Updates to the
2004 Landowner's Guide

Oil and Gas at Your Door?

A Landowner's Guide to Oil and Gas Development
Second Edition

OIL & GAS ACCOUNTABILITY PROJECT

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Updates to the 2004 Landowner's Guide

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SHOULD YOU BE CONCERNED ABOUT OIL AND GAS DEVELOPMENT?

If you own some land, but aren't presently dealing with oil and gas development, you may be wondering whether or not you need to read this guidebook. The following questions may shed some light on this issue.

What is the future of oil and gas production in the U.S.? In the United States, approximately four million wells have been drilled in the search for oil and gas, which started in this country in the early 1800s.[1]

Between 1992 and 2002, the number of producing domestic natural gas wells increased from approximately 202,000 to 262,000. Meanwhile, the number of domestic oil wells declined from 396,000 wells in 1992 to 319,000 wells in 2002.[2]

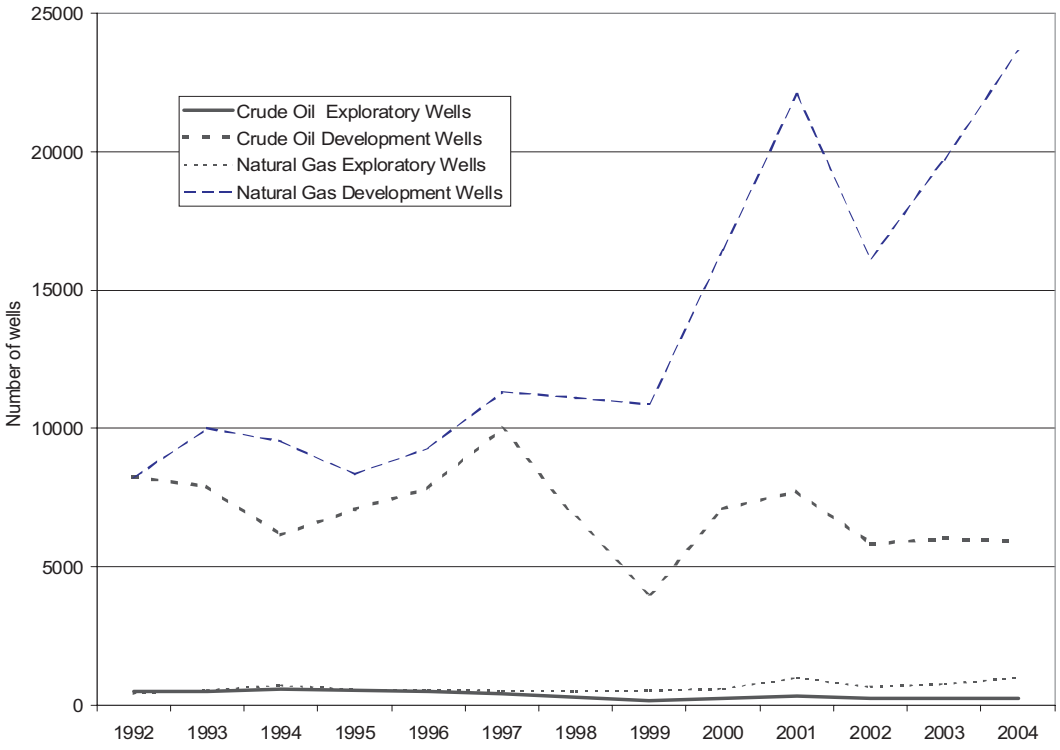


FIGURE i-1. NEW CRUDE OIL AND NATURAL GAS WELLS DRILLED IN THE U.S. BY YEAR.
Source: Energy Information Administration. U.S. Department Of Energy.[3]

Figure i-1 shows the number of oil and gas wells drilled per year in the U.S. since 1992. It is clear that the drilling of natural gas wells has skyrocketed since about 1999.

All signs point to the fact that drilling—at least for natural gas—is not going to slow down in the near future. The U.S. Department of Energy predicts that domestic natural gas production in the country is going to increase from 19.1 trillion cubic feet (2003) to 21.8 trillion cubic feet (2025).[4] Crude oil production is predicted to experience slower growth, and any increase is expected to come from offshore oil reserves.

The current administration contends that increasing our domestic energy supply is necessary to protect our national security.[5] In a 2001 speech on U.S. Energy Strategy, Vice President Cheney stated that:

For the oil we need, unless we choose to accept our growing dependence on foreign suppliers—and all that goes with that—we must increase domestic production from known sources. . . For the natural gas we need, we must lay more pipelines—at least 38,000 miles more—as well as many thousands of miles of added distribution lines to bring natural gas into our homes and workplaces.[6]

The United States will eventually deplete its oil and gas resources, but this is unlikely to occur in our lifetime. As development continues, more and more conflicts between oil and gas developers and landowners are sure to arise because of impacts to land, water and public health and safety, all of which are threatened by increased oil and gas extraction.

Do we "need" so much oil and gas? The United States is the number one consumer of oil—Americans use 23.5 million barrels per day.[7] There is the perceived need to increase oil production because the U.S. Department of Energy has forecast that our consumption will increase by 1.8% (423,000 barrels per day) every year until 2050.[8] Current government policy, however, is focused on increasing production rather than decreasing consumption. If a shift occurred in federal government priorities, the "need" to develop more wells, faster, would diminish.

For example, because nearly 70% of this country's oil consumption is currently used for transportation, the United States could reduce consumption if it focused on reducing oil use in the transportation sector. According to a report by the National Environmental Trust,[9] the U.S. government easily could implement a program to decrease U.S. oil demand by:

- Encouraging Americans to keep their engines tuned up and their tires properly inflated. This would cut U.S. oil consumption by a million barrels per day!
- Increasing federal fuel economy standards for cars and trucks to 40 miles per gallon by 2010. This would eliminate the projected growth in U.S. oil imports by that date. This is a reasonable recommendation, as U.S. auto companies have already committed to meeting this standard for cars exported to Europe by 2010. They simply need to implement the same standard here in the U.S.

With engines tuned and tires properly inflated, oil consumption would be decreased by 1,000,000 barrels per day

— National Environmental Trust

As for natural gas, the United States is the country with the second largest consumption rate in the world.[10] In June 1999, an article in *Oil & Gas Journal* reported that in Texas, a state that produces 1/3 of the nation's gas, 6,400 new wells must be drilled each year to keep its production stable. But Americans' demand for natural gas is not stable.[11] According to the U.S. Department of Energy, U.S. consumption is forecast to increase by 2.2% every year.[12] So, even if we continue to increase our drilling of natural gas wells, we are not going to meet our "needs."

What is really needed is an energy policy that provides incentives for reducing our demand for oil and natural gas, and promotes the development of less polluting, renewable energy sources.

Where will the oil and gas come from? Since it is likely that oil and gas development will continue to be promoted in the United States, information on the known locations of oil and gas reserves will help landowners know whether or not they are living in areas where oil or gas exploration and drilling may either begin to occur or intensify.

Known deposits of oil occur in more than 30 states, with the majority of current onshore oil production concentrated in Texas, Oklahoma, Louisiana, Wyoming, California, Kansas and New Mexico.[13] The majority of ***proved reserves*** of oil, however, have a slightly different geographic distribution. (The U.S. Department of Energy defines ***proved reserves*** as the volumes of oil or gas that geological and engineering data have demonstrated with reasonable certainty to be recoverable in the future, under existing economic and operating conditions.)[14] As seen in Figure i-2, Texas, Alaska, California, Louisiana, New Mexico and Oklahoma are the states with the largest on-shore proved reserves of oil.

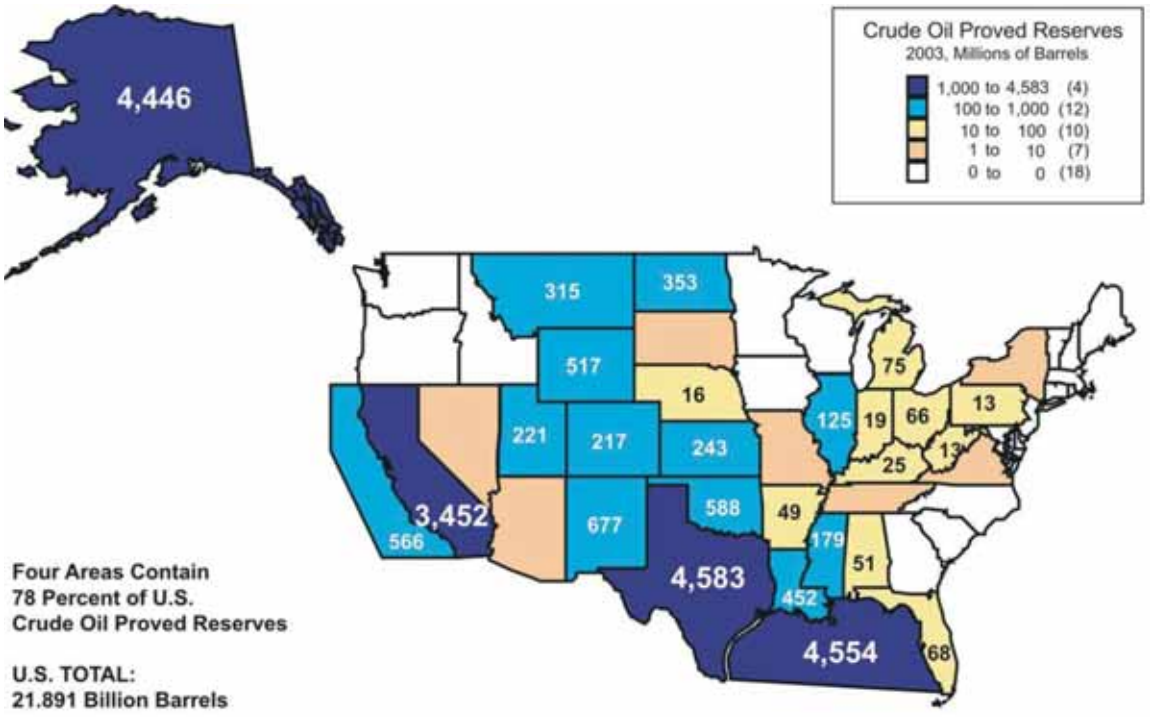


FIGURE i-2. 2003 U.S. CRUDE OIL PROVED RESERVES.
Source: Energy Information Administration, U.S. Department of Energy. [15]

The geographic distribution of natural gas is similar to that of oil, as natural gas often occurs in association with oil deposits. In terms of current production, three States (Texas, Louisiana, and Oklahoma) produce more than half of the natural gas in this country. New Mexico, Wyoming, Colorado and Kansas are also major gas-producing states.[16]

Large deposits of natural gas exist in half of the 50 states, but the deposits in Alaska, Texas, Louisiana, New Mexico and Oklahoma make up approximately half of the known U.S. dry natural gas proved reserves. See Figure i-3. ***Dry natural gas*** is almost entirely methane, with few impurities or other hydrocarbons.

