Petroleum Production on Agricultural Lands in Oklahoma: Managing Risks and Opportunities

Dr. Shannon L. Ferrell

Associate Professor
Oklahoma State University
Department of Agricultural Economics

Dr. Tiffany Dowell Lashmet

Assistant Professor and Extension Specialist
Texas AgriLife Extension Service

Dr. Rusty Rumley

Staff Attorney
National Agricultural Law Center

Southern Risk Management Education Center

United States Department of Agriculture
National Institute of Food and Agriculture

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Chapter 1
Basics of Oil and Gas Production

To understand the issues landowners face with respect to oil and gas production on their land, it is important to understand the process by which oil and gas resources are explored, produced, and transported.

The extraction and use of oil and gas by humans is not a recent event. Indeed, people have been using oil and gas in one form or another for millennia. Many of the processes used in the production of oil and gas are based on principles decades or even centuries old. On the other hand, there are also many new technologies surrounding the exploration for oil and gas resources. Recent advancements in the technology of horizontal drilling and hydraulic fracturing have also created new questions for both surface and mineral owners as well.

1.1. A brief history of oil and gas

Oil and gas, like many other fossil fuels, come from the transformation of organic materials over millions of years. Most oil and gas is formed from the remains of tiny plants and animals that died and accumulated in thick layers at the bottoms of ancient seas. Over time, layers of sand, silt, and other inorganic materials accumulated on top of these remains. As more and more materials piled on top of these layers, incredible pressures and temperatures developed. Over time, these pressures and temperatures converted the organic material into what we now refer to as hydrocarbons, such as coal, oil, and natural gas. Similarly, these pressures also transformed the inorganic material above them into rock, which trapped the hydrocarbons beneath them.

Occasionally, cracks would develop in these rock formations, allowing the hydrocarbons to reach the surface. Historians believe the first natural gas seeps were discovered in Iran between 6000 and 2000 B.C. As early as 900 B.C., natural gas was harvested and used in China, where the first wells dug specifically to obtain natural gas were dug around 200 B.C. The recorded use of oil by humans goes back to at least 4000 B.C., when oil that had seeped to the surface was used to waterproof boats and as an adhesive for buildings and weapons.

North America's first natural gas well came in 1821 in Fredonia, New York, nearly 40 years before North America's first oil well. That first oil well was located in near Titusville, Pennsylvania and struck oil in 1859. While natural gas use slowly expanded, petroleum developers still considered natural gas as a relatively worthless by-product of oil production to be disposed of rather than collected and used. At least initially, oil was favored over natural gas for refinement into kerosene for use as a lamp and heater fuel. Gradually, though, uses for both oil and gas expanded dramatically with the use of oil as a motor fuel and natural gas as a fuel for both heating and electrical generation.

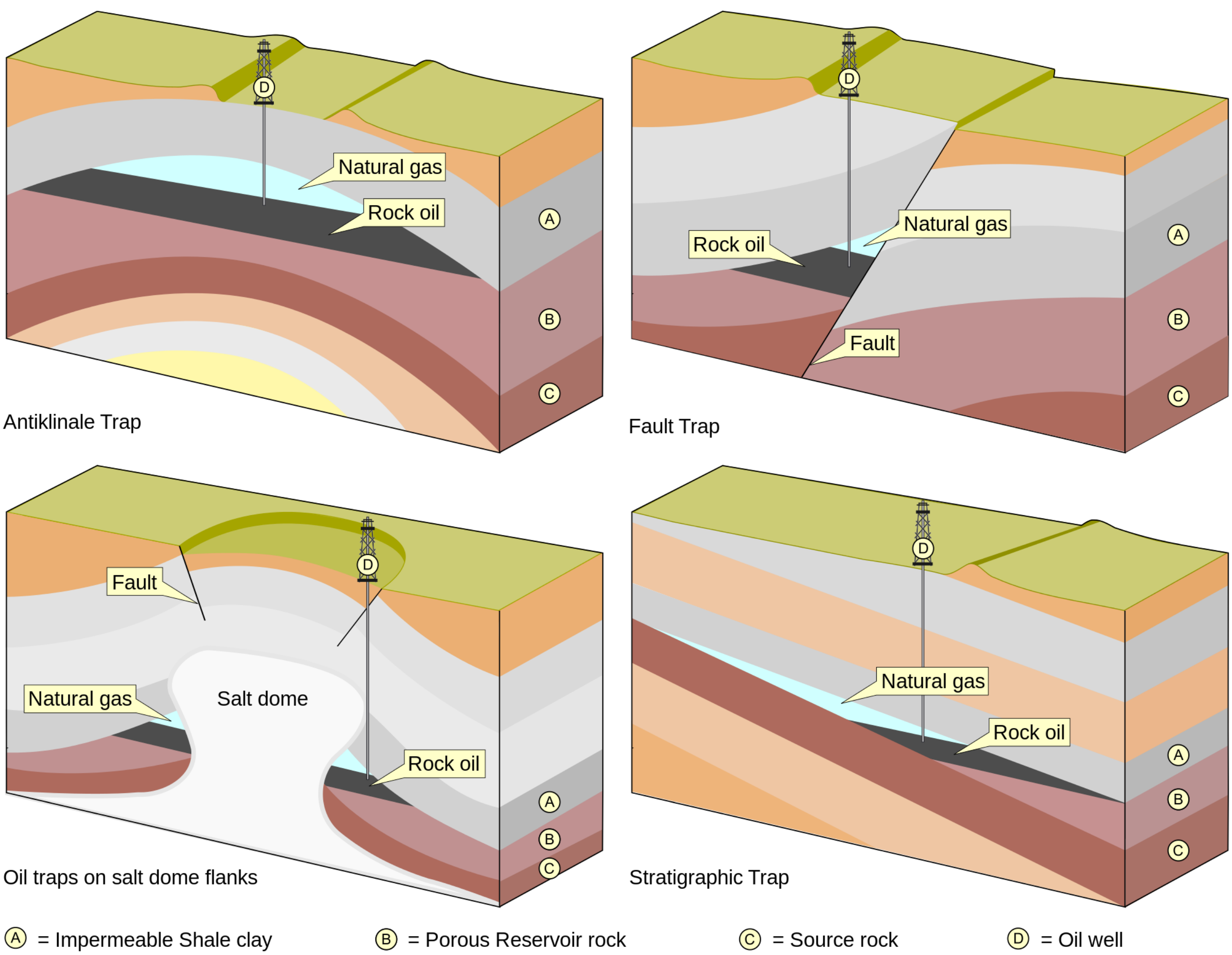
Society's increasing needs for energy have led oil and gas developers to constantly seek new technologies for extracting resources. The two technologies responsible for the significant growth of oil and gas production in recent years – horizontal (sometimes called "directional") drilling and hydraulic fracturing (sometimes called "fracing" or "fracking") – have actually been in use for decades. Relatively recent breakthroughs in these technologies made tremendous differences in their application, though, and made development of many more natural gas resources an economic possibility.

1.2. Exploring for oil and gas resources

Some deposits of oil and gas occur so close to the surface that they actually seep out of the ground, like the deposits of gas tapped in Fredonia, New York or the oil seeps of Titusville, Pennsylvania. More commonly, though, developers must drill wells hundreds or thousands of feet beneath the surface to reach formations that have trapped significant amounts of oil and/or natural gas. Understandably, companies carrying out oil and gas exploration and production operations (called "operators") would like to know as much about the subsurface as possible before committing the time, resources, and money needed to drill a well.

Generally, the oil and gas industry works to locate traps because they represent the easiest and therefore most economic sources of the resource. In the early days of the oil and gas industry, oil and gas operators looked for signs on the surface of land that might indicate sub-surface structures holding oil and gas. Subsurface traps and "domes" were known to create areas where oil and gas would gather and thus represented a better chance for the producer to locate a good well. Thus, operators looked for corresponding signs of these structures on the surface of the land. If the operators felt confident they had enough evidence for a good well, they would drill a wildcat or "exploratory" well to determine if oil and gas actually were present in the formation.

Figure 1-1: Examples of oil and gas "trap" structures



Eventually, new technologies arrived to provide much more detail about the subsurface structure of the Earth, improving the ability to pinpoint the location of oil and gas resources. One way of detecting potential oil and gas formations was the use of a gravimeter (or "gravity meter") to measure the strength of gravity in an area. Since oil and gas are less dense than the surrounding rock, a weaker gravity measurement can indicate the presence of oil and gas. Another detection tool is a magnetometer, used to measure the Earth's magnetic field. Higher than average magnetic field strengths in an area can suggest displacements in the subsurface that could indicate oil and gas traps.

Today in Oklahoma, seismic (sometimes called "vibroseis") exploration is frequently used to explore for oil and gas. In fact, seismic detection was first used to discover an oil field in Oklahoma in 1928. To locate these traps, developers frequently use seismic exploration. Seismic exploration directs waves of sound energy into the ground and uses sensors to record the reflection of those sound waves off of the subsurface rock layers. By measuring the differences in these reflections, petroleum geologists can visualize the shape of the formations and can locate areas likely to contain oil and gas traps, much like a sonogram uses vibrations and echoes to create images of what lies underneath the skin of patients.

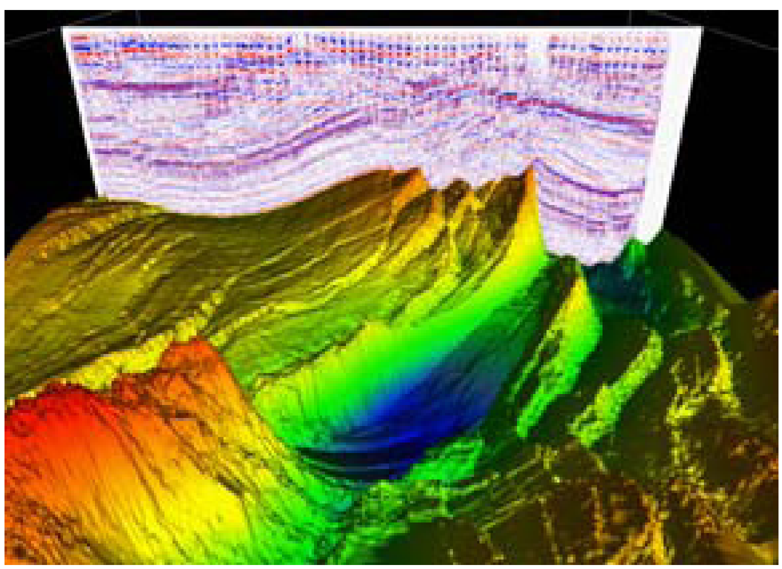
Different techniques may be used to generate the sound based on the local conditions. In most situations, a large truck (sometimes called a "vibrator" or "thumper" truck) will use hydraulic rams and the weight of the truck to generate the vibrations needed to generate the seismic data.. In other cases, holes may be dug between 60 and 100 feet deep to place explosives into the bedrock; these explosives are then detonated to generate the sound waves used for seismic data. Approximately 70% of seismic operations use thumper truck operations; shot hole operations generally are more expensive and are used where thumper truck operations are impractical.

Figure 1-2: Thumper trucks

Figure 1-3: Shot Hole Drill

With either method, a series of sensors are placed on the surface to listen to the echoes of the vibrations, and the sensors are then connected to computers that record the data generated. The recorded data is then processed by powerful computers to create the subsurface picture. When seismic techniques were developed in the 1920's, geologists recorded information manually on sheets of paper; now, extremely powerful computers record and analyze seismic data to create three-dimensional pictures of the subsurface. These technologies give operators much more confidence in where to place their wells, but the occasional non-producing well ("dry hole") still happens.

Figure 1-4: Example of three-dimensional seismic imaging



1.3. Bringing oil and gas to the surface

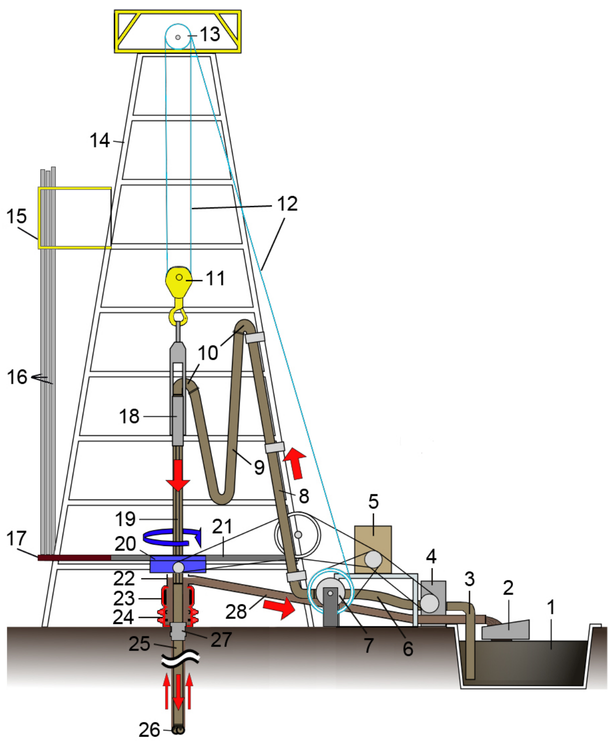
Once an operator feels confident they have located an area where oil and gas can be produced profitably, they must find a way to bring it to the surface. For many years, the overwhelming majority of oil and gas were produced through traditional vertical wells, but recent years have seen significant growth in the use of horizontal drilling techniques.

1.3.1. Traditional vertical well development

To drill an oil or gas well ("make hole" in the language of the industry), the developer attaches a bit that will cut, gouge, or break up the rock in the formations below the rig to a length of pipe called drill string. A turntable on the rig rotates the bit and drill string to create the drilling action. As the bit digs deeper and deeper, the developer uses the rig to attach additional lengths of drill string to make the overall drill string longer and longer.

Conditions for the drill bit are harsh. The action of drilling creates debris that must be removed from the well. Drilling also generates high temperatures for the bit. Additionally, at the depth of some wells – often thousands of feet deep – the surrounding formations themselves generate tremendous pressures and temperatures. For this purpose, the hollow drill string allows the developer to circulate drilling mud down the string, through the drill bit, and back up to the surface of the well. Despite its name, drilling mud is not simply water and dirt; rather, it is a carefully formulated mixture of another components designed to give it very specific properties of density and viscosity as well as allowing it to serve a number of functions in the creation of the well. Drilling mud serves a number of purposes, including creating internal pressure on the borehole to counteract the pressure of the surrounding geologic formation; to lubricate and cool the drill bit, and to lift the drill cuttings out of the borehole. Once the mud returns to the surface, it is processed through a shale shaker to remove the drill cuttings and recycled until it loses its usefulness. These drill cuttings include all of the materials removed from the wellbore and can include a wide variety of minerals and other substances. Operators frequently store spent mud, drill cuttings, and salt water produced form the well in a reserve pit." Eventually, the developer must dispose of the materials stored in the reserve pit or close the pit to permanently contain the materials it contains.

Figure 1-5: Diagram of a traditional rotary drilling oil rig

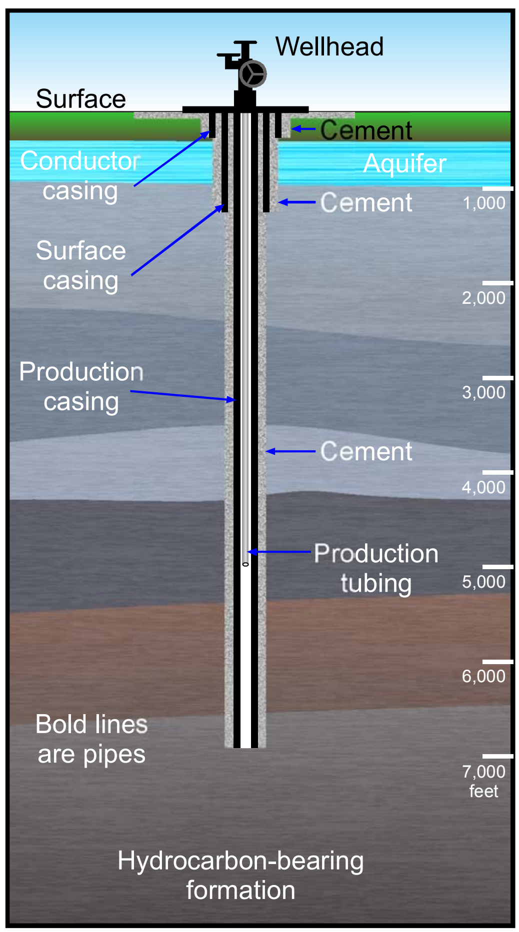


1) Mud tank (pit)	8) Standpipe	15) Monkey board	22) Bell nipple
2) Shale shakers	9) Kelly hose	16) Stand/string of pipe	23) Blowout preventer (annular)
3) Suction line	10) Goose-neck	17) Pipe rack/floor	24) Blowout preventer (ram)
4) Mud pump	11) Travelling block	18) Swivel/top drive	25) Drill string
5) Prime mover (motor)	12) Drill line	19) Kelly drive	26) Drill bit
6) Vibrating hose	13) Crown block	20) Rotary table	27) Casing head
7) Winch/draw works	14) Derrick	21)Drill floor	28) Flow line

To reach the targeted formation, the drill may pass through a number of formations including aquifers containing freshwater, saltwater formations, and other geologic strata. Without further action by the operator, the wellbore could create the opportunity for saltwater, hydrocarbons, or other materials to travel through it and mix with fresh water, thereby contaminating it. Thus, once the operator reaches the desired depth, a decision must be made – whether to "complete" the well or to "plug" it.

If the well appears capable of producing enough oil and/or gas to justify the cost, the developer will "complete" the well by installing casing. Several types off casing will be used to create the final structure of the well, enabling the well to withstand the pressures acting on it and to prevent the mixing of substances from the formations penetrated by it. The first casing, called "conductor casing" serves as a foundation and guide for the casings to follow. Next, the developer installs "surface casing." Surface casing serves a crucial function; it must be installed to a depth below the deepest source of fresh water encountered by the well and must be surrounded by cement to seal both the well and the fresh water-containing formation apart from each other. In some wells, "intermediate casing" may follow the surface casing. Finally, "production casing" forms the remainder of the well down to its final depth. After placing casing, the developer will pump cement down through the casing and out the end of the casing, causing it to flow back up the well around the outside of the casing (the space between the casing and the sides of the well is sometimes called the "annulus") until it reaches the surface again. This process seals off the formations encountered by the well to prevent leaking of substances from the formations and any pollution that could be caused by such leaking. Given the importance of this function, and the immense stresses placed on the well, the concrete used must be carefully formulated and installed.

Figure 1-6: Well Casing Diagram



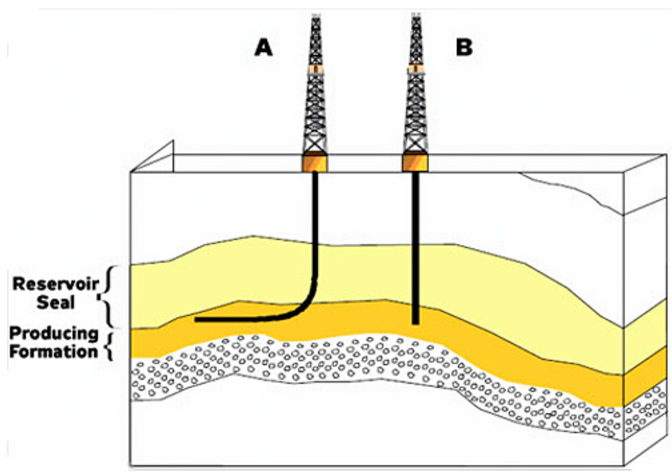
If the well seems uneconomic to produce, it will be "plugged." After removing any casing already in place, the developer will install a series of concrete plugs at specific depths to seal off any zones at risk of leaking substances that could contaminate groundwater, including a plug at the base of the lowest depth of fresh water.

1.3.2. Horizontal drilling

To this point, the discussion has focused on the development of a traditional vertical well. Such wells can only extract oil or gas from that portion of the well that intersects the hydrocarbon-bearing formation. As a result, developers sought formations that were highly permeable and thus allowed the oil or gas to flow to the end of the wellbore. Conversely, formations that were not highly permeable did not allow oil or gas to be recovered in amounts that justified the cost of drilling and completing the well.

Advancements in horizontal drilling technology changed the situation, though. With horizontal drilling, the wellbore direction can now follow along a formation for a significant length. This exposes a much greater portion of the wellbore to the formation than a traditional vertical well would allow. For example, some horizontal wells in Oklahoma intercept over 10,000 feed of a formation, where a vertical well could only intercept 50 feet.

Figure 1-7: Comparison of vertical and horizontal wells



Developers have had the capability of drilling wells at a non-vertical angle for decades. These wells, sometimes called "deviated" or "slant" wells were sometimes used to access formations that could not be accessed by a vertical well such as formations beneath water or other environmentally sensitive sites, or sites that were to rugged to reach. However, recent advancements in drilling technology have allowed developers to have much greater control in directing the drill bit. This allows developers to reach horizontal distances of nearly five miles from the well pad. Horizontal drilling also allows for eight or more wells to be drilled from a single wellpad, allowing a given parcel of land to be developed by a much smaller number of surface wellpads than if vertical wells were used. Horizontal wells generally require more time and expense to complete than a traditional vertical well.

1.3.3. Hydraulic fracturing

Horizontal drilling allows operators to expose a much greater area of the wellbore to the hydrocarbon-containing formation, but even that exposure will not produce the desired flow of oil or gas if the formation does not permit the oil and gas molecules to migrate through the formation and into the wellbore. This issue kept developers from tapping into the significant reserves of natural gas contained in shale formations. Shale rock's tight formations, in their natural state, frequently lack the pathways that allow a well to collect oil and gas economically. That is where hydraulic fracturing makes the difference.

Hydraulic fracturing was first used in the 1940's. Traditionally, wells that were near the end of their useful life were hydraulically fractured to stimulate the last remaining production from them. Fracturing fluid (composed primarily of water) was forced down the well at tremendous pressures to exploit weaknesses in the hydrocarbon-containing formation, opening fractures in the formation that would allow for an improved flow of oil and gas into the well. Hence, the term "hydraulic fracturing."

