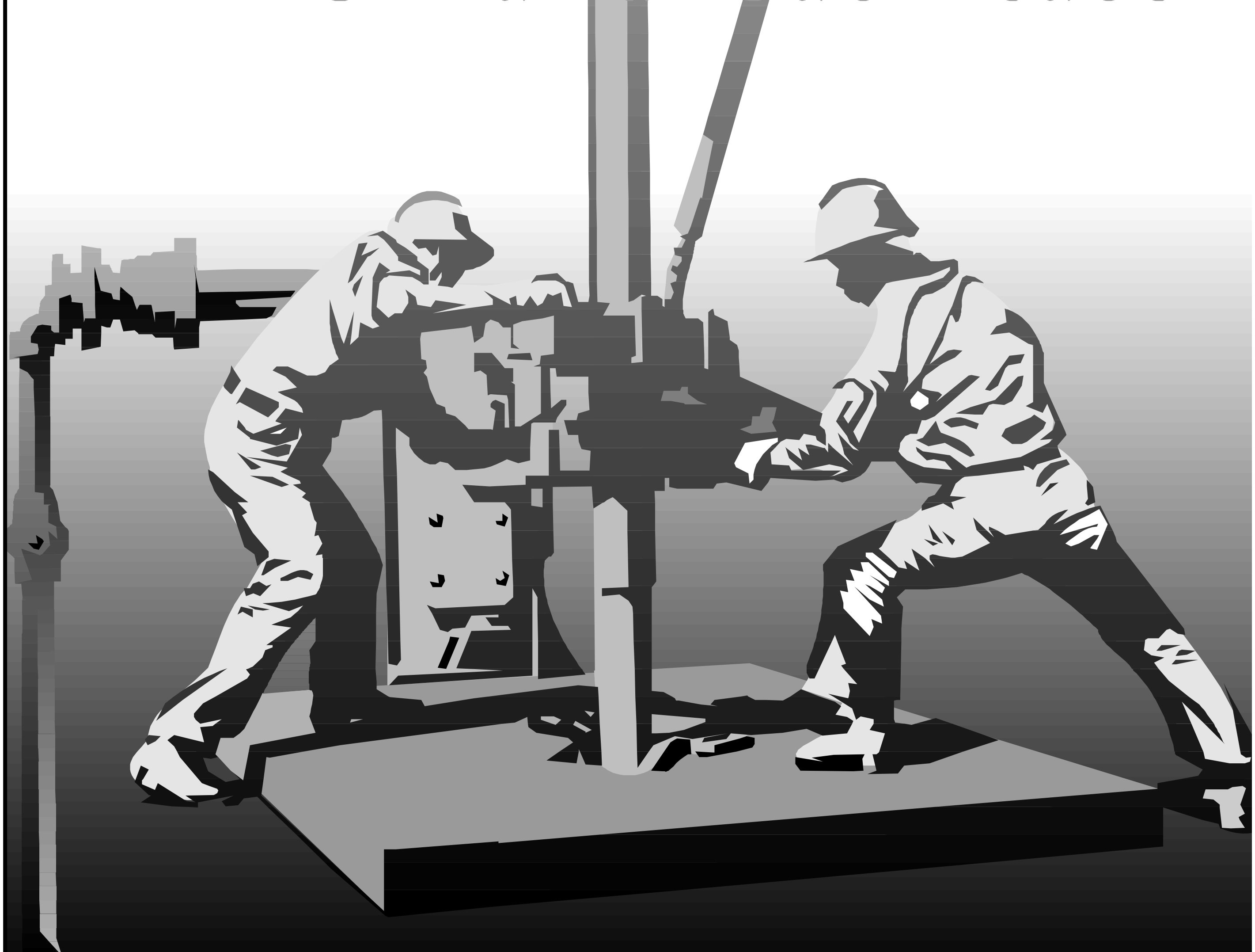
REAL ESTATE CENTER

Hints on Negotiating An Oil and Gas Lease



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Real Estate Center

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Advisory Committee

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Solutions Through Research

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Summary

From the mineral owner's perspective, an oil company seeking a lease is generally a welcome sight. The prospect of productive wells on the property could mean substantial income. Before exploration can begin, however, the mineral owner (lessor) and the oil company (lessee) must agree to certain terms regarding the rights, privileges and obligations of the respective parties during the exploration and possible production stages. The negotiation of these terms may be the mineral owner's first exposure to an oil and gas lease. Because of the legal nature of the leasing arrangement, an inexperienced mineral owner may be at a disadvantage when dealing with a more experienced lessee.

The purpose of this report is to acquaint nonexperts with the more common provisions of an oil and gas lease and explain their legal significance. The report details some provisions that the mineral owner may wish to insert for personal benefit and protection. However, the report is not a substitute for legal counsel.

Leasing Provisions

No standard or universal lease form is used by the oil and gas industry. Instead, each company (or independent lessee) has a predrafted agreement, usually some version of a Producers 88 Lease Form that has proven suitable to them in the past. The agreement may not necessarily be in the best interest of the mineral owners.

Mineral owners should remember that all provisions of a lease are negotiable. Even though the oil company representative or landman soliciting the lease may be unauthorized to make changes, certain clauses or even the complete lease may be altered. However, the mineral owner's ability to negotiate more favorable terms varies with each situation.

Three factors influence the negotiating power of the mineral owner. The first is the amount of acreage the lessor controls. The second is the proximity of the acreage to known production. And the third is the number of oil companies vying for the lease. The ideal situation for the mineral owner is to have a larger tract next to a newly discovered field with numerous oil companies seeking a lease.

If favorable terms are negotiated, they should be in writing and incorporated into the lease. There are three acceptable means of accomplishing this.

First, for minor modifications, strike the provision to be altered, insert the change and initial the margin of the page (both parties). Some authorities want the date inserted next to the initials. This process would be followed when changing the lease royalty from 1/8 to 1/6.

Second, for more pronounced modifications, attach an addendum to the lease. The preface to the addendum begins, "Notwithstanding anything to the contrary in the foregoing Oil, Gas and Mineral Lease, the following terms and provisions control. . . ." The individual changes are then listed.