With the recent boom in extraction of natural gas from coal beds (i.e., coalbed methane development), landowners should also be aware of the areas where coalbed methane development may potentially occur. See Figures i-4 and i-5.

In most regions of the country where oil and gas reserves exist, the federal government has plans to ramp up oil and gas production. For example, in New Mexico's San Juan Basin there are currently 18,000 producing wells, but the federal Bureau of Land Management (BLM) is proposing an additional 12,500 new wells to be drilled in one portion of the basin alone.[17] In Wyoming and Montana, the BLM is proposing that 77,000 new wells be drilled in the Powder River Basin.[18]

If you live in these regions, or other regions of proved reserves, you may have a visit from an oil or gas company representative in your future.

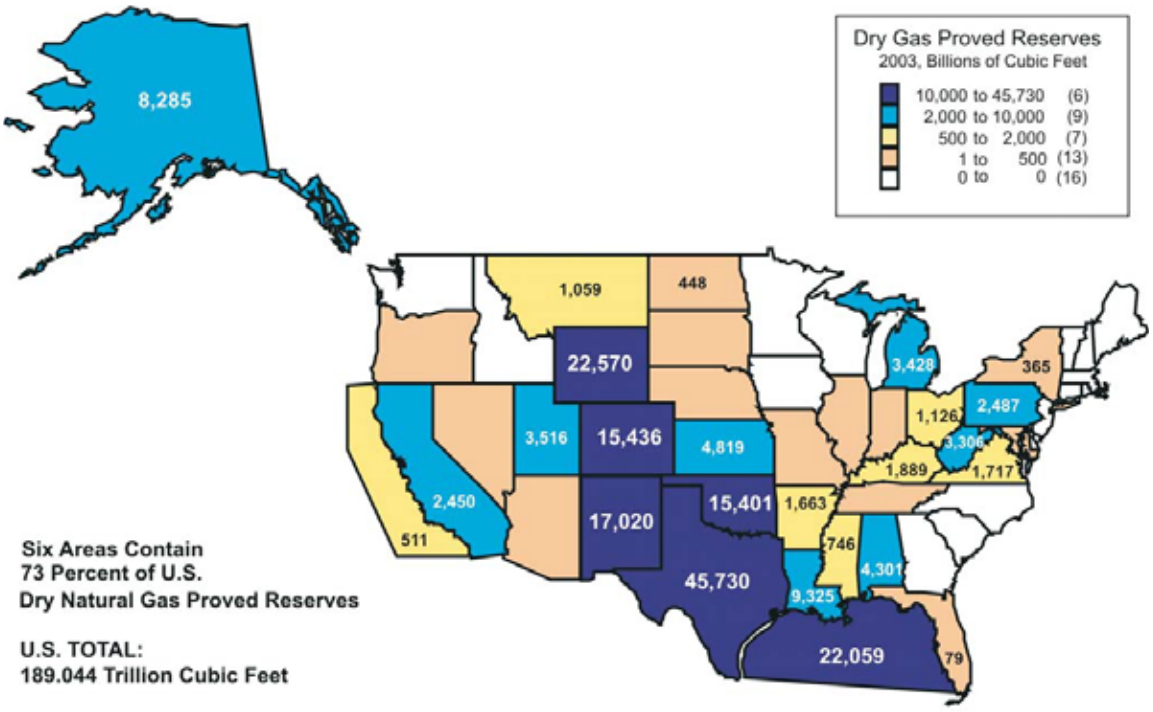


FIGURE i-3. 2003 U.S. DRY NATURAL GAS PROVED RESERVES.
Source: Energy Information Administration, U.S. Department of Energy. [19]

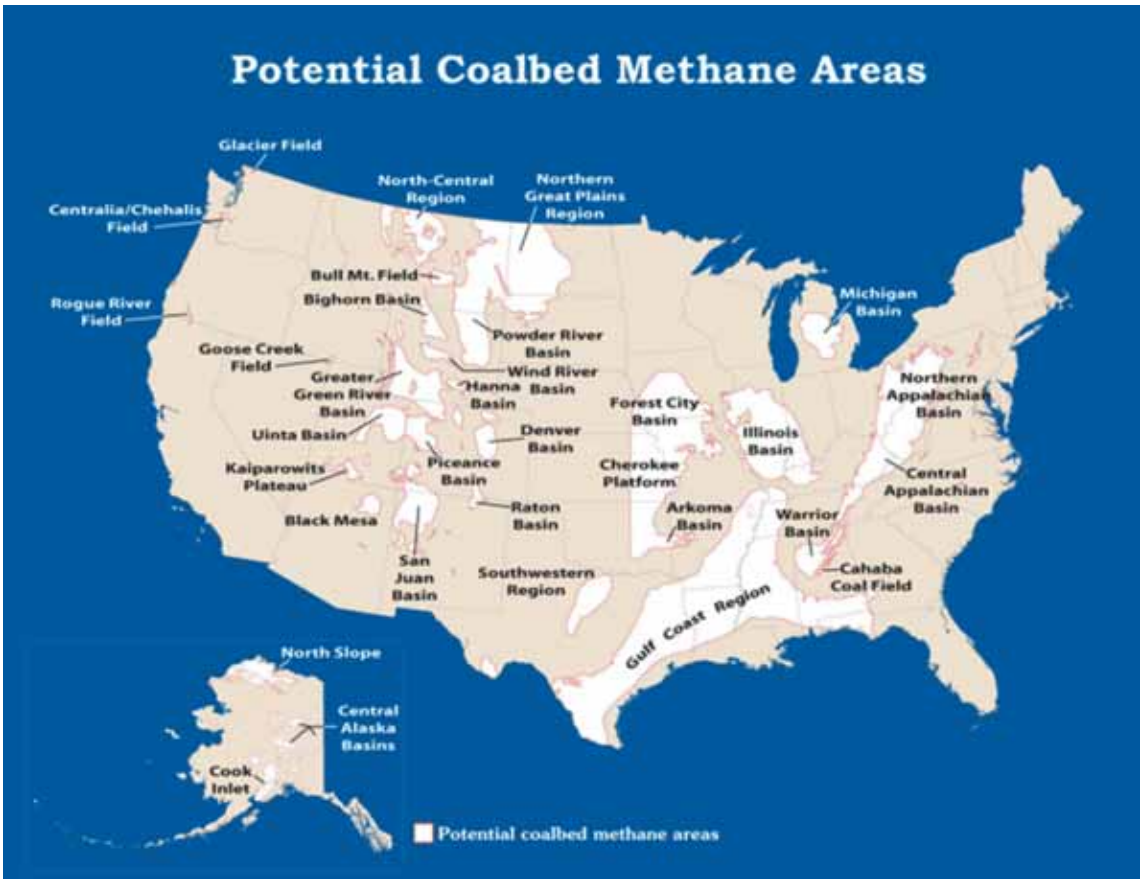
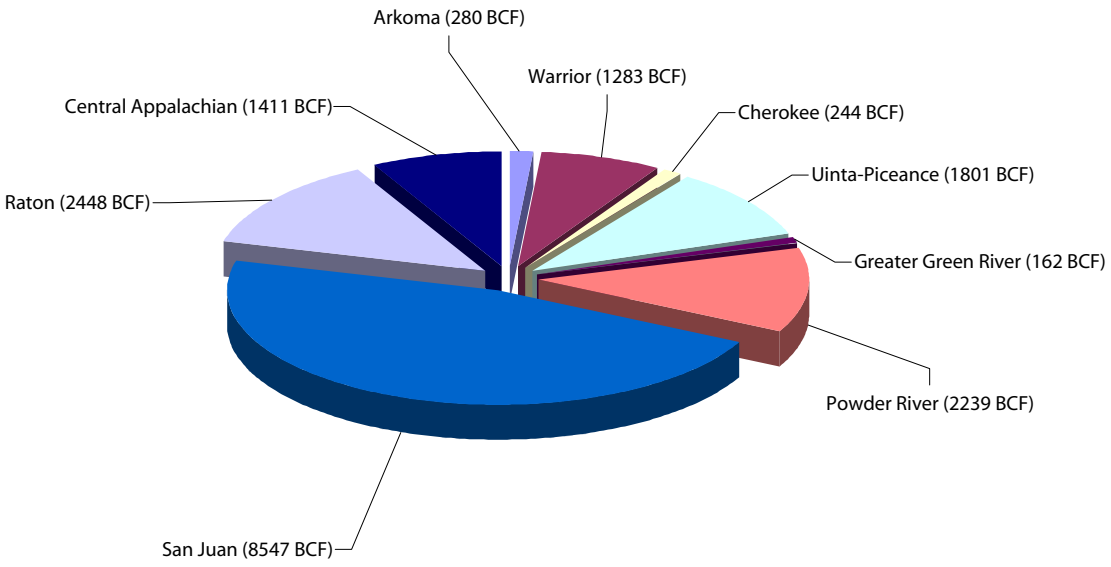


FIGURE i-4. POTENTIAL COALBED METHANE BASINS IN THE UNITED STATES.
Source: Interstate Oil and Gas Compact Commission.[20]



BCF - billion cubic feet of methane

FIGURE i-5. 2002 PROVED COALBED METHANE RESERVES.
Source: Energy Information Administration, U.S. Department of Energy.[21]

When natural gas is produced from oil wells it is called ***associated gas***, while natural gas and condensate wells produce ***nonassociated gas***. Approximately 35% of natural gas recovered in the U.S. is associated with oil recovery.[26]

Sour gas is a highly undesirable type of gas to have produced near your property.[27] It contains high concentrations of hydrogen sulfide (H_2S), which is toxic, potentially fatal at certain concentrations, and has a vile odor, much like rotten eggs. If H_2S dissolves in water, it forms a mild acid that can corrode pipes, valves, meters and other gas handling equipment. Sour gas is commonly found in deep, hot, high pressure natural gas deposits such as the foothills of the Rocky Mountains in Alberta and northeastern British Columbia. In the United States, some production of sour gas occurs in Michigan and Texas. H_2S may also be associated with coalbed methane extraction. In Colorado and New Mexico, there have been numerous complaints related to H_2S contamination of water wells and migration into homes following coalbed methane development.[28] (For more information on sour gas, see the section on Impacts Associated with Oil and Gas Operations.)