Modern hydraulic fracturing involves very precise seismic surveys of the formation to be fractured to determine the amount, composition, and pressure of fracturing fluid necessary to create fractures in the right rock formation. Water remains the primary component of most fracturing fluids, though some fluids are petroleum-based. Water provides a virtually incompressible fluid to generate pressure against the hydrocarbon-containing rock, giving the fluid volume, and serving as a carrier to transport the other materials. In some cases, diesel fuel may be used instead of water to modify the physical properties of the fluid (such as the fluid's viscosity or lubricity) or to serve as a solvent for other fluid components. Fracturing fluids also contain proppant, so called because it consists of particles (frequently sand, though ceramic beads or other spherical materials may be used) forced into the fractures to hold ("prop") them open, allowing oil or gas to flow through them. Fracturing fluid often contains numerous other substances with a wide variety of functions, as illustrated below.

Figure 1-8: Typical fracturing fluid components

MODERN SHALE GAS DEVELOPMENT IN THE UNITED STATES: A PRIMER

EXHIBIT 36: FRACTURING FLUID ADDITIVES, MAIN COMPOUNDS, AND COMMON USES.

Additive Type	Main Compound(s)	Purpose	Common Use of Main Compound
Diluted Acid (15%)	Hydrochloric acid or muriatic acid	Help dissolve minerals and initiate cracks in the rock	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Eliminates bacteria in the water that produce corrosive byproducts	Disinfectant; sterilize medical and dental equipment
Breaker	Ammonium persulfate	Allows a delayed break down of the gel polymer chains	Bleaching agent in detergent and hair cosmetics, manufacture of household plastics
Corrosion Inhibitor	N,n-dimethyl formamide	Prevents the corrosion of the pipe	Used in pharmaceuticals, acrylic fibers, plastics
Crosslinker	Borate salts	Maintains fluid viscosity as temperature increases	Laundry detergents, hand soaps, and cosmetics
Friction Reducer	Polyacrylamide	Minimizes friction between the fluid and the pipe	Water treatment, soil conditioner
	Mineral oil		Make-up remover, laxatives, and candy
Gel	Guar gum or hydroxyethyl cellulose	Thickens the water in order to suspend the sand	Cosmetics, toothpaste, sauces, baked goods, ice cream
Iron Control	Citric acid	Prevents precipitation of metal oxides	Food additive, flavoring in food and beverages; Lemon Juice ~7% Citric Acid
KCl	Potassium chloride	Creates a brine carrier fluid	Low sodium table salt substitute
Oxygen Scavenger	Ammonium bisulfite	Removes oxygen from the water to protect the pipe from corrosion	Cosmetics, food and beverage processing, water treatment
pH Adjusting Agent	Sodium or potassium carbonate	Maintains the effectiveness of other components, such as crosslinkers	Washing soda, detergents, soap, water softener, glass and ceramics
Proppant	Silica, quartz sand	Allows the fractures to remain open so the gas can escape	Drinking water filtration, play sand, concrete, brick mortar
Scale Inhibitor	Ethylene glycol	Prevents scale deposits in the pipe	Automotive antifreeze, household cleansers, and de-icing agent
Surfactant	Isopropanol	Used to increase the viscosity of the fracture fluid	Glass cleaner, antiperspirant, and hair color

Note: The specific compounds used in a given fracturing operation will vary depending on company preference, source water quality and site-specific characteristics of the target formation. The compounds shown above are representative of the major compounds used in hydraulic fracturing of gas shales.

Hydraulic fracturing requires significant amounts of water, frequently ranging between 2 and 4 million gallons or more to complete a well. Developers may use surface water from streams, rivers, ponds, and lakes if they are available; groundwater wells may provide water if no surface water is available.

Once the fracturing fluid is formulated, the developer injects it at high pressures into the targeted formation. This operation may take a number of fracturing trucks working together to generate the fluid pressures and volumes needed, as shown in figure 1-9.

Figure 1-9: Fracturing trucks working together to inject well

After the fractures form, the developer releases the pressure on the well. This allows some of the fracturing fluid to return to the surface (though the amount of this fluid, sometimes called flowback can vary greatly depending on the formation). The developer may recycle this flowback for subsequent hydraulic fracturing operations. Wells may also produce salt water occurring in the targeted formation ("produced water"). When flowback and produced water cannot be reused in the well, the developer must find a way to dispose of the water. Options for disposal include injecting the water in an underground disposal well, treating the water and releasing it to a nearby waterbody, application of the water to land, or disposal through a nearby waste water treatment plant.

1.2.4. Conditioning and transportation of oil and gas

Once oil and gas are brought to the surface, the operator must find a way to get them into marketable condition and, naturally, get them to market.

Some well sites may have conditioning equipment next to the well, while others might use a gathering system of flowlines to move oil and gas to a central processing unit where the product from several wells is processed.

In the case of oil, one of the most common conditioning operations is to separate the oil from any water that may be mixed with it by using a separator. Some separators my accomplish multiple tasks at once by separating oil, gas, and water from each other.

Figure 1-10: Oil separators

After the oil has been treated on-site, it will likely be stored in a tank or tank battery for storage until it is picked up by a tanker truck for delivery to a transmission pipeline site or refinery.

Figure 1-11: Tank battery

With natural gas, the operator may have to remove any remaining water from the gas in a process called "dehydration," often accomplished by bubbling the gas through a material that will absorb the water (often ethylene glycol). "Sweetening" units may remove corrosive gases such as carbon dioxide and hydrogen sulfide.

Figure 1-12: Natural gas dehydrator unit

Figure 1-13: Natural gas sweeting unit

Transportation of natural gas before it has been completely processed at a gas processing plant is rare, as transporting the gas by pipeline is usually more efficient and economical. Once the gas meets the requirements to be shipped to buyers by pipeline, large compressors bring the gas to the pressure needed to move the gas through the pipeline. These compressors may be powered by natural gas, electricity, or diesel.

Figure 1-14: Natural gas compressors

1.3 Conclusion

Oil and gas have been commercially produced in the United States for over 150 years, and the industry continues to be a mix of traditional practices and cutting-edge technologies. Coordinating the wide array of activities involved in discovering, producing, and marketing oil and gas and managing the economic risks associated with all of those activities requires a significant amount of work between the operator, the surface owner, and the mineral interest owner. The remainder of this handbook is devoted to examining these issues and helping the landowner manage their risks in those activities.

Chapter 2
Surface Owner Issues

While it might appear most of the action of oil and gas development occurs beneath the surface of the Earth, the exploration, production, and transportation of oil and gas involves a lot of activity on the surface. This means operators and the people who occupy and farm the surface of land being used for oil and gas production must find ways to work together. Understanding this cooperation requires understanding the different natures of surface and mineral ownership, and a number of laws and practices used to harmonize the rights of the two.

2.1. Severance of the surface and mineral estate

In many countries of the world, the minerals underlying the surface of land are held by the government, and that government has the power to negotiate if, when, and how those minerals are extracted. However, in the United States, the majority of all mineral rights – two-thirds in all – are held by private landowners, with the remaining one-third owned by the federal and state governments.

The fact that most minerals in the United States are owned by private landowners can create some challenges. In Oklahoma, and most other states, the ownership of the mineral estate (sometimes called "mineral rights") can be separated ("severed") from the ownership of the surface estate. Put another way, one person may own the rights to use the surface of a piece of property while another person has the right to the minerals underneath the property. Further complicating matters is the fact that both the surface and the minerals may be owned by multiple people or entities simultaneously.

To understand all the implications of severing the mineral and surface estate, it is necessary to examine what is considered part of the two estates.

2.1.1. The mineral estate

When one thinks of "minerals," solid substances like rock come to mind. Oil and gas are different, though, in that they are liquid and gas, respectively, and can move (albeit slowly) through the rock containing them. As a result, the law has had to find some way of defining who owns an asset that is closely tied to land, but unlike the land, can move about. Oklahoma, as most other states, has handled this by stating that the owner of the mineral estate associated with the land where the oil and gas can be found initially owns the oil and gas located there.

Many times, the mineral and surface estates are separated when a landowner holding both the surface and minerals (that is, a unified estate or fee estate) either sells the mineral estate to a party while retaining ownership of the surface estate, or sells the surface estate to one party while selling the mineral estate to another party. Often, the deed in such a transaction may only refer to "minerals" without defining what that term means. Courts in Oklahoma have determined that the term "minerals" includes oil and gas. Further, Oklahoma courts have stated that a conveyance of "all of the oil, gas and other minerals" intends to transfer the interest in "oil, gas, and other minerals produced as a component or constituent thereof, whether hydrocarbon or non-hydrocarbon" but that it did not convey any metallic ores or metallic minerals.

One common understanding of this rule is that the mineral estate includes rights in all of the substances produced through the wellbore of an oil and gas well. This can be an important point, as very valuable substances that are not hydrocarbons can also be produced through the wellbore. An example of a non-hydrocarbon substance produced along with oil and gas is helium, which is blended with oil and gas produced from some formations in Texas, Oklahoma, and Kansas. It is also important to note that one hydrocarbon – coal – is not included in the mineral estate unless it has been specifically mentioned in the conveyance creating the severed mineral estate.

2.1.2. The surface estate

It is a general rule in Oklahoma and many other states that when a party conveys real estate to another party, they convey all of their interests in the property with the exception of what is explicitly reserved. Thus, if someone conveys real estate but retains an interest in "oil, gas, and other minerals" they have conveyed everything they own in the property except they have retained the rights to the oil, gas and other minerals. As noted in the discussion above, this means the person receiving the conveyance owns the surface and everything but the minerals that could be produced through the oil and gas production process. Oklahoma courts have interpreted this to mean that the owner of a severed surface estate generally retains ownership of gravel, gypsum rock, limestone, metallic ores, and even coal (depending on the language of the conveyance, as discussed above).

2.1.3. Rights of the mineral and surface estates

The separation of the surface and mineral estates would seem to create some problems. If someone else owns the surface, how will the mineral estate owner be able to extract the oil and gas he or she supposedly owns? To deal with this issue, the law regards the mineral estate as the dominant estate and the surface estate as the servient estate with regard to the extraction of oil and gas. This means that the mineral estate has certain rights that the surface estate must honor. Put another way, the surface estate must sometimes "serve" the mineral estate.

The mineral estate carries with it "the right to make reasonable use of the surface in exploring for and extracting" oil and gas. What does that mean? Over time, reasonable use of the surface has been interpreted to mean the mineral estate owner (or, far more frequently, the operator to which the mineral owner has leased his or her minerals) can use the surface to:

- explore for the oil and gas by using seismic trucks or other exploration methods,
- construct roads, well sites, and gathering pipelines serving wells on the property
- dig pits for handling waste fluids,
- extract soil and clay to build up the site
- use groundwater for production operations.

The long-recognized limitation on these uses is that they must be "reasonable" meaning the mineral owner and any operator of the property must use care and not cause any unnecessary damage. This limitation is the primary source of rights that the surface owner has with respect to the extraction of oil and gas.

2.2. Surface impacts and establishing baseline conditions for your property

Clearly, the activities involved in oil and gas extraction will occupy a portion of the surface of the property, and may have impacts beyond the portion of the land occupied.

2.2.1. Potential surface impacts

The use of the surface for oil and gas production can have a number of potential effects, including land loss, off-site land use restrictions, environmental, wildlife, and aesthetic impacts.

2.2.1.1. Loss of land

One of the first impacts of oil and gas exploration and production that comes to mind is the land physically occupied by the production facilities. During the exploration process, there may be the temporary loss of land caused by damages resulting from the transport or use of the seismic exploration equipment, particularly in the case of growing crops or if the soil is soft from recent rains.

In almost every case, extracting oil and gas will require the construction of a well site (sometimes called a "well pad" or a "location"). In some cases, the well pad may be only an acre, but in others, it may be up to six acres. Horizontal drilling technology makes it possible to drill several wells from a single well pad, thus reducing overall land use, but the pad may have to be bigger than that for a traditional well since more equipment is required to complete the well. Once the well is completed, it may be possible to reduce the size of the pad down to only the area needed for the equipment that will remain (for example, pumps, treatment equipment, and storage tanks).

In addition to the well pad, access roads will be needed to reach the location, and the length and route of the road may vary depending on the location of the well relative to the nearest publicly accessible road.

Pipelines may also be constructed to the well. Although underground pipelines may no longer occupy the surface once they have been constructed and the surface reclaimed, there will be some disruption of the surface during construction and continuing restrictions about what can be done within the pipeline easement.

2.2.1.2. Off-site land use restrictions

The occupation of the surface by oil and gas production operations may have impacts beyond the land that is physically taken up by the well pad and equipment. In most cases, improvements cannot be built within the easement or rights of way. The location of oil and gas facilities may make portions of the property more difficult to access (although sometimes roads constructed for the well might also improve access), and may complicate crop tillage operations by creating new field obstacles.

2.2.1.3. Environmental impacts

Environmental issues may be the first impacts coming to mind for many people when they think about oil and gas operations. A number of state statutes and regulations exist to encourage operators to explore for, produce, and transport oil and gas in a way that eliminates or minimizes environmental impacts. Nevertheless, accidents can happen. Spills of oil can occur at the well site or while the oil is being transported by truck or pipeline. Pits used to hold saltwater and other wastes until disposal may develop leaks or be stressed by heavy rainfall. Improper land application of drilling fluids, also known as soil farming, can cause damage to plant life. As mentioned previously, though, care in the conduct of oil and gas operations will significantly reduce the risks of any such harms.

2.2.1.4. Wildlife impacts

Oil and gas exploration, production, and transportation may have impacts on wildlife in the area. Generally, any impacts from exploration activities will be short-lived, given the temporary nature of those activities. More long-term impacts can result from the loss or disruption (sometimes called "fragmentation") of habitat caused by the construction of facilities. Environmental impacts like those mentioned above obviously impact wildlife species in the area above. Aesthetic issues like those discussed below (such as light or noise) might also cause animal species to move away from the oil and gas facilities.

2.2.1.5. Aesthetic impacts

"Beauty is in the eye of the beholder" as the saying goes. Some people may not be bothered at all by the "look" of oil and gas facilities on their property, but others might find them disruptive of their rural landscape. In terms of visual impact and noise, the drilling phase of operations may be the most intense with high levels of activity (sometimes continuing for 24 hours a day). Generally, this intense level of activity is fairly short, as the operator wants to complete the well as quickly as possible. Still, there may remain visual impacts of the equipment left behind and security lights left on the well site. Compressors or pump motors may also be continuing sources of noise impacts.

2.2.2. Establishing baseline conditions for your property

The nature of the surface estate as the servient estate means surface owners may be at a bit of a disadvantage in negotiating for the use of the surface in oil and gas production; since they do not have the "trump" card of ultimately denying access to the surface, they must ultimately allow the use of their property for oil and gas development.

However, Oklahoma statutes and regulations provide a number of protections for surface owners. To take full advantage of these protections, though, surface owners should do some "homework" with respect to the current condition of their land.

In many industries, when someone is considering purchasing land for an industrial use, they conduct an "environmental baseline study" (EBS) to determine what the environmental condition of the property is before the use. This information can be very useful to prove that the property was in good condition at the time of the purchase and to help analyze any environmental problems that occur thereafter. In much the same way, a surface owner can conduct their own EBS to determine the condition of their property before oil and gas activities take place. If there is a significant amount of oil and gas development taking place in an area, and a surface owner thinks it is likely they will be approached about development of their property, it might be the right time to conduct an EBS.

A formal EBS will likely involve a number of environmental professionals and can be expensive. Nevertheless, landowners can conduct a number of similar actions fairly inexpensively on their own by following some of the same procedures used by professionals. Basically, an EBS consists of just a few steps:

2.2.2.1. Gathering information already known about the area
You can search the records of several state agencies such as the Oklahoma Corporation Commission (OCC), the Oklahoma Department of Environmental Quality (DEQ), the Oklahoma Water Resources Board (OWRB), and federal agencies such as the Natural Resources Conservation Service (NRCS) and Farm Service Agency (FSA) to get historical records regarding your land such as the history of oil and gas wells or other mining and industrial activities on your property, historical crop yields, water well locations, and surface water resources. Further, your own farm records may be important. Records of land use, crop yields, and other information can also help establish the baseline for your property.

2.2.2.2. Examine neighboring properties for potential impact sources
If oil and gas development or other mining and industrial activities are taking place on neighboring properties, those pre-existing activities may have an impact on your property. Documenting such impacts will be necessary to differentiate the impacts from those activities relative to the impacts on your own property.

2.2.2.3. Examine current and past aerial images to look at changes in the property
Aerial imagery is available from a number of sources. Historical aerial imagery from your property going back many years may be available from your local FSA office. Google Earth and other online tools also offer the ability to look at imagery of your property at different points in time. Understanding how your property has changed over time is important as it may help you determine what trends have already been taking place before oil and gas development, and how those trends were affected by such development.

2.2.2.4. Inspect the property and collect samples
In addition to all the steps listed above, you need to compile as much information as possible about the current condition of your property. Current aerial imagery (which now can be accomplished by accessing satellite imagery, manned photographic flights, or even unmanned aerial systems [UAS or "drones"]) as well as land-based photography of areas likely to be impacted by oil and gas development can serve as critical "before" pictures to be contrasted with "after" pictures if damages need to be documented.

Soil, water, and vegetation sampling in the area may be a good idea. Depending on the parameters to be measured, you may wish to send samples to the Soil, Water, and Forage Analytical Laboratory (SWFAL) or to the DEQ State Environmental Laboratory Services Division. In addition to water quality sampling, it may be prudent to also test water quantity. Data on flow rates for surface water bodies may be available for larger waterbodies from the OWRB, though individual streams on your property might require measurement on your own (note, though, that if you intend to use such measurements as evidence at some point in the future, strongly consider having an accredited environmental professional conduct any stream water volume assessments). A licensed engineer can conduct a flow test of groundwater wells; this may help determine a baseline flow rate for the wells if it is later suspected that oil and gas activities have adversely affected the flow of the well.

2.2.2.5. Address any current environmental issues
Your baseline work may reveal environmental issues already present on your property. If so, your baseline work may have already paid off by allowing you to handle the matter quickly!

2.2.2.5. Conclusions regarding your environmental baseline efforts
Once you have documented your environmental conditions, be sure to maintain the information you have gathered in a secure and easily-located spot in case you need it again. Further, keep the information updated as oil and gas activities begin and continue on your property so you can have the best possible information available if it should be needed.

2.3. Exploration issues
As mentioned in Chapter 1, the development of oil and gas resources on a piece of property likely will begin with the exploration of the property, most often in Oklahoma through seismic techniques. Indeed, when a significant oil or gas field is suspected in an area, developers may mobilize large fleets of seismic equipment to assess thousands of acres in an area over several months. Seismic exploration on your property may require the presence of several trucks and/or sensor arrays and could involve the clearing of brush, trees, or other vegetation and the drilling of shot holes. Rutting is possible, particularly on soft soils or in the event of recent rainfall, and depending on the time of year, crops may be damaged. In some cases, landowners have reported fence-cutting by seismic crews to access areas of the property.

2.3.1. The Oklahoma Seismic Exploration Regulation Act
As discussed above, the servient nature of the surface estate means surface owners are required to allow seismic exploration of the surface. For years, this left landowners with few alternatives to handle damages caused by seismic exploration, as such exploration was found to be outside the scope of the Oklahoma Surface Damage Act. However, recent amendments to the Oklahoma Seismic Exploration Regulation Act (SERA) have significantly increased the protections for surface owners.

Under SERA, the operator wishing to conduct seismic exploration must notify the surface owner in writing via U.S. mail at least fifteen days prior to entering the property to start exploration activities, and the notice must contain (1) the name of the company conducing the seismic exploration operation, (2) the anticipated date of the exploration activities, and (3) a description of the property to be entered.

SERA also requires an agreement between the surface owner and the operator that provides for the compensation of seismic damages to the landowner. This is one of the most significant changes brought about by SERA, since prior to the act it could be argued that an operator owed no damages to a surface owner unless they were grossly negligent. However, the offer of compensation triggers an obligation to respond on the part of the surface owner. The surface owner has fifteen days from the date of postmark on the notice to either accept or reject the offer. Acceptance must be in writing, and if the offer is accepted, the operator is required to pay the amount of compensation offered in the notice promptly. Acceptance of this amount by the surface owner means the surface owner agrees the amount covers all reasonable damages caused by the exploration activities. However, the surface owner can still bring a claim for any unreasonable damages caused by the operations, though such an action must be through separate negotiations or litigation if such damages occur.

It is very important to note the obligation of the surface owner to respond in writing to the operator within fifteen days of the postmark of the notice. Failing to do so (or is automatically deemed a rejection of the offer, and under SERA, such a rejection terminates the offer of compensation. In such a circumstance, no damages are due the surface owner unless those damages are unreasonable, and proving such damages must take place through either a small claims court action or a full civil suit. In the event such a suit is initiated by the surface owner, and the eventual amount awarded is less than the amount offered by the operator, the surface owner must pay all costs of the case for the operator; conversely, if the amount awarded is greater than the offer, the operator must pay all of the costs of the case for the surface owner.

If a seismic operator fails to follow the requirements of SERA, the party damaged by those violations can file a complaint with the OCC regarding the violation, and the operator may be subject to penalties up to $1,000 per violation per day.