If the addendum becomes quite extensive, and if it contains terms the lessee does not want to become public knowledge, a Memorandum Lease may be executed and recorded in its place. The Memorandum Lease contains the minimal information necessary to give constructive notice of the lessee's oil and gas lease. Generally, it will recite the name and address of both the lessor and lessee, the lease date, the length of the primary term and the legal description of the property.

Third, a way to make changes to a lease and, at the same time, to keep the changes from becoming public information is to enter a letter agreement. Letter agreements generally are used to clear up minor problems with the lease just prior to the commencement of drilling operations.

Granting Clause

The opening paragraph of the lease is the granting clause. It outlines the purpose of the lease and describes the substances that can be explored and produced. Typically, the clause will state that the lease is given for the purpose of exploring, drilling, mining and producing oil and gas and all other minerals, whether similar or dissimilar.

If substances other than oil and gas are produced, two problems become apparent in Texas. First, if the substances sought lie near the surface or will substantially damage the surface when produced, the substance may belong to the surface owner. (This creates a problem only when the mineral owner is not the respective surface owner.) Second, if substances other than oil and gas or associated hydrocarbons are discovered, will the lease cover them? (For more information, see *Minerals, Surface Rights and Royalty Payments,* publication 840.)

There are no easy answers, but here are some suggestions to consider:

- To avoid any dispute between the surface and the mineral owners, specify that the extraction method used by the lessee can be through a borehole only. Bar all strip mining and other methods that substantially destroy the surface. Mineral owners must realize that all substances lying beneath the surface do not necessarily belong to the mineral owner.
- Resolve speculation concerning the substances covered by the lease by specifying those included to the exclusion of all others, i.e., all petroleum and natural gas and related hydrocarbons except coal, lignite and uranium.

Granting Clause and Surface Operations

With few exceptions, the grant of an oil and gas lease carries the implied right to use as much of the surface area as is **reasonably necessary** to explore and produce the oil and gas. Most leases expand these implied rights and explicitly permit a wide range of surface activities.

Even though the lessee may be liable for surface damages (see p. 7), the inconvenience of unwanted and unwarranted structures and entries upon the surface may be avoided to some degree by the following:

- Do not grant an unrestricted right for the underground disposal of salt water in abandoned wells on the property. Instead, state that prior written consent of the lessor is needed.
- Confine the lessee's routes of ingress and egress to existing roadways on the leased premises. If deviations are necessary, require them from the nearest roadway. Determine whether new roadways built by lessee must be removed when the lease terminates. Specify where cattleguards are required and who will maintain locked gates. Discuss erosion prevention techniques along roadways and around drill sites. For convenience sake, leases generally do not permit wells within 200 feet (or some other stipulated distance) of a dwelling. The mineral owner may want more distance. Further, provide that all underground transmission devices such as pipelines and telephone lines must be buried below plow depth (or a specified depth) in agricultural areas.
- Mineral owners wishing to cultivate or graze the area immediately above any pipelines should direct the lessee to use the double ditch method for laying pipe. This method requires the top soil to be placed on one side of the trench and the subsoil on the other. When backfilling, the subsoil is replaced first, followed by the top soil.
- In Texas, the lessee has the implied right to use caliche found on the leased premises free of charge for construction of drill sites and roads. The mineral owner may wish to alter contractually this rule in the lease.
- Specify that the lessee's structures and equipment **must be removed** within a certain time after the lease expires or be

forfeited. Otherwise, problems may arise concerning their ownership.

- Identify the parties liable for the construction and maintenance of fences and gates or similar structures around the premises, pits, drilling sites and above intersecting pipelines. The precise dimensions and characteristics of the fences and gates may need to be included.
- The mineral owner may require prior consent for conducting seismic or other geophysical operations. With the advent of three-dimensional (3-D) seismic, the potential for surface damages is significantly increased, adding to the importance of this clause.
- If the lessee must cut a fence to build a road or install a pipeline, describe the methods for bracing the fence prior to its breach.

Duration of the Lease

Leases are divided into two periods. The first period (primary term) is a set number of years negotiated by the parties during which drilling operations must begin or delay rentals must be paid. The lease generally states that if drilling operations are not being conducted within one year after the lease is entered, the lease terminates **unless** an agreed sum is paid to the lessor. This sum is called a *delay rental.* Delay rentals must be paid on each subsequent anniversary date of the primary term whenever drilling operations or production are inactive.

Failure to receive a required delay rental payment automatically terminates the lease whenever the word *unless* is used to indicate the necessity of the payment. Some leases contain the word *or* rather than *unless.* In the latter case, the lease will not terminate for a delinquent payment. Some leases have all the delay rentals paid in advance at the commencement of the lease. These are known as *paid-up leases.*

If production is not established by the end of the primary term, the lease will end. If production has been established, the lease will continue into its secondary term and last so long as substances covered by the lease continue to be produced. Generally the full clause will read, "This lease shall remain in force and effect for a term of ______ years and as long thereafter as oil, gas or other mineral is produced from said land." Newer leases substitute the word *operations* for *production.* These leases read, ". . . as long thereafter as operations, as herein defined, are conducted upon the said land."

For protection, the lessor should consider one or more of the following recommendations:

- Strive to keep the primary term as short as possible. This will force earlier exploration.
- If the primary term cannot be shortened, strive to negotiate a higher annual delay rental payment.
- Make sure the word *unless* is used. Avoid using the word *or*. Keep a watchful eye on the date by which the delay rental payments must be received. Acceptance of a late payment may be construed as a ratification, and the lease will not terminate.
- Require the lessee, when tendering delay rentals, to identify the lease necessitating the payment. This is an invaluable aid for mineral owners trying to keep track of several different leases on their land, especially when all or part of a lease has been assigned to another oil company.
- State that the delay rentals must be received, not simply postmarked, on or before the due date. Delete any lease provisions requiring the prior notice to the lessee of nonpayment of delay rentals before the lease will terminate as drafted in a 12/79 Producers 88 Lease Form.

