific planning areas of the Gulf of Mexico region, have been restricted, with the central and western planning areas of the Gulf of Mexico region being the only areas of the OCS that have, to date, consistently held regularly scheduled annual lease sales.

There are statutory and regulatory requirements that must be followed for holding a lease sale, for a person to bid at a lease sale, and for the eventual award of a lease pursuant to a sale. When awarded, a lease covers a single block, is given an OCS serial number, and is identified to a particular leasing map or official protraction diagram. For example, following a successful bid for a lease covering Block 380, Atwater Valley area, in the Gulf of Mexico region, a lease was awarded effective July 1, 1996, was given OCS serial number OCS-G 16906, and was described as the area covered by it as "all of Block 380, Atwater Valley, OCS Official Protraction Diagram NG 16-1."

Pursuant to the statutory requirements of OCSLA, a successful bidder for an OCS lease must be qualified.[4] OCSLA also imposes upon the Secretary of the Interior the responsibility of prescribing rules and regulations governing the further assignment of OCS lease interests.[5] Accordingly, pursuant to applicable BOE regulations, all holders of interests in BOE leases (whether an original successful bidder or a subsequent assignee) must be one of the following: (a) citizens and nationals of the United States; (b) aliens lawfully admitted for permanent residence in

[4] ." See 43 U.S.C. §1337(a)
[5] See 43 U.S.C. §1334 (a)(3)

the United States[6]; (c) private, public or municipal corporations organized under the laws of the United States or any State or of the District of Columbia or territory thereof; or (d) associations of such citizens, nationals, resident aliens or private, public, or municipal corporations, States or political subdivisions of States.[7]

Appropriate paperwork must be filed with and approved by the BOE before any person or entity will be recognized as qualified to hold an interest in an OCS lease. Once this qualification has been established, the BOE issues an identifying qualification number, thereby permitting the accepted person or legal entity to conduct business with the federal government. This includes the right to bid on and be awarded OCS leases and to undertake exploration and production activities. As changes occur with the qualified person or legal entity (for example, as to a person, a change in citizenship, or as to a corporation, a change in the officers authorized to bind the company or a change in the name of the corporation), documentation must be filed to update and maintain the BOE-approved qualification status. The BOE maintains files for each person and legal entity that has been qualified, and these qualification files are available for public review.

In addition to the requirement that an OCS lease interest owner be qualified, the applicable regulations require lease interest owners to post certain bonds with the BOE. General bonds, either on a lease-by-lease basis or on an area-wide basis, must be posted before a lease will be awarded to an otherwise qualified holder, and subsequent bonds must be posted prior to lease exploration activities and again prior to further development and production activities. These requirements, found at 30 C.F.R. §§256.52(a) and 256.53(a) and (b), may be satisfied by posting either a bond in the required amount or furnishing other acceptable security such as a third party guarantee. With respect to required lease bonds or area-wide bonds, the requirements may also be satisfied if another record title owner in the lease has already posted the requisite bonds. The BOE and Office of Natural Resources Revenue (ONRR) have the right to require yet additional security to ensure compliance with lease obligations; the regulations as well as regional guidelines set forth the evaluation to be undertaken by the regional director in making this determination. They also describe how the request for additional security may be satisfied, whether through increasing existing bonds or posting supplemental bonds.[8]

If an OCS lease interest owner also intends to conduct exploration and production activities on the lease, and is not the sole record title owner of the lease, then all record title owners as well as any operating rights interest owners in the affected area must file signed designations of operator with the ONRR and the BOE/MMS.[9] The entity seeking to be operator must also have satisfied all bonding requirements, as well as submitted evidence in satisfaction of applicable oil spill financial responsibility laws and regulations, before it will be approved as operator and permitted to commence operations and to make permit and other filings with the Bureau of Safety and Environmental Enforcement (BSEE)/MMS.

Record title and operating rights in an OCS lease

The BOE/MMS describes the interest in an OCS hydrocarbon lease acquired by an

[6] as defined in 8 U.S.C. §1101(a)(20)

[7] See 30 CFR §256.35

[8] See 30 C.F.R. §256.53(d), (e) and (f); see also Gulf of Mexico Region, Notices to Lessees and Operators, NTL 2008-No7, dated August 28, 2008

[9] See 30 C.F.R. §250.143

original lessee as a record title interest. Although the term record title is not defined in the Boe/MMS regulations governing the OCS, the concept is borrowed from the federal regulations governing onshore oil and gas leasing; the term is there defined as "a lessee's interest in a lease which includes the obligation to pay rent, and the rights to assign and relinquish the lease. Overriding royalty and operating rights are severable from record title interest." 43 CFR §3100.0-5(c). As stated in this definition, adopted by BOE/MMS, the BOE/MMS allows and recognizes the creation of operating rights interests in OCS hydrocarbon leases as carve-outs from the record title lease interest. This term, "operating rights," is defined in the BOE/MMS regulations as "any interest held on a lease with a right to explore, develop and produce leased substances."[10]

Both the record title interest and the operating rights interest in an OCS lease are working interests as that term is defined and understood in the oil and gas industry. As a general matter, these terms are administrative aids for the BOE and the ONRR/MMS and serve to distinguish between the entire bundle of rights and obligations that may be held under an OCS oil and gas lease and a carve-out, or subset, of those rights. The term *operating rights* has developed in the federal regulatory scheme principally as a way to describe the interest held by a working interest owner in an OCS lease that has a horizontal depth limitation. For administrative ease, the BOE/MMS has to-date limited to two the number of horizontal depth severances that it will recognize, essentially, a shallow and a deep severance in each lease.

Operating rights interests are dependent for their continuation on the owners of record title interests. It is the latter which have the right, vis-à-vis the BOE/MMS, to relinquish the entirety of a lease, notwithstanding the existence of operating rights interests in the lease. As a counterbalance to this right is the obligation on the part of the record title holders to be jointly and severally liable with all other record title and operating rights owners in a given lease for all lease obligations. These obligations include the plugging and abandonment of wells, the abandonment of pipelines, and the removal of platforms and other facilities, even if the record title owner in question did not

participate in the operations giving rise to the obligations.

An example may be helpful to explain these two kinds of interests – record title and operating rights. Of course, much more complex situations can and do arise, but for the sake of illustration the following simple example is offered.

Company A is the sole successful bidder at lease sale of an oil and gas lease covering block 123, South Marsh Island area, Gulf of Mexico region, given serial number OCS-G 12345. At the time of award of the lease, the BOE/MMS will credit Company A with 100% record title interest in OCS-G 12345. Then Company A assigns 50% of its record title interest to Company B, with BOE/MMS approval. (The need for BOE/MMS approval, and the associated issues raised by this requirement, are discussed below.) The BOE and ONRR/MMS will then recognize Company A as an owner of a 50% record title interest and Company B as an owner of a 50% record title interest in lease OCS-G 12345.

Company A then proposes a well on the lease, and Company B decides to farm out its interest to Company C under a farmout that limits Company C's right to earn an assignment of the lease to the deepest depth drilled in the earning well. Company C participates with Company A in the successful

[10] 30 CFR §250.105

drilling of a well drilled to a depth of 7,000 feet true vertical depth (thereby earning under the farmout). Company B makes an assignment to Company C of a 50% interest in OCS-G 12345 to depths from the surface down to 7,000 feet TVD. The BOE/MMS (and the parties) will consider this assignment to be an assignment of operating rights only. ONRR/MMS records will thereafter show ownership in lease OCS-G 12345 as follows:

Record Title – 50% to Company A and 50% to Company B.
Operating Rights as to all of the block to depths from the surface down to 7,000 feet TVD – 50% to Company A and 50% to Company C.

Then, Company A and Company B assign to Company D all of their rights in the lease to the depths from 7,000 feet TVD down to and including 20,000 feet TVD. The BOE/MMS (and the parties) will also consider this assignment to be an assignment of operating rights only, and, following the assignment, the BOE and ONRR/MMS will show ownership in OCS-G 12345 to be held as follows:
Record Title – 50% to Company A and 50% to Company B.
Operating Rights as to all of the block from the surface down to 7,000 feet TVD – 50% to Company A and 50% to Company C.
Operating Rights as to all of the block from 7,000 feet TVD down to and including 20,000 feet TVD – 100% to Company D.

Following the assignment to Company D, the BOE/MMS will not recognize any further carve-outs of operating rights. The BOE and ONRR/MMS will continue to track ownership of both the record title and these two operating rights severances until the ownership of the record title interests and the interests in a particular operating rights carve-out are reunited in the same owner(s). At that time, unless ownership in all the severed operating rights have been reunited in the record title owners, it will be necessary to request that the BOE/MMS no longer recognize the particular operating rights severance that now has the same ownership as the record title interests. Such a request is not needed if the ownership in all of the operating rights carve-outs becomes the same as ownership of the record title interests.

Examining Title to OCS Leases

The BOE/MMS Records. With respect to OCS hydro-carbon leases, the BOE/MMS maintains ownership records for both record title and operating rights interests in each awarded and active OCS lease. In the Gulf of Mexico region, these lease ownership records are maintained by the Adjudication Unit. The lease records (or lease files) were once maintained only in hard copy but now are available on the BOE/MMS website (www.gomr.boemre.gov). They are also available through other commercial websites such as www.ocsbbs.com.

These lease files must be examined to determine the BOE/MMS approved ownership in a given OCS lease. The lease files will include both the relevant assignments as well as the BOE/MMS approval letter for each assignment showing that the BOE/MMS has approved the assignment. It will also indicate the effective date of the approval and the resulting ownership in the lease after taking into account the approved assignment. However, the ownership in the lease reflected in an approval letter is limited to the particular kind of interest involved in the assignment under consideration. That is, the approval letter will show either the approved record title ownership or the approved operating rights ownership as to the operating rights severance involved in the particular assignment under consideration. It will not show all of the operating rights. In fact, there is no single BOE/MMS source of information that reflects the BOE/MMS approved ownership of both record title and operating

rights interests across the entirety of the lease. The Gulf of Mexico regional office does maintain Serial Register Pages for each active lease that credits record title ownership in the lease and also identifies changes in the designated operator of the lease as well as notes certain changes in qualifications of the record title owners.