2.3.2. Negotiating seismic permits

SERA contains language regarding the damage compensation to be paid to surface owners, set forth in Exhibit 2-1:

Exhibit 2-1: SERA language for surface damage compensation:

> *"Operator will conduct the proposed seismic exploration in a prudent manner and agrees to indemnify and hold you harmless from personal injury or property damage claims that may result from the operator's seismic exploration to the extent that such damage claims are not the result of your acts or omissions. Pursuant to the Seismic Exploration Regulation Act, you, as the surface owner, are entitled to reasonable damages that will be sustained by reason of the operator's seismic exploration. The operator hereby offers you $______ [operator shall fill in the amount] as compensation for the reasonable damages to be sustained by reason of the operator's seismic exploration. If you accept this offer in writing to the operator within fifteen (15) days of the postmark of this letter, you will be deemed to have accepted and agreed to the amount as full consideration for all reasonable damages by reason of the operator's seismic exploration. Operator shall, upon receipt of your timely acceptance of the offer contained herein, remit to you the consideration described in this offer. The acceptance of this amount shall not prohibit you from attempting to recover damages which are unreasonable and caused by reason of the operator's seismic exploration on your surface estate.*
>
> *In the event that you either (a) reject the offer in this letter in writing to the operator within fifteen (15) days of the postmark of this letter, or (b) fail to make a timely acceptance of the offer contained herein, then you will be deemed to have rejected the offer contained herein, and pursuant to the Seismic Exploration Regulation Act, you may initiate an action pursuant to The Small Claims Procedure Act or a civil action pursuant to the Oklahoma Pleading Code, as appropriate, to recover the reasonable damages, if any, actually sustained by reason of the operator's seismic exploration. If an action to recover reasonable damages is commenced accordingly and a judgment is entered in the action for you as to the damages in an amount in excess of the amount set forth in this notice for reasonable damages by reason of the operator's seismic exploration, you shall be considered the prevailing party. If the judgment entered is for an amount equal to or less than the amount set forth in this notice for reasonable damages by reason of the operator's seismic exploration, although you will be entitled to receive the judgment amount, if any, the operator shall be considered the prevailing party. The prevailing party in any court proceeding brought pursuant to the Seismic Exploration Regulation Act shall be entitled to recover the costs of the suit, including but not limited to reasonable attorney and expert witness fees and litigation expenses. If the action should be dismissed other than by way of settlement prior to the entry of judgment, then the surface owner shall forfeit its right to receive any consideration for all reasonable damages by reason of the operator's seismic exploration."*

While many operators will use this language word-for-word, some may use a variation of it for their compensation terms. The compensation to be provided is not the end of the seismic permit (sometimes called a seismic agreement). Consider the following points when negotiating your seismic agreement:

- Remember, it is vital to respond to the notice immediately. This does not mean that you immediately must accept the offered compensation, but be careful not to reject the offer explicitly either if you wish to preserve that offer as an option. Not responding in a timely manner is deemed to be a rejection of the offer, and may mean you receive no compensation.
- Ask your neighbors what offers of compensation have been made to them. You may also contact organizations such as the National Association of Royalty Owners, the Oklahoma Mineral Owners Association, or Farmers Royalty Company to get information about prevailing rates for seismic exploration.
- A rule that will be repeated often in this publication: be reasonable. Acting in a courteous, professional manner and asking for terms that protect your interests while allowing the operator to perform their tasks efficiently and profitably will, in almost every circumstance, do much more good than immediately taking an extreme and firm position.

- Don't focus solely on compensation. While the payment for seismic exploration is certainly important, so too is protecting the surface from potential damage. In order to obtain greater protection for the surface, it may be necessary to yield some compensation.
- Define sensitive areas on your property that should not be disturbed by the seismic activities, such as occupied homes, livestock pens, water wells, or any other land uses that could be seriously damaged by the types of activity associated with seismic exploration, and include setback distances in the seismic agreement. For example: "No vibroseis or operations will be permitted within 500 feet of a water well." Longer setback distances are likely appropriate for shot-hole operations than for vibration operations. Note that on small parcels of property, setback distances that are too large can render most of the parcel unusable quickly, and that is likely unacceptable for the operator.
- Provide a map of your property using aerial imagery to highlight the sensitive areas mentioned above and indicating their setback areas. Also highlight permissible access points such as roads and gates to minimize the opportunity for fence cuts. An example of such a map is included in Exhibit 2-2.
- If shot-hole operations are to be used on your property, larger setback distances may be necessary. Additionally, if shot hole operations will take place near water wells, be sure to conduct a baseline study of both water quality and quantity (through a flow test) for the well.
- Ask if it is possible to time the seismic operations so they occur during a portion of the year when no crops are growing on the property. This may be difficult since seismic surveys may involve a large number of vehicles and other equipment that must be mobilized in a region, and it may be very difficult for the operator to change the timing of the exploration. In the absence of agreement on such a term, ask for a prohibition on operations within a certain period after a rain, such as 72 hours after a rainfall event of 0.25 inches or more.
- Another concept that will be important and emphasized multiple times in this book – develop very clear, objective measurements for calculating the damages to crops and livestock. One example (and note, there are numerous ways to calculate such damages) would be to measure the area of a crop damaged in operations and determine the compensation as follows:

Crop damage payment =
area damaged (in acres)
x five year average yield per acre
x nearby futures price for the commodity

- Clearly define how each item in the calculation can be objectively determined. In the example above, how the area damaged will be calculated (perhaps calculation by a Certified Crop Advisor), how the five-year average will be calculated (for example, by county average as reported by USDA or based on farm records), and the commodity contract to be used. The same principles can be applied to injured or killed livestock. Agreeing in advance to compensation terms can save significant time and expense should such a claim arise.
- Define specifications for any fence repairs or gates that are needed if fences must be cut (and fence cuts may be needed far less often than thought). These specifications are discussed in section 2.5 below.
- Include provisions holding the operator strictly liable for any costs incurred as a result of livestock escapes caused by the operations.
- No trash should be discarded on the property at any time during seismic operations. All equipment and debris must be removed from the property immediately upon the completion of operations on the property.
- Include an indemnity clause holding the operator liable for any damages to a third party caused by the operations on your property.

Exhibit 2-2: Example map with setback, fence, and gate markers

2.3.3 Conclusions regarding seismic permits

Surface owners may not have significant bargaining power when it comes to negotiating seismic permits, but being proactive and engaging the operator to let them know your concerns and working with them to help them achieve their goals while protecting your land can go a long way. If you anticipate seismic exploration of your property, consider working with your attorney to draft a seismic permit of your own, or draft a rider or attachment that can be appended to the permit you are offered, with the terms important to you.

2.4. Surface damages

Seismic exploration will likely be relatively quick and temporary in nature. On the other hand, the construction of a well pad location can cause some temporary impacts and some permanent impacts. Given that the surface estate is burdened with supporting oil and gas operations for the mineral estate and cannot stop such operations, the Surface Damage Act and the surface use agreement executed between the surface owner and operator are critical to balancing their respective rights.

2.4.1 History of the Surface Damage Act

For many years, Oklahoma law held the owner of surface property was only entitled to payment for damages to the property if the oil and gas producer was negligent in its operations; if there were no such negligence, the surface owner received no payment at all for the use of their property in oil and gas development. However, as Oklahoma's oil and gas industry grew during the Energy Crisis of the 1970's, this rule led to rising tensions and a significant increase in litigation between surface owners, mineral owners, and operators.

In 1982, the Oklahoma legislature realized a change was needed to protect Oklahoma's energy and agricultural industries and passed the Surface Damage Act. In short, the Surface Damage Act requires oil and gas companies to use "good faith" negotiations with landowners to determine and pay for the amount of damage that will likely occur to property as a result of oil and gas operations before those operations take place. If these negotiations are not successful, the Surface Damage Act provides a procedure for determining those damages by an appraisal and perhaps even by trial, if necessary.

2.4.2. When does the Surface Damage Act apply?

The Surface Damage Act applies to the "operator" and the "surface owner" of the property where oil and gas operations will occur. The "operator" is defined as "a mineral owner or [mineral] lessee who is engaged in drilling or preparing to drill for oil or gas." The "surface owner" is "the owner or owners of record of the surface of the property on which the drilling operation is to occur." Note that this definition means that if someone is leasing the surface, the negotiations will be with the landlord rather than the tenant. If oil and gas development of leased property is likely, the lease should address how the effects of such development will be handled by the landlord and tenant.

Oklahoma's courts have held that the Surface Damage Act applies to drilling operations (and preparations to drill). It does not apply to damages caused by the exploration for oil and gas. Such damages are discussed in section 2.3 above. The Surface Damage Act is primarily aimed at determining and paying damages before drilling starts. If damages from pollution, nuisance, or other causes arise from the well's operation, the surface owner may need to claim damages both under the Surface Damage Act and under other state law.
2.4.3. How are "surface damages" measured?

Under the Surface Damage Act, the amount of "damages" to be paid is the difference in the fair market value of the entire tract of property before the oil and gas operations on the property, and the fair market value of the entire tract of property after the oil and gas operations are completed. This is not always easy, though, because this amount has to be estimated before the operations have started. Thus, both operators and surface owners must carefully examine the plans for well operations and the affected property. Surface owners will need good records to show the productivity and value of the property.

The Oklahoma Supreme Court has noted that the following items are some (but not necessarily all) of the factors that may be considered in calculating the damages:

1. The location or site of the drilling operations.
2. The quality and value of the land used or disturbed by said drilling operations.
3. Incidental features resulting from said drilling operations which may affect convenient use and further enjoyment [in other words, "side effects" resulting from the operations that affect the ability to use the property later].
4. Inconvenience suffered in actual use of the land by the operator.
5. Whether the damages, if any, are temporary or permanent in nature.
6. Changes in physical condition of the tract.
7. Irregularity of shape and reduction, or denial, of access.
8. The destruction, if any, of native grasses, and/or growing crops, if any, caused by drilling operations.

2.4.4. What is the Surface Damage Act's procedure?

Before an operator enters the property, it must provide notice to the surface owner of its intent to drill. This notice must be sent by certified letter. The letter must include (1) the proposed location of the well, and (2) the approximate date that drilling operations are scheduled to start. Once this notice has been delivered, the operator has five days to start "good faith negotiations" with the surface owner. If the parties can agree to the amount of surface damages and surface use agreement (discussed in section 2.5 below), then the operator can enter the site and start drilling. Once this agreed-to amount is paid, the Surface Damages Act has been fulfilled.

If the operator and surface owner cannot reach an agreement, though, a new procedure begins. First, the operator must file a bond with the Oklahoma Secretary of State. This bond is meant to ensure the payment of whatever damages may be eventually determined in the case. Second, the operator must file a petition in the district court for the county in which the proposed well will be located. This petition asks the court to appoint appraisers to determine the surface damages to the property. It is very important to note here that if an operator properly completes these steps, it can enter the property even without the permission of the surface owner; however, the operator cannot enter the property until these steps are satisfied.

If the operator asks the district court for the appointment of appraisers, the surface owner must be given notice of the petition within ten days of its filing. Once the surface owner has received his or her notice, the parties have 20 days to choose their appraisers – one appraiser will be chosen by the surface owner, and one will be chosen by the operator. These two appraisers then meet to choose another appraiser, for a total of three.

After the appraisers have been appointed and sworn in by the court, they have 30 days to inspect the property, confer to estimate the amount of damages, and submit a written report to the district court, which is then forwarded by the court to the surface owner and the operator.

Once the report is filed, the surface owner and operator have three options from which to choose. First, if the parties agree to the appraised amount of damages, the damages can be paid to the surface owner by the operator, a surface use agreement is executed, and the matter is closed. Second, either party can, within 30 days of the filing of the report, file an "exception" with the court stating that the party believes the appraisal is inaccurate. If either party chooses this option, the court will review the appraisal and either confirm it, reject it, modify it, or ask for a new appraisal. Third, either party can, within 60 days of the filing of the report, demand a jury trial to determine the amount of damages.

It should be noted here that the oil and gas operations at the site in question may continue even if an exception or demand for jury trial is made, so long as the operator posts an amount equal to the appraised damages with the court clerk. The decision to demand jury trial should not be undertaken lightly, as it will trigger the Act's provisions regarding costs and attorneys' fees, as discussed in greater detail below.

2.4.5. What about attorneys' fees and penalties?

The Surface Damage Act provides for the award of costs and attorneys' fees, but such costs and fees are only awarded by the court if a demand for jury trial has been made. Further, costs and fees are only recoverable by a party if that party receives an award more favorable than the appraisal report. For example, an operator can only recover costs and attorneys' fees if the damages determined by the jury are less than the appraisal report indicated. On the other hand, a landowner can only recover costs and attorneys' fees if the jury awards the landowner more damages than the appraisal report indicated.

Aside from its provisions for attorneys fees, the Surface Damage Act also carries a penalty for operators who fail to follow its requirements. If an operator knowingly enters property for drilling operations without providing notice to the surface owner, or fails to carry through with the Act's requirements (i.e. fails to either secure an agreement with the landowner or follow the appraisal and bonding requirements), the operator may be liable to the surface owner for triple the amount of surface damages eventually determined.

2.5. Negotiating Surface Use Agreements

While the Surface Damage Act provides for compensation to the surface owner, that compensation is only one step in the process of balancing the rights of the surface owner and the operator working on behalf of the mineral owner. Many landowners focus exclusively on the compensation to be paid without considering the protections they may be forfeiting by not working to craft a surface use agreement that ensures the greatest possible preservation of their property. There are numerous issues to take into account in negotiating a surface use agreement, and the following section breaks these issues into a number of categories.

2.5.1. General considerations

- As mentioned above, take a reasonable approach in your negotiations. Be professional and courteous in your communications. This does not mean you should not seek the maximum protection of your rights, but it does mean "you catch more flies with honey than with vinegar."
- Keep thorough records of your communication with the operator. Those communications may be important later to clarify an ambiguity in the surface use agreement, or to address an issue that was omitted from the agreement. Some landowners go so far as to only negotiate via email, letter, or text message, so there is always a complete, written record of all communication.
- Be aware of the procedures and requirements of the Surface Damage Act; it is the greatest source of negotiating power for the surface owner.
- Inasmuch as possible, maintain a good working relationship with the mineral owners. This can be difficult if the minerals were severed long ago, or if they are now owned by many parties rather than one individual (and both may often be the case in Oklahoma). Staying in communication with the mineral owner(s) may help you anticipate when oil and gas activity will take place. With a sufficiently good relationship, the mineral owner may also serve as an advocate alongside you in the negotiation of both surface and mineral agreements.
- There is strength in numbers. Consider working with neighboring landowners to create a surface use agreement all of you agree to use when you are approached by an operator. Consistency in terms (so long as they are reasonable) may help all of you get more of what you hope for and can streamline the negotiation process.
- Limit the use of the surface to wells that directly serve the minerals underlying the property. Issues such as drilling and spacing units and horizontal drilling have clouded the issue somewhat in Oklahoma law, but existing law suggests the surface estate is only burdened by the minerals underlying it. Additional compensation should be sought if the surface is going to be used to serve other properties

2.5.2. Documenting baseline conditions

- Even before the surface use agreement is executed (or as soon as possible after it is executed), document the baseline conditions of your property using the points discussed in section 2.2.2. above.

2.5.3 Compensation

- As mentioned above, the National Association of Royalty Owners, the Oklahoma Mineral Owners Association, or Farmers Royalty may be able to provide information regarding compensation received by similarly-situated landowners.
- It may be possible to receive more compensation in the form of in-kind goods or services than in cash. If an operator offers $10,000 for damages, it might be possible to obtain more than $10,000 in value if, instead of cash, you ask for services such as earthmoving to build a pond or terraces, road construction, or used pipe that you can in turn use for construction projects around your farm or ranch.
- Think about any items or services you can offer the operator to assist in their operations. Water sales to the operator are quite common (be sure to consult with the Oklahoma Water Resources Board to see if any water permits will be required for such sales). If you own earthmoving equipment, you may offer to provide such services to the operator. Everything from catering meals at the well location to renting hunting cabins to the operator's crews have been done by entrepreneurial surface owners.
- Some items – especially damage items such as the location area itself, road rights of way, pipelines, flowlines, and electrical lines, are compensated on a specific basis, such as per acre, per square foot, or per foot (sometimes linear distances are defined by rods, which equal 16.5 feet). Define a schedule of these payments in your surface use agreement. As part of this schedule, be careful to define the width of the right of way. One foot of right of way 30 feet wide is not the same as one foot of right of way with a 50 foot width.

2.5.4. Location and configuration of facilities

- Wherever possible, negotiate the right to consult on the items that impact your use of the land, such as locations of facilities and construction methods used.
- Require that, to the extent possible, facilities should be located to minimize the impact to existing surface uses, such as occupied structures, irrigation pivots, wind turbines, and the like.

2.5.5. Water

- As discussed in section 2.1 above, the mineral owner (and by extension, the operator) may or may not have a vested right to access groundwater to operate the well. Consult with an attorney to examine the title to the minerals and determine water rights.
- If groundwater rights remain with the surface owner, negotiate a price and terms for which water will be sold to the operator.
- In some cases, the operator may be willing to construct a pond or water well that you can use after the well is completed in exchange for the use of water from the structure.

2.5.6. Roads

- Roads can be a highly-valuable in-kind consideration for the surface owner. Consult with the operator and work to make sure roads are built in a manner that minimizes interference with other uses of the property and minimizes the amount of land they occupy. You may also be able to negotiate for the construction of roads beyond those that directly access the well location as part of your surface damages compensation.
- If at all possible, ensure that roads do not cut across terraces or cause other interference with soil conservation measures.
- Require culverts be installed as appropriate to preserve necessary drainage on the property. Work with the operator to specify where these installation points are needed.
- Require that roads be graveled or otherwise constructed to resist damage and that they be maintained in good condition.
- Include a requirement that operators and anyone visiting their site drive only on the roads, and that any off-road driving must be approved in advance and in writing by you.
- Roadways should be kept free of weeds, trash, and debris.
- Set a speed limit for driving on the roads; many surface owners set such limits at 25 to 30 miles per hour.

2.5.7. Gates and cattle guards

- Operators should install a gate or cattle guard at any point where they access the property from a public road and where any of their roads intersect with an existing fence.
- Require any gates to be double locked (with one lock keyed for you, and the other lock keyed for the operator) to prevent unauthorized parties from accessing the property.
- Ensure gates are wide enough for any needed drilling or maintenance equipment to enter the property without the need for fence cuts.
- Gates should be braced on either side to prevent a loss of tension in the fence on either side (see the discussion of fencing below).
- Gates should be closed at all times unless in immediate use; include language holding the operator liable for any loss of livestock or other damage caused by a failure to close the gates.
- The University Lands - University of Texas System has created a number of specifications for cattle guards used on their lands and has made these specifications available to the public at their website: http://www.utlands.utsystem.edu/surface/Cattleguards.aspx ; you may wish to use these specifications (or specifications of your own) in the agreement.
- Require the operator and any related parties to leave the property from the same gate they entered. This may seem odd, but it is meant to prevent your property from being used as a “hub” or a central point from which many other locations can be accessed. Allowing such use can dramatically increase the traffic and activity on your property beyond that necessary to construct and operate the well serving your property.

2.5.8. Fencing

- Require the operator to repair any fence cuts immediately (within 24 hours) and to repair the fence to its previous condition or better.
- The operator should construct and maintain fence around all well heads, pumping units, tank batteries, pits, disposal wells, or any other equipment or areas that could cause injury to livestock or visitors to the property.

- Any fence cuts or other areas requiring fence re-tightening should also be braced. The University Lands - University of Texas System has specifications and plans for fence and gate braces available on its website at: http://www.utlands.utsystem.edu/surface/HBraces.aspx
- Define fencing specifications appropriate to the livestock in the area. Different fence specifications are required for cattle than for sheep and goats, and still other fencing may be needed in areas where deer or other species are raised.

2.5.9. Damage to livestock and crops

- As mentioned in section 2.3.2., any calculations for damages to crops or livestock need to be objectively determinable, and set out clearly in the agreement.

2.5.10. Pipelines and flowlines

- Pipelines and flowlines that are not buried should be located immediately adjacent to roads or fences.
- Any places where lines are placed under roads must be buried at least twelve inches and marked by signs.
- Any pipelines should be buried to a depth of at least 36 inches. Erosion will sometimes bring the soil surface down to the pipeline (sometimes landowners think of this as the pipeline "working its way up" to the surface), so include a requirement that the margin of 36 inches must be continuously maintained.
- Any subsurface structure (pipeline, flowline, pit, etc.) should be constructed so that topsoil is laid to one side, and subsoil laid to the other, with subsoil then replaced first with topsoil on top.
- Lines that are not buried should be removed immediately upon completion of the well.

2.5.11. Tank batteries

- Federal and state regulations will frequently require secondary containment areas around tanks. You may wish to add requirements for how berms or containment barriers made of fiberglass, corrosion-resistant metal, or petroleum-resistant plastics be constructed to contain any spills.
- If the tank battery location is in a low-lying area, you may also want to include requirements for a dike, levee, or other structure to prevent the flooding of the tanks.

2.5.12. Power lines

- Utility lines should be constructed and operated in a manner consistent with the most current version of the National Electric Code® (National Fire Protection Association Code 70), available at http://www.nfpa.org/codes-and-standards/document-information-pages?mode=code&code=70
- Utility lines should run along roads or run parallel to section lines.
- Define a minimum height at which lines should be hung that is compatible with the agricultural equipment you will be using most frequently on the property.
- Any power lines must be maintained in such a way as to prevent inadvertent contact with livestock or visitors to the property.
- Landowners may wish to prohibit burial of power lines. If power lines are permitted to be buried, they should be below a minimum of 36 inches to prevent accidental contact with tillage equipment.
- Include a requirement to consult with you on the location of power lines.
- Utility lines must be de-energized (and, preferably, removed) immediately once they are no longer used by the well location.

2.5.13. Maintenance of the location

- All vehicles, equipment, and machinery should be kept on the location (that is, the well pad).
- The well location may only be used for the short-term storage of equipment, parts, or materials for use on that location. Storage of surplus equipment, tanks, pipe, or other such items for other locations is not should not be permitted.
- No trash or other debris should be kept on the location except in appropriate containers (such as dumpsters), and such containers shall not be allowed to overflow or be maintained in any way that would permit trash or other debris on to the property. No disposal of trash or other items is permitted along access roads.
- Well locations should be kept free of weeds.

- Grass and any combustible materials should be kept clear of any pumps, tank batteries, or potential ignition sources.

2.5.14. Personnel issues

- Locations should to be used solely for activities reasonably necessary for the production of oil and gas; social gatherings and tours must be approved by the surface owner, in writing and in advance.
- No one is allowed to possess alcohol, drugs, or any illegal substances while on the property.
- No hunting or fishing is allowed, and no hunting or fishing equipment (including firearms) may be possessed by the operator or their related parties on the property.

2.5.15. Spills

- Require any spills or leaks to be cleaned up immediately (regardless of the amount of material spilled), and for any cleanups to be completed in compliance with applicable state or federal regulations.

2.5.16. Aesthetics

- Lighting systems should be constructed to direct light straight downward and to minimize any light impacts beyond the well location.
- Specify a sound level (measured in decibels [dBA]) to which operations must be kept. Different sound levels may be needed during the construction of the well than when it is operating.
- Sound baffling material may be required to reduce noise from sources such as compressor engines.
- Specifying a paint color for tanks and pumps might help the location blend into the surrounding environment and reduce visual impacts.

2.5.17. Indemnity

- Require the operator to indemnify you against any claims brought by third parties caused by the activities of the operator or any of its related parties on the property.