Extension of the Primary and Secondary Terms

The primary and secondary terms of the lease may be extended via the shut-in provisions, dry-hole provisions and cessation-of-production provisions. Most leases contain all three.

The shut-in provisions allow the lease to remain in effect whenever the production from a well is not being sold or used by the lessee. Only a well capable of producing in paying quantities may be shut in. A shut-in well, though, is classified as a producing well, and the lease will not terminate as long as the shut-in continues. Even so, a shut-in royalty (generally a sum approximating the amount of the delay rental payment) must be paid annually after the expiration of the primary term to continue the lease.

The dry-hole provisions, on the other hand, will extend both the primary and secondary terms of the lease. Basically, the lease provides that if oil or gas **has not** been discovered when a dry hole is drilled, the lessee has several options for continuing the lease. First, in the event the primary term has not expired and more than 15 months still remain, the lessee has **two options.** The lessee either can pay the next delay rental payment that comes due 90 days after the dry hole was drilled or alternatively commence drilling or reworking operations on or before the next anniversary date occurring 90 days after the dry hole.

Second, if less than 15 months remain in the primary term, the lease will continue to the end of the primary term even though the lessee's operations remain idle and no delay rentals are paid. However, drilling or reworking operations must recommence on or before the end of the primary term to continue the lease.

Finally, if the lessee was in the process of drilling a well when the primary term ended, the lease will not terminate when the dry hole is discovered. Instead, the lessee has 90 days to resume drilling or reworking operations to continue the lease. (A 90-day period is the most common time frame. However, the period may vary from 60 to 180 days, depending on the lease.)

The cessation-of-production provisions correspond quite closely to the dry-hole provisions. The main difference is that the cessation-of-production rules apply **only after** oil and gas have been discovered. In this event, the lease provides that if oil and gas production should cease for any reason, the lease will continue if the lessee follows one of the options previously described for the dry-hole provisions.

It is theoretically possible for the lease term to be extended indefinitely via the dry-hole and cessation-of-production provisions. If the lessee has not discovered oil or gas, and if the lessee is in the process of drilling or reworking operations when the primary term ends, the lease will continue in force for so long as the lessee faithfully renews drilling or reworking operations within 90 days after the termination of each operation. However, if a producing well subsequently should be discovered and its production later ceases, the lessee must again renew drilling or reworking operations within 90 days to hold the lease. Although the indefinite extension is theoretically possible, in reality it does not happen because of the costs involved.

More recent leases combine the dry-hole provisions and the cessation-of-production provisions under one general heading known as *operations.*

Most mineral owners usually do not disagree with the dry-hole and cessation-of-production provisions because, in either case, oil and gas are being sought diligently. However, mineral owners may have difficulty accepting the shut-in provisions, especially when no apparent reason for nonproduction exists.

Because of the high cost of bringing a well on line, shut-in provisions are used rarely except for the lack of a pipeline or buyer. Even so, mineral owners may wish to consider the following alternatives:

- Place a maximum limit on the shut-in, i.e., no more than three years or three years beyond the end of the primary term. Beware of placing a limit on the **consecutive** months for a shut-in without limiting the **cumulative** months.
- Possibly escalate the amount of the shut-in royalty payments for each year the gas or oil is shut in.
- As an alternative, permit the shut-in to continue after a stated period but only for a given number of acres immediately surrounding the well, i.e., 160 acres. The rest of the lease reverts to the lessor. (This provision may be qualified, depending on the reasons for the shut-in.)
- Because shut-in royalties are generally prepaid annually, confusion may arise if the lessee lifts the shut-in and produces during the year. Is the lessee allowed credit for both the money and the months that were prepaid but not used?

One alternative is for the lessee to prepay shut-in royalties monthly, not annually. Another is to require the lessee to account to the lessor for any months that were prepaid but not used at the end of each payment period. The failure to account causes a forfeiture of the unused months.

- Specify the circumstances when the shut-in clause may be invoked, i.e., for lack of market, available pipeline or governmental restrictions. As a possible alternative, permit the shut-in when, in the lessee's good faith judgment and with the lessor's consent, it is economically inadvisable to produce.
- Consider limiting shut-ins to gas wells only. Exclude oil wells from shut-ins.
- Automatically terminate the shut-in whenever a well located on adjacent land, situated within a certain number of feet of the leased premises and completed within the same producing reservoir, begins producing and selling gas in marketable quantities.

Royalty Clause

Each lease contains a paragraph that allocates to the mineral owner a certain portion of the substances produced. The allocation may be stated in terms of market price or value, proceeds or in kind. This is the *royalty clause.* From an economic standpoint, this may be the most important clause to the mineral owner.

The terms of royalty clauses vary from lease to lease. Through the evolution of court cases, the clause has been clarified in Texas. However, the mineral owner still should consider several items.

One consideration is expense that can be deducted from the royalty payments. The costs encountered throughout the exploration, drilling, production and marketing stages are divided into two categories:

- those borne solely by the oil company (producer) and
- those shared by the mineral owner.

All expenses encountered through the production stages are borne solely by the oil company unless the mineral owner has purchased a working interest in the well. Expenses subsequent to production either can be shared or borne solely by the oil company, again depending on the terms of the lease.

If any costs are shared, the lessor's percentage is dictated by the size of the royalty. If the royalty is 1/6, the royalty owner's share is 1/6. By negotiating a larger royalty, the mineral owners, in effect, are agreeing to shoulder a greater percentage of the costs.

The shared expenses depend partly on where the lease fixes the royalty. Commonly, the royalty for oil is set "at the well" or "wellhead." In such cases, the mineral owner's royalty payment is free of production costs, but **all costs** subsequent to production are shared. (Two 1996 Texas Supreme Court decisions, *Heritage Resources, Inc. v. NationsBank,* 09-0515, and *Judice v. Mewbourne Oil Co.,* 95-0115, so held even though the lease addendum stated the royalty was free of such costs.) If the lease fixes the royalty "in the pipeline," "at the place of sale" or at other delivery points, different costs subsequent to production may be shared. These costs may include items such as compression expenses necessary to make the product deliverable into the purchaser's pipeline, expenses necessary to make the product salable, transportation costs and the expenses used in measuring production.

