Oil and Gas Frequently Asked Questions

Surface Owner Questions

What is Chapter 38-11.1 of the ND Century Code?

Chapter 38-11.1 of the North Dakota Century Code ("NDCC") contains the statutes that require notice of drilling operations to surface owners , surface owner damage and disruption payments, ground water and environment protections, and mineral developer surface owner agreements.

Does a surface owner have any influence over the location of a well and other surface facility placement?

Yes, prudent operators always attempt to accommodate surface owner concerns on locating well sites, access roads and other facilities. An operator is required by law to notify the surface owner of its proposed drilling operations and provide a written offer of settlement for surface disruption. An operator's preferred location will usually be based largely on geology, but also other factors such as terrain and location limitations as prescribed by the North Dakota Industrial Commission ("NDIC"). It is the surface owner's responsibility to inform the operator of their concerns with the operator's desired location. The prudent operator will select a well site that has taken all the issues into consideration, including the surface owner's concerns.

In the event the parties cannot reach a Surface Agreement, the surface owner may seek relief in the court of proper jurisdiction.

Do landowners or mineral owners have any input on well spacing considerations?

After a "wildcat" or discovery well is drilled, a hearing is scheduled to review the ownership, geology, engineering and economics of the well and pool. First, temporary spacing for field development is set and then approximately 18 months later proper spacing for wells in the new field and pool are set by Industrial Commission order. This is a public hearing and notice is given so that all interested parties can have input on the spacing order issued by the Commission. Spacing is designed to prevent waste, prevent the drilling of unnecessary wells and protect correlative rights.

What can the surface owner expect to get from a seismographer? They used to run all over and not tell any landowners what they were up to. Can they still do that?

In 1997, the legislature passed NDCC 38-08.1 which requires a state permit and compliance with Industrial Commission regulations in NDAC 43-02-12. Seismic notice and damage payments are private contracts under NDCC 38-08.1 and 38-11.1.

How do we reclaim abandoned severed mineral rights? Can only the surface owner do it?

Chapter 38-18.1 of the Century Code defines the process for a surface owner to claim unused or abandoned mineral rights. . This statutory procedure is only available to the current surface owner.

Where can a landowner find out which rates should be paid for leases, damages, or other compensation?

This information is not made public; it's a private contract issue between the parties. Generally speaking, neighbors and friends tell each other and the going rates in specific areas become common local knowledge. But you will not find a posted price or fixed price. Each circumstance and situation is unique and treated as contractual agreement.

Shouldn't damage payments to surface owners be higher than they used to be since land values are worth more than they used to be?

The amount of damages may be determined by any formula mutually agreeable between the surface owner and the mineral developer, taking into consideration such factors as loss of agricultural production and lost land value caused by the drilling operations.

Mineral Owner Questions

What is Section 38-08-08 of the ND Century Code?

NDCC 38-08-08 is the statute that defines the process for compulsory pooling and penalties on those who do not participate in the cost and risk of drilling operations. In the absence of voluntary pooling, the Commission, upon the application of any interested person, shall enter an order pooling all interests in the spacing unit for the development and operations thereof.

Explain risk penalty provision.

Under NDCC 38-08-08 **working interest owners** ("lessees") can be assessed a 200% penalty out of proceeds from production of the pooled spacing unit if they choose not to participate in the cost and risk of drilling and completion. However, **mineral owners** who choose not to lease are provided a cost free royalty equal to the weighted average royalty in the spacing unit agreed to by all those who leased their minerals. The remaining interest of mineral interest owners who choose not to lease is a working interest in the well and can be assessed a 50% penalty out of proceeds from production of the pooled spacing unit if they choose not to participate in the cost and risk of drilling and completion. In either case the paying owner(s) must make an unsuccessful good-faith attempt to lease the minerals or get the working interest to participate. They must also provide proper notice of intent to impose the risk penalty and inform the non-participating parties that they can oppose the penalty before the Industrial Commission.

What percent must be leased before they can force others to act? Explain risk pooling.

There is no specific percent required for an operator to pursue "force pooling" or "Recovery of a Risk Penalty" as it's defined by the State of North Dakota Industrial Commission (NDIC). The NDIC has authority to approve such an action pursuant to statute 43-02-03-16.3. An operator does, however, need to have an interest in the drilling unit of the proposed well, whether it is by lease or mineral, in order to propose the forced action.