2.5.18. Site restoration

- All equipment, debris, and any other materials not absolutely necessary for the continued operation of the well should be removed promptly once the well has been completed. Define "promptly" – in some cases this may be as short as 120 days, though 180 days may be more common.
- The site should be restored to its original condition as reasonably as practicable. This includes the restoration of the original contours of the land.
- All disposal pits should have any harmful substances removed and should be restored in compliance with all applicable OCC rules. Pits should be filled in.
- Terraces and any other conservation structures damaged should be rebuilt or repaired.
- Vegetation comparable to the surrounding vegetation should be re-established. Note that this does not mean "re-seeding." Re-seeding can be as simple as broadcasting seed to the ground, but in a drought or even with an active bird or mammal population in the area, such seeding does little good. Define re-establishment to mean the vegetation must be seeded, fertilized, watered, and maintained until it is in a condition comparable to that of vegetation in the environment surrounding it. If the area affected is subject to a Conservation Reserve Program (CRP) contract, require the operator to restore the property in a matter compatible with the contract and to indemnify you for any penalties or other charges assessed under the CRP contract as a result of the operator's activities on the property.
- OCC regulations require that all wells be properly plugged and abandoned within a year of the cessation of use of the well (if the well is completed with the installation of production casing). Make proper plugging and abandonment of the well an explicit requirement of the surface agreement.
- An important question is when a well "ceases" to be used. Proving a well is no longer in use can be difficult. Consider asking for the production reports from the well as a part of the surface agreement. Define in the agreement a specific period of time with no production (or production at a specified level) after which the well is agreed to have ceased production.

2.5.19 Analyzing the economic impact of surface development

As you have learned from the previous pages, there are many ways oil and gas development can impact use of the surface. Understandably, it may be difficult to predict all of these impacts. As a result, it can also be difficult to determine the impact that development will have on your returns to land.

However, there is something that can be used to help with this: partial budgeting. Partial budgeting is a tool used to analyze changes in an element of the farm business. While you might not think about oil and gas development on your property as a business change, in some ways it is – essentially, the use of land is changing on a portion of your property from pasture or crop operations to oil and gas development.

A partial budget analysis consists of four primary components: added income, added costs, reduced income, and reduced cost. One side of our analysis consists of items that would increase our returns (added income and reduced costs) and the other side consists of items that would decrease our returns (reduced income and added costs). Comparing the two sides of our partial budget analysis shows us the predicted change in our profits resulting from the business change. An example of a partial budget for analyzing the impacts of oil and gas operations on the property is shown in Exhibit 2-3 below.

Exhibit 2-3: Partial budget analysis for oil and gas development

Added income		**Reduced Income**	
Surface damage payment (one time)		Reduction in crop sales	
Water sales (payments per barrel)			
Reduced costs		**Added Costs**	
No crops raised on well location		Increased costs for "farm around"	
Seed		Machine time	
Fertilizer		Labor	
Pesticide			
Machinery time			
Labor			
Total increases to returns		**Total decreases to returns**	
Net impact to returns (increases - decreases)			

2.5.20. Conclusions and reference materials

A lot of potential considerations have been offered for a surface use agreement. Remember to understand your bargaining position – the stronger your position (the more intense the market, the acreage you own, whether you are acting in concert with other landowners), the more terms you can likely get included in the agreement; conversely, the stronger your position, the fewer provisions you may be able to negotiate. Even so, provisions that simply require prudent construction and operation of the well location and that should not add additional cost to the operator may be mutually agreeable.

Appendix 1 and 2 to this chapter provide examples of two surface use agreements that are generally friendly to landowners. These examples show you how some of the points mentioned above can be written into the text of a surface use agreement. Additionally, for examples of some terms and best practices for surface use, you may wish to refer to the University Lands – University of Texas System Field Manual, http://www.utlands.utsystem.edu/

forms/pdfs/FieldManual.pdf?201507 . Bear in mind, this represents the perspective of a landowner with significant bargaining power (owning over 2 million acres of surface and mineral rights) so they have a bit more bargaining power than the surface-only owner of 160 acres, but many of the concepts included therein can provide you with ideas for terms to include in your own surface use agreement.

2.6. Waste disposal issues

Oil and gas production generates a number of waste streams, including salt water produced along with the oil and gas drawn up the well, as well as drilling fluid, also called "drilling mud." Salt water is frequently handled in large ponds or other containment structures on the well location until it can be disposed. Most often in Oklahoma such disposal takes place by injecting the saltwater into disposal wells, which in many cases are repurposed oil and gas wells that are no longer producing.

Perhaps the most common waste management practice directly involving surface owners is the disposal of drilling fluid. As mentioned in Chapter 1, drilling fluid is a mixture of materials continuously circulated through the drill pipe to cool the drill bit, to flush away drill cuttings, and to provide balancing pressure to the wellbore. This fluid can be recycled several times by the drilling rig, but eventually it loses its effectiveness and must be disposed.

The most common method of disposing drilling fluid is by applying it to land. When done correctly, the land application process allows soil bacteria to break down the hydrocarbons contained in the drilling fluid and for the migration of rainwater through the soil profile to carry salts in the drilling fluid below the root zone of the plant community. A number of environmental factors and characteristics of the land influence the success of this process.

Operators often turn their drilling fluids over to disposal companies, who then enter contracts with landowners to arrange for the land application of the drilling fluid. Under these contracts, landowners are usually paid by the barrel of drilling fluid applied, and prices for hydrocarbon-based fluids (in which a hydrocarbon, frequently diesel fuel, is used as the solvent for the fluid) are often significantly higher than those for water-based fluids (in which water is the solvent). In essence, the disposal company is paying the landowner to dispose of the fluid on their land.

The effect of drilling fluid disposal on agricultural land and the vegetation growing on it depends on many factors, and research continues to better understand this process. In the meantime, though, preliminary research suggests that there will be a negative impact on plant growth for at least the first few years after a drilling fluid application, particularly on salt-sensitive plants and crops.

2.6.1 Regulation of drilling fluid application

The OCC rules governing disposal of drilling fluid set out a number of requirements designed to minimize any negative environmental impacts. These requirements include the following:

- Soils must have a slope must be 8% or less
- The soil depth to bedrock 20 inches or more for water-based fluids, and 40 inches or more for hydrocarbon-based fluids
- Salinity:
    - The soil's electrical conductivity (EC) must be 4,000 mΩ or less
    - The soils exchangeable sodium percentage must be 10.0 or less
- The soil depth to the water table must be 6 feet or more
- The soil must fall into one of the eleven approved soil textures
- Soil sampling must be performed to confirm all required soil characteristics
- Fluids must be sampled for electrical conductivity and oil & grease (O&G) content
    - For hydrocarbon-based fluids, sampling is also required for gasoline range organics (GRO) and total petroleum hydrocarbons (TPH).

- Disposal companies must have written permission for application from the landowner
    - The application must include a topographic map and aerial photo of the application site, along with a site suitability report, analysis of soil samples, and the calculations demonstrating how much fluid the site can accept without violating the soil parameters set forth above
- Setbacks: applications must take place no less than
    - 1,320 feet (1/4 mile) from any municipal water well or water supply lake
    - 300 feet from any domestic water well or water supply lake
    - 100 feet from a perennial stream, freshwater pond, lake, or wetland
    - 50 feet from an intermittent stream
- Applications cannot take place during precipitation events (rain, snow, etc.), when soil moisture is too high to accept fluid, when the ground is frozen, or when winds are so high as to cause drift of the fluid during application
- Fluid applications must be uniform (that is, the applicator must use equipment and techniques to evenly distribute the applied fluid, and to not cause pooling or runoff
- Fluid applications must not cause permanent vegetative damage
- Hydrocarbon-based fluids must be incorporated into the soil by either disking or chiseling, and fertilizer must also be applied to adjust the carbon-nitrogen ratio for enhanced biodegradation of the fluid

2.6.2. Considerations for drilling fluid application agreements

Choosing whether to allow the application of drilling fluid on your land is clearly a decision that should not be taken lightly. Before even considering such applications, it is critical to have a sound understanding of your land and its soil traits. You must also consider whether you feel comfortable risking the productivity of the land receiving the fluid for at least a few years. If you think land application may be a viable decision for your land, consider the following items in your surface application agreement (and, of course, never allow application of drilling fluids without a written agreement).

- Regulations require sampling of every truckload of fluid applied; require results of each load of fluid and time to examine the results before the fluid is applied.
- Do you want to receive sample analyses for measures other than those required by the regulations? Some landowners would like to have information on parameters such as BTEX (benzene, toluene, elthylbenzene, and xylenes) or heavy metals. Bear in mind that testing for these parameters can take time and expense on the part of the disposal company, and requiring these tests may reduce your compensation amount.
- Clearly define restricted areas, setback areas (which can be larger than those specified in the regulations if the parties agree), and allowable access areas. As mentioned above, provide an aerial map of your land that clearly and visually lays out setback areas, areas in which fluids are not to be applied, and permitted access points.
- Also as mentioned earlier in this chapter, set clear means of calculating damages to crops and livestock.
- With livestock, agree to a method to be used (often examination by a licensed veterinarian) to determine whether the cause of the livestock injury was contact with the applied fluid. Understand that it may be necessary to restrict livestock access from application areas for some time to avoid them drinking any fluid that may have accumulated.
- Clearly define the payment terms and how payment is to be made.
- Define what will constitute “material breaches” of the agreement –that is, a breach of the agreement serious enough to result in its immediate termination. This may include application in restricted areas, application of wastes other than drilling fluid, or other serious harms.
- Specify contact information as to how you would prefer to be reached in the case of an emergency, how you want to receive sample analyses, and when a written notice about the agreement is required.
- If you have a tenant on the land, you may not be apply to apply drilling fluid without breaching your lease with the tenant. Always involve any tenants in the discussion of applications of land under lease and if the tenant will allow application, negotiate how the tenant will be compensated.
- Include an indemnity clause requiring the disposal company to protect you against any claims by parties injured as a result of the application of drilling fluid on the property.

2.7 Conclusion

Surface owners, rather than mineral owners, must deal with many of the impacts of oil and gas development on their land. Whenever you face the prospect of oil and gas activities on the surface of your property, be proactive and engage an attorney and any other needed professionals or consultants to help you protect your interests. Working with the operator in a professional and courteous manner can help you preserve your rights while allowing for the profitable production of oil and gas.

Appendix 2-1: Sample surface use agreement

This surface use agreement was written to be accommodating to surface owner interests. This agreement was provided by James Decker, Esq. of Shahan Guevara Decker & Arrott, Stamford, Texas. Please note: this agreement is provided only as an example to illustrate concepts discussed in this chapter and is not intended to serve as a form. Always consult with a licensed attorney to review and/or draft any legal agreement that may affect your rights.

SURFACE USE AGREEMENT

This Surface Use Agreement ("Agreement") is entered into this day by and between ______________________("Surface Owner") and ______________________ ("Operator"). For the mutual promises and covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties agree as follows:

1. Subject Lands. This Agreement covers the following lands (the "Subject Lands"):

   Legal description of property

2. Reasonable Use of Surface. Operator has a non-exclusive right of reasonable use of the surface of the Subject Lands for Operator's oil and gas operations thereon. Surface Owner acknowledges these rights and agrees not to interfere with Operator's operations on the Subject Lands. Surface Owner and Operator have agreed to the amounts listed on the attached Rate Schedule as payment by Operator for reasonable surface damages to Surface Owner's surface estate on the Subject Lands.

3. Notice of Operations. Operator shall notify Surface Owner of any drilling activity on the Subject Lands prior to commencement of operations.

4. Roads. Operator may utilize pre-existing roads or may construct and maintain new roads as is reasonably necessary for its operations. Any pre-existing road utilized by Operator shall be maintained, at a minimum, in a manner consistent with the road's condition prior to execution of this Agreement. If Operator chooses to expand the width of pre-existing roads or drive outside of pre-existing roads in lieu of constructing new roads, Operator shall pay the damages set forth on the Rate Schedule. New roads shall be reasonably straight and shall also be maintained in a condition similar to the condition of the existing roads. Operator shall install a metal culvert or otherwise address low-water crossings on terms mutually agreed by Operator and Surface Owner. Operator and its employees, agents, contractors, invitees, and other visitors shall confine their driving on the Subject Lands to these new and pre-existing roads and shall not drive elsewhere on the Subject Lands without prior written approval of Surface Owner.

5. Gates. Operator shall install a gate (or gates) where entry is made onto the Subject Lands from a public road or where roads intersect a fence, unless Operator elects to use existing or to install a new cattle guard. If Operator elects to install gates, Operator shall build such gates wide enough for entrance by a drilling rig and shall not permit the gates to weaken the balance of the fence. Operator shall provide a double lock for each gate at the request of Surface Owner.

6. Fences and Grazing. Operator acknowledges that Surface Owner utilizes the surface to graze livestock *OR insert other applicable provisions regarding cultivated agriculture as may be necessary.* As such, secure fences and closed gates are a necessity to prevent injury and death to livestock. Operator agrees to keep gates closed at all times and to take reasonable precautions to ensure fences are secure. If Operator damages or breaches Surface Owner's fences or gates, Operator shall promptly repair the fence or gate to its previous condition. Operator will erect and

maintain fencing around all wellheads, pumping units, tank batteries, working pits and slush pits, and disposal wells, sufficient to prevent access by livestock.

7. Damage to Livestock and Crops. Operator shall compensate Surface Owner for any injury or death caused to Surface Owner's livestock or damage to Surface Owner's growing crops. Damages will be based on the actual value of the animal or crop damaged.

8. Utility Poles. Operator may construct single pole utility lines on the Subject Lands. All lines shall be constructed so that the wires supported thereon are at least twenty (20) feet above ground at all points. Construction, maintenance, and operation of electrical lines must comply with the standards published in the National Electrical Code and in Chapter 1305 of the Texas Occupations Code. On transfer of equipment from a well site or removal of equipment from the Subject Lands, Operator must de-energize electrical lines as soon as practicable. Operator shall work with Surface Owner to locate utility lines in a manner that minimizes interference to Surface Owner's surface use. If Operator desires to bury any utility line, burial shall be a minimum of thirty-six (36) inches below surface grade. Damages shall be paid according to the Rate Schedule.

9. Pipelines. All pipelines, flowlines, and gathering systems shall be constructed, maintained, and operated in a manner, insofar as practicable, that minimizes interference to Surface Owner's surface use. If Operator desires to bury pipelines and other lines, burial shall be a minimum of thirty-six (36") inches below surface grade. Surface flowlines and gathering systems shall be placed parallel and immediately adjacent to roads and in common corridors. Damages shall be paid according to the Rate Schedule. Surface Owner shall have the right to drive over and across above-ground flowlines if needed, but Surface Owner shall use reasonable judgment regarding the type of equipment that is driven over said flowlines.

10. Water. Operator may not drill its own water wells on the Subject Lands without the written consent of Surface Owner. Operator may purchase fresh water from Surface Owner under mutually agreeable terms.

11. Surplus Equipment and Trash. Operator may not use the Subject Lands as a warehouse site or storage facility for surplus equipment that is not intended to be utilized on the Subject Lands. The Subject Lands shall be kept free at all times of trash, debris, and junk equipment.

12. Hunting and Fishing; Firearms. Operator and its employees, agents, contractors, invitees, and other visitors shall not be permitted to hunt or fish on the Subject Lands at any time, nor carry or discharge a firearm.

13. Leaks and Spills. Operator shall promptly, on notification, clean up and remediate any oil spill or leak on the Subject Lands. All cleanup and remediation shall meet the requirements of the Oklahoma Corporation Commission.

14. Preservation of Topsoil. All topsoil removed for a pit, pipeline, or trench of any kind shall be set aside, preserved, and replaced as topsoil when the pit, pipeline, or trench is covered.

15. Contour of Land. Within a reasonable time not to exceed one hundred twenty (120) days after completion of use of such facilities, Operator shall level dumps, fill pits, and restore well sites to as near original condition and contour of the ground as practicable, including repair of agricultural terraces. Operator shall restore the turf on well sites and other facilities by reseeding the site with a grass mix suitable to the area and mutually agreed on with Surface Owner.

16. Compliance with Laws and Regulations. Operator's use of the Subject Lands shall at all times comply with all applicable federal, state, and local laws and regulations, including the rules, regulations, and administrative procedures of the Oklahoma Corporation Commission.

17. Alcohol and Drugs. Use and possession of alcoholic beverages, illegal drugs, and narcotics by Operator and its employees, agents, contractors, invitees, and other visitors on the Subject Lands is strictly prohibited.

18. Indemnity. Operator shall indemnify and hold Surface Owner harmless against any claim, demand, damage, cost, or expense, including reasonable attorney's fees, arising from Operator's conduct, management, or use of the Subject Lands, or from any act or omission by Operator or Operator's employees, agents, contractors, invitees, or other visitors on or about the Subject Lands. If any action or proceeding is brought against Surface Owner arising from such circumstances, Operator agrees to defend Surface Owner with acceptable legal counsel.

19. Miscellaneous Provisions.

a. Counterparts; Multiple Originals. This Agreement may be executed in any number of counterparts and originals, each of which, when executed and delivered, shall be deemed to be an original instrument.

b. Paragraph Headings. The headings of the various paragraphs in this Agreement are for the convenience of the parties and shall not alter or modify the terms and provisions of this Agreement.

c. Parties Bound. This Agreement binds and inures to the benefit of the parties hereto and their respective heirs, personal representatives, successors, and assigns.

d. Enforceability. If any provision of this Agreement is held invalid, illegal, or unenforceable, then such provision will not affect the remainder of this Agreement, which will be construed as if it had never included such provision.

e. Choice of Law and Venue. This Agreement shall be interpreted and enforced in accordance with the laws of the State of Texas. Venue for any cause of action arising out of this Agreement shall be Your County County, Oklahoma.

f. Sole Agreement. This Agreement contains the entire understanding of the parties as to its subject matter. Any oral representation or modification thereto is of no force and effect. Any amendment must be in writing, executed by all parties.

EXECUTION

Effective Date: *Insert Date*

SURFACE OWNER

Name *INSERT NAME*

Address: *Insert Address*
Insert Address

Signature: ________________________________
Insert Name

OPERATOR

Name *INSERT NAME*

Address: *Insert Address*
Insert Address

Signature: ________________________________

Print Name: ________________________________

Print Title: ________________________________

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DAMAGE RATE SCHEDULE

New Drillsite Location (up to 1.25 acres)	$_______ per location
Damages for New Roads to new location (not to exceed 20') in width:	$_______ per location
Damages for expanding width or driving outside pre-existing roads	$____ per square foot
New Pipelines	Negotiate separate right-of-way and easement
New Flow Lines and Injection Lines on Surface	
Lines that run along and adjacent to roads	No charge
Lines that do not run along and adjacent to roads	$_______ per rod
New Electric Lines	
Lines that run along and adjacent to roads	No charge
Lines that do not run along and adjacent to roads	$_______ per rod
Temporary Lines of any kind, defined as lines not left in place for more than 120 days	No charge

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Appendix 2-2: Sample surface use agreement

This is another example of a surface use agreement and was written to be accommodating to surface owner interests. This agreement was provided by a petroleum landman with extensive experience in working with surface owners. Please note: this agreement is provided only as an example to illustrate concepts discussed in this chapter and is not intended to serve as a form. Always consult with a licensed attorney to review and/or draft any legal agreement that may affect your rights.

SURFACE DAMAGE SETTLEMENT AND RELEASE

STATE OF _________________________ §
§
COUNTY OF _______________________ §

KNOW ALL MEN BY THESE PRESENTS:

In consideration of the initial sum of ____ ($__________________), paid by ____ ("Company"), each of the undersigned surface owner(s), ________________________________ ____ ____ ____, ("Owner"), for themselves and their heirs, personal representatives, successors and assigns, hereby acknowledge the receipt and sufficiency of said payment as full and complete settlement for, and said parties do hereby release and forever discharge Company for, all claims and liabilities now existing or hereafter incurred for loss, damage or injury to the Subject Lands (as defined below) arising out of or related to Company's reasonable use of the Subject Lands for Company's drilling, completion, operation and plugging of the ___________________________ well or replacement well (the "Well") with a surface location within the approximate _______' x ________' (________ acres), more or less, drillsite location surrounding the surface location for the ________________________________ well pursuant to the plat attached hereto as Exhibit "A" (the "Location") and Company's installation, maintenance and operation of pipelines, electric transmission line(s), and roads serving such Well, which are situated on the following described real property located in __________________ County, State of **Oklahoma**, to wit:

(the "Subject Lands").

It is understood and agreed the acts and conduct related to the drilling, completion, operation and plugging of the Well on the Location which is covered by this Surface Damage Settlement and Release ("Agreement") including without limitation, the preparation of the drillsite location, the construction of pipelines and access roads to the drillsite location, the installation of tank batteries, and the installation of deadmen anchors and other equipment necessary to effectively and efficiently operate the Well on the Location. This Agreement does not release Company for (1) an unreasonable as opposed to a reasonable use of the Subject Lands for the Well, or (2) any future actual damages to the Subject Lands, improvements, or livestock thereon, caused by blow-outs, oil, salt water and other deleterious substance spills caused by Company's operations for the Well on the Subject Lands, if any.

The following terms and conditions shall also apply hereunder:

1. Company shall not allow its representatives, contractors or employees to bring firearms on the Subject Lands.

2. Except as specifically set forth herein, Company and Owner are not revising any of their respective rights or obligations under any oil and gas lease covering any mineral interested owned by Owner in the Subject Lands, if any.

3. Access road(s) and Location are for the Well described herein only. Any surface usage over _______ acres in size will be paid at the proportionate rate of $____________ per acre on a pro-rata basis and additional access road damages will be paid at $_________ per rod. Company has agreed to pay Owner on the basis of a ________ acre size surface location.

4. Owner has the option to supply Company with fresh water at a flat rate of $___________

for drilling operations and at a rate of $__________ per barrel for completion/hydraulic fracturing operations. In the event Owner is unable to fully meet Company's water requirements, Owner reserves the option to request Company drill a new water well or wells upon the Subject Lands at a location chosen by Owner, in order to meet Company's water capacity requirements. In the event Company uses fresh water of Owner, Company agrees to place a meter at Owner's water source, prior to installation of any flowlines, in order to properly measure water used. An image of said meter shall be taken prior to the use of Owner's water and again once operations are complete. Both images shall be provided to Owner to confirm water usage.

5. Company agrees to take all steps reasonably necessary to alleviate soil erosion on and immediately surrounding the surface location and access roads that may result from its operations.

6. Owner agrees that this Agreement shall serve as proper notice and agreement of surface damages for the __________________________________ well on the Location under the Oklahoma Surface Damage Act, as may be amended.

7. No earthen reserve pits shall be utilized in the re-entry, drilling, completion or operation of any well that may be drilled on the Subject Lands.