In addition to the lease files, the BOE/MMS (at least in the Gulf of Mexico region) also maintains a non-required documents file for each active lease. These non-required files are also available online. The non-required files may include assignments of overriding royalty interests, net profits interests and other similar interests, mortgages and deeds of trust, financing statements, lien statements, working interest assignments that do not fit within the record title or BOE/MMS-recognized operating rights categories. They will also include any other documents that may relate to the lease in question but do not qualify as either a record title interest assignment or a recognized operating rights assignment. Both the non-required files and the lease files for a given lease must always be reviewed as part of a complete assessment of title to OCS lease interests.

BOE/MMS Approval. Assignments and transfers of OCS leases are governed by regulation found in 30 C.F.R. §256. Under these regulations, and as required by OCSLA, all instruments that create or transfer ownership of an OCS lease interest must be filed for approval with the BOE/MMS. The BOE/MMS may approve an assignment in an OCS lease only if (a) the assignee qualifies to hold a lease under 30 CFR §256.35(b); (b) bond coverage pursuant to 30 CFR, Subpart I is provided; and (c) the requirements of OCSLA and the governing regulations have otherwise been satisfied, and the Regional Director of the BOE/MMS actually approves the assignment.

The requirement that an OCS lease holder be qualified is discussed above in the section on OCS leasing, as are the general requirements for the bonds that must be posted with the BOE/MMS. In addition to these requirements, it is also necessary to submit the acceptable BOE/MMS assignment forms. Without these, an assignment will not be approved. The BOE/MMS has recently promulgated various forms to ensure that the filing of assignments and other regulatory documents is more uniform and to improve the accuracy and efficiency of handling these filings. These forms may be found on the BOE/MMS website, www.boemre.gov.

An assignment must be approved by the regional director of the BOE/MMS; this approval remains within the discretion of the regional director even after the apparent satisfaction of the filing requirements. After the assignment is approved, the transfer is deemed to be effective on the first day of the month following its filing in the appropriate office of the BOE/MMS unless, at the request of the parties, an earlier date is specified in the approval. Under all circumstances, the assignor remains liable for all non-monetary obligations that have accrued under the lease before the effective date of BOE/MMS approval of the assignment.[11] Accordingly, if an assignee, or subsequent assignee, fails to perform any non-monetary obligation under the lease or the regulations, the BOE or ONRR/MMS may require prior assignors to bring the lease into compliance to the extent that the obligation accrued prior to the effective time of the approval of the assignment.[12]

BSEE and BOE/MMS regulations governing decommissioning responsibilities (plugging and abandonment of wells, platform, pipeline and facility removal, site clearance and other similar activities) expressly provide that decommissioning obligations arise or accrue

[11] . See 30 CFR §256.62(d) and §256.64(h)
[12] See 30 CFR §256.62(f)

at the time that the lessees (i.e., the record title owners) or operating rights owners

a) drill a well;
b) install a platform, pipeline or other facility;
c) create an obstruction to other uses of the OCS;
d) are or become a record title owner in the lease or the owner of operating rights in the relevant portion of the lease on which there is found a well that has not been permanently plugged according to applicable regulations, a platform, a lease term pipeline or other facility or an obstruction;
e) are or become the holder of a pipeline right-of-way on which there is a pipeline, platform, or other facility or an obstruction; or
f) re-enter a well that was previously plugged in accordance with the regulations.[13]

Thus, a succeeding record title owner will remain liable vis-a-vis the BOE or BSEE/MMS with its predecessors in title for decommissioning all wells, platforms, pipelines and other obstructions located on the lease as of the time that the record title owner acquires its interest in the lease. A succeeding operating rights owner will remain similarly liable with its predecessors for decommissioning obligations for all wells, pipelines and facilities found on the portion of the lease in which such owner has an operating rights interest.

Although OCSLA and the federal regulations provide the general legal framework governing leasing, exploration, and production on the OCS, the Gulf of Mexico regional office has issued the *Leasing Guidelines Handbook,* which provides the nuts and bolts of how to interact with the Gulf of Mexico regional office, especially in relation to leasing and lease maintenance activities. This handbook, found on the BOE website, provides practical guidance and information on a number of topics. While other regions may not follow the same procedures, many of the other regions have looked to the Gulf of Mexico region for examples of procedures and policies to be implemented. Accordingly, familiarity with the practices and procedures of the Gulf of Mexico region may be helpful when working in the other regions, although they will not be dispositive.

Examining Title to OCS Leases – the Adjacent State's Records. The MMS is principally concerned with the percentage ownership of each record title owner and the percentage ownership of each operating rights interest owner in the recognized operating rights severance of a given OCS lease. The agency does not keep track of the net revenue interests of its approved OCS lease holders nor monitor title to other interests in an OCS lease. Neither does it concern itself with contractual burdens and encumbrances created by OCS lease owners. The regulations do require filing with the BOE/MMS, for record purposes, all instruments creating or transferring overriding royalty interests, carried working interests or payments out of production, but these filings are not subject to BOE/MMS approval.[14]

The regulations also permit, but do not require, filing with the BOE/MMS, for record purposes, any document pertaining to an OCS lease.[15] As a result, the BOE/MMS records are not a reliable source or a true indication of all of the interests in or burdens on an OCS lease. As a consequence, it is often necessary to examine various state and county/parish records, as well as to review unrecorded documents, in order to gain a full understanding of the ownership of a given

[13] See 30 CFR §250.1700, *et seq.*, and §250.1702.

[14] See 30 CFR §256.64(a)(7

[15] *Id*

OCS lease. The question thus becomes which non-BOE/MMS records should be examined. Answering this question requires an understanding of the legal scheme governing the OCS as mandated by OCSLA.

By its terms, OCSLA extends the Constitution, laws, and jurisdiction of the United States to the subsoil and seabed of the OCS, as well as all "artificial islands" (i.e., platforms) located thereon as if the OCS were an area of exclusive federal jurisdiction located within a state. OCSLA provides, in pertinent part:

> To the extent that they are applicable and not inconsistent with this subchapter or with other Federal laws and regulations of the Secretary [of the Interior] now in effect or hereafter adopted, the civil and criminal laws of each adjacent State now in effect or hereafter adopted, amended or repealed, are declared to be the law of the United States for that portion of the subsoil and seabed of the outer Continental Shelf, and artificial islands and fixed structures erected thereon, which would be within the area of the State if its boundaries were extended seaward to the outer margin of the outer Continental Shelf. [16]

The jurisdiction and control afforded the United States over the OCS pursuant to OCSLA includes the power to make laws to govern OCS activities as well as to adjudicate the disputes that may arise (although the right to handle disputes is not exclusively left to the federal courts). However, Congress recognized that, despite OCSLA's comprehensive treatment of certain matters (as well as the broad scope of other federal laws), issues would nevertheless arise that were not addressed in OCSLA, its implementing regulations, or in other federal laws and regulations. Congress chose to fill these gaps by referring to state laws, declaring that, in a given instance, one should look to the laws of the state to which the block in question is adjacent, and that the state's laws would be considered to be federal laws for these purposes. Thus, under OCSLA, in the absence of applicable federal law, state law will be applied as surrogate federal law to the extent that the state law in question is applicable and is not inconsistent with OCSLA or other applicable federal law. As a result, both state laws and the laws and regulations of the United States must be considered when dealing with OCS title matters.

The United States Court of Appeals for the Fifth Circuit has articulated a three-part test for determining whether, in a given instance, state law should apply as surrogate federal law under OCSLA. Three conditions must be satisfied before reference will be made to state law: (a) the controversy must arise on a site covered by OCSLA, (b) federal maritime law must not apply of its own force, and (c) the state law must not be inconsistent with federal law.[17] Both the *situs* (location) test and the determination of whether federal maritime law is applicable require a careful analysis of the facts presented in each instance. Once it has been determined that the *situs* of the controversy is covered by OCSLA and the matter is not covered by federal maritime law, an assessment must be made of whether state law should be relied on to fill any voids in the applicable federal law.

If a conclusion is reached that state law is to be considered, then it must be decided which

[16] 43 U.S.C. §1333(a)(2)(A)

[17] *Union Texas Petroleum Corp. v. PLT Engineering, Inc.,* 895 F.2d 1043 (5th Cir. 1990), cert. denied, 498, U.S. 848 (1990),

state's law is to be analyzed. OCSLA mandates that it is the law of the adjacent state that should be adopted as surrogate federal law.[18] The adjacent state is that state in which the OCSLA *situs* (location) would be located if the state's "boundaries were extended seaward to the outer margin of the outer Continental Shelf."[19] Under the statute, the president was to draw these seaward extensions but has never done so, although for administrative purposes the BOE/MMS has drawn the boundaries. Because the state boundaries extending seaward have never been officially drawn, the courts have been left to "adjudicate adjacency in private disputes governed by OCSLA."[20]

The Fifth Circuit decisions have thus far refused to articulate a strict, formulaic test for determining adjacency. Rather, the Fifth Circuit in the *Snyder* case held that all relevant evidence should be considered to determine which state is the adjacent state. A prior Fifth Circuit decision, *Reeves v. B & S Welding, Inc.*,[21] identified certain evidence to be reviewed as part of this determination: (a) geographic proximity, (b) consideration of other federal agencies' conclusions about "adjacency, (c) prior court determinations (if any) and (d) projected boundaries. The *Snyder* court rejected these four categories as the exclusive types of evidence that could be considered in determining adjacency; leaving the determination to be made on a case-by-case basis based upon all the evidence presented.