Another consideration for the mineral owner is determining how the royalty payment is valued or received. The leases generally provide three methods.

First, the mineral owner's royalty may be based on the "market price" of the product produced. *Market price* basically means the highest posted field price existing for the field. If there is no field price, then the value is determined by comparable sales in time, quantity, quality and availability. And if there were no comparable sales, the actual or intrinsic value of the substance is used.

Sometimes the posted prices are discriminatory, set artificially and substantially less than the prices paid for comparable minerals at other fields. In such cases, it may be possible to get a higher valuation for the royalty payments but only after a difficult burden of proof has been met by the mineral owner in a judicial proceeding.

To avoid the problem, a formula may be inserted to determine how the market price or value will be established. For example, some leases read, "at the highest price (or percentage thereof) posted for a field within 100 miles by any of the seven major oil companies for like grade and gravity on the day the oil is removed."

The second means of evaluating royalty is "proceeds." This method bases the royalty upon the actual revenue derived from the sale of the mineral. As such, the resulting sales price may or may not equal the mineral's actual market price as discussed earlier. In the past, royalties based on proceeds have been popular for marketing gas. By committing gas to long-term contracts, the producer could insure the mineral owner of a constant, dependable royalty income over time. The disadvantage was that the resulting proceeds were not immediately sensitive to a rising market.

The third method of receiving royalties is "in kind." This method presents an excellent alternative for dealing with a lease based on proceeds. By inserting an option to take royalties either "in proceeds" or "in kind," the mineral owner can get the best of both worlds. When the market price rises above any long-term commitment price, the mineral owner can take his or her share "in kind" and seek a market outlet. When the market price falls below any long-term commitment, the lessor's share can be taken in proceeds.

The in-kind, in-proceeds alternative is quite attractive to a mineral owner when one or more gas wells or pipelines are dedicated to the highly regulated interstate market. By the mineral owner opting to take royalty "in kind," the gas possibly can be sold on a more lucrative intrastate market. As a general rule, lessees are hesitant about granting this option unless the lease is in a major producing field. Otherwise, the cost of storage, accounting, delivery and other associated expenses will outstrip any gains to the mineral owner.

Briefly, the following factors may be considered when negotiating a royalty clause:

- Detail the time, place and frequency royalty payments are to be tendered. Outline the consequences for missing royalty payments. Do not limit the penalty for a delinquent payment to interest only. Terminate the lease if the delinquency exceeds a stated period, such as 180 days. Should the lease terminate for nonpayment of royalties, make sure the equipment, tubing, casing and other machinery used in production are forfeited as well so the mineral owner may use them to withdraw any remaining oil or gas.
- Discuss whether or not the lessee has the right to disburse royalty payments. Some purchasers will give 100 percent of the proceeds to the lessee and require the lessee to pay the royalty owners. Operators have been known to keep the funds and disappear.
- Reserve the option to take "in kind" if feasible.
- Consider an extra royalty (or overriding royalty) based upon recovering all or a certain percentage of the production cost from the well. The overriding royalty also may be based on other variables.
- Determine if and when the mineral owner should have access to free gas. Many leases allow the lessor the free use of gas for domestic (and sometimes agricultural) purposes.
- By the same token, decide whether the lessee should have free use of water, oil and gas produced on the leased premises. (See p. 9 under the heading "Lessee's Right to Free Water, Oil and Gas" for further details.)
- Provide that costs subsequent to production may be deducted from the mineral owner's royalty, but that they will be reimbursed on a quarterly basis. This may be one way to avoid the effects of the *Heritage* and *Judice* decisions mentioned earlier.
- State that any division order tendered to the mineral owner after production begins cannot alter the lease. Texas law holds that any executed division order that contradicts the lease overrides the lease unless the division order conforms to the one described in Texas Natural Resources Code Section 91.402(c)(1). (See *Minerals, Surface*

Rights and Royalty Payments, publication 840, for more details.) Consequently, provide that if the division order, not in conformity with the statute, contradicts the lease, the mineral owner has the right to alter the division order to comply with the lease before executing it. If, by making the division order comply with the lease, additional charges are borne by the lessee, ask the lessee to agree to pay the additional charges in advance.

- Place a minimum royalty provision in the lease. A minimum royalty provision provides that unless a certain amount of revenue is received annually from royalties or other sources, such as shut-in royalties, the lease terminates. The minimum royalty provision prevents a small amount of production from perpetuating a lease for a large number of acres. (For more information, see *Termination of an Oil and Gas Lease,* publication 601.)

Surface Damages

Granting an oil and gas lease carries the implied right to use as much of the surface as is reasonably necessary for the development of the minerals. Only when the lessee goes beyond what is reasonably necessary, negligently injures the surface area or fails to accommodate estates will the lessee become liable to the surface owner for damages. Likewise, the lessee is under no legal obligation to restore the surface when production ceases. (For more information, see *Minerals, Surface Rights and Royalty Payments,* publication 840.)

For better protection, the mineral owner may wish to insert some provisions in the lease pertaining to surface damages. For instance, a lease clause requiring **compensation for all surface damages** will render the lessee liable even though the injuries were incurred during the reasonable development of the leased premises.

When compensation is required, it is commonly made at the site when drilling or production operations cease. To avoid any conflicts in this matter, the mineral owner should consider the following items when negotiating the lease:

- Require **compensation for all surface damages** such as injuries to growing crops and pastures; erosion and stagnation of the soil; growing timber; livestock; fences, ditches, canals, buildings and other structures; and the pollution of any surface or subsurface waters.
- Require the lessee to restore the land when operations cease.
- Describe the method or methods to be used for determining the extent of the damages. If the parties cannot agree, provide for some nonjudicial means of resolving dispute. Selecting an appraiser agreeable to both parties to determine the damages is a possibility.
- Determine if the compensation will be paid annually or in a lump sum. In part, this decision will depend on whether the damages are temporary or permanent.
- Resolve beforehand how payments will be distributed among the respective owners of the surface estate. This problem mainly arises when an agricultural lessee is on the premises.
- Designate the time by which all claims or notices must be submitted to the lessee and how soon thereafter the lessee must pay them.
- Possibly require a performance bond or an escrow account as security for payment of surface damages **before** drilling operations begin.
- Another possibility is to require a specific prepayment for each drill site in lieu of subsequent surface damages. Approximate the payment based on the fair market value of the land used for the drill site.
- If the lease is assigned, hold the assignor(s) and assignee(s) jointly and severally liable for surface damages. If this cannot be negotiated, require surface damages to be paid **before** the lease can be assigned. Otherwise, the lease may be assigned to a failing oil company that has no means of paying surface damages.