8. Please see Exhibit "B" attached hereto and made a part hereof for additional provisions.

Company and Owner agree pipelines and electric lines will be needed or desired or both to support Company's operations for the Well drilled on the Subject Lands. Furthermore, Company agrees to pay and Owner agrees to accept ______________________________Dollars ($____________) per rod and per line for each pipeline or electric line route on the Subject Lands as compensation for any damages and easement and right-of-way with full rights of ingress and egress for said pipeline(s) and electric line(s) that Company may from time to time lay over, across and under the Subject Lands in connection with the operation and production of the Well. Lastly, Owner agrees to execute and deliver to Company an easement and right-of-way agreement for said pipelines and electric lines on a form mutually agreeable to both parties.

Owner represents and warrants that Owner is the owner of the surface of the Subject Lands. Further, and for the same consideration, Owner shall distribute any of the proceeds received from Company pursuant to this Agreement that may be due to any third party claiming an interest in such proceeds through Owner, including without limitation any surface tenant or lessee, creditor or insurer, and agrees to indemnify and hold Company, its employees, agents, contractors, and consultants harmless from and against any and all such claims, demands or causes of action that may be brought or asserted by any such third party.

This Agreement shall apply and extend to Company's successors and assigns, its parent and subsidiary, affiliated, and related companies, trusts and partnerships, as well as their respective contractors, subcontractors, officers, directors, agents and employees. This Agreement shall be binding upon and shall inure to the benefit of the parties hereto, and their respective heirs, personal representatives, successors and assigns.

Owner agrees to keep confidential this Agreement and all negotiations leading up to or relating to this Agreement. Owner shall not copy or distribute this Agreement or disclose the substance hereof or the nature of such negotiations to others outside of Company without Company's express written consent or unless required to do so by law.

This Agreement may be executed in multiple counterparts, each of which shall be an original, but all of which shall constitute one instrument.

EXECUTED this ________ day of ____________________, 20______.

OWNER

____________________________________ ____________________________________
By: By:

COMPANY

____________________________________ Date__________________________
By:

Title: _______________________________

OWNER ACKNOWLEDGMENT

STATE OF ___________________)
)
COUNTY OF _________________)

This instrument was acknowledged before me on this ______ day of ________________, 20_____, by ____
____.

____
My Commission Expires:______________ Notary Public

COMPANY ACKNOWLEDGMENT

STATE OF ___________________)
)
COUNTY OF _________________)

This instrument was acknowledged before me on this ______ day of ________________, 20_____, by ____
____.

____
My Commission Expires:______________ Notary Public

EXHIBIT “A”

(RESERVED FOR PLAT/SURVEY OF ROAD AND LOCATION)

EXHIBIT "B"

Exhibit "B" attached to and made a part of that certain Surface Damage Settlement and Release dated ______________________________, by and between ____
____,
as Owner (whether one or more) and ____,
as Company.

This addendum is part of the Surface Damage Settlement and Release referred to above. If there be any conflict between the provisions of this addendum and any of the provisions of the above Surface Damage Settlement and Release, then the provisions of this addendum shall be controlling.

USE OF SURFACE:

1. Company will fence off Location and shall maintain said fence(s) in a prudent fashion. Company agrees to install a gate within the fence between Location and Subject Lands to allow access for Owner only to the Subject Lands. Owner shall not use the gate until Company has finished its drilling and completion operations. Said gate shall become the property of Owner upon installation and will be kept locked by Owner. Existing fences shall be H-Braced, utilizing posts with minimum 8 inch tops, before cutting existing fence(s) to fence off Location, and install gate.

2. Company shall be liable for any damage caused to present water well or wells that may be present and located upon the Subject Lands, as a result of Company's operations upon the Subject Lands. Should subject well or wells be damaged by subject operations, Company agrees to restore said well or wells to as close to original condition as reasonably possible or drill a new water well or wells as a replacement well(s) of original water well. Any plumbing and electrical needs necessitated by the drilling of a new water well or well will also be paid by the Company.

3. If Company drills a water well or wells for the use in Company's operations, the Owner shall have the option of retaining the water well(s), including casing therein, upon the completion of the drilling and completion operations of Company. Owner shall assume all costs, risks, and liabilities upon Owner assuming operations of a water well or wells.

4. Upon request from Owner, Company will reseed any grass pasture(s) or waterways of Owner that are disturbed as a result of Company's activities upon the Subject Lands, to the grasses specified by Owner. Any damages to Owner's crops or pastures outside of the drillsite location, pipeline(s) and electric transmission line(s), and access road(s) will be paid by Company to Owner based on the market price of the appropriate commodity at the time of damage multiplied by the Farm Service Agency's determined yield of such commodity upon the Subject Lands.

5. Any and all operations conducted by Company shall occur in a manner reasonable and prudent, and without conflict or disturbance to Owner's farming and/or ranching operations.

6. Company agrees to provide Owner the option for soil farming upon the Subject Lands, if said option is available. Company shall provide Owner with specific documentation describing the contents and properties of the drilling mud to allow Owner to seek consultation and approval, regarding the contents of the drilling mud, prior to exercising the option to perform soil farming operations upon the Subject Lands. Should the option be exercised, Company agrees that the drilling mud will be distributed evenly, as reasonably possible, upon the Subject Lands and shall only be performed if the ground is dry, in order to prevent rutting of the soil upon the Subject Lands.

7. **INDEMNIFICATION:** Company agrees to indemnify Owner against all claims, suits, costs, losses, injuries, and expenses arising out of claims by persons or entities other than Owner and its invitees for injury to person or property caused by the operations conducted by Company pursuant to this instrument, including reasonable attorney's fees and litigation expenses.

SIGNED FOR IDENTIFICATION BY:

OWNER:

______________________________________ ______________________________________
By: By:

Chapter 3
Mineral Owner Issues

As complex as the issues facing surface owners can be, the issues facing mineral owners may be even more intimidating. Countless statutes, cases, books, and articles have been written about the issues surrounding the nature of the mineral estate, conveying interests in minerals, and of course, the oil and gas lease.

To keep things as simple as possible, this chapter will focus on the centerpiece of oil and gas development where the mineral estate owner is concerned: the oil and gas lease. This chapter will discuss the oil and gas lease and its basic components, and points for the mineral owner to consider when negotiating their oil and gas lease.

3.1 The anatomy of an oil and gas lease

Perhaps the first thing to understand about the "typical" oil and gas lease is that there is no such thing as a typical oil and gas lease. Historically, many operators and the landmen working for them used pads of printed forms, the most popular of which was the "Producers 88" form. In the early days of the oil and gas industry, this form became so prevalent that many landowners simply assumed it was the only form of lease available, or that it was a form required by state statute. In the modern era of oil and gas production, there are almost as many leases as there are oil and gas operators.

That said, the nature of oil and gas production, the requirements of case law and statutes regarding the mineral interest, and the traditions of the oil and gas industry do cause most oil and gas leases to share a number of traits in common, as well as a fairly common structure. Thus, let's take a look at one example of a lease to see its parts and how they affect the operator and mineral owner.

Please note: The following example lease is not intended to serve as a template or form for you to use, but rather an illustration to help us understand its pieces and how they work. Always consult with a licensed attorney to help you review any oil and gas contract and to understand your rights and obligations with respect to it.

Exhibit 3-1: Sample Oil and Gas Lease

OIL AND GAS LEASE
(PAID UP)

THIS AGREEMENT, made and entered into this 1st day of January, 2015 by and between FRANK AND PATTY EATON, HUSBAND AND WIFE, AS JOINT TENANTS WITH RIGHT OF SURVIVORSHIP, party of the first part, hereinafter called Lessor (whether one or more), and PETROPOKES, LLC, party of the second part, hereinafter called Lessee.

WITNESSETH, That the said Lessor for and in consideration of TEN AND MORE DOLLARS, cash in hand paid, receipt of which is hereby acknowledged and of the covenants and agreements hereinafter contained on the part of Lessee to be paid, kept and performed, has granted, demised, leased and let and by these presents does grant, demise, lease and let unto the said Lessee, for the purpose of investigating, exploring, prospecting, drilling, and operating for and producing oil and all gas of whatsoever nature or kind, including all associated hydrocarbons produced in a liquid or gaseous form, also including sulphur produced in association with oil or gas, hereinafter sometimes collectively referred to as “oil and gas,” laying flow lines, storing oil, building tanks, power stations, telephone lines and other structures and things thereon to produce, save, take care of, treat, process, store and transport said oil and gas and other products manufactured therefrom situated in the County of Orange, State of Oklahoma, to-wit:

The Northwest Quarter (NW/4)

of Section 23, Township 23N, Range 1W, I.M., and containing 160 acres, more or less.

It is agreed that this lease shall remain in force for a term of three (3) years from date (herein called primary term) and as long thereafter as oil or gas, or either of them, is produced from said land by the Lessee.

In consideration of the premises the said Lessee covenants and agrees:

1st. To deliver to the credit of Lessor free of cost, in the pipe line to which it may connect its wells, the THREE-SIXTEENTHS (3/16) part of all oil (including but not limited to condensate and distillate) produced and saved from the leased premises.

2nd. To pay Lessor for gas of whatsoever nature or kind (with all of its constituents) produced and sold or used off the leased premises, or used in the manufacture of products therefrom, THREE-SIXTEENTHS (3/16)) of the gross proceeds received for the gas sold, used off the premises or in the manufacture of products therefrom, but in no event more than ONE TENTH (1/10) of the actual amount received by the Lessee, said payments to be made monthly. During any period (whether before or after expiration of the primary term hereof) when gas is not being so sold or used and the well or wells are shut in and there is no current production of oil or operations on said leased premises sufficient to keep this lease in force, Lessee shall pay or tender a royalty of One Dollar ($1.00) per year per net acre retained hereunder such payment or tender to be made on or before the anniversary date of this lease next ensuing after the expiration of ninety (90) days from the date of such well is shut in and thereafter on the anniversary date of this lease during the period such well is shut in, to the royalty owners. When such payment or tender is made it will be considered that gas is being produced within the meaning of the entire lease.

If Lessee shall, on or before any shut-in payment date, make a bona fide attempt to pay or deposit a shut-in payment to a royalty owner entitled thereto under this lease according to Lessee’s records at the time of such payment, and in such payment or deposit shall be erroneous in any regard, Lessee shall be obligated to pay to such royalty owner the shut-in payment properly payable for the period involved, but this lease shall be maintained in the same manner as If such erroneous payment or deposit had been properly made, provided that Lessee shall correct such erroneous payment within thirty (30) days following receipt by Lessee of written notice from such royalty owner of the error accompanied by any documents and other evidence necessary to enable Lessee to make proper payment.

3rd. To pay Lessor for gas produced from any oil well and used off the premises, or for the manufacture of casing-head gasoline or dry commercial gas THREE-SIXTEENTHS (3/16) of the gross proceeds, at the mouth of the well, received by Lessee for the gas during the time such gas shall be used, said payments to be made monthly.

If the Lessee shall commence to drill a well or commence reworking operations on an existing well within the term of this lease or any extension thereof or on acreage pooled therewith, the Lessee shall have the right to drill such well to completion or complete reworking operations with reasonable diligence and dispatch, and if oil or gas, or either of them, be found in paying quantities, this lease shall continue and be in force with like effect as if such well had been completed within the term of years first mentioned.

Lessee is hereby granted the right at any time and from time to time to unitize the leased premises or any portion or portions thereof, as to all strata or any stratum or strata, with any other lands as to all strata or any stratum or strata, for the production primarily of oil or primarily of gas with or without distillate. However, no unit for the production primarily of oil shall embrace more than 160 acres, or for the production primarily of gas with or without distillate more than 640 acres; provided that if any governmental regulation shall prescribe a spacing pattern for the development of the field or allocate a producing allowable based on acreage per well, then any such unit may embrace as much additional acreage as may be so prescribed or as may he used in such allocation of allowable. Lessee shall file written unit designations in the county in which the leased premises are located. Operations upon and production from the unit shall be treated as if such operations were upon or such production were from the leased premises whether or not the well or wells are located thereon. The entire acreage within a unit shall be treated for all purposes as if it were covered by and included in this lease except that the royalty on production from the unit shall be as below provided, and except that in calculating the amount of any shut in gas royalties, only the part of the acreage originally leased and then actually embraced by this lease shall be counted. In respect to production from the unit, Lessee shall pay Lessor in lieu of other royalties thereon, only such proportion of the royalties stipulated herein as the amount of his acreage placed in the unit, or his royalty interest therein on an acreage basis bears to the total acreage in the unit.

If said Lessor owns a less interest in the above described land than the entire and undivided fee simple estate therein whether stated hereinabove as whole or partial interest, then the royalties herein provided shall be paid to the Lessor only in the proportion which his interest bears to the whole and undivided fee.

Lessee shall have the right to use, free of cost, gas and oil produced on said land for its operations thereon. Royalties shall be owing on use of gas (including fuel use) off of the Lease.

Lessee shall bury his pipe lines below plow depth.

No well shall be drilled nearer than 400 feet to the house or barn now on said premises, without the written consent of the Lessor.

Lessee shall pay for all damages caused by its operations on said land.

Lessee shall have the right at any time to remove all machinery and fixtures placed on said premises, including the right to draw and remove casing.

If the estate of either party hereto is assigned, and the privilege of assigning in whole or in part is expressly allowed, the covenants hereof shall extend to their heirs" executors, administrators, successors or assigns. However, no change or division in ownership of the land or royalties shall enlarge the obligations or diminish the rights of Lessee. No change in the ownership of the land or royalties shall be binding on the Lessee until after the Lessee has been furnished with a written transfer or assignment or a true copy thereof. In case Lessee assigns this lease, in whole or in part, Lessee shall be relieved of all obligations with respect to the assigned portion or portions arising subsequent to the date of assignment.

All express or implied covenants of this lease shall be subject to all Federal and State Laws, Executive Orders, Rules and Regulations, and this lease shall not be terminated, in whole or in part, nor Lessee held liable in damages, for failure to comply therewith, if compliance is prevented by, or such failure is the result of any such Law, Order, Rule or Regulation, or operation of force majeure.

This lease shall be effective as to each Lessor on execution hereof as to his or her Interest and shall be binding on those signing, notwithstanding some of Lessors above named may not join in the execution hereof. The word “Lessor” as used in this lease means the party or parties who execute this lease as Lessor, although not named above.

Lessee may at any time and from time to time surrender this lease as to any part or parts of the leased premises by delivering or mailing a release thereof to Lessor, or by placing a release of record in the proper County.

Lessee agrees to indemnify Lessor against all claims, suits, costs, losses, and expenses that may in any manner result from or arise out of the operations conducted by Lessee pursuant to this instrument.

Lessor only warrants title to the land covered by this lease, by, through and under Lessor and not otherwise.

Please see Exhibit “A” attached hereto and made a part hereof for additional provisions.

IN TESTIMONY WHEREOF, we sign this the ________ day of ______________________________, 20______.

____ ______________________________________

Lessor: Lessor:

STATE OF _________________________ }
} ss.
COUNTY OF _______________________}

The foregoing instrument was acknowledged before me this ________ day of ____________________, 20____, by
____
____
____.

IN WITNESS WHEREOF, I hereunto set my official signature and affixed my notary seal the day and year last above written.

My commission expires ____________ ____
Notary Public

Let's take a look at the components of this lease.

3.1.1. Parties

```
THIS AGREEMENT, made and entered into this 1st day of January, 2015 by and between
FRANK AND PATTY EATON, HUSBAND AND WIFE, AS JOINT TENANTS WITH RIGHT OF SURVIVORSHIP, party
of the first part, hereinafter called Lessor (whether one or more), and PETROPOKES, LLC,
party of the second part, hereinafter called Lessee.
```

Not surprisingly, the lease starts off with the date of its execution and the parties involved. The person or people (for example, husband and wife) who own the mineral interest are giving a lease to the operator. As a result, the owner(s) are called the lessor (party granting the lease – the "landlord") while the operator is referred to as the lessee (party receiving the lease – the "tenant").

While the names of the parties involved may seem pretty straightforward, those names can sometimes be a point of confusion. It is important that the party named as the lessor be the parties that actually own the mineral estate. For example, if the minerals are owned in joint tenancy between a husband and wife, the lessor should be named "Husband Name and Wife Name, Husband and Wife, as Joint Tenants with Right of Survivorship." If the mineral estate has been placed in a trust, the lessor name should be something like "John Smith, as Trustee of the John Smith Revocable Living Trust, Dated January 1, 2000." Care in the name of the lessor not only avoids confusion; it may also be important to title issues, as will be discussed later in this chapter.

3.1.2. Granting clause

```
      WITNESSETH, That the said Lessor for and in consideration of TEN AND MORE DOLLARS,
cash in hand paid, receipt of which is hereby acknowledged and of the covenants and
agreements hereinafter contained on the part of Lessee to be paid, kept and performed, has
granted, demised, leased and let and by these presents does grant, demise, lease and let
unto the said Lessee, for the purpose of investigating, exploring, prospecting, drilling,
and operating for and producing oil and all gas of whatsoever nature or kind, including
all associated hydrocarbons produced in a liquid or gaseous form, also including sulphur
produced in association with oil or gas, hereinafter sometimes collectively referred to as
"oil and gas," laying flow lines, storing oil, building tanks, power stations, telephone
lines and other structures and things thereon to produce, save, take care of, treat,
process, store and transport said oil and gas and other products manufactured therefrom
situated in the County of Orange, State of Oklahoma, to-wit:

                          The Northwest Quarter (NW/4)

of Section 23, Township 23N, Range 1W, I.M., and containing 160 acres, more or less.
```

The granting clause starts out with a seemingly odd sentence (the first of many sentences that will sound odd, to be sure): "that the said lessor for and in consideration of TEN AND MORE DOLLARS, cash in hand paid, receipt of which is hereby acknowledged…" Upon reading this, the mineral owner probably thinks "hey, I better be doing this for more than ten bucks!" or "well, I didn't get ten dollars when they gave me this lease." This phrase is meant to convey a concept called "consideration" in contract law and is an old tradition in drafting contracts meant to indicate to a court or third party that the mineral owner and operator exchanged some form of value for the contract, i.e. the contract wasn't given for free.

This clause is one of the most important in the entire contract, as it is the language that legally gives a temporary interest in the mineral estate from the lessor to the lessee. In some ways, the granting clause (and the oil and gas lease overall) acts like a "conveyance" in that it is transferring an interest in property from party to another, and a "contract" in that it requires the operator and mineral owner to perform certain tasks.

The granting clause spells out the minerals included in the lease. Here, for example, the language "oil and all gas of whatsoever nature or kind, including all associated hydrocarbons produced in a liquid or gaseous form, also including sulphur produced in association with oil or gas" is used. As discussed in Chapter 2, there can sometimes be confusion as to what minerals are, and are not, included in the lease, so be sure to both examine the documents through which you got your mineral title to determine what you own, and to draft this provision carefully to grant interests only in those minerals you intend to convey. One example of a mineral produced with oil and gas that is excluded by the lessor in many Oklahoma and Texas leases is helium. Some mineral owners also include uranium, since it can also be mined by wellbore without disturbing the surface.

An important part of any conveyance or contract involving an interest in real property is the legal description of the property. The legal description will include the fraction of a section, if any, and the section, township, and range in which the property is locate (for more information on reading and interpreting legal descriptions, see OSU Fact Sheet F-9407, "Legal Land Descriptions in Oklahoma"). In the example above, the lessors own the minerals underlying the northwest quarter of one section. Since they own the minerals entirely by themselves – that is, no one else shares in the minerals – they would also own 160 "net mineral acres." Most oil and gas leases are written as though the lessor owns all of the mineral interest. This is not always the case, though, and the many ways in which minerals can be divided will be discussed below in the section regarding division orders.

The legal description will sometimes be followed by something called a "Mother Hubbard" clause. An example of a Mother Hubbard clause follows:

> *This lease also covers and includes any and all lands owned or claimed by the Lessor adjacent or contiguous to the land described hereinabove, whether the same be in said survey or surveys or in adjacent surveys, although not included within the boundaries of the land described above.*

The purpose of a Mother Hubbard clause is to correct potential small errors in the legal description of the minerals, such as failing to include a small piece of the lessor's property that lies outside the description in the lease but was intended by both lessor and lessee to be part of the agreement. While that would be fine, the Mother Hubbard clause could also cause a large piece of adjacent mineral interests owned by the mineral owner to come under the oil and gas lease, when that was never the intention of the lessor. Many mineral owners strike Mother Hubbard clauses from their leases.

3.1.3. The habendum clause

```
      It is agreed that this lease shall remain in force for a term of three (3) years from
date (herein called primary term) and as long thereafter as oil or gas, or either of them,
is produced from said land by the Lessee.
```

"Habendum" sounds strange, but it is simply Latin for "that is to be had." In the context, of an oil and gas lease, the habendum clause defines how long the lessor will have the lease (put another way, "how long the lease is to be had."). Almost every oil and gas lease includes two periods of time: a "primary term" and a "secondary term."

The primary term of the lease is almost always defined as a very specific period of time. In this lease, the language "It is agreed that this lease shall remain in force for a term of three (3) years from date" defines the primary term. You can think of the primary term as the period in which the operator can explore for oil and gas and determine if it is economically prudent for them to drill a well. Many attorneys and other professionals representing landowners suggest allowing a primary term of no longer than three years to avoid tying up the mineral interest longer than necessary in case other potential lessees are willing to offer more compensation or better terms to the lessor.

The secondary term in this language is defined as "so long thereafter as oil or gas, or either of them, is produced from said land by the Lessee." This means if an oil and gas well is started – and what it means to "start" a well is discussed in greater detail below – on or before the end of the primary term, the lessee can keep the lease so long as the well produces oil and gas. Many leases also add the language "in paying quantities," making the secondary term read "so long thereafter as oil and gas, or either of them, is produced in paying quantities from said land by the Lessee." The extension of the lease into the secondary term by the production of oil and gas is sometimes referred to as "holding" the lease by production.

The mineral owner should think carefully about the secondary term language. The language "for so long as the well produces oil and gas" means that the lease could last indefinitely, even if very, very small quantities of oil and gas are produced by the well. The mineral owner may not want this consequence, as they may want to re-lease the minerals to another party at some point in the future. On the other hand, most operators are likely to insist on at least the "paying quantities" language. Since the oil and gas operator is assuming the majority of the risk in oil and gas development, they want the opportunity to hold on to their lease as long as it remains profitable. There are many potential interpretations of what it means to produce oil and gas in "paying quantities" but the majority of courts seem to define the term to mean the well must be producing enough oil and gas to pay for the operating costs of the well and to provide a profit (however small) to the operator. The operating costs likely include the direct costs of operating the well such as the wages of employees servicing the well, utility costs to run pumps, repair costs, and so on, but there remain questions about whether costs like administrative overhead and depreciation are considered.