Because the inquiry is fact intensive, it will not always be easy to determine adjacency, with the result that more than one state may be considered to be the adjacent state. This choice of the state or states considered to be adjacent to a particular OCS lease for purposes of determining applicable law to be applied as surrogate federal law will also determine which state's (or states') records should be reviewed for purposes of examining ownership of that OCS lease. However, since most official real property records are maintained at the county (or, in Louisiana, the parish) level, not at the state level, a further adjacency determination is required to decide which particular records of the relevant states should be reviewed. This further identification of the appropriate county/parish records to review is also required because the laws of most states give effect to the recordation of documents affecting real property only if the documents are filed in the real property records of the county/parish in which the real property is located.

How a particular state extends its county/parish lines through its state waters is a matter of state law. And, under the much-cited decision of the United States Court of Appeals for the Fifth Circuit in *Union Texas Petroleum Corp. v. PLT Engineering, Inc.*,[22] it is these same state law principles for extending a state's county/parish boundaries seaward through its coastal waters that are to be applied to further extend the county/parish boundary lines into the OCS. While simple on its face, this approach can create difficulties the deeper one goes into the OCS, often requiring the examination of multiple county/parish records within a given state.

While there has not yet been a reported decision expressly holding that all state recording laws and related jurisprudence apply unquestionably to OCS leases, the Fifth Circuit's decision in *Union Texas* has held that the recordation requirements for perfection of lien rights under the Louisiana Oil Well Lien

[18] Section 1333(a)(2)(A),

[19] 43 USC §1333(a)(2)(A)

[20] *Snyder Oil Corp. v. Samedan Oil Corp.,* 208 F.3d 521, 523 (5th Cir. 2000)

[21] 897 F.2d 178, 179-80 (5th Cir. 1990)

[22] 895 F.2d 1043 (5th Cir. 1990), *cert. denied*, 498 U.S. 848 (1990)

Act apply to lands and leases situated on the OCS offshore Louisiana.[23] The Fifth Circuit further concluded that a lien claimant had complied with the statute's perfection requirements by filing its lien in the adjacent coastal parish. The court reasoned that OCSLA adopted the provision of Louisiana law that "[t]he gulfward boundaries of all … coastal parishes extend coextensively with the gulfward boundary of the State of Louisiana."[24] The court then concluded that the statute extended the "boundaries of [such] parish(es) to the outer limits of the OCS by providing that state law applies to the subsoil and seabed of the OCS and all artificial islands thereon 'which would be within the area of the state if the boundaries were extended seaward to the outer margin of the outer Continental Shelf. . . .'"[25] The rationale of the Fifth Circuit in *Union Texas* is most often relied upon for the conclusion that the recording statutes, laws, and jurisprudence of a particular state are applicable to the OCS lands adjacent to the state.

Reference to the laws of the adjacent state requires consideration of state law principles governing real property interests. As a result, in analyzing title to an OCS lease, and even after examining the records maintained by the BOE/MMS for the lease, and then separately examining the records of the adjacent state's adjacent county/parish, it may be necessary to explore the impact of state substantive laws on the title under examination. These matters requiring reference to state law principles may include questions of probate and estates if interests of individuals are involved, as may often be the case with overriding royalty interests, corporate law considerations such as in the event of a merger of OCS lease owners and the effect on title of unrecorded agreements, to name but a few examples.

Conclusion

This is but a summary introduction to some of the fundamentals of OCS title. Ascertaining the ownership of interests in an OCS lease may first appear to be a straightforward, simple exercise. However, this surface simplicity can often hide an underlying complexity. Knowledge of the many rules and regulations of the BOE and ONRR/MMS and the policies and procedures of the relevant regional office is essential to any title analysis. But, it is equally important to have an understanding of the legal framework created by OCSLA, which requires the interplay between federal and state laws and regulations, and a review and consideration of the files and records of all of these jurisdictions.

[23] La. R.S. 9:4861, *et seq*.
[24] See La. R.S. 49:6; see *also Union Texas*, 895 F.2d at 1051-52
[25] *Union Texas*, 895 F.2d at 1051-52

CHAPTER 21: TITLE ISSUES WITH RESPECT TO CORPORATIONS AND PARTNERSHIPS IN TEXAS AND NEW MEXICO

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Introduction

In the course of title examination for an oil and gas title opinion, be it a drilling opinion, division order opinion, or otherwise, a title examiner typically encounters conveyances of real property interests involving either a corporation or a partnership. Unlike individuals, in executing a conveyance of a real property interest, a corporation or a partnership is represented by an individual acting on behalf of the entity. In this respect, the authority to execute on behalf of either a corporation or partnership will be discussed.

Corporations

A corporation, both in Texas and New Mexico, is vested with powers to buy, sell, lease, convey, transfer, mortgage and otherwise dispose of real property interests in the same fashion that an individual is allowed. However, a corporation can only control and operate its real property interests through its duly authorized agents or employees. A conveyance of a real property interest vested in a Texas corporation is governed by Article 5.08 of the Texas Business Corporation Act; a conveyance of a real property interest vested in a New Mexico corporation is governed by Chapter 53, Article 15-1 of the New Mexico Business Corporation Act.

Article 5.08 of the Texas Business Corporation Act provides that any corporation may convey land with or without the seal of the corporation, signed by an officer or attorney-in-fact of the corporation when authorized by the appropriate resolution of the board of directors. Such deed, when acknowledged by the officer or attorney-in-fact to be the act of the corporation or approved in like manner prescribed for other conveyances of lands may be recorded in like manner and with the same effect as other deeds. Any such deed, when recorded, if signed by an officer of the corporation, constitutes *prima facie* evidence that the resolution of the board of directors was duly adopted.

In Texas prior to August 28, 1989, the conveyance had to be executed by the president or vice president of the corporation to constitute *prima facie* evidence that the resolution of the board of directors was adopted. However, in 1989, the act was amended to provide that any officer's execution on behalf of the corporation constituted the required evidence. If the instrument does not show that the person executing was an officer of the corporation either in the signature block or in the acknowledgment, a title requirement will be made to determine whether the person who signed was an officer or was otherwise authorized to act on behalf of the corporation in executing the document.

It should be noted that when the person executing the document on behalf of the corporation executed as attorney-in-fact, the title examiner should be furnished with a copy of the power of attorney. The power of attorney need not be recorded for the executing party to be authorized to execute.

Chapter 53, Article 15-4 of the New Mexico Business Corporation Act is similar to the Texas statute. It provides that the sale, lease, exchange, or other disposition of all, or substantially all, of the property and assets of a corporation in the usual and regular course of its business and the mortgage or pledge of any or all property and assets of a corporation, whether or not in the usual and regular course of business, may be made upon such terms and conditions and for such consideration, which may consist in whole or in part of money or property, real or personal, including shares of any other corporation, domestic or foreign, as authorized by its board of directors. In any case, no authorization or consent of the shareholders is required.

Of important note, though not specified in Article 15-1, the responsibility for executing a conveyance of a real property interest generally lies with the officers and agents of the corporation as prescribed in the corporation's bylaws. This typically is construed to be the president, a vice president or a duly appointed attorney-in-fact of the corporation. Other corporate officers, such as a treasurer or secretary, are typically not vested with the implied powers to execute instruments in the name of the corporation in New Mexico. In the event an instrument is executed by an officer such as a treasurer or secretary of the corporation, the title examiner should require that a copy of the resolution of the board of directors be examined which authorized the treasurer or secretary to execute the conveyance.

Both Texas and New Mexico have statutes of limitations which prevent a corporation from filing an action against a grantee for recovery of real property under certain circumstances and allow third parties to rely upon instruments filed of record which were not executed by an authorized corporate officer. The Texas statute[1] provides that no action can be brought after two years after the day the instrument was filed for record for recovery of real property where the corporation claims that an instrument was not executed by a proper corporate officer or that the record does not show the authority of the officer executing the instrument. This statute applies to all instruments filed for record on or after September 1, 2007. For instruments recorded from September 1, 1993 to September 1, 2007, the statute provides a limitations period of four years. For instruments recorded prior to September 1, 1993, the limitations period is ten years.

The New Mexico[2] statute involving Limitations of Actions provides that no action can be brought after fifteen years from the date the instrument affecting title to real estate is recorded for claims that the instru-ment was not signed by the proper officer of a corporation or that the record does not show any authorization of the board of directors for the transaction.

Partnerships

Partnerships, like corporations, are also vested with the same powers to deal with real property interests in the same fashion as an individual. A conveyance of a real property interest vested in a Texas partnership is governed by Section 152 of the Texas Business Organizations Code and Article 6132(b) of the Texas Revised Partnership Act, while a conveyance of a real property interest vested in a New Mexico partnership is governed by Chapter 54, Article 1A of the New Mexico Uniform Partnership Act.

Each of these separate code sections provides that a partner is an agent for the partnership and that any action by the partner in what appears to be the ordinary course of business, including the conveyance of a real property interest in the partnership name, is binding upon the partnership. However, the partnership is not bound by the act of the partner where the partner does not have authority to act on behalf of the partnership in a particular matter and that the person with whom the partner is dealing has knowledge of the partner's lack of authority, thus allowing the partnership to void the transaction. Conversely, if the real property interest was conveyed by the grantee and a third party claiming through the grantee paid value and is without knowledge of the partner's lack of authority in the initial

[1] Section 16.033 of the Texas Civil Practice and Remedies Code

[2] Chapter 37, Article 1-28 of the 1978 New Mexico Statutes

conveyance, the act of the partner is binding upon the partnership.