Obtaining NDIC approval requires the operator to provide a written invitation to participate in the risk and cost of a well. If the party receiving the invitation to participate is not subject to a lease or other contract for development (mineral interest), the operator seeking such recovery action must make a good-faith attempt to lease said party. The risk penalty for this interest owner is 50% of their share of the costs of drilling and completing a well, while an owner with an interest derived by lease or contract realizes a 200% penalty.

The written invitation to participate must include the well site location, depth and objective zone, along with estimated cost, projected commencement date, date the invitation must be accepted and a notice to the invited party about the plan to impose the risk penalty. The invited party may convey its opposition to the proposed risk notice directly to the operator, or pursue its opposition with the NDIC through hearing.

An election to participate, by the invited party, must be returned in writing to the operator, and is binding provided the well operations are commenced within ninety (90) days after the date the operator advises it must be accepted.

Do landowners or mineral owners have any input on well spacing considerations?

Yes, landowners or mineral owners do have a right to appear at spacing hearings. This is a public hearing and notice is given so that all interested parties can have input on the spacing order issued by the Commission. Since spacing is designed to prevent waste, prevent the drilling of unnecessary wells and protect correlative rights, a landowners testimony or comments should address one of these technical issues.

How long after discovery of oil does a mineral owner's royalty payment take?

Issuance of the first royalty payments can vary greatly from as little as two months from date of first sales to many months. First, the spacing unit needs to be determined and if the well is not already spaced, a hearing may be required, which can take several months. The operator must also determine the identity of all mineral, royalty and other interest owners in the well and determine each party's proper ownership interest in the well. In order to do so, a title opinion may need to be completed. Depending upon the size of the spacing unit and overall complexity of the title, this process alone can take several additional months. Further, if all leases do not contain voluntary pooling language, a pooling hearing must be held and a pooling order issued by the Industrial Commission.

I signed a five year lease for my minerals; it's now year two with no oil wells or activity to date. How long am I locked into the lease provisions?

The lease is a binding contract and typically remains in effect until the primary term expires (assuming all bonus and rentals were timely and properly paid). If production is obtained during the primary term, the typical lease provisions provide it is extended for so long as oil and/or gas are produced.

When leases are purchased whose name is typically used? Does the oil company's name appear?

Quite often the oil and gas company's (operator) name is not listed as the Lessee on the oil and gas lease. Many Operators prefer to remain confidential to the public when they are in the leasing stage of an oil and gas exploration play. In order to accomplish that, operators will contract a lease broker to purchase leases on their behalf. Should a Lessor want to know who the eventual operator of the lease will be, the Lessor can inquire about this from the lease broker. Should the lease broker not divulge such information then it is up to the Lessor as to whether or not they want to lease to an entity that is not provided.

Talk about mineral lease bonus money paid.

Mineral leases are taken by a wide variety of interests in the oil and gas industry. Sometimes oil companies who plan to drill buy the lease, other times it's interested parties leasing up parcels in order to get a piece of the action. . Many factors are relevant as to determining the lease bonus, including commodity prices, proximity to existing production, and competition in the area.

Regulatory Questions

What are the setback distance requirements from an occupied dwelling or structure?

The legislature imposed a setback of 500 feet in NDCC 38-08-05.

How long do companies have to drill after issuance of permit?

Drilling permits expire after one year. The well can be re-permitted or the permit renewed by making written application and paying an additional permit fee.

How do you determine the spacing requirements for different types of wells in different fields?

Through over 50 years of oil and gas production history, the Industrial Commission has developed engineering and geology principles and standard drilling unit provisions for various types of wells. These can be found in the North Dakota Administrative Code 43-02-03-18. Current drilling practices frequently require drilling units that do not comply with the standard provisions so public notice, a hearing, and a commission order are required. After a well is drilled, hearings are scheduled to review the ownership, geology, engineering and economics of the well and pool. First, temporary spacing for field development is set and then approximately 18 months later proper spacing for wells in the new field and pool are set by Industrial Commission order.