Not surprisingly, the oil and gas industry has focused most of its attention on the deposits that are the easiest to find and extract, e.g., those in relatively shallow, highly porous rock formations. These are known as ***conventional*** accumulations, and they tend to exist in localized deposits. ***Nonconventional*** (also known as ***unconventional***) oil and gas deposits tend to occur over large geographic areas rather than in localized accumulations.

Historically, it was not possible to develop nonconventional deposits since the technology to do so did not exist, or it was much too expensive to access and process the oil and gas. Over the past two decades, however, improvements in technology have occurred largely as a result of government subsidies. As a result, nonconventional gas deposits have become a noticeable source of total U.S. domestic production.

The U.S. Energy Information Administration (EIA) predicts that natural gas production from nonconventional sources (tight sands, shale, and coalbed methane) is going to increase more rapidly than conventional production in the U.S. The EIA predictions show nonconventional gas production from the lower 48 states growing from 6.6 trillion cubic feet (tcf) in 2003 (35% of natural gas production in lower 48) to 8.6 tcf in 2025 (44% of lower 48 natural gas production). Industry experts expect a much faster growth in nonconventional gas production, predicting that more than 10 tcf will be produced in 2005.[29]

This guide focuses primarily on the development of conventional oil and gas deposits. Recognizing, however, that development of nonconventional resources is on the rise, Chapter 1 includes a section on Development of Nonconventional Oil and Gas.

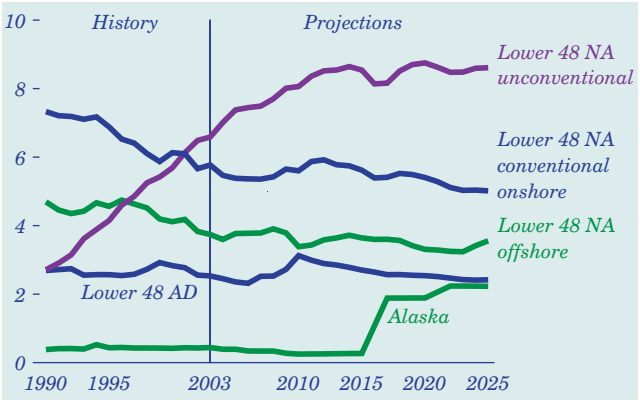


FIGURE I-1. NATURAL GAS PRODUCTION (CONVENTIONAL VS. UNCONVENTIONAL), 1990-2025. Note: AD stands for gas that is associated (dissolved) with crude oil production. Energy Information Administration.[29a]

- Camps for workers may be set up on a surface owner's property.
- If drilling does not produce a viable well, it is important to ensure that wells are properly plugged, and the site satisfactorily reclaimed.

FIGURE I-5. IMPROPERLY FENCED DRILLING MUD RESERVE PIT
Poses threat to wildlife and livestock.

Air Emissions

- Drilling operations produce air emissions from diesel engines and turbines that power the drilling equipment. The air pollutants from these devices may include: nitrogen oxides, particulates, volatile organic compounds, and carbon monoxide. Additionally, hydrogen sulfide may be released during the drilling process.[57]

Wastes

- When improperly drilled or cased, or when the casing has corroded, wells can serve as pathways for contamination of aquifers.
- There are numerous wastes that are commonly associated with drilling. These include: pipe dope, hydraulic fluids, used oils and oil filters, rigwash, spilled fuel, drill cuttings, drums and containers, spent and unused solvents, paint and paint wastes, sandblast media, scrap metal, solid waste, and garbage.
- According to the American Petroleum Institute, approximately 146 million barrels of drilling waste were produced in the U.S. 1995.[58] Drilling fluids and drill cuttings are the largest sources of drilling wastes.[59]

Drilling Fluid/Mud

- Drilling fluids or muds are made up of a base fluid (water, diesel or mineral oil, or a synthetic compound); weighting agents (most frequently barite is used); bentonite clay to help remove cuttings from the well and to form a filter cake on the walls of the hole; chrome lignosulfonates and lignites to keep the mud in a fluid state; and various additives that serve specific functions, such as biocides, diesel lubricants and chromate corrosion inhibitors.
- Whether the drilling muds are water-based, oil-based, or synthetic-based largely depends upon the drilling conditions encountered.
- Water-based muds (WBMs) are used most frequently. They are the least expensive of the major types of drilling fluids. This is mainly because water-based drilling wastes are less toxic than the alternatives, and often can be discharged on site. For difficult drilling situations, such as wells drilled in reactive shales, deep wells, and horizontal and extended-reach wells, WBMs do not offer consistently good drilling performance. For these types of drilling situations at onshore sites, the industry relies primarily on oil-based muds (OBMs).[60]
- Oil-based muds commonly are used while drilling deep wells, high-pressure shales, or during high-angle directional drilling because oil components (such as diesel or mineral oil) can avoid the pore-clogging that may occur with water-based mud. The downside of OBMs is the high cost, as well as the cost of disposing of the oil-contaminated drill cuttings, which contain hazardous chemicals, e.g., polycyclic aromatic hydrocarbons (PAHs), which may cause cancer, organ damage and reproductive effects.[61]
- Since 1990, the oil and gas industry has been developing a number of synthetic-based muds (SBMs), which are less toxic than oil-based muds. Instead of diesel or mineral oils, SBMs use internal olefins, esters, linear alpha-olefins, poly alpha-olefins, and linear paraffins. SBMs are free of PAHs, which decreases the toxicity of these muds.[62] Under certain circumstances, SBMs are used in place of OBMs or WBMs.
- Muds usually contain bentonite clay and other additives. Bentonite is a very expansive soil

FIGURE I-6. DEWATERED DRILLING MUD
Is often buried on-site.

material. This may create a site with the potential for great soil volume change, and possibly damage to surface structures. The common practice for disposing of drilling muds is to either bury the mud reserve pit, or discharge the mud to the surface. For landowners who may want to build on what was previously a drill site, it is worth noting that in order to be eligible for FHA mortgage insurance, all unstable and toxic materials must be removed and the pit must be filled with compacted selected materials.[63]

- Wastes that may be associated with drilling fluid include oil derivatives (e.g., PAHs), spilled chemicals, and empty containers.[64] Drilling muds that circulate through the well and return to the surface may contain dissolved and suspended contaminants including cadmium, arsenic, and metals such as mercury, copper and lead; hydrocarbons; hydrogen sulfide and natural gas,[65] as well as drilling mud additives, many of which contain potentially harmful chemicals (e.g., chromate, barite).

Drill Cuttings

- The main toxic agents in drilling cuttings are oil and oil products. These accumulate in the solid phase of drilling cuttings when crude oil and oil-based drilling fluids contact cuttings during the drilling process.[66] Rock cuttings may also contain arsenic or metals depending upon the geology.[67]
- Cuttings may be spilled around the well pad due to high pressures, dangerous working conditions, and lack of government oversight of drilling operations.[68]
- In West Virginia, the Department of Mines, Minerals and Energy (DMME) received complaints from residents about soap bubbles flowing from residential faucets. The DMME attributed this to the drilling process associated with coalbed methane well installation. Soaps and other substances are used to extract drilling cuttings from the borehole because the foam expands and rises. As it rises, it carries the cuttings to the surface. During drilling of the shallow portion of the well (and before the required groundwater casing is cemented in place) these drilling fluids may migrate from the borehole into the groundwater zone that supplies private wells. In the incidents of soap contamination in West Virginia, water was provided to the affected residents until the soaps were completely purged from the area surrounding their water well.[69]

Waste Disposal

- Onshore oil production operations produce quantities of cuttings and mud ranging from 60,000 to 300,000 gallons per day. Lined pits for disposal and storage are sometimes used, but mud, drill cuttings and other materials are often discharged into unlined pits, allowing potentially toxic substances to seep into the ground.[70] If improperly fenced, these pits can be a hazard for livestock and wildlife.
- While it is common for oil and gas companies to drain off fluids from drilling mud pits, it is very common for companies to simply bury the remaining solids in place or spread them on the lease site.[71]

Blowouts

- Well blowouts are rare, but can be extremely serious. Blowouts have been known to completely destroy rigs and kill nearby workers. They are most likely to occur during drilling, but can occur during any phase of well development including production (especially during well workover operations). If the pressure exerted by the geological formation is much higher than that exerted by the drilling fluid, then the gas, oil or other fluids in the well may rise uncontrollably to the surface. Equipment that is within the well may also be thrust to the surface. If there is a significant quantity of natural gas in the blowout materials, the fluid may ignite from an engine spark or other source of flame. Some blowouts are controlled in a matter of days, but others have taken months to cap and control.[72] The section on Impacts Associated with Oil and Gas Operations has more information on blowouts.

Surface and Other Disturbances—Tips for Landowners

- Revegetation of the pad surface and pipeline rights-of-way with native grasses is one of the best methods for controlling the spread of noxious weeds.[73]
- Lined pits or preferably tanks should be used to store spent mud, drill cuttings and solids, water used to wash any machinery, and surface runoff from the drilling area. These waste materials should be transported to a proper disposal site.
- Pitless or closed-loop drilling, which does not require pits for disposal of drilling wastes, is an option that reduces the potential for soil and water contamination. More details on pitless drilling are included in Alternative Technologies and Practices later in this chapter.
- Some traditional drilling fluid additives are toxic, but substitutes do exist: 1) replacement of chrome lignosulfonate dispersants with chrome-free lignosulfonates and polysaccharide polymers; 2) use of amines instead of pentachlorophenols and paraformaldehyde as biocides; 3) lubrication with mineral oil and lubra-beads instead of diesel oil.[74]
- Instead of disposing of drilling fluids in pits on-site, companies can use filtration processes to recondition the mud, so that it can be used for multiple wells before being discarded. Other possible uses for used drilling fluids include using it to plug unproductive wells or to spud in new wells.[75]

2. FIELD ORGANIZATION

This stage is primarily administrative, and usually involves government regulators. The purpose of field organization is to make the development of the oil or gas field more financially lucrative by creating a system for efficiently extracting the oil and gas from a particular region or field. Well spacing, pooling, and unitization are examples of organizational techniques that are applied during this stage.

It is during this stage of development that many citizens become involved because the impacts are broadly distributed over a geographic area (i.e., the oil or gas field), and governments often provide the public with an opportunity to comment on how the development might occur.