For purposes of title examination, it is impossible for an examining attorney to know whether the party acquiring a real property interest knew of the authority of the partner executing the deed or assignment of the real property interest. In addition, it is not possible to know whether a person who has acquired the interest from the grantee, if there has been a subsequent conveyance, was a holder for value without knowledge that the partner, in making the initial conveyance, had exceeded the partner's authority. For these reasons, the examining attorney should always make a requirement to examine the partnership agreement to determine whether the partner had authority to execute the conveyance of the real property interest on behalf of the partnership. In the case where all of the partners in the partnership have executed the conveyance, especially where the conveyance is not in the ordinary course of business, this requirement is unnecessary.

As stated previously with regard to corporations, Section 16.033 of the Texas Civil Practice and Remedies Code applies to prevent a partnership from recovering real property after two years from the date the instrument was filed for record where the partnership claims that the executing partner was not the proper partner to execute instruments or that the executing partner did not have the authority from the other partners to execute the instrument on behalf of the partnership. Prior to September 1, 1993, Section 16.033 did not include partnerships, but partnerships were added by the 1993 amendment, at which time the limitations period was four years. The New Mexico statute of limitations does not apply to partnerships.

Conclusion

As with any conveyance of a real property interest, the authority of the person executing the instrument is critical with respect to title examination. Corporations and partnerships present special issues in light of the fact that those persons executing instruments on behalf of their respective entity do so in a representative capacity. A division order analyst must be familiar with the current Texas and New Mexico statutes involving corporations and partnerships and the authority of their respective officers, agents, and employees is vital so as to not overlook a serious title issue based upon a party's lack of authority to execute an instrument affecting title to real property. Other oil and gas producing states have statutes that are similar to Texas and New Mexico. So the general principals expressed in the paper apply. However, the analyst should be familiar with the statutes involving corporatons and partnership in the state where the property is located.

CHAPTER 22: AN INTRODUCTION TO ESCHEAT AND UNCLAIMED PROPERTY

Paula Smith

Introduction to escheat

In the United States, **escheat** most commonly refers to the process by which unclaimed intangible property is transferred to the custody and safekeeping of the state. Unclaimed property typically consists of bank balances, uncashed checks, deposits and even royalties. In general, the property becomes unclaimed when there is neither communication between the entity holding the property (the holder) and its owner, nor owner activity for a statutorily specified period of time. Some of the most common reasons for the lack of activity or communication are: change of address without notification to the holder; failure to cash checks; and the death of the owner. The state is deemed to "step into the shoes" of the missing owner and maintain custody of the property in perpetuity. If the owner or the owner's heirs are located or remember the abandoned property, the owner may reclaim it at any time. Every year about $4 billion dollars is reported to the states.

Purpose of escheat laws

The underlying purpose of the escheat or unclaimed property law is consumer protection. Businesses (or "holders") change hands, names, and locations and records may be lost as time passes. Having the state maintain custody of abandoned property preserves the property in the name of the owner as shown on the records of the bank or company that reported the account and other identifying information. With states now maintaining databases of unclaimed owners online and participating in a centralized national database (www.missingmoney.com), an owners or his or her heirs will have many fewer places to search for unclaimed property and a much great likelihood of reclaiming it.

Holders benefit from state unclaimed property laws as well, because the state laws relieve holders of further liability for this property, and the states assume the responsibility of satisfying owner claims.

Finally, the citizens of the states benefit, because the economic windfall of unclaimed property enures to the benefit of state revenues and programs and not to the individual holder.

While it is true that all states have laws with similar underlying purposes, specifics of those laws, such as periods of abandonment, reporting requirements, and reporting formats differ for each state. Most states now have abandonment periods (the length of time during which there has been no owner activity) of three to five years. For a company to report correctly, it must either develop its own escheat expertise within the company or outsource the process. While software[1], a valuable tool, is available, law and reporting format changes occur frequently, and the company administrator who manages the escheat process will benefit from courses offered by states or others to keep abreast of the changes.

Reporting guidelines

The determine to which state a specific owner's account or check should be reported is relatively simple. As a result of the decisions in a series of United States Supreme Court opinions, a holder reports unclaimed property to the state of the apparent owner's last known address as shown on the holder's books and records. If there is no address, or if the owner is unknown, the holder reports the property to the holder's state of incorporation. The Supreme Court was called upon to decide these priority reporting rules because different states were claiming the same abandoned property under different rules. Since it was unfair to expect a holder to pay over the same property to different states, a

[1] Free reporting software is available at www.wagers.net

simple national approach and common set of rules was very desirable. Several subsequent decisions of the U.S. Supreme Court affirmed and further clarified these rules, which have eliminated most disputes among states and have given holders clear guidelines.

Uniform laws

Laws regarding unclaimed property have been the subject for the drafting of uniform law provisions by the National Conference of Commissioners on Uniform State Laws. Uniform laws, such as the uniform Commercial Code and the Uniform Probate Code, are drafted by legal experts as model laws. Several versions of Uniform Unclaimed Property Acts have been approved by the National Conference and have been proposed and enacted with numerous exceptions by state legislatures. The most recent model is the Uniform Unclaimed Property Act (1995). This version included an express provision with regard to mineral proceeds, including language covering **current balance**.

Current balance means that when the earliest payment to a royalty or mineral proceeds owner becomes abandoned, then all ensuing payments are deemed abandoned as well. Some 25 states now have current balance provisions. (Additional discussion regarding current balance appears below.)

Another provision of the 1995 Uniform Unclaimed Property Act that many states have adopted prohibits provisions in agreements to locate property that call for the payment of compensation including a portion of the underlying minerals or including any mineral proceeds not then presumed abandoned.

Due diligence

An important precursor to the escheat of unclaimed property is a process stipulated in most state laws that requires the holder to send written notice, or due diligence letters, to the owner at the owner's last known address at some specified period before the property is remitted to the state. Commonly, the letters notifying owners that their property is subject to escheat unless they promptly claim it should be sent 60 to 120 days before the property is due to be remitted. This gives the owner one last chance to reclaim the property from the holder before it is remitted to the state. However, these letters are not required under certain dollar amounts varying from 25 to 100 dollars. Also, due diligence letters are not required to be sent to addresses from which mail has already been returned as undeliverable. For suspended royalties or owner accounts, it is desirable to note on company records that mail to the owner has been returned as undeliverable.

Special provisions

Several states have unique provisions worth noting here.

- Kentucky exempts reporting royalties entirely. However, because of the operation of the priority rules, most states take the position that if property is exempted from reporting in one state, it should be reported to the holder's state of incorporation, if that state has an applicable law.

- In Oklahoma, mineral proceeds arising from forced pooled units are placed in the custody of the Oklahoma Corporation Commission. If these monies are held for seven years or more after the date of pooling, they are then transferred to the Oklahoma treasury and held in the Unclaimed Property Fund. The Oklahoma treasury will ordinarily transfer these monies to the state of the last known address.

- Wyoming requires production proceeds that cannot be paid within a prescribed time period to be placed in a Wyoming bank or saving and loan escrow account. If the proceeds are still unclaimed after three years, the payments are then remitted to the Wyoming State Treasurer's Unclaimed Property Division. The Wyoming Unclaimed Property administrator will transfer the payments to the state of the last known address if it is other than Wyoming.

Other states have adopted business-to-business exemptions that may be relied upon to exempt certain checks or accounts from reporting to the state of the last known address. However, these vary significantly from state to state, and most companies have elected not to claim these exemptions.

Reportable property types

Mineral proceeds. The Uniform Unclaimed Property Act (1995) defines *mineral* as "gas; oil; coal; other gaseous, liquid, and solid hydrocarbons; oil shale; cement material; sand and gravel; road material; building stone, chemical raw material; gemstone; fissionable and nonfissionable ores; colloidal and other clay; steam and other geothermal resource; or any other substance defined as a mineral by the law [of the adopting state]. The act defined *mineral proceeds* as "amounts payable for the extraction, production or sale of minerals, or upon the abandonment of those payments, all payments that become payable thereafter." Thus, in addition to royalties and production payments, such outstanding liabilities as uncashed delay rentals, bonuses and other payments are covered. The definitions for *mineral* and *mineral proceeds* were meant to be expansive in order to avoid any confusion about what was subject to abandonment regulations.

States that do not include definitions of mineral or mineral proceeds in the unclaimed property statues still interpret their laws as applying to abandoned property. The statutory provisions that relate to undefined property types is covered in a general rule, such as this one contained in the Uniform Unclaimed Property Act (1981) §2A:

> *Except as otherwise provided by this Act, all intangible property, including any income or increment derived therefrom, less any lawful charges, that is held issued, or owing in the ordinary course of a holder's business and has remained unclaimed by the owner for more than 5 years after it became payable or distributable is presumed abandoned.*

This type of provision is a catch-all that covers property not otherwise defined or for which an abandonment period is not expressly stated.

It bears repeating that mineral proceeds are not, with one exception noted below, reportable to the state in which the minerals are produced. Because of the rulings by the Supreme Court, proceeds such as these are reportable to the state of the last known address of the owner, not the state of production.

Suspended accounts

Most companies are aware that accounts held in suspense are subject to escheat, but often there is confusion about which suspense codes must be reviewed to determine if the property is abandoned according to that code. It is not uncommon for a company to conclude that only accounts included in a code denoting "bad address" or "returned by post office" are reportable. This is incorrect. If the liability is owed and the account has had no owner activity for the requisite period of time, the account should be examined for escheat.

For example, if an account is placed in suspense because the company has received notice that the owner is deceased, and there is no documentation of subsequent probate or heirship determination, that account is reportable. This is also true if there is no contact from any executor, administrator, or heir for the abandonment period. Of course, both good business practices and most escheat laws would suggest that the company should attempt to contact the decedent's representative or heirs in a final due diligence effort before the suspended account is reported to the state.