Most of our oil and/or gas wells were drilled in a conventional manner, being a vertical well bore with spacing of wells that vary from 40 acres up to 640 acres. A typical well bore will be open in the producing formation for less than 30 feet. In the last few years, the State has seen considerable activity of "unconventional wells" being drilled in a horizontal manner. These well bores are open in the producing formation from 4,000 to 9,000 feet in a lateral fashion. (Depending on the operator's preference and the NDIC's concurrence, the length of the wellbore determines whether these wells will be 640 acres or 1,280 acres.)

Are gas lease terms the same as oil leases?

Generally, yes, but due to the complexities and long development times for gas processing and marketing infrastructure to be built, gas leases frequently contain a shut-in gas well clause. Most leases cover both oil and gas.

How can you have both 1,280 acres and 320 acres or some other spacing in the same section?

Occasionally more than one well type is drilled in a pool and spacing unit as technology to maximize productivity and recover is developed. Each well type is capable of recovering the oil and gas from a different area and those areas may be allowed to overlap if correlative rights are protected.

How does the state decide on production cutbacks to eliminate flaring?

Through over 50 years of oil and gas production history, the Industrial Commission has developed engineering and geology principles to guide the imposition of oil production restrictions so that cash flow can be maintained while information to evaluate gas reserves versus gathering and processing costs is collected. A balance must be struck to prevent physical and economic waste, protect correlative rights, and gather vital information while preserving the cash flow required for development drilling and gas gathering construction.

How is drilling monitored to know that the oil company is doing what their drilling permit allows?

The North Dakota Industrial Commission Oil and Gas Division has a staff of engineers and geologists that inspect every drilling rig one to two times per week. They collect the data directly from the directional drilling contractor and enter it into the state agencies computer system which allows them to compare the permitted and actual well path within minutes. The Oil and Gas Division has the authority to stop the drilling and/or make them sidetrack the hole.

Are oil companies required to reclaim the land after a well is plugged?

Yes, the land must be reclaimed after the well is plugged. Consideration of reclamation requirements actually begins while the well is being permitted. On federal lands there is a rigorous process companies must follow when reclaiming the land. A similar process is followed on private and state land. For more information on the reclamation process, along with photos of reclaimed well sites see - http://www.ndoil.org/content/view/17/31/.

How does a company get title work done on a well using 1,280 spacing?

Great question, the answer is not easy. Under two miles of ground there are usually a large number of mineral owners and the title work becomes extremely burdensome. North Dakota law firms along with lawyers in many states are working tirelessly to keep up with the 80 drilling rigs working today.

Bakken Basics

On a frac job – how far back into the formation does it extend?

The distance into the formation a fracture stimulation extends depends on the mechanical properties of the rock as well as the rate, pressure, and physical properties of the fracturing fluid. The typical current Bakken fracture stimulation creates cracks that may be as long as 1,000-1,200 feet.

What's the lifespan of these new Bakken wells? How many times can you frac a Bakken well?

Engineering analysis of the new Bakken wells indicates they will produce for about 30 years. Most new Bakken wells have been frac'd twice and many three times.

How thick is the Bakken formation?

The Bakken formation thickness varies from about 11 feet at the erosional edge, or subcrop, to about 180 feet just east of Tioga at the depositional center.

What is the API gravity of Bakken crude oil? Explain its relative quality.

Bakken crude oil gravity ranges from 36 to 44 degrees API. The quality of this oil is excellent, almost identical to WTI. The benchmark crude oil is West Texas Intermediate, which is 40 degrees API sweet crude. It is the benchmark because it requires the least amount of processing in a modern refinery to make the most valuable products, unleaded gasoline and diesel fuel.

With the high cost of drilling these Bakken wells, do you see more emphasis on vertical drilling of other formations?

We have not observed this as a trend. The Bakken is an "unconventional" resource that requires very expensive drilling and completion techniques. There are other more conventional oil and gas plays in the Williston Basin, some of which benefit from horizontal drilling and others which utilize traditional vertical drilling. All of these activities have an important role in the economy of the State of North Dakota and the oil and gas industry.

What is the potential for Bakken activity to extend outside of traditional oil counties?

The success of Bakken and Three Forks wells in Saskatchewan and Manitoba indicates that this activity may extend 50-100 miles east and north of historical producing areas.

How long could Bakken activity potentially last?

The current fleet of rigs drilling Bakken and Three Forks wells will take 15-20 years to develop the entire thermally mature resource area. We believe that future technologies to recover much more than the current 1.4% of the oil in place will extend Bakken activity for many years.