Well Spacing

Through well testing and geologic analyses it is possible to estimate the volume of oil and gas in a particular reservoir that can be drained by a single well, and then estimate how many wells will be needed to drain all of the oil or gas from the reservoir. Using these types of calculations, state governments determine how close together the wells need to be located (i.e., the well density) to most efficiently and economically drain the reservoir. The state agencies then define the number of wells that can be drilled in a specified surface area (usually per acre). The area allocated by the state for the drilling of an oil or gas well is sometimes referred to as the ***drilling unit.***

Typically, states enact spacing laws on a state-wide basis. States may also adopt different rules for particular fields.

- For example, in Colorado an operator can generally drill one well per 40 acres per formation anywhere in the state, unless there is an existing field rule in place, like the Ignacio-Blanco field rule in Southwestern Colorado. As of May, 2005, the Ignacio-Blanco field rule allows only one well to be drilled into the Fruitland Formation per every 160 acres.

Spacing rules apply to geological formations. That means if there are two or more formations that produce gas or oil in an area, then it is possible to end up with many more wells.

- For instance, in Southeast Colorado there are two major producing formations for coalbed methane: the Vermejo and Raton formations. In that region, an operator is allowed to drill

two wells per 40 acres – one well to access the methane in the Vermejo formation, and one to access methane in the Raton formation. In that situation, however, the wells must be located on the same pad unless the operator gets a variance or exception to the rule.

Spacing requirements vary drastically from state to state. For example, in California, wells can be spaced as closely as one well per acre; while in Florida, gas wells are spaced at one well per 640 acres.[76] Shallow wells are usually spaced more closely together than deep wells. For more information on spacing requirements, the Interstate Oil and Gas Compact Commission has produced a summary of the various spacing requirements on a state-by-state basis.[77]

Downspacing and Public Health and Safety Concerns

In the 30,000-acre Jonah conventional natural gas field in Wyoming, industry hopes to use 20-acre well spacing (32 well pads per section of land) instead of the current 40-acre spacing. The industry proposal would increase six-fold the number of permitted natural gas wells in the Jonah Field (from about 500 to more than 3,000). If this were to occur, it is likely that air quality for the entire area would fail both national and Wyoming ambient air-quality standards. Consequently, in order to protect public health and safety, federal Bureau of Land Management officials have been discussing closing all public roads into the Jonah Field and forbidding any hunting or discharge of firearms in the 30,000-acre area.

Photo at right shows Jonah Field with 40-acre spacing of gas wells.

Adapted from: Taylor, Meredith. Fall, 2003. "Industry Stakes its Claim to the Upper Green's Public Lands,"[78] Photo credit: Image by SkyTruth for the Upper Green River Valley Coalition.

Well Spacing—Tips for Landowners

- Landowners should be aware that it is not uncommon for well spacing densities to change over time. While the state sets the initial well density requirements for an area, it is common for companies to later request that the wells be more closely spaced together. When states increase the number of wells that can be located in an area, it is referred to as ***infilling*** or ***downspacing***. Landowners who buy land thinking that there will not be oil and gas development on their property (based on current well density regulations) may be shocked to find that a few years after buying property the spacing regulations have changed, and that there are wells proposed on their land. See the story "County officials say residents ignored," in Chapter IV for an example of downspacing.
- Additionally, companies are sometimes exempted from the spacing requirements. A state's spacing regulations usually mention the conditions under which a company may be exempted from the spacing rules.
- Within the drilling unit, some states may designate a ***drilling window***, which is an area within a drilling unit where wells may be drilled. The location of the drilling window is dependent on a number of factors. In many states, wells cannot be drilled within a certain distance of homes. So, if there are a number of homes within a drilling unit, there may be a limited number of areas that can be used for drilling. In many states, however, it is not uncommon for com-

panies to apply for waivers, which allow them to drill outside the drilling window. Sometimes the waiver requires that if drilling occurs at a surface location outside the drilling window, the company must still hit the targeted drilling window at a certain depth (e.g., by using directional or horizontal drilling techniques).

Mineral Pooling

Often, mineral leases cover much smaller areas than the drilling units designated by the state. If this is the case, a company may pool two or more leases to create a tract that is sufficient in size to form a drilling unit for a single well.

- For example, in Colorado, an operator needs 40 acres to drill a well (unless there is a field-wide spacing rule in place). To obtain the 40 acres, the operator may have to lease minerals from 4 contiguous mineral owners that each own 10 acres. In addition to acquiring a minimum of 40 acres, those 40 acres may have to be located in a particular area. Typically, the 40 acres represent a quarter-quarter section of land (to ensure that drilling occurs in a uniform pattern of 4 wells per quarter section or 16 wells per section).

When mineral leases are pooled into a drilling unit, the mineral owners share proportionately in the proceeds from oil and gas production. For instance if you own 10 acres and are in a 40 acre unit, your income will be figured as 1/4 of the unit's production multiplied by your royalty interest.

Before a company can develop on a pooled unit, approval must be obtained from state agencies. It is sometimes the case that not all mineral owners within a drilling unit want to pool their minerals to allow for oil and gas extraction. For example, they may want to wait until gas prices are higher before they develop their minerals, or wait until technologies can be developed that cause less impact on the surface property. Unfortunately, for mineral owners who want to resist development of oil and gas, many states have what are known as ***force pooling*** laws. These laws allow mineral properties to be pooled into a drilling unit and developed without the consent of all of the mineral owners.

Force pooling laws can be of assistance to mineral owners who are concerned that their oil and gas resources are being removed without any compensation. When companies drill for oil or gas on a particular property, they will usually drain the resources that are located adjacent to that property. If mineral owners suspect that a well on a neighboring property is draining the oil or gas on their property, they can go to the state agencies (usually oil and gas boards or commissions) and request that the company be forced to pool their minerals with their neighbor's minerals, thereby allowing them their share of the profits.

Mineral Pooling—Tips for Mineral Owners

Participate in pooling hearings. When a pooling application is filed by a company, a hearing is held by the state to determine whether the pooled unit complies with the pertinent laws. These are the hearings that mineral and surface owners should attend if they want to protest the pooling terms. If mineral owners do nothing, they will be deemed to have accepted the terms approved in the hearing.[79]

In many states, these hearings are not held in the mineral owner's community, but rather, are held in a larger city (often the state capital), which does not make it easy for mineral owners to participate. In Michigan, a bill was passed in 1998 that helped to lessen the burden on mineral owners who were being force pooled by energy companies. This law moved the administrative hearings from the larger city to a community in the mineral owners' region.[80]

If mineral owners have not yet leased their mineral rights, and they are approached by a company about leasing, they are usually presented with three options.

1. Negotiate and sign a lease and take the offered bonus and royalty interest.
2. Decide to not sign and likely be force pooled under terms established by the state.
3. Elect to participate in the well and pay their proportionate share of the drilling and completion costs in order to receive their pro rata payout as a working interest owner.

It is important to look into the pooling laws in the state where your property is located, or talk with a lawyer, in order to evaluate which of these options works best for you.

For more resources on force pooling, see references to East of Huajatolla Citizens Alliance information sheets in Chapter V. And for landowner experiences with force pooling, refer to Chapter IV stories: "Threats and Intimidation—This is Called Negotiation? Force Pooling an Affront"; "State Could Force Property Owners to Allow Drilling"; and Terry Fitzgerald's story.

Unitization

Unitization is the process of bringing together a group of drilling units (see pooling above) to form a large operating area. Typically, there are several operators in the operating area. Unitization takes place through an order from a state agency, and participation by operators may occur either voluntarily or involuntarily. Unitization orders may specify things such as well spacing or extraction rates in order ensure that all operators are working together to efficiently and effectively remove the oil or gas from the operating area. Unitization often occurs when an older field's production has begun to decline and it is necessary to utilize secondary recovery practices such as water or CO_2 flooding techniques to stimulate more production. As a result of a compulsory unitization statute for oil and gas reservoirs, Louisiana's oil and gas wells are, on average, one-third more productive than those in Texas, which does not require unitization.[81]

For more information on spacing, pooling and unitization (including federal units), visit the OGAP website (www.ogap.org).

3. PRODUCTION

The first step in production is to complete the well and start the well fluids flowing to the surface. Stimulation techniques may be used to enhance the flow of fluids during well completion. Once the fluid begins flowing, it must be separated into its components of oil, gas, and water. Finally, the oil and gas are treated, measured, and tested before being transported to the refinery. In addition to extracting and transporting the oil and gas, other tasks carried out during the production stage include: production enhancement, which uses techniques similar to those used to stimulate wells; well servicing, which includes routine maintenance operations such replacing worn or malfunctioning equipment; and well workover, which is more extensive equipment repair.

Well Completion

To begin completing a well, casing material (usually steel pipe) is inserted into the well bore. As with the casing used during the drilling stage, the casing material is supposed to prevent the oil or gas from contaminating groundwater, and stop the walls of the hole from collapsing. Cement is pumped down the casing to fill the space between the casing and the walls of the drilled hole. This is done to protect the casing and to further decrease movement of oil, gas or other fluids into ground water or rock formations.

When cementing of the casing is completed, the drilling rig and other associated equipment are removed from the site, and a smaller rig (a workover or completion rig) is moved over the well bore to finish the well completion. This rig is used to puncture or perforate the casing at specific locations where the casing comes in contact with the formations that contain oil or gas. The oil and gas can then enter the well through these perforations.

Next, tubing, which will carry the oil or gas to the surface, is threaded into the casing. At the surface, a well head (sometimes referred to as a Christmas tree) is installed, which has valves that control the flow of oil or gas from the well. The valves connect the well to equipment that will separate the oil, gas and water, and remove impurities. Finally, a pipeline connection or storage tank is connected to the well to allow for transport or storage of the product. In the case of natural gas, which cannot be stored easily, a pipeline connection is necessary before the well can be placed into production.

If there is not enough pressure in the reservoir to force the oil, gas or produced water to flow naturally to the surface, pumping is necessary.[82] Pumping equipment is installed at the lower end of the tubing. There are many different types of pumps that can be used: beam pumps; gas lift: piston pumps; submersible pumps; jet pumps and pneumatic pumps. The power to operate these pumps may be supplied by a gas or diesel engine or an electrical motor.