Current balance

As mentioned above, *current balance* or *pay to current* refers to the escheatment of subsequent royalties or other payments for the account of an owner that has been escheated to the state. The question arises: Are subsequent payments for this owner reportable to the state as they accrue, or should the current payments for this owner be consolidated in the next annual report? Most states have concluded that the best practice is to consolidate the payments and report the owner in the year after the account first became escheatable, rather than reporting to the state monthly, quarterly or semi-annually. However, reporting instructions from a specific state should be reviewed annually to verify current instructions.

Other property types

In addition to the types of property associated with the production or sale of minerals discussed above, oil and gas companies also have abandoned property common to other businesses: vendor and payroll checks, uncashed employee benefit checks, uncased dividends and undelivered or underlying shares. However, it is beyond the scope of this chapter to discuss all escheatable property types that are held by mineral producers.

Underlying mineral interest

Because most states' unclaimed property laws deal almost exclusively with intangible property, the underlying mineral real property interest owned by an owner whose royalties have been deemed abandoned is not placed in the custody of the state. However, Oklahoma has a specific provision relating to mineral interests in land that have generated intangible unclaimed property (royalty payments, for example). Oklahoma requires, in addition to other reporting, that the holder report to the state treasurer (1) the names and last known addresses of owners of record of the unclaimed mineral interest, (2) the legal description of the land affected, and (3) the extent of the property rights in the mineral interest.

This information need only be reported by the holder once to the state treasurer. The state treasurer then sends a copy of the report filed by the holder to the Attorney General and the district attorney of the county in which the land is located. This information is deemed confidential and is not released to the general public. The state treasurer also sends a report of the owners and the last known addresses of the owners of record to the county clerk of the county in which the land is located. This report is available for public viewing. If the proceeds derived from the mineral interest are abandoned for fifteen (15) years, the mineral interest that generates the abandoned mineral proceeds are subject to judicial sale by the state.

State enforcement of unclaimed property laws

Penalties and interest. Unclaimed property statues typically include imposition of interest on property reported late, along with penalties for failure to file the report or willful failure to file the report and deliver the property. For example, California's statute calls for annual

interest of 12% to be paid on late reported or delivered property to run from the time the property should have been reported, paid, or delivered. Additionally, a fine of up to $100 per day, not to exceed $10,000, may be imposed for each past due report or other duty not performed by the holder.

Most states will waive interest and penalties for first time filers; they also offer programs to help holders who may be past due in reporting. Some states have voluntary disclosure agreement procedures in place. Holders negotiate these agreements on a state-by-state basis.

A holder also has the option to work with the Unclaimed Property Clearing-house[2], an association of more than forty-five states which provide services to out-of-compliance holders on behalf of the participating states. The Clearinghouse simplifies reporting and payment mechanisms by providing a uniform method, agreed to by its member states, for cooperating holders. The Clearinghouse also conducts audits on behalf of member states when requested to do so.

State audits. State unclaimed property laws authorize the state to conduct audits of holder records to determine if the holder has complied with the requirements of the law. Under some state statutes, the state may audit a holder's records if there is reason to believe that the holder is not in compliance with the state's law. A state may choose to audit a holder for many reasons: (1) failure to file any report; (2) filing a report which, on analysis, appears to be significantly less than the reports of similar-size holders in the same industry; and (3) filing reports that appear to omit certain property types that the state would expect to see reported by that type of holder.

Some states, such as Colorado, permit the state administrator to assess a daily rate for the auditor's time spent conducting the audit, so holder cooperation with the audit is important. State audits generally begin with an opening conference in which the state auditors and the holder representatives discuss the scope of the audit, which states are involved in the audit[3], and what types of records will be examined. If records are unavailable for periods under audit or the expense of obtaining last known address information far outweighs the value of the property reportable, companies will need to negotiate with states and their represent-tatives to arrive at a fair solution. A company cannot avoid its reporting obligations by failing to maintain adequate records.

A common question holders have is how far back in time may a state auditor examine company records. Not surprisingly, the answer lies in each state's law. For a holder that has never filed a report, the audit may extend back to the inception of the corporation if records indicate amounts abandoned are material.

State custody and owner claims

When an owner comes forward to reclaim abandoned property, the state should be able to honor or deny the claim based on the information supplied by the holder. Some states will seek additional owner identifying information from the holder (which may or may not be available) if there is inadequate owner information on the report or if the claimant is unable to supply corroborating information in pursuit of the claim.

[2] www.acsupch.com

[3] Some states either conduct joint audits with other states or appoint a single contract auditor to work on behalf of a number of participating states.

Conclusion

Filing state unclaimed property reports requires understanding and attention to state formatting and reporting requirements. For the division order analysts or company staff maintaining mineral proceeds records, these concerns may vie with other job responsibilities. Ensuring that good company reporting policies are in place and making every effort to reduce the number of owners whose accounts become escheatable will facilitate unclaimed property auditing.

CHAPTER 23: ACQUISITIONS, DIVESTITURES, AND TRADES

25th Annual Institute Journal

Introduction

An acquisition, divestiture, or trade can be a means of managing company assets and improving on processes and business decisions, or it can be the means of destroying the continuity of a "well-run" Land Administration department. If handled poorly, the repercussions can be evident for years, even for the entire life of the property.

Land Administration should be involved from the very inception of the deal. Land Administration will be one of the last to complete all tasks necessary to have a property fully integrated into the company or transitioned out of the company.

These deals are actually opportunities for Administration to step forward and take a leadership role in planning and completing tasks which can make a significant difference to almost every other department in the company as well as the future performance of the company as a whole. This is a time to step forward and cover all critical items with management. It is not the time to be in a reactionary mode.

This is a guide to assist in moving through each step that must be accomplished when these deals are made. Some example worksheets are provided for reference. The worksheets are for reference only, since each project has its own set of circumstances and needs. All project planning and tools used to complete the project should be customized to that project since no article or checklist will ever take the place of applying one's own professional experience to a situation.

Trades are simply a combination of both acquisitions and divestitures, each occurring at the same time. Both guidelines should be used in this event. Trades are extremely difficult to manage in that the same resources are required concurrently. Focus is split between the tasks necessary to move property management in and out of the company.

One of the biggest mistakes made in industry is the assumption that all the work associated with Acquisition and Divestiture (A&D) work can be absorbed by existing staff. Depending on the size of the deal, this could be true. Perhaps if the number of properties is small enough, the deal has only offshore properties involved, or systems compatibility is significant, this may be a possibility. However, even then it must never be assumed. The answer may not be evident up front. It may only be determined after all of the deal is understood and an initial administrative due diligence is completed. Property transfer costs should always be considered. Administration should not be a deal-killer, but should be managed and dollars budgeted in a common-sense business-like manner. Many A&D employees and management are not always aware of these issues. Administration should be professional and advisory in informing management of these business considerations and reasonable in requesting resources. It takes concerted effort to be able to do this in a competent manner.

The pressures of each deal vary, and planning is essential. One might believe that the requirements for both an acquisition and divestiture from a project viewpoint might be very similar. Actually, they vary substantially. If one keeps a clear picture of duties that must be accomplished in each situation, then less time, effort, and money will be spent in the long run.

There will (and should) always be a buyer's due diligence team and a seller's due diligence team. The key is to not duplicate each other's efforts. Clarity is essential, especially in situations where a land consulting team is hired to complete a portion of a due diligence effort. Delineating tasks for that team, for regular staff, and for the other party's team is essential.

Steps to be completed by each team must be clearly defined. If this is not done, duplicated effort is almost guaranteed. The most common area of concern is *verification of title*. Many due diligence groups define a seller's due diligence as building title from creation/acquisition of that interest forward from the files. The buyer's due diligence team will always be doing this task, so the seller should be able to rely on his or her own records in building the divestiture list. The attached checklists can assist in addressing title defects or other problems.

Several general pitfalls commonly affect A&D activities:

Closing Date – Property Management Cut-off Date – Post Closing Date. Many confuse these dates and consider them to be the same date or that they are all somehow interrelated.

Companies are repeatedly encountered which have divested properties and have given employees notice without a thought to the transition of property and ownership management to the new owners.

The close date of the agreement is just the closing of the deal, when the parties sign off to major deal terms. This is almost never the same as the Property Management Cut-off date (also known as the Disbursement Cut-off date), which is usually several months later, depending on the number of properties or the complexity of the set-up by the buyer. A *transition agreement* usually controls this date.

Post Closing on all financial items is usually six months or more after the deal is consummated.

The key item to remember is that *staffing needs have not changed until the management responsibility transfers.*

Suspense. Many companies have insisted on keeping legal suspense finds accumulated to the point of property transfer. Reasons given vary, but usually it is because these were production periods when the seller operated the property, and the seller feels the owners will look to them for these funds. Also, many do not like giving up this cash or are afraid the new company will not manage it properly. Again, the expectation is that the owner will hold the seller liable for management of these funds.

In any event, retention of suspended dollars creates a myriad of problems. Any lag-time in taking over ownership maintenance and suspense management is very costly.

- Suspense is loaded by owner, property, and production month. Ownership and this suspense detail must be loaded simultaneously. If not, ownership changes and title will have to be traced back to the original owner and dollars prorated to the new ownership percentages. If a company does not have a mechanical ownership tracking system, this could mean hundreds of hours of work.
- If suspense is not transferred with the sale, then all owners with these suspended funds must still be retained and managed on the seller's BA, ownership, and revenue systems. Unfortunately, administration costs continue on properties no longer generating revenues for the company. In addition, owners expect to be dealing with companies who disburse to them. It forces owners to have to provide documentation and curative to two companies instead of one and to collect suspended funds from two sources, which may have two standards of title requirements.
- Other difficulties arise with out-of-period adjustments if suspense is not

transferred. Usually the buyer assumes all adjustments unless they are extremely large and are provided for in the post-close or side agreements. Any adjustments without related suspense would be skewed, and positives and negatives would not balance correctly.

If the language clearly shows the transfer of these funds to the buying party, liability should be clearly transferred. Of course, any amounts out of the ordinary should be specially handled.