What's the formation below the Bakken?

Devonian Three Forks, which is a Devonian age dolomitic silt stone that is found just below the lower Bakken shale. The Three Forks is considered part of the Bakken pool.

With current technology, how much oil from the Bakken is recoverable?

With today's best technology, it is predicted that 1%-2% of the reserves can be recovered.

How close to the U.S. boundary are the Canadians drilling in the Bakken?

Current development has gotten within one mile of the border, but the focus area appears to be 8-10 miles north of the US/Canada border.

What is the difference between upper, lower, and middle Bakken formations?

The Bakken Formation has three informal members, an upper and a lower black, organic-rich shale, separated by an arenaceous limestone to siltstone.

What percentage of a barrel of Bakken oil is gasoline and diesel fuel?

A modern refinery can make about 95% of a barrel of Bakken crude oil into gasoline, diesel, and jet fuel.

Royalties and Tax Questions

What affect did the oil tax of 1981 have on the oil industry during the last boom cycle?

When Measure #6 was passed by the citizens of North Dakota in November 1980, the price of oil was $36 per barrel, down from a high of $39.50 and the drilling rig count was 100. By the time the new tax took effect on July 1, 1981, the oil price had declined to $35 per barrel and the drilling rig count had climbed to 135. Eighteen months later the oil price was $33 per barrel and the drilling rig count had plummeted to 48 after peaking at 147.

Does the state collect "use tax" or "sales tax" on all the steel and equipment being used?

Sales tax is paid on everything that is permanently installed in or on the well. With booming oil activity, the sales tax revenues in western North Dakota cities have been growing at a record pace each quarter.

How much does the oil industry pay in oil production taxes?

In fiscal year 2008, the oil and gas industry in North Dakota paid $398 million in oil production taxes. This was the second highest revenue source to the state behind sales tax and surpassed all individual income tax and corporate income collections.

How do townships, counties, cities, and schools benefit from oil and gas tax revenues?

The state collects oil taxes and distributes revenues to counties, cities, and schools in oil and gas producing counties. In 2005 to 2007, the revenues paid to counties exceeded $94 million. However, the revenues to counties are capped and a growing number of counties are reaching the cap. The Legislature, over the past two sessions, has made improvements but the distribution formula was created in 1981 and it is likely that further modifications will be made in future sessions. There will be a number of bills in the 2009 Legislature to increase the amount of funding that counties receive for oil and gas impacts.

What is the Oil Impact Fund?

The Oil Impact Fund is a special fund that is managed by the State Land Department. The Fund receives up to six million dollars per biennium to address impact in oil and gas producing areas.

What is the timeline for money coming back to the counties?

The State Treasurer has recently made some improvements in the payment distribution system and the revenues are now paid monthly instead of quarterly which has been a significant benefit to those entities.

Why don't oil companies pay annual rental payments?

This is generally an upfront cost associated with drilling a well. Oil companies prefer and traditionally have made one lump-sum payment to surface owners instead of prorating the payments over an unknown period of years since nobody really knows how long the well will be active. The lump-sum payment has traditionally worked out well for the surface owner.

Oil and Gas Production

What has been the success ratio of the horizontal wells drilled in Mountrail County?

At this point the success rate is over 99%. This does not mean that 99% of the wells are economic successes but that the Bakken oil is prevalent and virtually every well is capable of producing some volume of oil. The success of the wells varies from well to well and field to field and especially county to county.

What is a frac job or fracture stimulation?

A frac job or fracture stimulation is a process to increase the production rate of an oil or gas well. A fluid, usually water containing surfactants or gelling agents, is pumped down the well at high enough pressure and rate to open cracks in the rock followed by more fluid containing sand. When the fracturing fluid flows back out of the well, the sand remains and holds the cracks open so oil and gas can flow to the well much faster.

On a frac job – how far back into the formation does it extend?

The distance into the formation a fracture stimulation extends depends on the mechanical properties of the rock as well as the rate, pressure, and physical properties of the fracturing fluid. The typical current Bakken fracture stimulation creates cracks approximately 1,000-1,200 feet long.

What does the "average" Bakken well produce?