A number of pits may be constructed at this stage. These may include a skimming pit, which reclaims residual oil removed with produced water; a sediment pit, which stores solids that have settled out in storage tanks; or a percolation or evaporation pit, to dispose of produced water.[83]

Stimulation

Often an oil- or gas-bearing formation may contain large quantities of oil or gas, but have a poor flow rate due to low permeability, or from damage or clogging of the formation during drilling.[84] This is particularly true for tight sands, oil shales and coalbed methane, discussed later in this chapter. Stimulation techniques may be used prior to production, or during maintenance operations that take place after the well has been put into production. In later years, when the flow of oil or gas from a well begins to decline, stimulation techniques, as well as other enhancement techniques, may be used to encourage oil or gas to flow to those wells. Some of the more common stimulation techniques include: hydraulic fracturing; acidizing; and cavitation, which will be described in the section on coalbed methane.

Hydraulic fracturing (also known as fracing, which rhymes with cracking) is a technique used to create fractures that extend from the well bore into rock or coal formations. These fractures allow the oil or gas to travel more easily from the rock pores, where the oil or gas is trapped, to the production well.[85] Typically, in order to create fractures a mixture of water, proppants (sand or ceramic beads) and chemicals is pumped into the rock or coal formation. Eventually, the formation will not be able to absorb the fluid as quickly as it is being injected. At this point, the pressure created causes the formation to crack or fracture. The fractures are held open by the proppants, and the oil or gas is then able to flow through the fractures to the well.[86] Some of the fracturing fluids are pumped out of the well during the process of extracting oil, gas and any produced water, but studies have shown that anywhere from 20-40% of fracing fluids may remain underground.[87]

FIGURE I-7. CHRISTMAS TREE
The wellhead of a gas well. The first step as natural gas leaves the ground. Photo by OGAP.

FIGURE I-8. MUD RESERVE PIT
Torn liners can lead to groundwater contamination.

FIGURE I-9. WASTE PIT
Waste pits for fluids and sediments associated with gas processing. These can contain water, sand, hydrocarbons, glycol and other chemicals.

Acidizing involves pumping acid (usually hydrochloric acid), into the formation. The acid dissolves some of the rock material so that the rock pores open and fluid flows more quickly into the well. Fracing and acidizing are sometimes performed simultaneously, in an acid fracture treatment.[88]

Stimulation—Issues and Impacts

Potential Groundwater Contamination—Coalbed fracture treatments use anywhere from 50,000 to 350,000 gallons of various stimulation and fracturing fluids, and from 75,000 to 320,000 pounds of proppant during the hydraulic fracturing of a single well.[89] Many fracturing fluids contain chemicals that can be toxic to humans and wildlife, and chemicals that are known to cause cancer. These include potentially toxic substances such as diesel fuel, which contains benzene, ethylbenzene, toluene, xylene, naphthalene and other chemicals; polycyclic aromatic hydrocarbons; methanol; formaldehyde; ethylene glycol; glycol ethers; hydrochloric acid; and sodium hydroxide.[90] Very small quantities of chemicals such as benzene, which causes cancer, are capable of contaminating millions of gallons of water.

FIGURE I-10. FRAC PIT
Unlined pits may allow toxic fracing fluids to seep into soil and contaminate groundwater.

As mentioned previously, hydraulic fracturing is used in many coalbed methane (CBM) production areas. Some coal beds contain groundwater of high enough quality to be considered ***underground sources of drinking water*** (USDWs). According to the U.S. Environmental Protection Agency (EPA) ten out of eleven CBM basins in the U.S. are located, at least in part, within USDWs. Furthermore, EPA has determined that in some cases, hydraulic fracturing chemicals are injected directly into USDWs during the course of normal fracturing operations.[91]

Calculations performed by EPA show that at least nine hydraulic fracturing chemicals may be injected into or close to USDWs at concentrations that pose a threat to human health. These chemicals may be injected at concentrations that are anywhere from 4 to almost 13,000 times the acceptable concentration in drinking water.[92] (See Peggy Hocutt's letter and Laura Amos' story in Chapter IV, to read landowner stories about how hydraulic fracturing of coalbeds and other geological formations has affected drinking water.)

Not only does the injection of these chemicals pose a short-term threat to drinking water quality, it is quite possible that there could be long-term negative consequences for USDWs from these fracturing fluids. According to the EPA study, and studies conducted by the oil and gas industry,[93] between 20 and 40% of the fracturing fluids may remain in the formation, which means the fluids could continue to be a source of groundwater contamination for years to come.

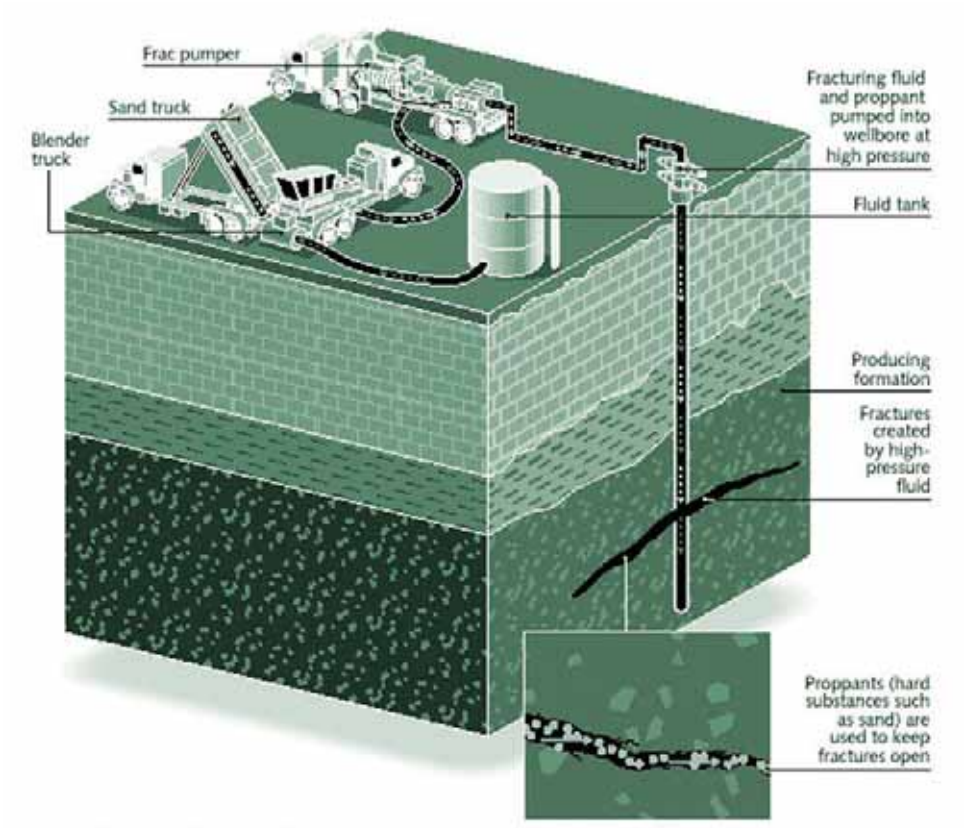
The potential long-term consequences of dewatering and hydraulic fracturing on water resources have been summed up by professional hydrogeologist who spent 32 years with the U.S. Geological Survey:

> *At greatest risk of contamination are the coalbed aquifers currently used as sources of drinking water. For example, in the Powder River Basin (PRB) the coalbeds are the best aquifers. CBM production in the PRB will destroy most of these water wells; BLM predicts drawdowns...that will render the water wells in the coal unusable because the water levels will drop 600 to 800 feet. The CBM production in the PRB is predicted to be largely over by the year 2020. By the year 2060 water levels in the coalbeds are predicted to have recovered to within 95% of their current levels; the coalbeds will again become useful aquifers. However, contamination associated with hydrofracturing in the basin could threaten the usefulness of the aquifers for future use.*[94]

One potentially frustrating issue for surface owners is that it may not be easy to find out what chemicals are being used during the hydraulic fracturing operations in your neighborhood. According to the Natural Resources Defense Council, attempts by various environmental and ranching advocacy organizations to obtain chemical compositions of hydraulic fracturing fluids have not been successful because oil and gas companies refuse to reveal this "proprietary information."[95]

As mentioned above, anywhere from 20-40% of fracing fluids remain in the ground. Some fracturing gels remain stranded in the formation, even when companies have tried to flush out the gels using water and strong acids.[96] Also, studies show that gelling agents in hydraulic fracturing fluids decrease the permeability of coals, which is the opposite of what hydraulic fracturing is supposed to do (i.e., increase the permeability of the coal formations). Other similar, unwanted side effects from water- and chemical-based fracturing include: solids plugging up the cracks; water retention in the formation; and chemical reactions between the formation minerals and stimulation fluids. All of these cause a reduction in the permeability in the geological formations.[97]

From a public health perspective, if hydraulic fracturing stimulation takes place, the best option is to fracture formations using sand and water without any additives, or sand and water with non-toxic additives. Non-toxic additives are being used by the offshore oil and gas industry, which has had to develop fracturing fluids that are non-toxic to marine organisms.[98]



High-pressure fluid creates cracks extending 300 metres (990 feet) or more into the producing formation. Sand props open the cracks, which are typically five to ten metres high but only two to six millimetres wide (0.078 to 0.236 inches).

FIGURE I-11. DIAGRAM OF HYDRAULIC FRACTURING OPERATION.
Source: Petroleum Communication Foundation. (Canadian Centre for Energy Information). 1999.[99]

It is common to use diesel in hydraulic fracturing fluids. This should be avoided, since diesel contains the carcinogen benzene, as well as other harmful chemicals such as naphthalene, toluene, ethylbenzene and xylene. According to the company Halliburton, "Diesel does not enhance the efficiency of the fracturing fluid; it is merely a component of the delivery system."[100] It is technologically feasible to replace diesel with non-toxic "delivery systems," such as plain water. According to the EPA, "Water-based alternatives exist and from an environmental perspective, these water-based products are preferable."[101]

Stimulation—Tip for Landowners

The law requires that all employees have access to a Material Safety Data Sheet (MSDS), which contains information on health hazards, chemical ingredients, physical characteristics, control measures, and special handling procedures for all hazardous substances in the work area. The MSDSs are produced and distributed by the chemical manufacturers and distributors. It should be noted that MSDSs may not list all of the chemicals or chemical constituents being used (if they are trade secrets).[102] Landowners may be able to obtain copies of MSDSs from company employees, the chemical manufacturers, or possibly from state agency representatives.

For more information on impacts associated with hydraulic fracturing, and alternative fracturing techniques, please visit the Oil and Gas Accountability web site: http://www.ogap.org .

Well Testing

After the well has been drilled, and before production begins, the reservoir pressure is tested. Prior to testing, however, large volumes of debris, fluids and gases must be cleaned out of the well bore. For example, any fluid, rock debris and sand remaining in the well bore and surrounding reservoir from stimulation activities (e.g., cavitation or hydraulic fracturing) has to be cleaned out. The conventional method for doing this is to pump air down the well bore to lift the sand and fracturing fluid up and out.[103] These wastes are usually dumped into earthen pits.