Issues surrounding suspense should be clarified immediately. Agreements must be agreed to in writing in the Purchase and Sale Agreement or the Transition Agreement. This is where Land can be instrumental in affecting the wording of the agreements.

The buyer should insist on receiving this information current to the same date. If suspense detail does not match active property ownership, do not take the owners or suspense that do not match. Refer them back to the seller.

Minimum accumulated suspense is really a separate issue from legal suspense. Try to avoid assuming this suspense due to its small multiple amounts and varying levels of difficulty in loading this information. One of the best solutions is asking the seller to have a separate checkwrite or minimum suspense payment in the next checkwrite to clear these accounts up to the date of last disbursement by the seller.

In the alternative, ask that these funds be held until the seller's next regular minimum suspense clearance.

Files. A warning about file – don't assume that the files a buyer sees at a seller's office will be the same files delivered to the buyer's door.

A very structured, specific buyer's file due diligence is recommended. This effort will pay back in countless ways.

Well Status. Well status is a very important element in a divestiture. The usual intent is to include an entire field and/or all wellbores in a spacing unit. If shut-in or temporarily abandoned wells are not included on the exhibits, they will not be conveyed unless wording in a body of the assignment overrides the exhibit. This would leave a selling party with scattered properties in an area where it is abandoning operations. Also plugging liabilities would be left with the seller which were intended to be passed to the new owner. The buyer needs to know these properties exist if he or she wants to pursue secondary recovery, future completion attempts, and planning for plugging liabilities.

There is also a caution if a decision is made to not set up shut-in or temporarily abandoned wells when they are conveyed. If there is no ownership existing on the system on the properties, when future operations are conducted, they must be treated as new set-ups and time allowed for ownership to be researched or pulled from archived files. Confusion arises when Production conducts rework or recompletion on wells not existing on the system.

Title due diligence. Title due diligence is often conducted separately from administrative due diligence.

Each type of due diligence needs to be handled concurrently in order to more timely move the properties to the new owner.

Title due diligence concentrates on the interest the buyer is actually purchasing. It is easy to get diverted to side issues regarding pending deals, title problems with other owner's interests and pending administrative or operational issues.

Title due diligence must concentrate only on the legal validity of the interest to be conveyed and any encumbrances burdening that interest.

Administrative Acquisition Checklist

Task	Responsible Party	Due Date	Date Accomplished	Comments
1. Read and understand the Purchase and Sale Agreement, memorandum of understanding, or any other document pertinent to the deal.				
2. Preliminary review of the properties in order to build appropriate acquisition teams. Request a first review of the following for administration purposes:				
a) Lease Data Sheets and leasehold listings showing producing, non-producing, minerals, surface, Federal, State, and Indian.				
b) Leasehold obligations for 12 month period. (Delay Rentals, surface, rights-of-way, known shut-in payments, etc.)				
c) System-generated Divisions of Interest for Revenue and Joint Interest. (Oklahoma properties are involved, Proportionate Production Interests [PPIs].)				
d) Full explanation of disbursements responsibility.				
e) Preliminary land file review; ie., Lease Mineral, Surface, Contract Division Order and Prospect files.				
f) Imaged documents, if applicable.				
g) Suspense records.				
h) Number of consents to assign and Preferential Rights to Purchase.				
i) Change of Operator requirements, if applicable.				
3. Determine magnitude of property integration by:				

a) Number of properties, leases, and new owners.				
b) Restructure necessary to integrate the properties (mechanical load vs. manual load, burden ties, burden groups, suspense load, Oklahoma PPI load, Federal, State, and Indian).				
c) Operatorship and/or marketing changes				
4. Set up a preliminary draft (high-level) timeline based on understanding of the deal and preliminary administrative review.				
5. Participate in Transition Agreement terms based on review to dates.				
6. Meet with systems experts to scope and time-line any mechanical load.				
7. Scope Imaging system load, if compatible. If not, scope project to load properties per company guidelines. Enter into timeline.				
8. Obtain final property listing after title defect, consent and preferential right deletions. Rescope effort.				
9. Prepare Federal, State, Indian assignments and forward to appropriate agencies (log mailings).				
10. Commence lease system load mechanically and/or manually from data sheets or file information. Assign in-house BA and lease numbers and integrate with existing numbers where interest was just increased.				
11. Begin Property Master Load.				
a) Assign in-house new prospect numbers, property numbers, and well completion numbers. (Add to existing units if only				

increasing interest.)				
b) Populate new Business Associate (BA) numbers.`				
12. Load Revenue and Joint Interest Divisions of Interest with new or existing numbers.				
13. Obtain any ownership changes from date of load to management turn-over date. Make these ownership changes.				
14. Prepare and mail Letter-in-Lieu and/or notices per agreement with Seller. (Log)				
15. If marketing arrangements changes, obtain title from disbursor and set up or forward title to disbursor.				
16. Pile all appropriate Changes of Operatorship forms.				
17. Send joint interest owner change notice to working interest partners.				
18. File recordable documents in appropriate recording office (log mailing and returns).				
19. Send Seller copies of recorded instruments upon receipt from recording office (Log).				
20. Receive files with inventory. Complete a full inventory review from earlier file due diligence. Reformat as necessary and load to "File Tracker". Image as appropriate.				
21. Coordinate with Accounting if revenues and billings are not transferred pursuant to the Letter-in-Lieu with 60 days (perhaps 90 days for ORRIs). Send follow-up letter to payor if not changed.				

Title Due Diligence
Acquisition Procedures

Task	Responsible Party	Due Date	Date Accomplished	Comments
Due diligence				
1. Create major value list (usually top 80% of properties				
2. Review				
a)Prospect Files				
- Maps				
- Area Agreements				
- Area facilities owned				
- Intersection with other working interest owners				
b) Contracts				
- Operating Agreements				
- Exploration Agreements				
- Area of mutual interest agreements				
- Farmout agreements				
- Miscellaneous letter agreements				
- Participants/investor agreements				
- Communization Agreements				
c) Lease				
- Original/copy of lease				
- Supplemental/curative instruments				
(1)Ratifications				
(2)Stipulations of interest				
(3)Mortgage subordination agreements				
- Rental division orders				
- Delay rental receipts				
- Side agreements with lessor				
- Easements/surface damage agreements				
- Assignments				
d) Title to Interest Conveyed				
- Lease Purchase title opinions				
- Drilling title opinions				
- Special problems opinions				
- Division order title opinions				
- Supplemental opinions				

- Mortgage title opinions				
- Curative instruments				
e) Well				
- Operator				
- Completion reports				
- Drilling reports				
- AFEs				
- Regulatory authority orders				
(1)Spacing orders				
(2) Force pooling orders				
(3) Well location exception orders				
(4) Increased density orders				
(5) Order – enhanced recovery units				
(6) Miscellaneous orders				
- Elections of parties				
- Well location reports				
- Production reports				
- Working interest ownership information as related to interest to be conveyed.				
f) Division Order				
- Purchaser for seller				
- Magnitude of D/Os to distributes (Administration will handle the details)				
g) Mortgages				
h) Pending legal claims demands and lawsuits				
i) Synopsis of property				
- Chain of title into Seller complete				
- Any unsatisfied Seller's title requirements				

Pre-Divestiture Duties
(Offer or Data Room Stage)

Task	Responsible Party	Due Date	Date Accomplished	Comments
1. Coordinate with Reservoir Engineering and Business Development on divestiture properties. (Organize in value order)				
2. Prepare Well Listing (API, Production status, Operator, Well Zone, Well Completion, etc.)				
3. General verification of interests (Working, Revenue, BPO, APO interest types)				
4. Identify all program properties (Trusts, Partnerships, special burdened interests)				
5. Determine any interests to be retained (deep rights, acreage outside producing units, ORRIs, etc.)				
6. Determine undeveloped acreage and expiration dates.				
7. Start building task force team for the full effort.				
8. Build file list for these properties.				

Note: The amount of information offered in a data-room setting varies. Since no real offer has been extended, it is advisable to do only the amount of work necessary to promote a sale. Many complete consent and preferential rights to purchase review during this stage. However, this research usually overlaps after purchase and sale agreement is signed, depending on the number of properties.

Divestiture Checklist

Task	Responsible Party	Due Date	Date Accomplished	Comments
1. Understand the Purchase and Sale Agreement and Memorandum of Understanding with the specific properties to be sold. Set up preliminary timeline based on the deal. (**Note**: Many times sales get fragmented into multiple sales to various buying parties. Timeline each one.)				
2. Edit sales list down to those properties actually being sold.				
3. Schedule space for long-term due diligence use. Use previously created file list and pull files to be placed in due diligence room(s). (If any files are missing, log and follow up.)				
4. Draft a plan to coordinate use of files to ongoing business.				
5. Review all pertinent contracts for Preferential Rights to Purchase (value order).				
6. Review leases and contracts for consent to assign provisions.				
7. Determine federal, state, and Indian leases.				
8. Prepare and mail consents and Preferential Rights to Purchase letters (dollar proration needed for Preferential Rights letters).				
9. Prepare Exhibits to Assignments (Deeds to Mineral Interests separate). (Federal, state, and Indian also separate)				
10. Run lease data sheets. Provide related codes.				
11. Run copies of Division of Interest (preliminaries only; finals won't be provided until transfer of property management is completed). Provide related codes.				
12. Run preliminary related suspense (if requested).				
13. Manage Land Due Diligence Room.				