Pooling

Most leases will contain some provision giving the lessee the right to consolidate the leased premises with adjoining leased tracts. The area thus formed is called a *pool* or sometimes a *pooled unit.* Pools are established to unite under one operator all the mineral owners having an interest in a common underground reservoir. By doing so, the lessee avoids unnecessary drilling, protects the rights of the mineral owners in the common reservoir and prevents waste. Pooling also permits the lessee to drill the best site otherwise prohibited by the state spacing requirement of 467 feet from a lease line. Sometimes pooling arrangements are necessary to meet the minimum acreage requirement for a drilling permit under Rule 37 of the Texas Railroad Commission.

In Texas, mineral owners may be subjected to two types of pooling. One is voluntary, and the other is compulsory or statutory. The voluntary arrangement requires the consent of the mineral owner and is generally found in the context of most lease forms. The statutory arrangement, on the other hand, is mandatory when the requirements specified in Chapter 10 of the Texas Natural Resource Code have been met. By entering either type of pooling arrangement, the mineral owner's share of the production will be determined by multiplying the lease royalty times the resulting fraction found by dividing the number of acres the mineral owner has in the pool by the total number of acres in the pooled unit.

Obviously, the mineral owner can do little to avoid compulsory or statutory pooling. However, the mineral owner may want to be cautious before consenting to voluntary pooling. The following suggestions may be helpful:

- In Texas, unless the mineral owner consents to voluntary pooling, the lease cannot be pooled. Consequently, the mineral owner may wish to withhold consent until the full impact of the pooling arrangement on the lease terms is understood.
- Alternatively, the mineral owner may consent to voluntary pooling in the lease but state that any pooled unit formed using the leased premises must contain a minimum percentage of the lessor’s land.
- To limit a pool, stipulate the maximum acres a pool may contain. As a rule of thumb, limit the acreage to no more than that specified in the Texas statutory pooling provisions, which is presently 160 acres for an oil well and 640 acres for a gas well plus 10 percent tolerance for each. However, where the field rules differ or where horizontal drilling occurs, allow the size to conform to whatever is needed for maximum allowables based on the rules of the railroad commission.
- If possible, negotiate all pooling prior to drilling operations and not afterwards.
- Consider whether or not the lessee may change the size or shape of the pool after the mineral owner consents.
- In all cases, negotiate the inclusion of a *Pugh clause.* A Pugh clause provides for the severance of the lease between the pooled and unpooled acreage whenever less than all of the lease tract is included in a pooled unit. The severance generally occurs at the end of the primary term or at the end of a continuous drilling program, whichever is longer. By having the severance, operations conducted on the pooled unit will not hold unpooled acreage and vice versa.

Without a Pugh clause, leases generally provide that any operations conducted on the pool shall be construed as operations on the entire lease tract. Therefore, production, drilling or reworking operations conducted on any portion of the pool, whether actually on the lease tract or not, hold the entire lease.

- On larger tracts, modify the Pugh clause for the severance between the acreage in a production or proration unit (whether pooled or unpooled) and the rest of the lease at the end of the primary term. It is possible to create a production unit using only the acreage from one lease. (This is known as a *tract well*.) In such cases, one well holds all the leased premises unless the wording of the Pugh clause is modified.

Assignment Clause

Typically, leases contain a provision permitting both the lessor and the lessee to assign their rights and interest under the lease. To a large extent, these provisions are for the lessee's benefit to negotiate with other oil companies.

A customary practice is for an individual or independent oil company to lease a large tract and assign (sell) all or a part of it to another oil company. Consequently, the ultimate developer-producer may not necessarily be the original lessee. To retain partial control over assignments, the mineral owner may incorporate some of the following suggestions:

- State that the lessee must notify the mineral owner of any assignment. A 1989 Texas appellate case upheld the validity of a clause providing for $1,000 liquidated damages if the lessee fails to notify the lessor of an assignment.
- Do not release the original lessee from liability for a default on any assigned portion of the lease or leased area. This is particularly important when surface damages and royalties remain unpaid.
- Nullify any assignment unless the production from a well exceeds a certain limit. Many times a marginal lease changes hands because another operator has discovered the "key" for making the well produce. The lessee will attempt production, fail and leave without paying royalties and surface damages.

Warranty Clause

Leases generally contain provisions requiring mineral owners to defend their interest in, or title to, the leased premises should an ownership dispute arise. This is known as the *warranty clause.* If the mineral owner breaches the warranty, the lessee has two alternatives. The lessee may sue the mineral owner for the return of any consideration paid for the lease such as bonuses, delay rentals or royalties. Alternatively, the lessee can reduce any payments forthcoming to the mineral owner according to undivided interest owned by the mineral owner in the property. For example, if the lessor owns half the minerals and purports to own all the minerals, the oil company may pay the lessor only half the bonus, half the delay rentals and half the royalties. The latter alternative is described in a lease provision known as the *proportionate reduction clause.*

To avoid litigation, mineral owners should delete any language that infers they will warrant or defend the chain of title to the land. Instead, a limited or special warranty should be used. Because most oil companies or landmen generally conduct title searches prior to leasing, negotiating a special warranty should not be a problem.

Lessee's Right to Free Water, Oil and Gas

Mineral owners should pay close attention to lease provisions allowing free water, oil or gas to the producer for operations. In Texas, the oil company has the right to use fresh water, found either above or below the ground, for exploration and production purposes unless a change is negotiated. Particularly in areas where water is scarce, certain limitations should be placed on these rights.