Natural gas is mixed in with the air, sand and liquids exiting the well bore. These gases are either "blown off" (i.e., vented to the atmosphere) or "burned off" (i.e., flared).

During the well test, the gas in a newly drilled well is allowed to flow freely for a number of days while the rate-of-flow and pressure of the gas in the reservoir are measured. According to the Pembina Institute for Appropriate Development, "a company can normally get enough data in one to three days, [therefore] well testing should be minimized and not exceed three days, especially when there is flaring or direct venting to the atmosphere."[104]

Well Testing—Tips for Landowners

- To minimize potential environmental impacts from the storage of solid and liquid wastes that flow from the well, "flowback units" rather than earthen pits should be used. Also, "flareless completions" or "green completion" techniques can be used to minimize the air pollution from the venting or flaring of natural gas during the well clean-up and testing phases.
- For more information on both of these technologies, see the section on Alternative Technologies and Practices, later in this chapter.

Oil and Gas Treatment and Conditioning

The fluids that flow or are pumped to the surface from conventional oil or gas wells include a mixture of oil, water, various gases and dissolved and suspended solids.[105] Before oil and natural gas can be marketed, the fluids must go through a ***treatment*** process to separate out water and remove dangerous gases and other impurities. Some of the treatment can occur at the well site (***field processing***). After initial treatment, however, the crude oil or natural gas is sent through a pipeline to a centralized processing facility such as an oil battery or a gas plant.

Gathering is the movement of bulk oil or gas from a production well to the treatment facility.

Below is a general overview of some of the processes involved in preparing the oil and gas for sale.

If crude oil is being recovered: Some separation of associated natural gas from the raw crude oil may occur at the wellhead. The most basic type of separator is known as a conventional separator. It consists of a simple closed tank, where the force of gravity serves to separate the heavier liquids like oil, and the lighter gases, like natural gas. The natural gas may be captured and sold, but often it is simply flared or vented to the atmosphere. Flowlines or gathering lines move the raw crude oil to an oil battery, for additional conditioning before sending the oil to a refinery. At the oil battery, the fluids pass through a production separator, which separates gases from the oil and water. The oil and water then go to a heater treater, where the oil is separated from the water and any solids that are present. The crude oil is at least 98% free of solids after it passes through this treatment.[106] The oil is then piped to a storage facility, where it remains until it is transported offsite by either trucks or by pipeline.

If a gas pipeline or gas transportation vehicles are present, the gases may be transported to a gas plant for processing into products such as methane, ethane, propane, and butane. Alternatively, the gases may be treated as a waste product, and be vented or flared.[107] The water and solids removed may be piped to a pit, a tank, or into a flowline leading to an underground disposal well.[108]

If natural gas is being recovered: Natural gas conditioning methods will be used to remove impurities from the gas so that it meets the quality required to be accepted by gas transportation systems. This is not always necessary, as some natural gas is pure enough to pass directly into the pipeline. Often, the most significant impurity is hydrogen sulfide (H_2S). Other impurities that may have to be removed include: water vapor, natural gas liquids, sand, nitrogen, and aromatic compounds such as benzene, toluene, ethylbenzene, and xylene.

Sweetening removes H_2S from the gas. The most common method of sweetening involves exposing the gas to an amine solution, which reacts with H_2S and separates it from the natural gas. The H_2S may be disposed of by flaring, incineration, or, if a market exists, by sending it to a sulfur-recovery facility. Another sweetening method uses an iron sponge, which reacts with H_2S to form iron sulfide. The iron sulfide is oxidized, then buried or incinerated.[109]

Dehydration removes water from the gas. The most common dehydration method used at the wellhead is glycol dehydration. In this method, gas is exposed to glycol, which absorbs the water. The water can be evaporated from the glycol so that the glycol can be reused. If the gas is sent to a natural gas plant for processing, solid desiccants are more commonly used to remove the water. Solid desiccants are crystals that have large surface areas that attract water molecules. Like glycol, these desiccants can be reused after water has been removed from them. If gas is extracted from deep, hot wells, simply cooling the gas to a low enough temperature can remove enough water to allow it to be transported.[110]

FIGURE I-12. NATURAL GAS DEHYDRATOR. Source of benzene.

FIGURE I-13. GAS PROCESSING PLANT. Source of NO_X.
Photo by Dan Randolph

FIGURE I-14. WELLHEAD COMPRESSORS
With and without sound abatement.

FIGURE I-15. COMPRESSOR STATION Source of NO_X.

FIGURE I-16. SEPARATOR AND STORAGE TANK FOR THE SEPARATED LIQUIDS

Natural gas coming directly from a well contains many natural gas liquids (NGLs), e.g., ethane, propane, butane, iso-butane, and natural gasoline. NGLs often have a higher value when sold as separate products, making it economical to remove them from the gas stream. The removal of natural gas liquids usually takes place in a centralized processing plant, and uses techniques similar to those used to dehydrate natural gas.[111]

In addition to the processes mentioned above, scrubbers and heaters are installed either at or near the wellhead. The scrubbers remove sand and other large-particle impurities. The heaters ensure that the temperature of the gas does not drop too low and form natural gas ***hydrates***, which are solid or semi-solid compounds that resemble ice crystals. Should these hydrates accumulate, they can impede the passage of natural gas through valves and gathering systems. In addition to wellhead heaters, small natural gas-fired heating units are typically installed along the gathering pipe wherever it is likely that hydrates may form.[112]

While some of the processing can be accomplished at or near the wellhead, the complete processing of natural gas takes place at a processing plant. The extracted natural gas is transported to these processing plants through a network of gathering pipelines, which are small-diameter, low pressure pipes. Some gathering systems are quite complex, consisting of thousands of miles of pipes that connect the processing plant to as many as 100 wells in the area. Should natural gas from a particular well have high sulfur and carbon dioxide contents, a specialized sour gas gathering pipe must be installed.

If the natural gas is being piped into larger pipelines, such as interstate pipelines, it must be compressed. To ensure that the natural gas flowing through any one pipeline remains pressurized, compressor stations are usually placed at 40-100-mile intervals along the pipeline. The natural gas enters the compressor station, where it is compressed by a gas-powered turbine, electric motor, or gas powered engine.

It is not uncommon for a certain amount of water and hydrocarbons to condense out of the gas stream while in transit. Thus, in addition to compressing natural gas, compressor stations often contain a liquid separator that has scrubbers and filters to remove liquids or other undesirable particles from the natural gas in the pipeline.

In some regions, such as the Appalachian states, natural gas might not require sweetening or extensive dehydration. Therefore, the gas may be piped directly from the wellhead to a main transmission line and, in some cases, directly to the customer. Compressor stations are located as needed along the pipelines that run between the wellhead and the main transmission line or the customer to maintain pressure in the lines.[113]

Compressors vary in size. Some compressors serve an individual well (wellhead compressors); others may serve a number of wells.

Plugging Wells

Before a company permanently leaves a well site, the well should be plugged or capped. The purpose of plugging is to prevent formation water from migrating into and contaminating aquifers or surface water.

All oil and gas producing states have specific regulations governing the plugging and abandonment of wells.[140] Generally, however, when a well is plugged there are a number of steps that are taken. First, the downhole equipment is removed and the perforated sections of the well bore are cleaned of scale and other wastes. Then, a minimum of three cement plugs, each between 100-200 feet in length, are placed into the well. Plugs should be placed: 1) into the perforated zones of the well, in order to prevent the inflow of fluid; 2) in the middle of the wellbore; and 3) within a couple hundred feet of the surface. Also, fluid with an appropriate density is placed between the cement plugs in order to maintain adequate pressure in the voids. Finally, the casing is cut off below the surface and capped with a steel plate welded to the casing. Surface reclamation should then be undertaken to restore natural soil consistency and plant cover.

FIGURE I-22. LEFT-RIGHT: PLUGGED WELL, NOT RECLAIMED. PLUGGED WELL, RECLAIMED. Photo at right used with permission of Vermejo Park Ranches.

Conversion to an Injection Well

If the well is located in an area where a company has many nearby wells still in production, the company may decide to convert the well to an injection well. If this occurs, the well will be regulated by the federal government as an *Underground Injection Control (UIC) Class II Injection well*, and will be subject to the federal *Safe Drinking Water Act and Underground Injection Control Regulations*.[141] Such a well can be used either for disposal of the produced water from other wells, or as part of oil enhancement operations in the production field.

Reclamation

Federal, state, and sometimes local rules and regulations describe how reclamation is supposed to occur when a site is abandoned. In some states, companies are required to provide financial assurance (e.g., bonds) to ensure that some funds are available to plug the wells and carry out the reclamation activities. Reclamation clauses in surface use agreements negotiated during the early stages also come into play at this stage.

Full reclamation should leave the land, air and water in the same condition as before oil and gas development was carried out. This is rarely the case. In many states, the unwillingness of companies to completely restore the original environment is accepted by state governments. Consequently, operators are required only to reclaim the land "as nearly as is possible" to it predevelopment condition.

Reclamation activities typically include: removal of all well-related equipment; re-grading of roads and other surfaces; removal of trash and debris; road closures; closure and remediation of pits and contaminated soils; and site revegetation. While this stage appears at the end of the development process, there are interim reclamation activities that can and often must be performed by operators at other stages of development. An example of interim or "annual" reclamation requirements can be found in the Vermejo Park Ranch Mineral Extraction Agreement in Chapter III.

SITE ABANDONMENT—ISSUES AND IMPACTS

Orphaned and Idle Wells

Surface owners should be aware that as a well becomes less and less profitable, some larger companies will sell these wells to smaller companies. Eventually, these wells may become the responsibility of the state, for example, if the smaller company does not have the funding to properly plug the wells and reclaim the site. If a company goes bankrupt and has no assets available to be used for proper well abandonment the well is considered to be an ***orphan well***.[142] The term orphan well also applies to the situation where the operator is unknown (e.g., in the case of wells drilled in the early part of the century).