14. Participate in terms during the drafting of the Transition Agreement (if applicable). Assist in cost determination and advise as to land timeline.				
15. Receive and respond to title defects claims.				
16. Agree on file transfer. (Usually originals are kept by the seller if interest is retained by the seller and originals sent to the buyer.) Files are usually transferred after maintenance by the seller ends.				
17. Inventory files and arrange for shipping. Have a final sign-off from the Land Administration Due Diligence Lead as well as Document Control.				
18. Run final lease data sheets and Division of Interests. Transfer as of end of maintenance date along with related suspense.				
19. Depending on agreement, prepare Letters-in-Lieu and mail (if applicable)				
20. Inactivate all old properties/contracts or lease, contract and DOI systems. Adjust ownership on partially conveyed interests.				

Andrew R. Scott

Introduction

Coalbed methane (CBM), or coalbed gas, is a form of natural gas extracted from coal beds. The term coalbed methane has been used since the early days of the industry, because during the early years it was assumed that the only type of gas that would be generated from coal would be methane. Subsequent research changed this perspective once it was demonstrated that coalbed methane is comprised of methane, ethane, butane, pentane, and higher hydrocarbons, as well as carbon dioxide and nitrogen, rather than simply methane (Scott, 1994). In some areas, light weight (API 40+ gravity) oils are produced from coal seams. The term *coal gas* is being used more frequently when addressing the natural gases that occur in coal seams, whereas the term *coalbed methane* is still used to refer to the industry as a whole.

Coalbed methane represents an important part of the natural gas supply for the United States and will continue to do so in the foreseeable future. Initial coal gas exploration and development was conducted by major oil companies and larger independents, but smaller operators have played a progressively more important role in developing this natural resource.

Coalbed methane production in the United States has increased from 10 bcf in 1985 to more than 1,754 bcf in 2007. It now represents nine percent of total dry gas production and nine percent of proved dry gas reserves (Energy Information Administration, 2008). Coalbed methane resources are estimated to be more than 755 trillion cubic feet (tcf; 126 billion barrels of oil equivalent or BOE) in the contiguous United States, more than 80 percent of which is located in the western United States. Coalbed methane resources in Alaska probably exceed 1,037 tcf (173 billion BOE) (Clough and others, 2001), indicating that the total coalbed methane resources for the entire United States are 1,792 tcf (299 billion BOE).

However, expanded exploration efforts into other parts of the country and better resource assessments will undoubtedly increase these values. Coal gas proved reserves increased significantly over the past three years, primarily from new coalbed methane plays, and is currently estimated to be approximately 21.875 tcf (3.6 billion BOE)(Energy Information Association; 2008). Although over 50 percent of current coal gas production is derived from the San Juan Basin, coal gas production from other western basins continues to increase, particularly from the Powder River Basin, which now represents 23 percent of the total production. The unusually high water production associated with coal beds in the Powder River Basin is unique worldwide; many coal beds have relatively little or, in some cases, essentially zero water production.

Coalbed methane represents an abundant supply of environmentally clean energy and a source of hydrogen. Furthermore, unwanted greenhouse gases such as carbon dioxide also can be sequestered into coal beds. Injection of carbon dioxide into coal beds enhances coalbed methane production while simultaneously reducing greenhouse gas emissions to the atmosphere, thereby reducing global warming potential. Additionally, given the tragic events of September 1lth, the probability continued conflicts in the Middle East, and exponential population growth, there is a strong incentive for the United States to develop new environmentally friendly, energy resources in order to reduce our dependence on foreign energy supplies.

The increase in proved coal gas reserves despite the significant increase in production is attributed to the efforts of smaller operators and independents in finding new reserves. Coal gas production and reserves are expected to increase as exploration continues in unexplored areas and as secondary recovery techniques using nitrogen or carbon dioxide are employed.

This chapter summarizes various aspects of how gas is stored on coal seams, including sorption isotherms, and the critical hydro-geologic factors that affect coalbed methane production. Additionally, water disposal methods and coal gas ownership issues are reviewed.

Coal gas sorption and gas content

In conventional gas reservoirs, coal gases occupy the voids, which are either pore spaces or fractures, in clastic (sandstone) and carbonate (limestone and dolomite) reservoirs. The gas is not generally physically sorbed (trapped) to the mineral grains, but can be sorbed to organic matter in the rocks. The gases within these conventional reservoirs have been generated by source rocks such as shale and coal, and subsequently migrated to the reservoir. In contract, coal seams are often the source and the reservoir for the natural gas, although gases generated from other source rocks can migrate to the coal seams and become sorbed by the coal.

Well cuttings are collected during the drilling process and sealed in canisters and then taken to the laboratory for several tests. The amount of gas liberated from the coal is called the *gas content* and is usually given in standard cubic feet per ton of coal (scf/ton). Proximate analysis measures the moisture and ash (inorganic fraction) content of the coal. This is important because the coal gases are sorbed only on the organic fraction of the coal and not the ash. The gas content values are often corrected to a moisture and ash-free basis (dry ash-free or DAF) for comparison. Gas contents (DAF) in the subsurface can range from zero to more than 800 scf/ton, but most operators prefer a minimum of 150to 250 scf/ton depending on natural gas prices.

More natural gas can retained or sorbed to the coal surface as the pressure increases and in general, lower rank (less thermally mature) coals have a higher sorption capacity than higher rank (more thermally mature) coal seams. The coal samples are placed into canisters and the amount of gas that is sorbed at various pressures is measured. The laboratory tests are run under reservoir temperature and moisture conditions taking into consideration the types of gases that are sorbed on the coal. From these tests, a sorption isotherm is created. Each coal has a unique sorption isotherm, so it is important to perform enough sorption isotherm tests to characterize the reservoir,

If the measured gas content values at reservoir pressure fall on the laboratory-determined sorption isotherm, the coal is called *saturated* or saturated with respect to methane. If the measured gas content value falls below the isotherm, the coal is called *undersaturated,* and if the gas content value falls above the isotherm at reservoir pressure, the coal is *oversaturated* with respect to methane. For a variety of hydrogeologic reasons, most coal beds are undersaturated with respect to methane, and oversaturated conditions usually indicate errors in the gas content measurements or the laboratory-derived sorption isotherms. Truly oversaturated conditions in coal beds are very rare and cannot be determined from laboratory analyses.

For the operator, finding saturated or nearly saturated coal beds is very important economically, because the coal beds must be depressurized in order for gas production to begin. The coal seams are depressurized by removing water from the fractures (or cleats) in the coal. In undersaturated coal seams, coal gas production will start only when the measured gas content intersects the sorption isotherm at the critical desorption pressure during the dewatering stage. Therefore, coalbed methane production will continually increase during the first few years of production during the dewatering or depressurization stage, reach a maximum production rate, and then follow a normal type of production decline curve similar to conventional oil and gas reservoirs. In some cases, the production decline curve in coalbed methane reservoirs is nearly flat, indicating

that production may continue for 40 or more years.

Review of water disposal issues

Recently, concerns regarding coalbed methane water disposal have been raised, but many of the arguments against coalbed methane development as whole (industry) are based on misconceptions and omission of information. Arguments against future coal-bed methane development anywhere in the United States (and internationally) appear to focus primarily on activity in the Powder River Basin and ignore data from other basins worldwide.

Coal seams are heterogeneous arid; therefore, the water and gas production varies significantly among basins and even within coal-bearing basins. In some areas, there is essentially zero water production (e.g., less than one barrel per day), whereas some basins, such as the Powder River Basin, have very high production rates. Note that the high water production rates in the Powder River Basin are the exception and not the rule for coalbed methane. Unfortunately, some opposed to future coalbed methane development appear not to have looked at other coal-bearing basins before reaching their conclusions and passing judgment on the industry as a whole. Using natural gas produced from coal seams is much cleaner than burning coal for electricity generation. Natural gas generates only 117 pounds of carbon dioxide per million Btu's compared to over 205 pounds of carbon dioxide for bituminous coal (Energy Information Administration, 2009). Additionally, it will be natural gas that leads the way into the new "hydrogen economy", because natural gas appears to be the dominant source of hydrogen in the near term.

Coal seam waters can range from being fresh (potable) to highly saline and the water chemistry generally varies across the basin. The freshest coal seam water generally occurs near the outcrop where meteoric recharge occurs, but in highly permeable systems (such as the Powder River Basin), the fresh water can extend tens of miles from the outcrop. Fresh water can be disposed of through surface discharge or vaporization techniques using high pressure jet sprays to enhance evaporation, whereas less fresh water can be placed in evaporation pits. However, saline waters must be re-injected into the subsurface. In some cases, operators have re-injected the produced coalbed methane into oil reservoirs water as part of enhanced oil recovery water floods, thereby reducing the need for water from other sources. The rules for water disposal and the definitions regarding "too saline" vary significantly among the states. Some states insist that any coal seam water (potable or saline) is oilfield waste fluid and must be re-injected into an appropriate formation.

Review of coal gas ownership issues

During the initial stages of coalbed methane development, multiple lawsuits developed over who owned the coal gas — coal owners or gas owners. Much of the following information is taken from Lewin et. al., (1993) and documentation taken from the EPA 2003 website.

In 1993, Lewin *et al.* noted that the courts could apply any of six rules pertaining to ownership: (1) CBM is gas and gas owners have title to CBM, (2) CBM is coal and coal owners have title to CBM, (3) priority of severance, where the purchaser in the severing transaction receives title to CBM, (4) case-by-case, where title to CBM is based upon the documents in the severing transaction, (5) successive ownership where coal owners have title to the gas to CBM within the coal, but gas owners have tide to escaped or free gas in the gob zone, and (6) mutual simultaneous rights where gas owners have title to CBM and gob gas in conjunction with mining as an "incidental mining right". The primary focus of ownership issues appears to be the definitions of *coal*, *coal gas*, and how the gas is stored on the coal.