- Decide whether free water, oil or gas privileges should be granted to the lessee. If so, stipulate whether the substances may be used for operations conducted both **on** and **off** the leased premises. (These provisions may be incorporated into the royalty clause as mentioned earlier.)
- If the land should contain a central supportive device, such as an oil-gas separator, prorate the free use of oil and gas needed to run the separator according to the amount of production from the leased premises if free rights are given.
- Do not allow the lessee to take free water from wells, tanks, ponds or reservoirs.
- Stipulate that any water use by the lessee cannot restrict the lessor's supply of fresh water for domestic, livestock or agricultural purposes.
- If secondary recovery operations are undertaken by the lessee involving waterflood operations, deny the use of potable water. State that such water must come from nonfresh sources.

- If water is to be purchased, state how the price will be determined. Many mineral owners sell the water based on the number of feet drilled for a vertical well, i.e., 10 cents per drilled foot. This method may be infeasible for a horizontal well because water usage is not always a direct function of drilled feet.
- Possibly require the lessee to drill a water well for drilling and production operations. The water well with all pipes, pump, casing and so forth reverts to the mineral owner when the lease terminates.

Force Majeure Clause

Leases generally contain provisions that protect the oil companies from liability and loss of the lease whenever causes reasonably beyond their control suspend operations. This is known as the *force majeure clause.* Mineral owners may consider several factors when this clause is proposed in a lease:

- Require a timely written notice of any sustained work stoppage. Require the notice to specify whether the stoppage was pursuant to the force majeure clause or the shut-in clause. The two generally overlap. However, a stoppage under the force majeure requires no payment while a sustained shut-in does. Consequently, if they overlap, provide that a stoppage must be governed by the shut-in.
- If an unavoidable stoppage should occur during the primary term, require delay rental payments anyway.
- Also, specify how soon operations must resume once the cause is removed. Some leases allow 15 months, but 90 days may be preferable.
- Consider whether financial difficulties, lack of water, lack of materials, lack of transportation facilities and so forth constitute a force majeure.

Horizontal Drilling

Two factors contributed to the Texas oil boom during the late 1970s and early 1980s. Foremost was the skyrocketing oil prices; the other was the intense drilling activity in the Austin Chalk.

Ten years later, a new mini-boom struck the oil fields. This time the price of oil was not a significant factor. Instead, it was the renewed drilling activity in the Austin Chalk spurred by a new technique known as *horizontal drilling.*

The Chalk is a narrow, cretaceous limestone formation running from Mexico through Texas. Its width varies from 20 to 30 miles. The formation is punctuated with numerous vertical cracks or fractures that harbor potential oil-producing veins.

Much attention was focused on the Chalk during the last oil boom because of a renewed emphasis on fracturing techniques. Fracturing (or fraccing) is an artificial way to enhance the permeability (or flow) of the formation surrounding the well's perforation point. Fluids such as sand and water, polymers and even crude oil are pumped into the formation under tremendous pressure.

Fraccing was important to the Chalk because conventional drilling could miss a vertical fracture by a few feet. An apparently dry hole could be transformed into a producing well if linkage between the borehole and the vertical fracture could be established. Thus, successful Chalk wells depended both on a correct location and the proper fraccing techniques.

In 1989, a new drilling technique known as *horizontal drilling* was successfully introduced to the Chalk. The new technique eliminated the need for the drillstring to pierce the fractures vertically. By using redesigned tools, mud motors and flexible drillstrings, drillers could make a vertical hole gradually turn 90 degrees. The horizontal drillstring could be directed to intersect numerous vertical fractures.

Location is still important because costs are significantly increased. Beyond a 1,200-foot horizontal drainhole, the added costs may cause an unsatisfactory return on investment. However, a well was drilled in the Pearsall Austin Chalk Field having a 4,200-foot horizontal drainhole.

Horizontal drilling required the Texas Railroad Commission to develop new field rules to regulate the activity. In June 1990, Statewide Rule 86 became effective. Here is the basic concept.

First, the state-wide rules governing the spacing of vertical wells continues to apply to horizontal wells. A vertical well must be 467 feet from a lease line and 1,200 feet from another well on the same lease. A horizontal well *and its drainhole* must continue to meet the same offset requirements.

Second, a horizontal drainhole with multiple completions in different fractures is still classified as a single well. Multiple drainholes in different directions from one vertical point are permitted.

Third, the size of proration units—the number of acres assigned to a well for purposes of allowables—remains the same as vertical wells. However, additional acreage may be added based on the length of the horizontal bore.

The amount of additional acreage permitted for a unit depends on the vertical field rules. If field rules for vertical wells permit units of 40 acres or less, an additional 20 acres may be assigned to the proration unit if the horizontal drainhole is between 100 and 585 feet. Thereafter, for each additional 585 feet (or any part thereof) drilled horizontally, another 20 acres may be added.

If field rules for vertical wells permit units of more than 40 acres, an additional 40 acres may be added if the horizontal drainhole is between 150 and 827 feet. Thereafter, another 40 acres may be added for each 827 feet (or any part thereof) the horizontal drainhole is extended.

Fourth, no acreage assigned to a horizontal well may be assigned to another well in the field. All assigned acreage must be considered reasonably productive.

To ensure compliance with the rules, the Texas Railroad Commission requires extensive surveys and plats to be filed with the commission indicating the location of the horizontal drainhole. No allowables may be assigned to any horizontal well until a proration-unit plat has been filed with and accepted by the commission.

Fifth, horizontal drilling increases the size of pooled units. Typically the pooling clause in a Producers 88 Lease Form provides that pooled units of a certain size for oil and another for gas may be formed by the lessee ". . . provided that should governmental authority having jurisdiction prescribe or permit the creation of units larger than those specified . . . [then] units thereafter created may conform substantially in size with those prescribed or permitted by governmental regulations." Thus, the larger units are presently permitted by the lease terms.

To mineral owners, this means that a strongly worded Pugh clause is necessary. Otherwise, pooling a portion of a lease will hold on the entire lease tract.

Finally, horizontal drilling increases water usage. When the drill bit pierces a horizontal fracture, a tremendous amount of water is released with the drilling mud before the bit enters the other side of the fracture. Thus, as mentioned earlier, selling water to the lessee based on drilled feet may not be an accurate measure of the water used.