Idle wells are wells that have ceased production but have not been plugged. In most states, wells require regulatory approval to be idle.[143] Most states allow some period of time of inactivity (usually six months to one year) without approval. When this initial time has elapsed, states may require a statement of the operator's intentions, which may include extensive geological and engineering information and a schedule for returning the well to production.[144] Also, a state may require periodical mechanical integrity tests to ensure that the well does not pose a threat to the environment.[145]

- In 1995, there were 134,000 wells in the U.S. that had stopped production yet had neither been plugged nor received government approval to be idle.[146]
- Orphan wells and idle wells that do not have government approval may present a groundwater contamination hazard. With many of these wells, the integrity of the casing is not known, and so there is a possibility that reservoir fluids or gases are contaminating or will contaminate nearby fresh water aquifers. Not all wells will cause contamination, but until the wells are evaluated, the risk that they pose is unknown.
- Most oil- and gas-producing states have a program for addressing orphan wells, which includes: prioritizing wells (because states do not have the funding to assess and properly plug all orphan wells); programs to plug dangerous orphan wells; and clean up of any contamination that may have already occurred.
- There is no guarantee that a state will have adequate funding to properly plug and reclaim orphan sites; leaving the surface owner with concerns about long-term risk of contamination. See "Bankrupt companies walk away from oil wells in Texas," Chapter II.
- One source of information that can help inform state regulators of the risks posed by orphan or idle wells comes from area of review (AOR) studies that are required for the approval of new underground injection wells. Under this requirement, the operator of the new well must study all active, idle and abandoned wells within an area (often a ¼ mile radius) to determine whether they pose a risk of contamination.[147]

Improperly Plugged and Abandoned Wells

- Improperly completed and abandoned wells may allow contaminants such as pesticides to be transferred from the surface to groundwater.

- Oil, gas, and salt water can leak from abandoned, unplugged, or improperly plugged oil and gas wells, especially older wells, and pollute groundwater resources,[148] or migrate to the surface. In Colorado, Oil and Gas Conservation Commission (COGCC) staff believe that increased methane concentrations found in water wells and buildings in some areas are partially due to old, improperly abandoned gas wells and older, deeper conventional gas wells that were not completely isolated. According to COGCC officials, a mitigation program focused on sealing old, improperly abandoned gas wells appears to have reduced methane concentrations in approximately 27 percent of the water wells sampled.[149]
- Additionally, improperly closed sites can be a safety hazard to humans and livestock.

Tips for Landowners

- Surface owners should work with state agencies to ensure that abandonment is satisfactorily completed.
- Owners may want to consider pressuring companies to use native species in their re-seeding projects, as these may be better able to combat noxious weed species.
- The company should have saved topsoil during the drilling and production stages for use in their reclamation efforts.
- Almost all states require companies to set aside funds to properly plug and abandon their wells. There is more information on financial assurance (or bonding) in Chapter II.

Ideally, full reclamation should leave vegetation, soil, air and water in the same condition that existed prior to oil and gas development. This rarely occurs.

Development of Nonconventional Gas and Oil

Forward-thinking landowners may want to investigate the possibility of unconventional reservoirs beneath their land, since it is likely that more non-conventional oil and gas deposits will be developed in the near future. This is certainly happening with the nonconventional coalbed methane gas deposits.

Nonconventional gas includes gas trapped in coal formations (***coalbed methane***); and low-permeability sandstone (***tight sands***) and shale formations (***gas shales***). These three types of natural gas are currently being exploited in some areas of the U.S., and will be discussed in this section. Other nonconventional natural gas resources, such as gas hydrates, are not likely to become commercially viable for decades to come.[150] Consequently, they will not be discussed in this guide.

Nonconventional oil deposits include ***heavy oils***, ***tar sands*** and ***oil shales***. As mentioned previously, petroleum is a broad term for hydrocarbons that includes gases, highly fluid "light" oils, viscous "heavy" oils, tars and bitumens. Today, light oils comprise approximately 95 % of petroleum production.[151] As will be discussed later in this section, when compared to conventional deposits and methods, the amount of work required to produce an equivalent amount of crude oil from tar sands or oil shales makes it cost prohibitive under most circumstances.[152]

COALBED METHANE (CBM)

As many landowners in Wyoming, Montana, Colorado, New Mexico and Alabama can attest, an increasingly significant source of natural gas is coalbed methane (see the Introduction chapter for a map of CBM producing areas). Two decades ago, coalbed methane was not a highly profitable source of natural gas. By the year 2004, however, CBM accounted for more than 8% of natural gas production in the U.S.[153]

According to the CBM Association of Alabama, 13% of the land in the lower 48 United States has some coal under it, and in all coal deposits methane is found as a byproduct of the coal formation process. Historically, this methane was considered a safety hazard in the coal mining process and was purposely vented to the atmosphere. Recently, however, companies have begun to capture the methane found in coal mines, as well as recover methane from coalbed deposits that are too deep to mine.[154]

Coal beds are an attractive prospect for development because of their ability to retain large amounts of gas—coal is able to store six to seven times more gas than an equivalent volume of rock common to conventional gas reservoirs.[155] On a daily basis, however, CBM wells typically do not produce as much gas as conventional wells.[156] In most regions of the U.S., coalbed methane wells produce between 100 and 500 thousand cubic feet (Mcf) per day, while the average conventional well in the lower 48 states produces approximately 1.7 million cubic feet (MMcf) per day.[157] There are, however, some extremely productive coalbed methane areas, such as the San Juan basin in Colorado and New Mexico, where some wells produce up to 3 MMcf of methane per day.[158]

The amount of methane in a coal deposit depends on the quality and depth of the deposit. In general, the higher the energy value of the coal[159] and the deeper the coal bed, the more methane in the deposit.[160]

Methane is loosely bound to coal—held in place by the water in the coal deposits. The water contributes pressure that keeps methane gas attached to the coal. In CBM development, water is removed from the coal bed (by pumping), which decreases the pressure on the gas and allows it to detach from the coal and flow up the well.

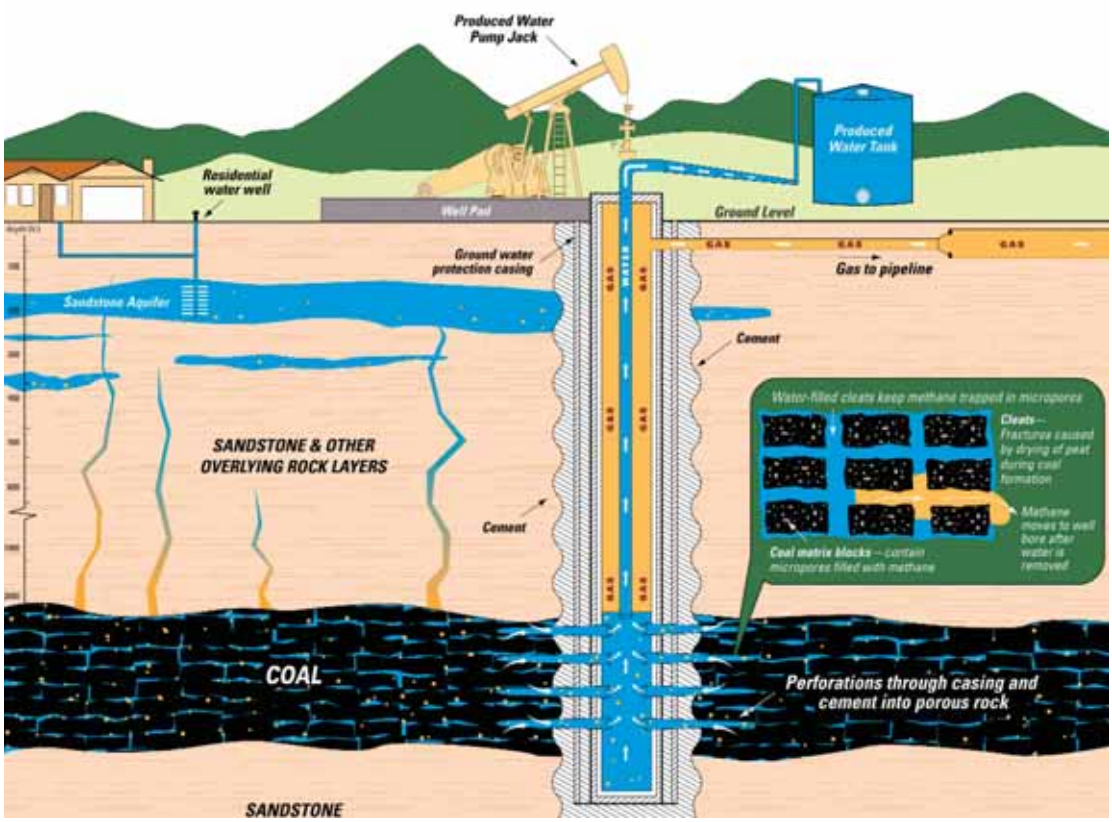


FIGURE I-24. TYPICAL COALBED METHANE WELL. Source: Ecos Consulting.

In the initial production stage of coalbed methane, the wells produce mostly water. Eventually, as the coal beds near the pumping well are dewatered, the volume of pumped water decreases and the production of gas increases.[161] Depending on the geological conditions, it may take several years to achieve full-scale gas production. Generally, the deeper the coal bed the less water present, and the sooner the well will begin to produce gas.

Water removed from coal beds is known as produced water. The amount of water produced from most CBM wells is relatively high compared to conventional gas wells because coal beds contain many fractures and pores that can contain and move large volumes of water.[162]

CBM wells are drilled with techniques similar to those used for conventional wells. In some regions where the coal beds are shallow, smaller, less expensive rigs, such as modified water-well drilling rigs, can be used to drill CBM wells, rather than the more expensive, specialized oil and gas drilling rigs.[163]

As with conventional gas wells, hydraulic fracturing is used as a primary means of stimulating gas flow in CBM wells.[164] Another gas stimulation technique, unique to CBM wells, is known as ***cavitation*** (also known as open-hole cavity completion).

Cavitation is a similar phenomenon to opening a shaken pop bottle, only on a much larger scale.[165] Water, and air or foam are pumped into the well to increase the pressure in the reservoir. Shortly thereafter, the pressure is suddenly released, and the well violently blows out, spewing gas, water, coal and rock fragments out of the well. This action is sometimes referred to as "surging," and it is accompanied by a jet engine-like noise, which can last up to 15 minutes.[166]

The coal fragments and gas that escape from the well are directed at an earthen berm, which is supposed to prevent the materials from entering the greater environment. The gas is burned or flared, and the coal fines and fluids initially collect in a pit at the base of the berm. Some loose rock and coal materials remain in the well. They are cleaned out by circulating water (and often a soap solution or surfactant) within the well and pumping the material into a pit. The coal refuse is then typically burned on-site in a pit, which is either referred to as a "burn pit" or "blooie pit." (See Figure I-25.)