Mineral owners need not rely on the standard definition of paying quantities – they can negotiate their own definition if the operator is willing. This could be done in a number of ways, including defining the production by volume (a set number of barrels per day of oil and/or cubic feet for natural gas) or by value (a set dollar value of the well's production over a given period of time such as per day, week, or month).

In some cases, the mineral owner may own more than one formation capable of producing oil and gas. In such circumstances, an operator may only intend to produce one formation and completes a well only to that formation. However, the mineral owner may want to reserve the right to lease the other formation to another operator willing to produce it. Under the terms of the lease here, though, the first well would hold the lease as to all minerals underlying the property described in the lease. To preserve the right to lease other formations to other operators, some mineral owners include a "depth clause" (sometimes also called a "horizontal Pugh clause") that states the mineral owner is free to lease minerals below the deepest point to which the operator has drilled. An example of a depth clause follows:

> DEPTH CLAUSE: In the event this lease is extended by commercial production beyond its primary term, then on such date this lease shall terminate as to all rights one hundred feet and more below the stratigraphic equivalent of the deepest penetrated formation in the well or wells located on the leased premises, or land unitized therewith. If Lessee is in the process of drilling or completing a well at the end of the primary term of this lease, this clause shall become effective upon conclusion of such operations.

The secondary term may not include only wells on the mineral owners' property – wells on other properties might also act to hold the lease if they are part of the same "unit" or "pool." Pooling and unitization are discussed later in this chapter.

3.1.4. The lease royalty clause

```
       In consideration of the premises the said Lessee covenants and agrees:
       1st. To deliver to the credit of Lessor free of cost, in the pipe line to which it may
connect its wells, the THREE-SIXTEENTHS (3/16) part of all oil (including but not limited
to condensate and distillate) produced and saved from the leased premises.
       2nd. To pay Lessor for gas of whatsoever nature or kind (with all of its constituents)
produced and sold or used off the leased premises, or used in the manufacture of products
therefrom, THREE-SIXTEENTHS (3/16)) of the gross proceeds received for the gas sold, used
off the premises or in the manufacture of products therefrom, but in no event more than ONE
TENTH (1/10) of the actual amount received by the Lessee, said payments to be made monthly.
During any period (whether before or after expiration of the primary term hereof) when gas
is not being so sold or used and the well or wells are shut in and there is no current
production of oil or operations on said leased premises sufficient to keep this lease in
force, Lessee shall pay or tender a royalty of One Dollar ($1.00) per year per net acre
retained hereunder such payment or tender to be made on or before the anniversary date of
this lease next ensuing after the expiration of ninety (90) days from the date of such well
is shut in and thereafter on the anniversary date of this lease during the period such well
is shut in, to the royalty owners. When such payment or tender is made it will be considered
that gas is being produced within the meaning of the entire lease.
       If Lessee shall, on or before any shut-in payment date, make a bona fide attempt to pay
or deposit a shut-in payment to a royalty owner entitled thereto under this lease according
to Lessee's records at the time of such payment, and in such payment or deposit shall be
erroneous in any regard, Lessee shall be obligated to pay to such royalty owner the shut-in
payment properly payable for the period involved, but this lease shall be maintained in the
same manner as If such erroneous payment or deposit had been properly made, provided that
Lessee shall correct such erroneous payment within thirty (30) days following receipt by
Lessee of written notice from such royalty owner of the error accompanied by any documents
and other evidence necessary to enable Lessee to make proper payment.
       3rd. To pay Lessor for gas produced from any oil well and used off the premises, or
for the manufacture of casing-head gasoline or dry commercial gas THREE-SIXTEENTHS (3/16)
of the gross proceeds, at the mouth of the well, received by Lessee for the gas during the
time such gas shall be used, said payments to be made monthly.
```

The royalty clause is what excites many mineral owners, as it contains the language for payment of revenues from the sale of oil and gas produced from the well by the operator. When market and industry conditions are right, mineral royalties can be a significant source of additional revenue for mineral owners.

It is important to discuss the meaning of a royalty. In simplest terms, the mineral owner is compensated out of the oil and gas produced from the well. In the purest sense of the word, a "royalty" means a portion of the actual product. This would mean the operator would not send you a check, but would send you a portion of the oil and gas produced from the well. Indeed, if you look closely at the language of this lease, the paragraph labeled "1st" says the operator will "deliver to the credit of Lessor free of cost, in the pipe line to which it may connect its wells the [3/16] part of all oil… produced." Conversely, the paragraphs labeled "2nd" and "3rd" say the operator will "pay lessor" (rather than deliver) for 3/16ths of the gas and casinghead gasoline or dry commercial gas. As a practical matter, oil can be stored at the well in tanks, and some mineral owners choose to take their royalty in the actual oil which they receive and market themselves. For the vast majority of mineral owners, though, this is impractical or too time- and resource-intensive, so they take their royalty simply in the form of payment. Natural gas is very difficult to store on-site, and so virtually all mineral owners are paid for their share of natural gas, rather than taking the actual gas.

3.1.4.1. Royalty fractions

Many people think a 3/16ths (18.75%) of the oil and gas is a standard royalty, and it has certainly become fairly common in Oklahoma and Texas. However, depending on the market for leases, the bargaining power of the mineral owner, or the certainty of a very productive well, 1/5 (20%) or even 1/3 (33.3%) and 40% royalties may be possible.

Conversely, in areas where only marginal production may be possible or for exploratory ("wildcat") wells, 1/8 (12.5%) or 1/6 (16.67%) may be used.

3.1.4.2. Deductions from proceeds for royalty calculations

The royalty fraction is obviously important, but the mineral owner should ask "3/16 of what?" The answer might seem fairly straightforward: "of the oil and gas produced, of course," so take the amount of money generated from the sale of the oil and gas and pay the mineral owner 3/16 of that amount, deducting nothing, right? The actual answer is much more complicated.

It is generally assumed the operator alone bears the cost of getting the oil and gas out of the formation in which it is found and to the surface. However, there has been some dispute as to whether the operator could also deduct the cost of making the oil or gas "marketable" could also be deducted before the royalty is calculated. Costs of making oil or gas "marketable" could include the costs of removing water from oil and removing hydrogen sulfide or water vapor from gas. Further, if the product has already been rendered marketable, does the lease allow for deduction of costs to make it "more marketable," that is, to increase its value further? Depending on the language used in the lease, Oklahoma courts have held the operator may be able to deduct some such costs.

The example lease provided specifies the oil is delivered "free of cost, in the pipe line" indicating that no deductions should be taken from the proceeds of the sale before calculating the royalty amount owed to the mineral interest owner. Since the factors involved in production, transport, and sale of gas are somewhat different, different language is often used for natural gas transactions. Thus, in the sample lease, you will see the term "3/16ths of the gross proceeds" (emphasis added). This "gross proceeds" language is intended to minimize the deductions that can be taken before the calculation of the royalty for gas under the lease.

With respect to the costs that can be deducted before the royalty is calculated, it is in the mineral owner's interests to allow for the deduction of as few costs as possible. One way to handle this would be to negotiate for the inclusion of a "no deductions" clause, set forth here:

> NO DEDUCTIONS CLAUSE: It is agreed between the Lessor and Lessee that, notwithstanding any language herein to the contrary, all oil, gas or other proceeds accruing to the Lessor under this lease or by state law shall be without deduction, for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and marketing the oil, gas and other products produced hereunder to transform the product into marketable form; however, Lessor's share of any such costs which result in enhancing the value of the already marketable oil, gas or other products to receive a better price may be deducted from Lessor's share of production so long as they are based on Lessee's actual cost of such enhancements. However, in no event shall Lessor receive a price that is less than the price received by Lessee. The right of the Lessee to charge costs as provided in this paragraph will not include any cost of any kind related to the purchase, installation or operation of equipment on the premises for compression or dehydration.

Another factor to consider in calculating the royalties is determining exactly what price has been paid to the operator for the oil or gas. If, in our lease, PetroPokes sells the oil and gas to a company that it owns, like PetroPokes Marketing, Inc., it may charge a far lower price than the open market price. Such a transaction is sometimes called an "affiliate transaction." While there are a number of statutes and case precedents that restrict this practice, it may be prudent to deal with it explicitly in the lease. The following language is an example of a lease clause used to make sure the open market price is used in the case of any affiliate transactions:

NON ARMS-LENGTH TRANSACTIONS: Notwithstanding the provisions of the lease, if Lessee elects to market oil and/or gas produced from the leased premises, or from lands pooled therewith, under any contract or other arrangement whereby the purchase is not an unrelated third party purchasing such production under an arms-length bona fide agreement providing for terms and prices comparable to those prevailing in the general area of the leased premises, the royalties payable to the Lessor shall be based on the prevailing market value in the general area for sales between unrelated parties affecting comparable production.

3.1.4.3. Shut-in royalties

You may have noticed there was a significant amount of language after the royalty fractions that starts with the phrase "During any period (whether before or after expiration of the primary term hereof) when gas is not being sold or used…" This is an example of a "shut in royalty" or "delay royalty" clause. Sometimes, the natural gas market might not be favorable for the operator, and since it is very difficult to produce gas and then store it, the operator may want to "store" the gas by not producing it in the first place. However, since this would mean the well is not producing at all or not producing "in paying quantities" (see discussion above), the operator could be in jeopardy of losing a lease on what might otherwise be a productive well. Thus, the shut-in royalty clause represents an agreement between the operator and the mineral owner that the well will sometimes not produce – even though it is capable of doing so – but the operator will make a modest payment to the mineral owner in those circumstances and the mineral owner will consider the well as producing, thus holding the lease.

Shut-in royalties can sometimes represent a source of revenue to the mineral owner in periods of low gas prices, but sometimes shut-in royalties may be used to simply hold a lease for a very modest cost. To avoid the latter circumstance, a limit to how long a shut-in royalty can be used to hold a well, and/or an increased amount of shut in royalty may be used to encourage the operator to either start production again or to relinquish the lease. An example of such language follows:

SHUT-IN ROYALTY: Notwithstanding anything to the contrary herein, it is understood and agreed that this lease may not be maintained in force for any one continuous period of time longer than two (2) consecutive years after the expiration of the primary term hereof solely by the provisions of the shut-in royalty clause. Lease is amended where Lessor is paid $10.00 per year per net acre shut-in payment.

3.1.5. Commencement / delay rental clause

If the Lessee shall commence to drill a well or commence reworking operations on an existing well within the term of this lease or any extension thereof or on acreage pooled therewith, the Lessee shall have the right to drill such well to completion or complete reworking operations with reasonable diligence and dispatch, and if oil or gas, or either of them, be found in paying quantities, this lease shall continue and be in force with like effect as if such well had been completed within the term of years first mentioned.

Recall that once the primary term (in the example lease, three years from the date of the lease's execution) has expired, the only thing holding the lease for the operator is the production of oil and gas. But does that mean that a well must be completed before the end of the three year period, and that must be producing oil and gas? This lease's language uses a "commencement" clause stating it is the obligation of the operator to start drilling a well before the three year primary term has expired. Once the well has been started, the operator is obligated to finish it as quickly and carefully as prudent, and if the well eventually produces oil and gas in paying quantities, the operator can retain the lease; if it is not, though, the lease must be let go by the operator.

As you may be suspecting, oil and gas leases are exercises in definitions, so what does it mean to "start" a well? Some leases define starting very leniently, simply allowing for some earthwork on the property to prepare the well pad, or even just surveying and flagging the site. This may not be enough to satisfy the mineral owner, though, and they may wish to include more of a commitment on the part of the operator to create a well. They may wish to include a commencement clause requiring the actual start of drilling, such as this:

> COMMENCEMENT: Commencement of a well according to the terms of this lease will require that a drilling rig capable of drilling to total depth be on location and drilling on or before expiration of the primary term, and that the drilling of said well be continued with due diligence until completion. Construction of a well location without actual drilling as detailed above will not be deemed commencement of a well.

Some leases include a "delay rental" which, much like a shut-in royalty, is an amount paid to extend the primary term of the lease without the actual drilling of a well. Just as with shut-in royalties, mineral owners should consider whether they want to allow a delay royalty, and if the amount is sufficient. In recent times, delay royalties have not been used as frequently, and other tools such as lease options have been used to deal with the issues typically handled by delay rentals.

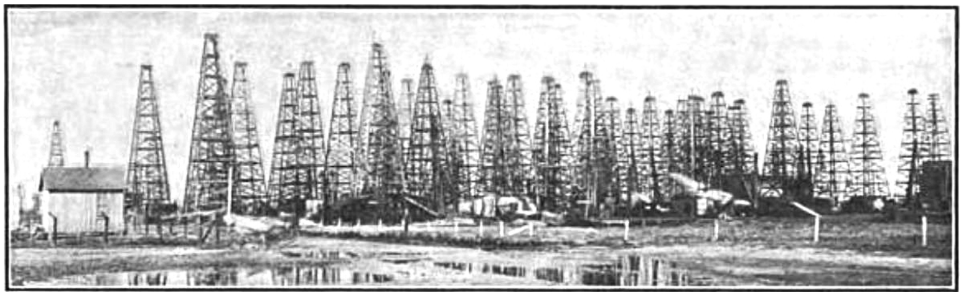
It should be noted that in a "paid-up" lease, the mineral owner and the operator acknowledge that the lease is in effect from the day it is executed, and no further payments are needed during the primary term to keep the lease in effect. If you will note the very top of the example lease, you will see it designates the lease as "Paid Up."

3.1.6. Pooling and unitization clause

> Lessee is hereby granted the right at any time and from time to time to unitize the leased premises or any portion or portions thereof, as to all strata or any stratum or strata, with any other lands as to all strata or any stratum or strata, for the production primarily of oil or primarily of gas with or without distillate. However, no unit for the production primarily of oil shall embrace more than 160 acres, or for the production primarily of gas with or without distillate more than 640 acres; provided that if any governmental regulation shall prescribe a spacing pattern for the development of the field or allocate a producing allowable based on acreage per well, then any such unit may embrace as much additional acreage as may be so prescribed or as may he used in such allocation of allowable. Lessee shall file written unit designations in the county in which the leased premises are located. Operations upon and production from the unit shall be treated as if such operations were upon or such production were from the leased premises whether or not the well or wells are located thereon. The entire acreage within a unit shall be treated for all purposes as if it were covered by and included in this lease except that the royalty on production from the unit shall be as below provided, and except that in calculating the amount of any shut in gas royalties, only the part of the acreage originally leased and then actually embraced by this lease shall be counted. In respect to production from the unit, Lessee shall pay Lessor in lieu of other royalties thereon, only such proportion of the royalties stipulated herein as the amount of his acreage placed in the unit, or his royalty interest therein on an acreage basis bears to the total acreage in the unit.

In the early days of the oil and gas industry, the "rule of capture" stated oil and gas was owned by whoever brought it to the surface first. This meant in some cases there was a mad dash to complete as many wells as possible and pump them as aggressively as possible before someone else "sucked" the oil and gas away from them. This led to oil fields that looked like the one below.

Figure 3-1: Spindeltop Oil Field near Beaumont, Texas, circa 1903



In the earlier part of the 20th century, though, the oil and gas industry quickly figured out this was not a good way to do business, as it led to highly inefficient production practices and, in many cases, led to significant amounts of oil and gas being "stranded" and no longer producible. This concept was recognized by courts and state agencies regulating oil and gas, and the concept of "correlative rights" was born. In simplest terms, the concept of correlative rights doctrine requires the mineral owners and operators in a specific oil and gas producing formation to manage the formation in such a way that they do not cause unnecessary harm to the formation or to each other.

An outgrowth of the correlative rights doctrine was the concept of "untitization." To ensure the most efficient production of an oil and gas formation, the OCC may create a "unit" requiring all of the production from a specific formation in a given area. Typically, units for oil production range from 40 to 160 acres, and units for natural gas production typically run from 160 to 640 acres. Units for horizontal drilling units in Oklahoma for both oil and gas are typically 640 acres. One well is typically allowed per unit. This one well is deemed to be producing all of the minerals within the unit. Thus, if your mineral land is part of a unit, even if the one well is not located on your property, your lease is held by the production of that well as if it were on your property.

For the most part, this arrangement works well for both mineral owners and operators since it allows for the most efficient production of oil and gas from the formation. However, unitization sometimes causes unintended consequences. For example, say you own two adjoining tracts of land. One is the northeast quarter of section 7, and the other is the northwest quarter of section 8. You execute an oil and gas lease for both pieces of property as one tract of land. Later, the OCC creates a unit defining all 640 acres of section 7 and a well is drilled to produce the section 7 unit. Under some interpretations, this could mean that production from the unit holds not only your land within section 7, but also your contiguous land in section 8. Thus, if you wanted to lease your land within section 8 to another party, you could not, since the lease was still held by production from the unit.

To counteract this, Oklahoma enacted a statutory provision (sometimes called the "statutory Pugh clause") which states that in any spacing unit of 160 acres or more, production from the unit cannot hold any land outside the borders of the unit for more than 90 days past the expiration of the primary term of the lease. Some landowners take this protection one step further with language that makes it clear production from a unit can only hold land within the unit, regardless of size or time constraints. This is often called a "Pugh" clause, named after the case first interpreting it.

```
PUGH CLAUSE: Notwithstanding anything to the contrary in this lease, all portions of this lease not included in a unit created by the Oklahoma Corporation Commission and not producing or upon which drilling operations have not commenced, shall be released at the expiration of the primary term of this lease. Should the unit as established by the Corporation Commission be changed after the expiration of the primary term, all portions of this lease not included in the newly prescribed Corporation Commission unit will be released.
```

Pooling is similar to unitization in many respects, but is more often used to piece together very small tracts of land into more efficiently-produced groups or to avoid "holdouts" that would block production of the oil and gas in an area. Pooling cases at the OCC can also result in pooled units that function much as those described above.

3.1.7. Lesser interest clause

```
      If said Lessor owns a less interest in the above described land than the entire and
undivided fee simple estate therein whether stated hereinabove as whole or partial interest,
then the royalties herein provided shall be paid to the Lessor only in the proportion which
his interest bears to the whole and undivided fee.
```

As mentioned above, most oil and gas leases are written as though the mineral owner (lessor) owns all of the mineral interest underlying the described land. That may not always be the case. This clause states if the lessor owns less than all the minerals, the royalties they are paid will be reduced proportionately to their ownership interest. Put another way, if the lessor owns a 1/2 interest in the minerals described by the lease, their royalty would be 3/32 (or 1/2 of 3/16) of the revenues from oil and gas production on the property.

3.1.8. Notice of assignment clause

```
      If the estate of either party hereto is assigned, and the privilege of assigning
in whole or in part is expressly allowed, the covenants hereof shall extend to their
heirs" executors, administrators, successors or assigns. However, no change or division in
ownership of the land or royalties shall enlarge the obligations or diminish the rights
of Lessee. No change in the ownership of the land or royalties shall be binding on the
Lessee until after the Lessee has been furnished with a written transfer or assignment or
a true copy thereof. In case Lessee assigns this lease, in whole or in part, Lessee shall
be relieved of all obligations with respect to the assigned portion or portions arising
subsequent to the date of assignment.
```

The assignment clause deals with situations in which either the mineral owner or the operator assigns the lease. In such cases, both parties agree that the "new" party will abide by the terms of the lease. If the mineral owner transfers their interest, a copy of that transfer and the contact information for the new mineral interest owner should be provided to the operator (for many reasons, not the least of which is to make sure royalties are promptly paid to the proper party). This particular assignment clause also notes that once the lessee has transferred their interest, the lessee has no more obligations to the mineral owner after the transfer has occurred.

```
      Lessor only warrants title to the land covered by this lease, by, through and under
Lessor and not otherwise.
```

3.1.9. Warranty clause

Some leases will contain clauses much different than the one above. An example might be "Lessor hereby warrants and agrees to defend title to the lands covered by this lease." This is sometimes called a warranty clause.

This language may sound innocent, but it can cause significant problems for mineral owners. The latter language can be interpreted to mean that if there is any defect in the title to the minerals, regardless of who caused it or when it occurred, the mineral owner could be held liable for that defect and would have to bear the costs of curing the title defect. This is a significant potential burden for the mineral owner, and potentially holds the owner responsible for title problems with which they had nothing to do. Further, most mineral interest owners are not trained in title examination or land title issues; operators or the landmen they engage do have access to such expertise and can reasonably be expected to conduct due diligence examinations of title to avoid such problems in the first place.

The language included in the example lease deals with this issue by limiting the warranty to title "by, through, and under Lessor" meaning that the mineral interest owner is only held responsible for title issues occurring after they have acquired the mineral interest, but not before. Many mineral owners will strike the warranty clause from the lease and replace it with the "by, through, and under" language in the example lease.

3.1.10 "Top lease" clause

> If at any time within the primary term of this lease or any continuation thereof, Lessor receives any bona fide offer, acceptable to Lessor, to grant an additional lease (top lease) covering all or part of the afore described lands, Lessee shall have the continuing option by meeting any such offer to acquire such top lease. Any offer must be in writing and must set forth the proposed Lessee's name, bonus consideration and royalty consideration to be paid for such lease, and include a copy of the lease form to be utilized reflecting all pertinent and relevant terms and conditions of the top lease. Lessee shall have fifteen (15) days after receipt from Lessor of a complete copy of any such offer to advise Lessor in writing of its election to enter into an oil and gas lease with Lessor on equivalent terms and conditions. If Lessee fails to notify Lessor within the aforesaid fifteen (15) day period of its election to meet any such bona fide offer, Lessor shall have the right to accept said offer. Any top lease granted by Lessor in violation of this provision shall be null and void.