Bakken wells drilled in calendar year 2007 had an average initial production rate of 240 barrels of oil per day during the first 30 days.

What elements are considered when a company plans for the location of a plant, station, or whatever?

Proximity to producing wells, highways, railroads, electrical power, and workers are all important factors that have to be considered.

What impact does oil activity have on water resources?

The typical new Bakken well requires about one million gallons (3 acre feet) of water to drill and complete. The vast majority of this is surface water purchased form city treatment facilities. By comparison the average application rate is 2.48 acre-feet per acre for center pivot irrigation in the United States.

How does horizontal drilling affect the environment?

Horizontal drilling is very environmentally friendly. The typical new Bakken well uses a 5 acre surface location that is reclaimed to about two acres for production to develop 1,280 acres of minerals. Vertical well technology of 20 years ago would utilize 4-20 times the number of wells and surface acres.

Roads, Pipelines, and Electrical Transmission Questions

What has the state actually done to improve the pipeline problem?

The legislature has created the North Dakota Pipeline Authority. The Pipeline Authority has published reports on oil, natural gas, refinery and refined product infrastructure and has provided support for expansion of the Enbridge and Belle Fourche pipelines as well as construction of the Keystone pipeline.

What is the timeline for development of roads, pipelines, electrical transmission, and gas processing facilities?

Infrastructure typically lags oil and gas production, since industry generally needs to validate the discovery and determine what size and scope of pipelines, gas plants, and other facilities are going to be needed in order to meet the demand. In addition, oil companies are fierce competitors and don't usually work together until absolutely necessary to get the infrastructure in-place. Usually the pipeline and other infrastructure is owned by companies who specialize in those areas and it simply takes time to put together the projects and commitments to offset the capital risks.

How much tax revenue is the state losing due to a lack of infrastructure?

The lack of sufficient pipeline capacity was a major issue in 2006. The state lost an estimated $19 million due to discounts on the price of oil received in North Dakota. Since then, pipelines have expanded numerous time but once again the state's and Williston Basin's oil production is nearly exceeding the export capacity. This will be an issue of great discussion over the next few months as companies weigh their options. For more information on pipelines and bottlenecks, see the ND Pipeline Authority website at http://www.nd.gov/ndic/pipe-infopage.htm.

What part do oil companies take in helping to fund roads?

Oil companies pay a significant amount of taxes to the state of North Dakota. Nearly $400 million was paid to the state just in oil and gas production taxes in fiscal year 2008. The North Dakota Legislature determines how those funds are distributed. In addition, for access roads to wells that are not state, county, or township roads, the oil companies are completely responsible for all building and maintenance.

As a city or county, what can they do to prepare as much as possible and be ready for all the development?

As we learned in the 1980's, growth that is too fast and taken without proper planning can be risky for communities and industry. Planning short and long-term goals as well as working together to understand all the potential opportunities and obstacles is critical. For towns looking to attract business, planning an energy park or areas for new housing has been effective. Nobody really knows at this point how long the current boom will last but we can all work together to do a better job of making the impacts more positive this time around.

What can you tell us about what it may take to build an oil refinery?

The North Dakota Pipeline Authority wrote a series of publications regarding refineries and refined products. See http://www.nd.gov/ndic/pipe-infopage.htm.

How do townships, counties, cities, and schools benefit from oil and gas tax revenues?

The state collects oil taxes and distributes part of the revenues to counties, cities, and schools in the 16 oil and gas producing counties. In fiscal year 2008, the gross production tax totaled $227.8 million dollars. Of that total, the counties received approximately 26% as a region or $47.5 million which includes a small impact fund. The state general fund received $180.2 million. The county revenues are capped by a dollar amount set in 1983. The legislature over the past two sessions has made improvements to the state oil formula but it's likely there will be legislative bills introduced to address the oil impacts and long term infrastructure in the oil counties.

What is the Oil Impact Fund?

The Oil Impact Fund is a special fund that is managed by the State Land Department. The Fund receives up to six million dollars per biennium to address impact in oil and gas producing areas.

What is the timeline for money coming back to the counties?

The State Treasure has recently made some improvements in the payment distribution system and the revenues are now paid monthly instead of quarterly which has been a significant benefit to those entities

Additional Resources:

Recent Town Hall Presentations:

http://www.ndoil.org/content/view/91/2/