Coal is a complex compound consisting of an organic fraction and an inorganic fraction, called ash. The length of time for one foot of coal to form ranges from 65 years along the Mississippi River to 1,250 years in the Arctic. The organic fraction (ash-free coal) consists entirely of organic material deposited in the peat swamp over time. The ash fraction (ash) can be silt or clay that is carried into the peat environment by depositional processes, volcanic ash carried to the peat swamps by wind, and silica within the plant material itself. Coal gases are sorbed (adsorbed and absorbed) to the organic fraction of the coal, whose structure will expand or swell during the sorption process. Therefore, the argument boils down to whether the sorbed gas is actually part of the coal structure or whether the sorbed gas is separate from the coal.

The coal owner will argue that the coalbed methane is an inherent part of the coal and that ownership of the gas contained within the coal. Additionally, the coal owner may argue that (1) coal gases are adsorbed to the coal. (2) the physical bond between the coal and the coal gas is so close that the two cannot be separated, and (3) the coal is the source of and the reservoir for the coal gas (EPA, 1998).

The oil and gas owner may argue that the chemical composition of the coal gas is nearly identical to natural gases derived from other sources and that the gases may have migrated to the coal seams. These arguments provide the gas owner with a significant argument for ownership. The gas owner can further argue that the right to produce coalbed methane from coal is no different than the right to remove gas from other types of subsurface formations. The plain meaning of *gas* appears to definitely include coalbed methane, whereas in contrast *coal* commonly refers to a solid mineral, not a gas (EPA, 1998).

The oil and gas owner may further argue that (1) recovery methods parallel that of natural gas, (2) the migratory nature of coalbed methane is the same as natural gas, and (3) revision of the container space the gas owner once the coal is mined gives them the right to the gas (in cases where the gas owner is also the surface owner).

The surface owner may also claim interest in the coalbed methane, although this position is clearly the weakest (EPA, 1998). In states where the ownership of the container space reverts to the surface owner once the coal is removed, a surface owner could claim that that since he or she owns the space where the coal was previously situated, he or she could also claim ownership to the coal gases within that space. EPA (1998) states that this would not be a substantial argument since the gas or coal owner could easily counter that as the mineral owner, he or she is entitled to the mineral within the container space. However, where the coal and oil and gas rights have been specifically severed, the surface owner may be able to claim that since coalbed methane was not contemplated (but rather coal gas was considered to be a hazard) at the time of severance, ownership of the non-severed minerals (coal gas), remains with the surface or other mineral owner (EPA, 1998).

The ownership issue for coalbed methane is still being determined in some states, but on June 7, 1999, the United States Supreme Court ruled that coalbed methane (or coal gas) was not a part of the coal in the case of *Amoco Production Co. vs. Southern Ute Indian Tribe*. Therefore, the oil and gas operators were given ownership of coalbed methane. However, it appears that coalmine operators still retain ownership of the gob gas removed for safety purposes during or preceding mining operations. Hopefully, the Supreme Court decision will resolve most of the issues concerning coalbed methane ownership.

Coalbed exploration model

Previous coalbed methane exploration strategies are often based only on the location of the greatest net coal thickness and ignore other hydrologic and geologic factors affecting coalbed methane producibility . Coalbed methane producibility is determined

by the complex interplay among six critical controls: (1) depositional systems and coal distribution, (2) coal rank, (3) gas content, (4) permeability, (5) hydrodynamics, and (6) tectonic/structural setting (Scott, 1999). If one or more of these key hydrogeologic factors is missing, then the potential for higher coalbed methane producibility will be reduced. However, even with a missing key factor, the coalbed methane play may remain economically viable. For example, the Piceance Basin is characterized by exceptionally high gas content values (more than 700 scf/ton), but coalbed methane production has been limited because of low permeability. Conversely, the Powder River Basin remains economically successful with gas contents generally less than 20 scf/ton, because thick (more than 100 ft) coal beds are present at shallow depths.

The following summary of the key hydrogeologic factors affecting coalbed methane is after Scott (2002). It is important to note that coal seams are heterogeneous on many different levels ranging from microscopic (coal rnacerals or types of organic matter) to regional (basinwide). Therefore, an integrated hydrogeologic approach on a regional scale is critical for delineating coalbed methane sweet spots. Of equal importance, application of the exploration model can allow the operator to avoid areas with marginal coalbed methane potential, thereby allowing company resources to be focused in more profitable ventures.

Depositional setting and coal distribution

Coal beds are the source and reservoir for methane, indicating that their widespread distribution within a basin is critical to establishing a significant coalbed methane resource. Coal distribution is closely tied to the tectonic, structural, and depositional settings, because peat accumulation and preservation as coal require a delicately balanced subsidence rate that maintains optimum water-table levels but excludes disruptive clastic sediment influx. The depositional systems define the substrate upon which peat growth is initiated and within which the peat swamps proliferate. Net coal thickness trends and depositional fabric strongly influence migration pathways and the distribution of gas content. The depositional setting also controls the types of organic matter – macerals - which affect sorption characteristics and the quantity of hydrocarbons produced from the coal. Knowledge of depositional framework enables predication of coalbed thickness, geometry, and continuity and, therefore, which potential coalbed methane resources.

Tectonic and structural setting

The tectonic and structural setting control of a basin control the distribution and geometry of coal beds in the basin during deposition, and therefore, exert a strong control on the lateral variability of maceral. Both the burial history and stress direction control the timing of cleat development in various parts of the basin and the final orientation of face cleats. The basin burial history and variability of regional heat flow control coalification and the types and quantities of thermogenic gases generated from the coals. Additionally, present-day *in situ* (in its original place) stress directions may significantly affect coalbed methane producibility. Stress directions orthogonal to face cleats will lower permeability, whereas stress directions *parallel* to face cleat orientation may enhance permeability. Uplift and basinal cooling often result in undersaturation with respect to methane in the coals and possible degassing of coal beds. Finally, the location and geometry of faults may strongly influence the recharge of meteoric water, and therefore, the generation of biogenic gases.

Coal rank and gas generation

Coals must reach a certain threshold of thermal maturity (vitrinite reflectance values between 0.8 and 1.0 percent; high-volatile A bituminous) before large volumes of thermogenic gases are generated. The amount and types of coal gases generated during coalification are a function of burial history, geothermal gradient, maceral composition,

and coal distribution within the thermally mature parts of a basin. Gases in coal beds may also be formed through the process of secondary biogenic gas generation. Secondary biogenic gases are generated through the metabolic activity of bacteria, introduced by meteoric waters moving through permeable coal beds or other organic-rich rocks. Thus, secondary biogenic gases differ from primary biogenic gases because the bacteria are introduced into the coal beds after burial, coalification, and subsequent uplift and erosion of basin margins. Secondary biogenic gases are known to occur in sub-bituminous through low-volatile bituminous and higher-rank coals (Scott, 1993; Scott et al., 1994).

Gas content

Gas content is one of the more important controls of coalbed methane producibility, yet often is one of the more difficult parameters to accurately assess. Gas content is not fixed, but changes when equilibrium conditions within the reservoir are disrupted and is strongly dependent upon other hydrogeologic factors and reservoir conditions (Scott, 2002). The distribution of gas content varies laterally within individual coal beds, vertically among coals within a single well, and laterally and vertically within thicker coal beds. In general, gas content increases with depth and coal rank, but is often highly variable due to geological heterogeneities, the type of samples taken, and/or the analytical laboratory. The gas content of coals can be enhanced, either locally or regionally, by generation of secondary biogenic gases or by diffusion and long-distance migration of thermogenic and secondary biogenic gases to no-flow boundaries such as structural hingelines or faults for eventual resorption and conventional trapping. Therefore, determination of migration direction through isotopic and hydrogeologic studies is critical for determining migration direction and the areas of higher gas content.

Permeability

Permeability in coal beds is determined by its fracture (cleat) system, which is in turn largely controlled by the tectonic/structural regime as mentioned previously. Cleats are the permeability pathways for migration of gas and water to the producing well head, and cleats may either enhance or retard the success of the coalbed methane completion. Permeability will decrease with increasing depth, suggesting that in the absence of structurally enhanced permeability at depth, coalbed methane production may be limited to depths less than 5,000 to 6,000 A . Permeability is highly variable in coal beds ranging from darcies to microdarcies, but the most highly productive wells have permeability ranging between 0.5 to 100 md. Higher permeability will result in recovery of more sorbed coal gases, because lower reservoir pressures and, therefore, more coal gas desorption will occur in higher permeability reservoirs. However, permeability that is too high results in high water production and may be as detrimental to the economic production of coalbed gas as extremely low permeability.

Hydrodynamics

Hydrodynamics strongly affects coalbed methane producibility and includes both the movement of meteoric water basinward as well as the migration of fluids from deeper in the basin. Basinward migration of ground water is intimately related to coal distribution and depositional and tectonic/structural setting because ground water movement through coal beds requires the recharge of laterally continuous permeable coals at the structurally defined basin margins. Coal beds act not only as conduits for gas migration but also are commonly ground-water aquifers having permeabilities that are orders of magnitude larger than associated sandstones. The presence of appreciable secondary biogenic gas indicates an active dynamic flow system with overall permeability sufficient for high productivity. Migration of thermogenic gases may result in abnormally high gas contents in lower rank coals or coals that are saturated or oversaturated with methane. Basin hydrogeology, reservoir heterogeneity, location of permeability barriers (no-flow

boundaries), and the timing of biogenic gas generation and trap development are critical for exploration and development of unconventional gas resources in organic-rich rocks.

Conclusions

Coalbed methane is an important resource that has evolved from a possibility 25 years ago to a significant part of our national energy supply today. Coal gas chemistry is highly variable and is comprised of mostly methane. Therefore, coalbed methane represents an environmentally friendly source of energy; recovery of only a small fraction of the natural gas from coal seams will reduce the nation's dependence on foreign sources of energy, thus enhancing national security. Concerns regarding excessive water production from the industry as a whole, derived from the exceptionally high water production in the Powder River Basin, appear to be unfounded. Coal gas ownership issues have been resolved in many states, although it is important to verify ownership before securing a land position.

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