A Leasing Perspective

Oil wells are linked to visions of wealth. Consequently, when an oil company seeks an oil and gas lease, the mineral owner's perception may be distorted. The mineral owner may succumb to an oil company's bidding to sign the lease as quickly as possible. A hastily executed lease may turn a dream into a nightmare.

The mineral owner may want to consider at least two items before signing a lease. These include an examination of both the potential lessee and the lease provisions protecting the lessor's potential cash flows. A little investigative work at the start may lessen anxiety later.

First, scrutinize the lessee. Find out if the lease is being taken by an oil company or by an individual. If a company is taking the lease and if the words *corporation, incorporated* or an abbreviation thereof are used in the name, call the secretary of state, corporations division, and ask for the name and address of the registered agent. If the corporation has a duly authorized registered agent on file, the corporation is legally authorized to conduct business in Texas. No other questions need be asked of the secretary of state.

If the lease is being taken in an individual's name, inquire whether the individual intends to explore and produce the property or assign it. If an assignment is likely, find out who the assignee is. If the prospective assignee is a corporation, again call the secretary of state, corporations division, concerning its registered agent.

Once the ultimate producer is discovered, find out how many wells the producer has drilled, if any of the wells were drilled in the same formation as may be encountered under the leased premises and what the success rate was in the number of barrels of oil or cubic feet of gas produced. Obtain the names, addresses and phone numbers of the surface and royalty owners of the wells. Check with the individuals to see how they were treated, i.e., were royalties and surface damages paid in a timely fashion and were there any other problems? Finally, ask if any lawsuits are pending against the producer, where they are filed and what are the alleged offenses.

If an individual or newly formed company is taking the lease, prior work experience in the oil fields may be hard to trace. However, find out what oil companies have previously employed the individual and if the previous employers are still in business. Inquire about the names, addresses and telephone numbers of both the mineral and surface owners where the previous employer drilled wells. If the lessor uncovers a chain of dissolved companies and a history of dissatisfied landowners, the lessor may wish to seek another lessee.

Second, the mineral owner needs to examine the lease provisions to see if the potential cash flows are adequately protected. Even though the lessor may have provisions addressing the issue, they may be inadaquate. To determine the adequacy, the mineral owner must grasp the difference between a lease covenant and a lease condition.

The difference between the two lies in the consequence for their breach. The breach of a covenant permits a lawsuit for damages, whereas the breach of a condition automatically terminates the lease.

Most of the lease provisions are covenants. There are only two conditions in the context of a Producers 88 Lease Form, i.e., one for failing to pay delay rentals and the other for failing to pay shut-in royalties. Consequently, if the lessee fails to pay production royalties or surface damages, the lease does not terminate. The lessor's only recourse is to sue for damages. If the lessee has insufficient assets to cover the judgment, the mineral owner may never be compensated. The lessee is said to be "judgment proof."

At least four potential payments may be made to the mineral owner via the oil and gas lease: (1) bonus payments, (2) delay rentals and shut-in royalties, (3) surface damages and (4) production royalties.

The first two payments come directly from the lessee. Bonuses are tendered to the lessor at the beginning of a lease as an incentive to sign. Generally, the tender comes in the form of a sight draft, not a check, even though the draft may resemble a check.

The lessor is required to endorse the back of the draft just like a check. However, the lessor will not be paid once the draft is deposited. The bank receiving the draft will forward it to the lessee's collecting bank. After the specified number of *banking days* (not calendar days) indicated on the draft, the lessee must honor or deny payment. If denied, the lessor has no recourse against the lessee.

Sight drafts serve two functions. They allow the lessee time to check the lessor's title to the property and also to confirm that the lease is the same one negotiated by the parties.

The lessor may ask to be paid by check, but it is unlikely the lessee will consent. Consequently, the only factor left to negotiate is the number of days specified on the sight draft. Typically, the period is 30 banking days, which translates into 45 calendar days. The lessor may ask for a shorter period such as 10 to 15 days.

Recently, a Texas appellate court was asked to decide whether the lessor could execute a valid lease with another oil company after the sight draft was deposited but before it was honored. The court held that the lessor was free to sign with another oil company as long as the lessee was free to dishonor the draft without liability.

The second payments coming directly from the lessee are the delay rentals and shut-in royalties. These are described under the headings "Duration of the Lease" and "Extension of the Primary and Secondary Terms" (p. 3). Generally, there are no problems with either payment with older Producers 88 Lease Forms. Both are conditions. If the lessee fails to timely tender either, the lease terminates. However, the newer Producers 88 Lease Forms, such as the 12/79, have provisions stating the lease will not terminate until the lessor informs the lessee of the nonpayment. The lessee has 15 days thereafter to cure the default. As previously stated, mineral owners may wish to delete such provisions or ask for an older lease form such as the 7/69.

The final lease payment coming directly from the lessee is surface damages. Generally, these are forthcoming when the well is plugged and abandoned or when a dry hole is drilled. Even though the lease may hold the lessee liable for surface damages, problems may still arise.

The problems are caused by the timing of the payment, the financial condition of the lessee when the payment is due and the fact that the payment is a covenant.

Because the surface damages are tendered toward the end of the lease, there is a likelihood that the lease has been assigned. The assignee (current lessee) will deny liability because the damages were caused by the assignor. Even if there has been no assignment, the current lessee may be judgment proof.

There is no ready solution. Even if the payment is changed from a covenant to a condition, there is little security because the lease is practically over by the time the payment is due. One solution is to make the payment a condition payable **before** drilling operations commence, not after production ceases. The amount of the payment generally parallels the fair market value of the land used for the drill site. Also, the lease may provide that no assignment is valid until surface damages have been paid. Mineral owners may inquire about the amount of surface damages the lessee budgets per well.

A similar problem confronting the lessor is restoration and clean-up costs. Although these are not a payment tendered to the lessor, they are covenants performable toward the end of the lease. If the lessee leaves without restoring the drill site and cleaning up, the only recourse is for the lessor to sue. As before, the lessee may be judgment proof. There is no readily available solution

Royalty payments are the final payments the lessor may receive. These monthly payments have the potential of exceeding all the other payments combined. They are payable once production commences. The royalty payment is a covenant, not a condition.