The following language does not appear in the example lease, but many leases will contain it or similar language: This is what is referred to as a "top lease" clause. Top leasing is the practice of negotiating a lease with a mineral interest owner for minerals that are already under a lease – this lease is called a top lease, and it goes into effect immediately once the underlying lease expires either due to the conclusion of the primary term with no well drilled, or once the secondary term ends once oil and gas are no longer produced in paying quantities. A top lease provision in a lease will either prohibit a top lease or give the first lessor a right of first refusal to match or beat the terms of the offered top lease. Some landowners do not object to a top lease provision in the lease, but others prefer to strike the top lease provision to preserve their rights to lease to someone else willing to offer better terms. Striking the top lease provision may also motivate the first lessor to diligently pursue their obligations under the lease since someone else is already waiting to take over the minerals.

```
      Lessee shall have the right to use, free of cost, gas and oil produced on said land
for its operations thereon. Royalties shall be owing on use of gas (including fuel use) off
of the Lease.
      Lessee shall bury his pipe lines below plow depth.
No well shall be drilled nearer than 400 feet to the house or barn now on said premises,
without the written consent of the Lessor.
      Lessee shall pay for all damages caused by its operations on said land.
      Lessee shall have the right at any time to remove all machinery and fixtures placed
on said premises, including the right to draw and remove casing.
```

```
      All express or implied covenants of this lease shall be subject to all Federal and
State Laws, Executive Orders, Rules and Regulations, and this lease shall not be terminated,
in whole or in part, nor Lessee held liable in damages, for failure to comply therewith, if
compliance is prevented by, or such failure is the result of any such Law, Order, Rule or
Regulation, or operation of force majeure.
      This lease shall be effective as to each Lessor on execution hereof as to his or her
Interest and shall be binding on those signing, notwithstanding some of Lessors above named
may not join in the execution hereof. The word "Lessor" as used in this lease means the
party or parties who execute this lease as Lessor, although not named above.
      Lessee may at any time and from time to time surrender this lease as to any part or
parts of the leased premises by delivering or mailing a release thereof to Lessor, or by
placing a release of record in the proper County.
      Lessee agrees to indemnify Lessor against all claims, suits, costs, losses, and
expenses that may in any manner result from or arise out of the operations conducted by
Lessee pursuant to this instrument.
```

3.1.11. Miscellaneous provisions

The balance of the terms in the example lease include items such as the use of oil and gas from the well to operate equipment on the lease, burial of pipelines, limitations on distances from wells to structures, removal of equipment, and "boilerplate" language to help in the implementation and interpretation of the lease.

3.1.12 What isn't there that should be, or is there that shouldn't be

As important as the language in the lease is, sometimes important items are not found within the lease. Perhaps the most important of these it the lease bonus agreement.

3.1.12.1. Lease bonuses

You may be thinking to yourself that there has been no discussion of lease bonuses to this point, and there was no mention of the lease bonus in the lease itself. You are correct, and lease bonuses are virtually never mentioned in the lease itself. Often, the operator wants to negotiate the terms of the bonus and the lease separately, even though the terms of the lease may affect the lease bonus the operator is willing to pay. Additionally, the mineral lease (or a memorandum thereof) will be recorded in the county land records, and the operator may not want the lease bonus amount made part of publicly available records.

The lease bonus is obviously an important part of the value paid to the mineral owner for the lease arrangement. Ask neighboring landowners for information about the bonuses they have been offered, and work with organizations such as the National Association of Royalty Owners, the Oklahoma Mineral Owners Association, or Farmers Royalty Company for information on prevailing bonus rates in your area. Perhaps even more than with royalties, lease bonuses are very much a function of the competition in the local mineral rights market and the amount of minerals you control.

3.1.12.2. Amending the lease

If there is language in the lease that you wish to delete, sometimes it can simply be marked though, with both the lessor and lessee initialing the strike. Sometimes, though, language must be added to replace the language that was stricken. Further, sometimes so many changes are made that the lease cannot be read with all the strikes and scribbles. In such circumstances, it may be best to create a "rider," "attachment," "addendum," or "exhibit" to the lease. This additional document contains the changes made to the initial language of the agreement, whether they are additions, deletions, or both. It is important to note that there is some form of amendment somewhere on the face of the document itself. An example of this signal is in the example lease provided:

```
Please see Exhibit "A" attached hereto and made a part hereof for additional provisions.
```

Exhibit 3-2 includes an example of what such an amending document might look like.

3.2. Points to consider in negotiating your oil and gas lease

Many of the considerations involved in negotiating your mineral lease have been discussed through the anatomy of a lease above. However, below is an outline of a number of additional issues to be considered as you negotiate your own agreement.

3.2.1. The party across the table

- Always find out exactly who the other party is. Some operators – especially larger operators - deal directly with landowners through their own land management departments. Other operators will hire landmen to gather the leases they intend to operate. In some cases, landmen may gather leases on their own, with the intent of packaging them together for later sale to operators. Such landmen are sometimes called "speculators." The very nature of these different business arrangements creates different communication, negotiation, and risk issues.
- Ask as many questions as needed to determine the exact arrangement the landman has with potential operators, if any. As someone once noted "landmen don't wear nametags that say 'I'm a land speculator!'"
- Ask for other landowners in the area with whom the landman and/or the company they represent has dealt. Contact them to learn about their experiences with the landman and the company.
- Run a "background check" on the company. Check the records of the OCC and the Oklahoma Secretary of State as well as searching the Internet for records and information about the company.
- Once again, being professional and courteous in your communication, and reasonable in your demands, can go a long way toward successfully negotiating a beneficial lease.

3.2.2. Take your time and get help

- A longstanding negotiating tactic is to put the mineral owner under time pressure: "if you don't sign today, I'm moving on!" Never sign an oil and gas lease without having time to carefully and thoroughly review it. If someone won't permit you the time to have a lease reviewed by an attorney, decline the offer.
- Hiring an attorney can cost money, but it can also be well worth that investment. A mineral lease has the potential to be a lucrative investment, and you owe it to yourself to maximize the value by getting the help of someone experienced in such matters.
- When getting help from an attorney, ask for his or her specific experience with oil and gas matters. Ask for reference clients, and contact them about their work with the attorney.
- Have a written engagement agreement with the attorney defining the scope of work to be performed, the billing rate, and whether a retainer (payment in advance) will be required.
- Ask the party with which you are negotiating if they would compensate you for a review. Some will, some won't, but it never hurts to ask.

3.2.3. Know your bargaining position

- Keep in mind the fundamental rule: everything is negotiable.
- How negotiable everything may be depends on your bargaining position, however. A number of things can influence your bargaining strength as a mineral owner. The amount of mineral acreage you own, the proximity of your land to wells known to be good producers, and the level of activity in the marketplace can all influence how much money and/or the terms an operator or speculator may be willing to pay for access to your minerals.
- Membership in an organization such as the National Association of Royalty Owners, the Oklahoma Mineral Owners Association, or Farmers Royalty Company can help you stay current on market trends and going rates for lease compensation. You can also talk to the county clerk and assessor –they likely have insights regarding the level of leasing activity in the area.
- There is strength in numbers. Try to form connections with your fellow mineral owners in the area to negotiate collectively. This will require coordination, leadership, and communication, but it can also yield significant rewards.
- Try to increase the level of competition in the area – form connections with operators and landmen and solicit competing offers for any transactions with which you have been approached.

3.2.4. Get everything in writing

- Always document any communication you have with the landman, preferably in writing. Some mineral owners will only communicate with the landman in by either letter, email, or text so the entire course of their discussions is in writing.
- Any and all promises have to be in writing to be enforceable; oral promises made are quickly forgotten, and in most cases, cannot be legally enforceable with regard to an interest in land such as minerals.
- Some commentators advise making provisions in the lease conditions for termination (that is, add language stating the lease will terminate if the condition is broken).
- If you execute an amending instrument (such as an exhibit, addendum, rider, etc.) make sure the face of the original lease contains a clear reference to the amending instrument and make sure the amending instrument clearly refers to the lease it is amending. Attach the instrument physically to the original lease.
- Remember, there is no "standard lease form." Never assume you know everything that is contained in the lease without reading it thoroughly yourself and having it reviewed by an attorney experienced in oil and gas matters.
- Since there is no standard lease form, you can write your own lease with the help of an experienced attorney. Not all operators may accept it, but they may if the terms are reasonable. In fact, the example lease form in this book is a form that was created by landowners and has been widely accepted by operators. In the absence of your own lease form, consider drafting an amendment document with the help of your attorney, addressing the common issues you've spotted.

3.2.5. Royalty and bonus provisions

- Weigh the merits of asking for a larger bonus versus a larger royalty. The former is a higher guaranteed payday, but if you don't need cash right away, then the latter offers an opportunity for a longer-term and potentially greater eventual value.
- Another point to consider in the "bonus versus royalty" discussion is the likelihood that a well will be drilled. If the higher bonus money is not a necessity and you believe the operator will drill a well, the higher royalty rate will generally pay you back more than the higher bonus in some cases. If you don't think a well will be drilled, the higher bonus may be the way to go. Of course, all this presumes you can predict the probability of a well being drilled –a tall order, to be sure. Talk to industry experts to gauge the likelihood of long-term development in your area.
- An old negotiating tip is "never take the first offer." Ask for more money and multiple royalty options to consider.
- Some mineral owners ask for a dual royalty clause, with the royalty increasing to a larger fraction after the operator recoups all their well costs. Such clauses may take significant bargaining power, though.

- Ask for the highest and best terms paid in the prospect they are working. The landman may not volunteer that information, but you can certainly ask for it.
- Remember to be clear about what costs of production can and cannot be deducted prior to calculation of the royalty amount. Ask for a "gross proceeds" lease if presented with a "net proceeds" lease.
- Include an "affiliate transactions" clause to make sure the prevailing market price can be realized for the oil or gas.
- Some mineral owners make this a formal part of the agreement through a "most favored nations clause" requiring that the lease be automatically amended to include the most favorable payment terms and other conditions found in any other agreement with the formation to be produced. Such clauses may require considerable negotiating power to secure, and can be difficult to enforce without voluntary compliance on the part of the landman to share terms negotiated in other agreements either past or future.
- Specify clearly how the bonus and any royalties or other payments are to be made (i.e. if by direct deposit to a bank account, check, etc.) and when they are due (monthly, quarterly, annually). If there are periods where the royalties are small, is there an accumulated amount that triggers payments (can royalties be accumulated until they reach $100?). Explicitly require prompt payment, and specify that the lease shall terminate if payments are not made on time.
- Reserve the right to audit the books and records of the operator to confirm the correct payment of royalties. You may also consider a provision that states if an error is found over a certain percentage (for example, if the payments made are found to be 4% or more below the correct payment), the operator will pay the expenses of the audit.
- Specify that the mineral owner has no personal liability for overpayment of royalties. Absent such language, an operator could discover an overpayment and, perhaps even years later, seek recoupment of that overpayment from the landowner, meaning a royalty would not be fully yours until the statute of limitations had passed.

3.2.6. Defining the primary and secondary term

- Many professionals advise to avoid primary terms longer than 3 years and avoid options to extend the primary term when at all possible.
- An option is not a lease; it is a separate agreement that give the operator the right, but not the obligation, to enter into a lease at a later date. If the operator insists on an option contract, request that the bonus paid for the option be higher than the original bonus paid (for example, 125% or more of the original bonus paid) and limit the option to extend a limited period of time (for example, no more than 2 years).
- Clearly define what constitutes the commencement of drilling operations. Consider using a definition that requires a drilling rig present on the premises that is capable of reaching the depth of the formation in question, and that the rig is actually drilling on or before the end of the primary term. Another definition of commencement of drilling is "whenever the drill bit is rotating in the ground under its own power with appropriate drilling equipment on site to reach the depth specified in the drilling permit issued by the OCC."
- "Continuous operations" language is also needed for a commencement of drilling clause. If a well is drilled but is a "dry hole" the operator may include language stating they have another 180 or even 360 days to commence drilling. Such terms can significantly expand the primary term. Instead, seek to limit such periods to 90 days. Some mineral owners offer "credits" that extend the primary term by a specific period for each exploratory well drilled – for example, if an exploratory well is drilled, the operator receives an additional 180 days of primary term.
- Define clearly what can extend the lease beyond the primary term. Some producers use specific amounts of production. Others amend the lease by striking "so long as oil and gas are produced in paying quantities" language and changing it to "so long as operations continue" and defining specific operations that must continuously take place to hold the lease. This encourages the operator to either actively produce the well or terminate the lease.

3.2.7. Pugh Clauses

- Remember that production from wells not on your property could hold your lease if the property has been unitized or pooled. Oklahoma has a statutory Pugh clause, but consider adding your own clause to clarify the issue (see section 3.1.6. above).

3.2.8. Depth clauses / "horizontal Pugh" clauses

- Mineral owners can sometimes negotiate a depth clause (sometimes called a horizontal Pugh clause) specifying that the lease is only held by production down to a certain depth (often 100 feet) below the bottom of the wellbore; after the primary term of the lease, the mineral owner is free to lease the minerals for formations below that depth.
- Some mineral owners have the negotiating power to specify formations both below and above the depth of the producing formation.

3.2.9. Shut in royalties

- Shut-in circumstances typically affect gas wells due to the fact that it is difficult to store gas once it is produced. The same does not apply to oil wells, and thus some landowners exclude any sort of shut in provision if the well is primarily an oil well.
- If a well located on adjacent land, situated within a certain distance (for example, 3 miles) of the leased premises and completed in the same formation, begins producing and selling gas, automatically terminate a shut-in; such circumstances indicate the shut-in is only a preference by the operator and is not dictated by market conditions.
- Limit the amount of time a well may be shut in. Many landowners specify the well may only be shut in for a defined period of time, such as 24 consecutive months. However, this can be circumvented to some extent by smaller shut in periods that occur off and on. Other landowners deal with this by specifying the shut-in months are cumulative and not consecutive (that is, once there have been 24 shut-in months, no matter when they occurred, the lease terminates).

3.2.10. Title issues

- Request a special warranty in place of the full warranty, wherein the Lessor only warrants title, by, through, and under Lessor only.
- Negotiate to obtain copies of all mineral abstracts or title opinions held by the operator with respect to the property

3.2.11. Top lease provisions

- Many mineral owners strike any top lease provision from the lease to preserve all of their options to lease to other parties.

3.2.12. Surface damages

- If you own the surface as well as the minerals, do not forget to address surface issues in the lease. Refer to Chapter 2 of this book for more information about surface damage issues.
- As the owner of the mineral estate, you have much more negotiating power than a severed surface owner to negotiate requirements for the protection of the surface, since you ultimately have the power to withhold access to the minerals by not executing a lease.
- Balance both surface and mineral considerations – there may be tradeoffs in the negotiating process between those considerations, so keep in mind what is most important to you.

3.3. Understanding division orders

Almost always, an oil and gas lease will be accompanied by a division order. In the 1980's and 1990's, there was a significant amount of litigation surrounding the issue of payments for oil and gas that were based on incorrect calculations of the actual amount of mineral interest owned by the lessor. This was very easy to calculate in the sample lease above, where one party owned all of the mineral interest in the property subject to the lease. This is far from being the typical case, though. In many cases, the minerals underlying a piece of property may be divided multiple times.

Let's say one of our lessors, Frank, had a great-great-grandfather with 16 acres of land. He gave a joint interest in the minerals underlying the property that he gave jointly to his two children. Each of them now owns a 1/2 interest in 16 acres, or 8 net mineral acres. Let's say this continues until Frank inherits his father's interest – this means Frank now owns one net mineral acre. Though this example may sound far-fetched, this circumstance happens often in mineral-rich states, and results in highly fractionalized mineral interests.

Now, say Frank's one net mineral acre has been leased with a 3/16 royalty. An oil and gas unit 640 acres in size has been created by the OCC that includes Frank's one net acre of minerals. How will Frank be paid for his interest? That is where the division order comes into play. The division order serves to define the specific royalty interest that is to be paid to each mineral owner within the unit. Exhibit 3-3 is an example of the division order Frank might receive.

Exhibit 3-2: Division order example

Exhibit "A"

Exhibit "A" attached to and made a part of that certain Oil and Gas Lease dated the 1st day of January, **20** 15, by and between Frank and Patty Eaton, husband and wife, as joint tenants with Right of Survivorship, as Lessor (whether one or more) and PetroPokes, LLC, as Lessee.

This Exhibit "A" is made a part of the Oil and Gas Lease referred to above. If there be any conflict between the provisions of this addendum and any of the provisions of the above lease, then the provisions of this addendum shall be controlling.

COMMENCEMENT: Commencement of a well according to the terms of this lease will require that a drilling rig capable of drilling to total depth be on location and drilling on or before expiration of the primary term, and that the drilling of said well be continued with due diligence until completion. Construction of a well location without actual drilling as detailed above will not be deemed commencement of a well.

DEPTH CLAUSE: In the event this lease is extended by commercial production beyond its primary term, then on such date this lease shall terminate as to all rights one hundred feet and more below the stratigraphic equivalent of the deepest penetrated formation in the well or wells located on the leased premises, or land unitized therewith. If Lessee is in the process of drilling or completing a well at the end of the primary term of this lease, this clause shall become effective upon conclusion of such operations.

PUGH CLAUSE: Notwithstanding anything to the contrary in this lease, all portions of this lease not included in a unit created by the Oklahoma Corporation Commission and not producing or upon which drilling operations have not commenced, shall be released at the expiration of the primary term of this lease. Should the unit as established by the Corporation Commission be changed after the expiration of the primary term, all portions of this lease not included in the newly prescribed Corporation Commission unit will be released.

NO DEDUCTIONS CLAUSE: It is agreed between the Lessor and Lessee that, notwithstanding any language herein to the contrary, all oil, gas or other proceeds accruing to the Lessor under this lease or by state law shall be without deduction, for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and marketing the oil, gas and other products produced hereunder to transform the product into marketable form; however, Lessor's share of any such costs which result in enhancing the value of the already marketable oil, gas or other products to receive a better price may be deducted from Lessor's share of production so long as they are based on Lessee's actual cost of such enhancements. However, in no event shall Lessor receive a price that is less than the price received by Lessee. The right of the Lessee to charge costs as provided in this paragraph will not include any cost of any kind related to the purchase, installation or operation of equipment on the premises for compression or dehydration.

SHUT-IN ROYALTY: Notwithstanding anything to the contrary herein, it is understood and agreed that this lease may not be maintained in force for any one continuous period of time longer than two (2) consecutive years after the expiration of the primary term hereof solely by the provisions of the shut-in royalty clause. Lease is amended where Lessor is paid $10.00 per year per net acre shut-in payment.

NON ARMS-LENGTH TRANSACTIONS: Notwithstanding the provisions of the lease, if Lessee elects to market oil and/or gas produced from the leased premises, or from lands pooled therewith, under any contract or other arrangement whereby the purchase is not an unrelated third party purchasing such production under an arms-length bonafide agreement providing for terms and prices comparable to those prevailing in the general area of the leased premises, the royalties payable to the Lessor shall be based on the prevailing market value in the general area for sales between unrelated parties affecting comparable production.

Signed for Identification by:

The division order specifies the owner's name and address, the property identifier for the unit and where the property is located, the type of production from the unit (here, both oil and gas), and then the interest – a very curious-looking 0.00029296875 with an "RI" at the end. What does this mean?

First, RI indicates royalty interest. This means that the number preceding it indicates the fractional royalty interest Frank has with respect to the unit. Frank has one net mineral acre with a 3/16 royalty in a 640 acre unit, so:

$$\frac{1\ net\ mineral\ acre}{640\ acre\ unit} \times \frac{3}{16} = 0.00029296875$$

This means Frank is owed the proceeds from the sale of 0.00029296875 of the total production of the unit. This may be a very small example, but the same principle applies regardless of the size of mineral interest owned. If Frank and Patricia's 160 acres of full ownership in the sample lease were inserted, the decimal would come out as 0.046875.

The division order is an agreement between the mineral owner and the operator as to the correct payment fraction to be used in calculation of royalties. Thus, the mineral owner should be extremely careful to confirm that the calculation is indeed correct. This requires thoroughly examining the mineral abstract to confirm the ownership interest owned.

Another saying in the oil and gas industry is "the lease giveth and the division order taketh away." In some cases, the terms negotiated in the lease conflict with terms in the division order (such as the royalty interest – in our examples, this has been 3/16). Since the division order is often executed after the lease, it can supercede the lease, thus undoing what was negotiated in the lease. Be sure to include language in the lease that says nothing in the division order can alter or amend the terms of the lease.

You will also note that the division order includes provisions for a W-9 form to be attached later. The operator will need your Social Security number (SSN) to report royalty payments to the IRS, and to make any necessary withholdings. It is absolutely critical to note that your SSN should never be included on any document that could be placed into the public land records. Only report your SSN on a W-9 form, and do not attach it to any document that will be recorded, such as an oil and gas lease or lease memorandum. You may include a W-9 with your signed division order, but do not put the SSN on the division order itself.

3.4. Conclusions

Oil and gas leases can be lucrative arrangements for mineral owners, but they carry a number of potential risks that are handled through an oil and gas lease. The lease can be a difficult-to-understand document, but if properly handled and negotiated, it can preserve the mineral owner's interests and provide a path for a profitable venture for both mineral owner and operator. Whenever you are presented with a mineral lease, take the time to carefully evaluate it with the help of an attorney experienced in oil and gas matters.

Appendix 3-1: Sample oil and gas amendment document

This oil and gas lease amendment document (sometimes called an "exhibit," "appendix" or "rider") lists the amendments to the original oil and gas lease that have been negotiated by the mineral owner and operator. Please note: *this agreement is provided only as an example to illustrate concepts discussed in this chapter and is not intended to serve as a form. Always consult with a licensed attorney to review and/or draft any legal agreement that may affect your rights.*

Exhibit "A"

Exhibit "A" attached to and made a part of that certain Oil and Gas Lease dated the ________ day of ______________________, 20____, by and between ____ ____as Lessor (whether one or more) and ____ ____, as Lessee.

This Exhibit "A" is made a part of the Oil and Gas Lease referred to above. If there be any conflict between the provisions of this addendum and any of the provisions of the above lease, then the provisions of this addendum shall be controlling.

COMMENCEMENT: Commencement of a well according to the terms of this lease will require that a drilling rig capable of drilling to total depth be on location and drilling on or before expiration of the primary term, and that the drilling of said well be continued with due diligence until completion. Construction of a well location without actual drilling as detailed above will not be deemed commencement of a well.

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PUGH CLAUSE: Notwithstanding anything to the contrary in this lease, all portions of this lease not included in a unit created by the Oklahoma Corporation Commission and not producing or upon which drilling operations have not commenced, shall be released at the expiration of the primary term of this lease. Should the unit as established by the Corporation Commission be changed after the expiration of the primary term, all portions of this lease not included in the newly prescribed Corporation Commission unit will be released.