This payment may not come directly from the lessee. As a general rule, the purchaser of oil tenders royalty payments to the lessor, while the gas producer (or operator) tenders gas royalties.

Perhaps the sequence of events between the time production commences and royalty payments are tendered is confusing. However, the sequence must be understood if mineral owners are to protect their royalties.

When either oil or gas production commences in Texas, the producer must file monthly production reports with the railroad commission. Also, the producer must inform the commission of the purchaser's name and address. Both the production reports and the purchaser's identity are public information.

However, when the actual product reaches the purchaser, the similarity between an oil and a gas purchaser ends. A significantly greater burden is placed on the oil producer before the purchaser will relinquish payment.

As a general rule, the oil purchaser requires the oil producer to hire an attorney to render a division order title opinion based on the information currently recorded in the county deed records. The purchaser will then send division orders to the respective persons and entities indicated on the title opinion as owners of production. Ownership is stated in fractions carried to the seventh digit. Upon receipt of the executed division orders, the oil purchaser commences paying monthly royalties to the owners indicated on the title opinion.

On the other hand, gas purchasers disburse 100 percent of the proceeds from gas sales to the producer as the production is received. The gas purchaser requires no title opinion and no division orders. The gas purchaser may require the producer to sign an indemnification agreement if the purchaser is sued for the producer's failure to pay royalties or to pay the royalties in the correct amounts.

In some instances, the oil purchaser will relinquish 100 percent of the proceeds to the oil producer based on an indemnification agreement. This is generally the exception, not the rule.

The mineral owner must be cautious concerning a producer's ability to withdraw 100 percent of the proceeds or the producer's right to withdraw a share of the proceeds without giving the royalty owners the same privilege. The temptation may be too great for an oil company to use the royalty payments to bail itself out of a financial crisis or to abscond with the funds. Likewise, whenever producers can receive their portion of the proceeds without filing a title opinion, there is little incentive to pay the royalty owners.

As mentioned, the lessor may stipulate that the lease terminates if royalties are not paid within six months after production begins (see p. 6). This may provide inadequate protection.

The first six months of a well's production are critical because a well's revenue usually will be greatest during this period. Many wells may never reach pay-out status if they do not pay for themselves during this period or shortly thereafter.

Thus, the termination of the lease after six months of nonpayment of royalties is recommended. However, if the lessee can abscond with the funds in the interim, the lessor is not protected. The lessor must make sure the proceeds, at least the lessor's share, never leave the purchaser.

This is not to say that proceeds are absolutely protected with the purchaser. Charter Oil Company's bankruptcy in the early 1980s serves as a prime example. However, purchasers typically stay in business much longer and move less often than oil companies.

The difficulty lies in binding the purchaser to a lease provision stating that no royalties will be released to the operator. The purchaser is not a party to the lease agreement. Typically, the purchaser is totally unaware of the lease provisions. Consequently, if the purchaser releases all or a part of the proceeds to the lessee, generally the only recourse is to pursue the lessee, not the purchaser, for the royalties. One possible solution is to obtain the name and address of the purchaser from the Texas Railroad Commission and notify the purchaser of the lessor's right to receive direct royalty payments as soon as possible.

Other Terms for the Mineral Owner's Consideration

Without going into detail, the following terms may be considered by mineral owners when negotiating a lease.

- If the land contains several producing formations at varying depths, lease each strata separately. This is accomplished by negotiating a *horizontal severance clause*. If the severance cannot be based on formations, condition it on how deeply the lessee drills during the primary term.
- Insert provisions allowing free access to books, records and drilling data accumulated pursuant to operations conducted on the leased premises. Always try to obtain copies of the logs for the mineral owner's files.
- By the same token, obtain copies of all title opinions and abstracts of title acquired by the lessee. These will bolster the lessor's negotiating position with any subsequent lessee.
- If possible, negotiate some provisions whereby the mineral owner may assume control of the casing when operations are abandoned. The casing could be used to withdraw any remaining gas or extract fresh water for domestic or agricultural purposes. However, the mineral owner may be required to assume the cost and liability for plugging the well.
- Explicitly define when drilling operations commence. The criteria may be the time the well is spudded with appropriate equipment on site to drill to the depth indicated on the drilling permit. Otherwise, Texas case law is quite lenient and vague in defining the term.
- Define when a well is completed. This may be the time the drilling rig is released from the drill site. The definitions are indispensable when calculating the 90-day period between wells for continuous drilling operations described on p. 4.
- Require lessee to indemnify, save and hold lessor harmless from all claims,

demands and causes of actions stemming from activities undertaken by lessee or lessee's assignees, their employees, agents, contractors and subcontractors during operations conducted on the leased premises. Make sure the indemnification covers infractions of environmental laws. If possible, require the lessee to post bond and carry comprehensive liability insurance of a specified amount as added security from such claims.

- If a Pugh clause cannot be negotiated, never place noncontiguous tracts in the same lease. Otherwise, production from one tract or the pooling of one tract will hold all the noncontiguous acreage even though miles apart.

Conclusion

Negotiating an oil and gas lease requires legal knowledge, foresight and common sense.

No mineral owner could possibly hope to include all these suggestions in one lease. The provisions successfully incorporated depend upon negotiating power. Even so, the information contained herein describes some possible alternatives, and, if nothing else, will foster frank discussion between the mineral owner and the lessee prior to signing any agreements.

This report is for information only and is not a substitute for legal counsel.

The publications mentioned in this report are available from the Real Estate Center, Texas A&M University, College Station, Texas 77843-2115. Enclose a check in the appropriate amount.

Minerals, Surface Rights and Royalty Payments (Technical report 840, $3 in Texas/$4 outside of Texas)

Rights and Responsibilities of Mineral Cotenants (Technical report 843, $3 in Texas/$5 outside of Texas)

Termination of an Oil and Gas Lease (Technical report 601, $3 in Texas/$5 outside of Texas)

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