NO DEDUCTIONS CLAUSE: It is agreed between the Lessor and Lessee that, notwithstanding any language herein to the contrary, all oil, gas or other proceeds accruing to the Lessor under this lease or by state law shall be without deduction, for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting, and marketing the oil, gas and other products produced hereunder to transform the product into marketable form; however, Lessor's share of any such costs which result in enhancing the value of the already marketable oil, gas or other products to receive a better price may be deducted from Lessor's share of production so long as they are based on Lessee's actual cost of such enhancements. However, in no event shall Lessor receive a price that is less than the price received by Lessee. The right of the Lessee to charge costs as provided in this paragraph will not include any cost of any kind related to the purchase, installation or operation of equipment on the premises for compression or dehydration.

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Signed for Identification by:

____________________________________ ____________________________________

Lessor Lessee:

Chapter 4
Pipeline Issues

Pipelines represent an important means of transportation for both oil and gas. In fact, Oklahoma alone has more than 43,500 miles of pipeline. Natural gas is transported almost exclusively by pipeline, and a great deal of oil and refined oil products are transported by pipeline as well.

Naturally, pipelines have to cross significant amounts of land, and that means contracting with rural landowners to use a portion of their property for the pipeline. As with both surface use agreements and mineral leases, the pipeline agreement strives to balance the interests of the surface owner and the pipeline operator. This chapter will lay out the basics of the pipeline right of way negotiation process and items you should consider in the negotiation of your right of way agreement.

It should be noted that this chapter will focus on transmission or transportation pipelines. Shorter underground pipelines such as flowlines or gathering lines that simply connect oil or gas wells on the property or to neighboring properties likely will be handled by the surface use agreement or the mineral lease.

4.1. The pipeline right of way negotiation process.

The pipeline right of way negotiation process likely starts well before the landowner is approached for a right of way agreement. In most instances, the company seeking to construct the pipeline must get approval from the Oklahoma Corporation Commission (OCC) for the project, and to get recognition as a "common carrier" public utility. This provides not only state approval of the project, but also conveys to the pipeline operator the right of eminent domain. This means the pipeline operator has the right to condemn land if necessary for the pipeline – that is, to require a landowner to provide land for the pipeline even if a deal cannot be negotiated between him or her and the pipeline operator.

Such a power is necessary to minimize the amount of land needed for the pipeline route (otherwise, landowners could "hold out" causing the pipeline to be routed around their property and creating a much more indirect route) and thus provides some public good. Nevertheless, the condemnation power can also weaken the bargaining position of the landowner as well. Thus, landowners must undertake a delicate balancing act in their negotiations: they must work to make sure they preserve their rights and get fair compensation for the use of their land, but must also deal with the fact that if they ask for "too much" the pipeline operator may choose instead to use the condemnation procedure.

All other things being equal, the pipeline operator would prefer to privately negotiate the pipeline right of way without having to resort to the condemnation procedure, since it adds time and potentially expense to the process. In private negotiation, the pipeline operator will often provide the landowner with a map of the proposed pipeline route and will offer a pipeline right of way agreement that includes, among other things, an offer of compensation for the damages caused by the installation of the pipeline and the continuing use of the right of way over time. If the landowner and pipeline operator can arrive at an understanding, the agreement is signed, the payment made, and construction can commence.

If an agreement cannot be made, though, the pipeline operator will likely seek a condemnation case by filing a petition in the county court for the county in which the property is located. Once the condemnation case is started, the judge will instruct the landowner and the pipeline operator to each select an appraiser, and the two appraisers chosen will consult to select a third appraiser. The appraisers will examine the property to determine how the value of the property will be affected by the pipeline, with the goal of determining the fair market value of the property both before and after the installation of the pipeline. Once the appraisal is complete, the appraisers make their report to the court. At this point, the landowner and pipeline operator have the option of accepting the report and the compensation is paid to the landowner, or the parties can proceed to a jury trial.

As mentioned before, most pipeline operators and landowners would much prefer to work through the private negotiation process rather than the condemnation process. Thus, let's consider the items to be addressed by the pipeline right of way agreement.

4.2. Considerations in negotiating a right of way agreement

Pipeline agreements come in many forms, and you should always seek the help of a qualified oil and gas attorney to help you evaluate the terms of the agreement presented to you. As you evaluate the agreement, consider the following items.

4.2.1. Determine whether eminent domain power exists.

- Before beginning negotiations, determine whether the pipeline company has eminent domain power. An entity holding power of eminent domain has the right to take private property for a public use upon payment of adequate compensation to the landowner, even without the landowner's consent. A landowner dealing with a company that does not have eminent domain power is in a much stronger negotiation position. In that case, if the company does not agree to the landowner's terms, it may not legally acquire the easement. If the company has eminent domain power, however, and an agreement cannot be reached, the company could still obtain the easement through eminent domain by filing a condemnation proceeding in court. To understand the positions of the parties, make this determination at the outset of negotiations.
- To get this information:
    - — Ask the company for a copy of the statute that grants them eminent domain power.
    - — Find out if the company is validly registered with the OCC as having eminent domain power.
    - — If the pipeline company claims eminent domain power because it is a common carrier pipeline (a pipeline-for-hire), request evidence supporting its common carrier status.

4.2.2. Identify the parties.

- Include the names and addresses of the landowner and the company acquiring the easement. Require the pipeline company to designate a specific contact person in case any issues arise and to provide the landowner with a notice in a set period (such as 30 days) if the designated contact person changes.

4.2.3. Determine compensation.

- Specify the compensation the company will make for the easement, including when the payment is due. Generally, payment is based per foot, per acre, or per rod (a rod is 16.5 feet) of the pipeline, but may also be a set sum rather than tied to a measurement. Consider seeking payment per square foot rather than per foot or per rod to be adequately compensated for the entire area the company will use. If the company wants a temporary work area on the property in addition to the actual easement area, seek additional compensation for the temporary use of this area (bear in mind, though, these provisions may be difficult to negotiate)..
- In addition to a damage payment for the portion of the land used, Oklahoma courts recognize remainder damages (the decreased value of the remainder of the property outside of the easement strip) because of an easement on the property. This is important when the easement agreement limits some or all of the future surface use over the easement area. Consider these types of damages when calculating compensation.
- Finally, discuss with an accountant how the payment will be described or structured. The payment description as an easement purchase versus a payment combined with remainder damages may have tax consequences.

4.2.4. See that the easement is specific, not blanket.

Easement agreements often state that a pipeline will be laid "over and across" the landowner's property. This is a blanket easement that allows the company to place the line anywhere on the property, even if the company verbally promised to place the line in a certain location. To avoid this issue, define a specific easement area and have the company survey it and any temporary work areas. Make that survey an exhibit (documented evidence) to the easement. Also consider requiring a specific setback distance from any buildings or structures if this is a potential issue.

4.2.5. Grant a nonexclusive easement.

- Reserve the right to grant additional easements to other parties within the easement area. For example, if another pipeline company wants to place a line on the property, the landowner may want the right to have the line placed within the same easement, rather than having two separate easements across the property.

4.2.6. Check restrictive covenants.

- The easement may be planned for property that is subject to restrictive covenants, which might specify the required location and depth of any pipelines. Check any restrictive covenants to determine how they might apply.

4.2.7. Limit the easement agreement to only one pipeline.

- Many proposed easement agreements seek to allow the company to "lay lines" or "construct pipelines" across the property. Limit the easement agreement to allow only one line on the property. Also, prohibit the company from assigning or granting rights to another party to lay an additional pipeline in the easement. With this term included, the landowner retains the right to negotiate and receive payment for all additional lines to be added to the easement area, rather than receiving just a one-time payment for an easement that could allow additional lines in the future.

4.2.8. Limit the types of products run through the line.

- In addition to restricting the easement to a single line, seek to limit that line to carrying a single product. For example, a landowner might grant the right to lay a natural gas pipeline, but if the company later wants to flow carbon dioxide through the line, a second easement would be necessary. At minimum, a landowner should know what products are running through the line.

4.2.9. Determine the permissible pipeline diameter and pressure.

- Generally, a landowner wants a smaller, lower-pressure line and a company wants the right to place the largest, highest-pressure line it may ever need. During negotiations, seek an agreement that the line will not exceed a certain diameter and specific pressure to help alleviate safety concerns.

4.2.10. Determine the width of the easement.

- Widths are often described in two measurements, a temporary construction easement (generally 50 feet or wider) and a permanent pipeline easement (typically ranging from 20 to 50 feet). Limit both of these measurements to the narrowest width possible to control the amount of land used or damaged by the easement. Also, determine a date by which the temporary pipeline easement will terminate and provide for damages if the company extends this deadline.

4.2.11. Require a specific pipeline depth.

- In the past, many easements stated that the pipeline would be "plow depth." Avoid this nonspecific, subjective term. Easements usually stipulate that the line will be buried 36 inches below the ground. If a pipeline is buried at 36 inches, erosion will eventually make the line too shallow to comply with state law. In light of this, have the line buried to at least 48 inches deep, or stipulate that the company maintain the 36-inch depth.

4.2.12. Specify what surface facilities, if any, are permitted.

- Even underground pipelines require some surface facilities such as cleaning stations, compressor units, and pump stations at points along the line. Require a pipeline company to either waive all surface facilities on the property or specify exactly how many surface facilities will be allowed, their size, type, and location. If surface facilities will be placed on the property, negotiate additional compensation.

4.2.13. Reserve surface use.

- Retain the right to use as much of the easement area as necessary. For example, once an underground pipeline is in place, the landowner may want to graze his cows on the property, including the surface above the pipeline. Similar consideration applies to the landowner's ability to place roadways, ponds or tanks, and water lines across the easement.

4.2.14. Provide property access for the landowner.

- It is not uncommon to install a pipeline beneath an entry road or driveway to the landowner's property. State in the agreement that the company will provide access to the landowner's property during the pipeline installation, as well as after the construction is completed.

4.2.15. Limit access to the easement.

- A landowner can limit the company's access to the easement in a number of ways:
  - — Require that notice be given before entry.
  - — Set certain times or days when entry is not permitted.
  - — Determine where company employees may enter and exit the property.
  - — Designate what roads may be used while on the property.
  - — Prohibit any fishing or hunting on the easement or any of the landowner's property by the company or any of its employees, agents, or contractors without landowner permission.
  - — If there are no limitations in the easement agreement, the company can enter the easement at any time for any purpose.

4.2.16. Request the use of the double ditch method.

- The double ditch method requires the company to dig the pipeline trench so that the topsoil remains separate from the subsurface soil and is placed back on top of the subsoil when the construction is completed and the line buried.

4.2.17. Include the right to damages for construction, maintenance, repair, replacement, and removal.

- Require the company to be responsible for damages caused not only during construction, but also during future maintenance, repair, and replacement activities. Also, include any limitations or notice requirements desired for the company's maintenance schedule. For example, a farmer growing crops near the pipeline may want written notice before any pesticide or herbicide is sprayed on the easement area.

4.2.18. Set specific restoration standards.

- To ensure that the easement area is properly restored, state the company's responsibilities regarding repairs. How will the disturbed area over the pipeline be treated after the pipeline has been installed? Will the operator remedy any changes to the slope of the land or replace the topsoil? Will the reseeding be done with native grass or is a special type of seed required? Address these issues in detail. Consider setting a measurable standard to ensure that repairs are adequate or appoint a neutral third party to inspect the land after the damages have been repaired to determine if the repairs are sufficient.

4.2.19 Request payment for damages.

- Because pipeline easements generally last a long time, request an up-front payment for damages or require the company to post a bond so that money is available for future damages. This provides some protection to the landowner in the event the company disappears before making damage repairs. Additionally, require that repairs to the surface of the easement be done when the construction is completed as well as when the easement terminates.

4.2.20. Specify fencing requirements.

- Require the pipeline company to fence any areas that may need restricted access (for example, if there is surface equipment that could injure livestock) according to specifications such as the type of fence to be built, the number and type of H-braces to be installed, and the tensile strength of the wire.

4.2.21. Include repairs or improvements to existing roadways.

- Constructing a pipeline requires significant equipment and vehicle traffic. If the company will use any roads owned by the landowner or will construct roads across the landowner's property, require that it restore or improve the roads when the construction is finished.

4.2.22. Determine maintenance responsibilities.

- Define whether the company or the landowner is responsible for surface maintenance over the pipeline, such as mowing or removing weeds and overhanging limbs.

4.2.23. Define when the easement will terminate.

- From a landowner's perspective, this is perhaps the most important provision of an easement agreement. There are several circumstances under which an easement might terminate under Oklahoma law, but abandonment is the most common concern for landowners with pipeline easements.
  An easement is considered abandoned if there is non-use by the company (an objective test) and the company indicates an intent not to use the line in the future (a subjective test). Under this rule, it is difficult for a landowner to prove the subjective test in order to have the easement terminate due to abandonment.

  Instead of relying on the general rule, set a specific, objective standard for when the easement will end. This could be a specific time in the future (for example, the easement will last for 10 years) or may be a statement that if the pipeline company does not flow product through the line for a certain period (for example, 1 year), it is considered abandoned and the easement terminates. Whatever the standard, including it in the agreement prevents easements from lasting into eternity. Further, require that the company provide a release of the easement so it can be recorded in the public record when the easement ends.

4.2.24 State the requirements for removing facilities.

- Require the company to remove all lines and structures after termination of the easement or forfeit them to the landowner. Also, state that any damages caused by this removal will be the responsibility of the company.

4.2.25 Determine remedies for violating the easement agreement.

- If a company violates the easement agreement, the landowner can file a lawsuit to terminate the agreement, but the court will require that the violation is "material" before granting termination of the agreement. Whether a violation is material is determined on a case-by-case basis on the specific facts at issue. This causes two potential problems: (1) the landowner must go to court, which is expensive and time-consuming, and (2) the violation must be material for termination to be permitted.

  To avoid these issues, consider two options:

  First, the landowner may be able to define what violations are deemed material and state that in the agreement. For example, the agreement could state that "employees shall be permitted on the easement only and if they leave the easement and enter the landowner's property, this shall constitute a material breach." This material breach would permit the landowner to terminate the agreement without court action.

  Second, require conditions in the agreement by stating "or the agreement shall terminate without further action by the landowner." For example, the agreement could say, "employees shall be permitted on the easement only. If they leave the easement and enter the landowner's property, this shall constitute trespass and the agreement shall terminate."

Under either of these scenarios, the landowner knows precisely when he or she may terminate the agreement, rather than having to wait for a judicial determination of material.

4.2.26. Include liability and indemnification provisions.

- Incorporate liability and indemnification responsibility in the easement agreement. Provide that the landowner is not liable for any acts, omissions, or damages caused by the company, its agents, contractors, or employees. Further, stipulate that if any claim is made against the landowner by any party related to the pipeline or surface facilities, any of the company's activities, or any environmental laws, the company will hold the landowner harmless and state that this includes paying any judgment against the landowner and providing a defense to the landowner without charge.

4.2.27. List the landowner as "additional insured" on the company insurance policy.

- Require the pipeline company to list the landowner as an "additional insured" on its insurance policy. This is not usually a major cost to the company and may allow the landowner the protections of the company's insurance policy if he or she is sued based on something related to the pipeline.

4.2.28. Do not be responsible for warranty of title.

- Frequently, standard easement agreements require the landowner to warrant title (the landowner promises that there are no other unknown owners or encumbrances on the property). Because the pipeline company is in a better position to conduct a title search and make sure they are negotiating with all the right parties, the landowner should not take the risk of warranting title.

4.2.29 Limit the terms of transferability.

- Specify whether the company can assign its rights under the agreement to a third party. Request that no assignment be made without prior written consent of the landowner, state that any assignee will be held to the terms of the original agreement between the landowner and the company, and state that the company will remain liable in the event of a breach of the agreement by the assignee. At a minimum, require notification before an assignment occurs.

4.2.30. Request a most-favored-nations clause.

- Although pipeline companies dislike these requests, ask for a most-favored-nations clause. This provides that if any other landowner in the area negotiates a more favorable deal within a certain timeframe, the landowner is given the benefit of the more favorable deal.

4.2.31. Seek payment for negotiation costs.

- Because the landowner may incur significant costs during the negotiation process, including appraiser costs, fees for forestry or agricultural experts, surveyor expenses, and attorney's fees, require the company to pay all or a portion of these costs. This could be paid under "signing bonus."

4.2.32. Use a choice-of-law provision.

- A choice-of-law provision allows the parties to determine which state's law will govern the agreement in the event of a dispute. For example, a pipeline company headquartered in another state may try to require that the law in their home state apply to any dispute involving the easement agreement. Generally, courts enforce these clauses as long as they are not against public policy and are reasonably related to the contract. Because many laws vary by state and a choice-of-law provision could significantly impact rights under the agreement, consult with an attorney to determine which options are the most advantageous to the landowner.

4.2.33 Include a forum clause.

- A forum clause provides that a dispute over the agreement will be heard in a particular location or court. Include a requirement that any lawsuit be filed in the county where the land is located or the landowner lives. This can significantly lower litigation and travel costs and ensures that if a jury trial occurs, the jury will be made up of local citizens.

4.2.34 Understand dispute resolution clauses.

- These types of clauses limit the time and expense of a court action in the event of a dispute. There are two primary types of dispute resolution: arbitration and mediation. In arbitration, a third party arbitrator (usually an attorney) hears evidence and delivers a decision. If the arbitration is "binding," that judgment is final, absent evidence of fraud by the arbitrator. Mediation involves a neutral third party who works with the landowner and the company to reach a mutually acceptable resolution. If both parties refuse to agree to settle, the case goes to court. Understanding the difference between these options is important; consult with an attorney to determine which option is best. A dispute resolution clause should identify how the arbitrator or mediator is selected.

4.2.35. Have the agreement reviewed by a licensed attorney and other qualified professionals.

- A licensed attorney familiar with easement negotiation issues should review all pipeline easement agreements. Although hiring an attorney who specializes in representing landowners in these types of transactions may be an additional cost, it could save money in the long run by preventing a dispute from arising because of an unclear or inadequate easement agreement.

4.2.36. Money-saving tip.

- Because most attorneys bill by the hour, a client can save considerable fees by doing as much legwork as possible before going to the attorney's office. For example, a landowner could collect necessary documents such as the legal description or sketch of the property, saving the attorney the time of locating that information. Moreover, a landowner could prepare a first draft of the easement agreement using this checklist. This would save the attorney the effort of starting from scratch and allow him or her to simply edit the draft prepared by the landowner.

Appendix 4-1: Sample Right of Way Agreement

This right of way was written to be accommodating to surface owner interests and serves as an example to help you see some of the provisions commonly included in such agreements. Please note: this agreement is provided only as an example to illustrate concepts discussed in this chapter and is not intended to serve as a form. Always consult with a licensed attorney to review and/or draft any legal agreement that may affect your rights.

PIPELINE AND RIGHT OF WAY AGREEMENT

FOR GOOD AND VALUABLE CONSIDERATION, the receipt and sufficiency of which is hereby acknowledged, ____ ____ ____, (whether one or more, hereinafter referred to as "Grantor"), does hereby grant, transfer and convey to _______________ ____, (hereinafter referred to as "Grantee"), a Twenty-Five (25.00) feet wide right-of-way and easement (hereinafter referred to as the "Easement") together with all improvements located on, in, over, under, through and across Grantor's land for the purpose of locating, establishing, constructing, laying, installing, operating, using, maintaining, inspecting, testing, protecting, catholically protecting, repairing, assigning, restoring, renewing, reconstructing, replacing within the Easement, changing the size of, and removing **one (1) pipeline only,** together in connection with the use and convenient operation of the pipeline, for the transportation of oil, gas, petroleum products, fresh water, saltwater, or any other liquids, gases (including inert gases) or substances which can be transported through pipelines, upon and along a route as generally depicted on Exhibit "A" attached hereto on, over and through the following described lands located in _____________________ County, State of **Oklahoma**:

Please see Exhibit "A" attached hereto and made a part hereof for a survey of the proposed easement and Exhibit "B" attached hereto and made a part hereof for additional provisions.

together with the right of ingress and egress on, over, and across said lands for all purposes incident to the rights herein granted. The pipeline to be laid under the Easement shall be constructed at a depth of at least forty-eight (48) inches below the surface of the ground at the time of construction. Incident to construction and installation activities, Grantor also does hereby grant, transfer and convey to Grantee a fifty (50) feet wide temporary access and construction easement. Said temporary access and construction easement shall commence on the date of construction activities for the pipeline and automatically terminate upon the completion of the initial construction and installation of the pipeline.

Grantor acknowledges and agrees that: (a) the payment made to Grantor by Grantee for the Easement includes payment for any and all damages to land, crops, timber, fences, drain tile, or other improvements that may arise from the construction of the pipeline installed in the Easement; (b) Grantor shall pay to any tenant any and all damages to crops, timber, fences, drain tile, or other improvements on the Easement that may arise from the construction of the pipeline installed in the Easement; (c) Grantee shall have the right, but not the obligation, of keeping the Easement clear of trees, undergrowth, brush and obstruction and Grantee shall be liable for additional damages caused on the Easement by keeping the right-of-way clear of trees, undergrowth and brush in the exercise of the rights granted; and (d) Grantor shall not build, construct or create any buildings, structures or engineering works on the Easement.

Grantee agrees that in the event said Easement is abandoned, Grantee shall file a release of easement within twelve (12) months after abandonment. Grantee shall retain the right, at its expense, to remove pipeline within twelve (12) months of abandonment. If pipeline is not removed within twelve (12) months, the pipeline shall become the property of Grantors. Abandonment shall be defined as complete non-use of said pipeline for a period of two (2) consecutive years, after the pipeline has been placed into full service.

Grantee hereby agrees to indemnify and hold Grantor harmless from and against, and to reimburse, Grantor with respect to any and all future liabilities, claims, demands, damages, expenses or causes of action of whatever nature, specifically including, but not limited to, reasonable attorney's fees and costs of suit paid or incurred by Grantor, asserted by others and related, directly or indirectly, to Grantee's use of the Easement property and that are caused by or arise in any manner out of acts or omissions of Grantee, its agents, employees, representatives or any other person under Grantee's control or acting at Grantee's direction. Grantee agrees that it will comply with all regulations and statutes of all governmental entities having jurisdiction over compliance with environment legislation.

The provisions of this instrument shall extend to and be binding upon the parties hereto and their respective heirs, executors, representatives, successors and assigns. Grantee shall have the right to license, lease, sublease and/or assign the Easement, in whole or in part. The Easement creates a real property interest that shall continue in full force and effect regardless of whether any pipeline constructed hereunder is in operation, and may only be terminated by a written instrument executed by Grantee.

GRANTOR HAS EXECUTED THIS INSTRUMENT this _______ day of _______________________, 20_____.

_______________________________________ _______________________________________

Grantor: Grantor:

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