The cavitation process is repeated several dozen times over a 2-week period.[167] This results in an enlargement of the initially drilled hole (well bore) by as much as 16 feet in diameter in the coal zone, as well as fractures that extend from the well bore.[168] If the cavitation fractures connect to natural fractures in the coal, they provide channels for gas to more easily flow to the well.

At the present time, cavitation is not widely practiced. The U.S. Department of Energy reported that in 2000, the only "cavity fairway" in the United States was located in the central San Juan Basin, in Colorado and New Mexico.[169]

FIGURE I-25. CAVITATION BURN PIT.

A decline in quality of life may result from: economic issues that arise from energy development (e.g., decline in property values; attorney fees related to negotiations with companies); noise; water well depletion or loss; degradation of water quality; land disturbance and soil erosion; vegetation die-off; the presence of industrial facilities (unsightly buildings and odors); damage to roads; and traffic congestion.

Several of these issues are addressed in more detail below.

The following information on housing, crime, roads, and dust emissions related to coalbed methane (CBM) development comes from a study conducted in Wyoming. As part of the Wyoming Energy Commission Community Outreach Program, the Commission contracted with a consultant, Pedersen Planning Consultants, to perform community assessments related to CBM development in six counties – Campbell, Sheridan, Johnson, Sweetwater, Converse and Carbon.[216] The information below reflects insights and recommendations from various community leaders.

Soil erosion can be unsightly; it can lead to excessive turbidity in streams; and the loose soils can create problems with dust and decrease visibility.

Housing

Since 1998, the coalbed methane boom in Campbell, Sheridan and Johnson counties has increased housing costs and decreased availability of rental apartments and homes to purchase. The lack of housing frustrates workers who are working 12-hour shifts, as they have little time to make an extensive search for housing. Increased housing costs have increased the overall cost of living for most households in Campbell County. Law enforcement representatives point out that these stresses have contributed to more petty theft, domestic violence, and other criminal behavior.

Crime

Campbell County has experienced an increase in larceny, destruction of private property, family violence, and child abuse since CBM development came to the county. The heavy amount of shift work has resulted in children being left at home unsupervised. Other crimes are attributed to alcohol and drug problems, which are linked, in part, to the increase in CBM development – as more people in the community earn more income, greater drug usage occurs. Ninety-nine percent of all crimes in Johnson County tie back to drug or alcohol abuse. Police from the City of Gillette report that methamphetamines are a growing community concern because of the addictiveness of these drugs. As more money is needed to sustain the drug habit, both sellers and users often commit crimes to obtain money. Drug users are also more likely to be involved in marital and child abuse.

In Sheridan County, there has been an increase in population of at least 300 people since 1998. Many of the new residents are CBM workers and their dependents. The county has experienced an increase in aggravated assaults from 40 in 1998 to 90 assaults in 2000. Burglary and larceny crimes also increased considerably during that period.

In both Sheridan and Campbell counties, the CBM development has affected the ability of the sheriff's department to hold on to their employees. The higher wages offered by CBM companies have enticed many experienced crime prevention workers to leave their jobs and join the CBM industry. It is also more difficult to attract new police recruits, as the higher wages again draw more young men and women to the industry jobs.

Safety

There are no local or state-wide safety standards being applied in the coal bed methane exploration and production areas of Wyoming. Most of the larger CBM companies, however, have adopted their own operational and safety standards, but subcontractors do not necessarily follow them (and companies do no monitor their subcontractors to ensure that they are following

the company's safety standards). In the aftermath of some industrial accidents, the Campbell County Fire Chief has witnessed CBM contractor crews that were somewhat drunk and/or unprepared to carry out work safely.

Roads

In Sheridan County, 50% of county roads have been impacted by CBM development, while in Campbell county more than 25% have been affected. Increased road usage by the CBM industry and new residents has reduced the facility life of the roads, and has increased the cost of road operations and maintenance. In Sheridan County, some impacts on county roads are being mitigated by CBM companies that sign road "user agreements" with the county (in which the companies agree to: repair road damages beyond normal wear and tear; restore roads to existing condition; and provide labor and materials for road repairs). Even with these agreements, however, Sheridan County estimates that $8.7 million will have to be spent on road improvements in the county and City of Gillette.

Dust

Another consequence of CBM development is significant dust emissions along county roads. Horses in some areas of Sheridan County have experienced chronic coughing from increased dust emissions. Some ranchers in Campbell County have found that cattle do not eat grass that is within 0.25 miles of both sides of some county roads. Some counties are applying magnesium chloride to suppress dust; others are using gravel, which is thought to be a more effective dust suppressant. Campbell County, which does not have its own gravel source, imports gravel for dust suppression at a cost of $6/ton.

Property Values

In some Wyoming counties, housing values, in general, have increased due to the recent boom in CBM development combined with an overall housing shortage in those counties.

A study conducted in La Plata County in Colorado, found that despite an overall increase in housing values between 1990 and 2000, the selling price for properties that had an oil or gas well on them was 22% less than a similar property without a well on site.[217]

Interestingly, the study found that if a property did not have a well, but was located within 550 feet of a property with an oil or gas well, that the non-well-bearing property increased in value. The authors suggested that this occurred because buyers assumed that there was a low likelihood of two wells being drilled right next to each other. This assumption may have disappointing results for those buyers, however, because state agencies can and do change well spacing requirements – especially as the oil or gas field ages – and wells may eventually have to be drilled in between existing wells in order to get more oil or gas out of the formation. (Read about well spacing in the section on Field Organization earlier in this chapter)

Noise

Many landowners choose to live in rural areas because they want to live a peaceful life. Oil and gas development, however, can greatly affect the peace and tranquility of rural areas, and can become a major annoyance to those living close to oil and gas facilities. This, in turn, may affect a person's health and quality of life. The following section provides an overview of noise issues for landowners dealing with oil and gas development. See Chapter V for additional resources related to noise.

Noise from oil and gas development comes from a number of sources: truck traffic, drilling and completion activities, well pumps and compressors.

In general, the volume of a sound is measured in decibels (dB). According to the World Health

Organization, outdoor sound that exceeds 55 dB begins to be a nuisance to people.[218] During the nighttime hours (10 p.m. to 7 a.m.), sound levels in rural or quiet suburban areas are often as low as 25 to 35 dBA,[219] while urban areas may be 80 dB or more.[220]

Oil and Gas Development Noise

In a La Plata County, Colorado study[221] noise levels were reported for a number of oil and gas activities and equipment:

- A typical compressor station: 50 dBA* at 375 feet from the property boundary (noise emitted 24-hours-a-day)
- Pumping units: 50 dBA at 325 feet from the well pad (noise emitted 24-hours-a-day)
- Fuel and water trucks: 88 dBA at 50 feet; 68 dBA at 500 feet
- Crane (used to hoist rigging equipment): 88 dBA at 50 feet; 68 dBA at 500 feet
- Concrete pump (used during drilling): 82 dBA at 50 feet; 62 dBA at 500 feet
- Average well construction site: 85 dBA at 50 feet; 65 dBA at 500 feet

*Often, equipment used to measure sound is designed to account for sensitivity of human hearing to various frequencies. This is known as A-weighted correction, and the measurement is an A-weighted decibel (dBA).[222]

How Sound Travels—Sound is caused by changes in air pressure. For example, when a mallet strikes a drum the drumhead begins to move back and forth (vibrate). As the drumhead moves down, air is pulled toward it, and as the head bounces back up it pushes air away. This creates changes in air pressure that move (or propagate) away from the drum, eventually striking our eardrum. These changes in pressure are known as sound waves.

There are a number of factors that affect the propagation of sound. The most important include: distance from source; obstacles such as barriers and buildings; atmospheric absorption; wind direction and speed; temperature and temperature gradient; humidity; precipitation; reflections; and ground absorption.[223]

Prolonged periods of noise exposure to 65 dBA can cause mental and bodily fatigue.

It is important to understand that noise does not always decrease as one moves away from a noise source. The above factors can work to increase or decrease noise levels. For example, at short distances (up to 160 feet) the wind has a minor influence on the measured sound level. At distances greater than 1,000 feet from a noise source, noise can become louder on the downwind side by as much as 20 dB, while on the upwind side levels can drop by 20 dB (depending on wind speed and distance).[224]

Other things to consider include the fact that while barriers may act to reduce high frequency sounds, low frequency sounds are difficult to reduce using obstacles or barriers. Additionally, while soft ground surfaces and the atmosphere are effective at absorbing mid-frequency and high frequency noise, these factors do not tend to reduce low frequency noise to the same degree. This means that as one moves away from the source, low frequencies often become much more prominent.[225]

What Makes Certain Sounds Annoying?—Whether a noise is objectionable will vary depending on its type (tonal, impulsive, etc.), the circumstances (e.g., does the noise occur in an area where there are already loud noises versus a quiet rural setting), and the sensitivity of the indi-

vidual who hears it. Certain noise characteristics can greatly increase the annoyance and the health impacts associated with a noise. These factors include: 1) tonality; 2) impulsiveness 3) fluctuation or intermittence and 4) presence of low frequencies.

When a noise contains sound that has distinct frequency components (tones), e.g., noise from fans, compressors, or saws, the noise is generally far more annoying than other types of noise. *Most energy industry facilities typically exhibit either a tonal or impulse/impact component.*[226] Impulsive noise comes from impacts or explosions, e.g., from a pile driver, or pieces of pipe hitting one another. The noise is brief and abrupt, and its startling effect causes greater annoyance than would be expected from a simple measurement of the sound decibel level. Fluctuating noises, as well, may be far more annoying than predicted by average sound levels.[227] Oil and gas pump jacks can create fluctuating and intermittent noises. Pump jacks may operate and automatically shut off for specific periods of time. When improperly maintained, pump jacks can develop intermittent rubbing noises or squeaking noises that occur at regular intervals. Regular variations in noise have been found to increase the annoying aspects of the noise.[228]

FIGURE I-28. NOISE EXAMPLES
Left to right: Pump jack noise is intermittent; compressor noise is constant and long-term; noise from drill rigs is short-term but very loud.

Some jurisdictions have developed noise regulations that penalize individuals or industries that generate tonal, impulsive or fluctuating noises. For example, if a noise has an obvious tonal content, a "penalty" or correction may be added to account for the additional annoyance.[229] Currently, the penalty for tones varies between 0 dB (no penalty) and 6 dB.[230] The penalty is added to the measured decibel level, and this combined decibel level is compared to the acceptable decibel standard.

- For example, if the noise from a compressor is measured as 49 dBA, but it is determined that the noise has tonal components, a penalty of 6 dBA would result in a noise level of 55 dBA. If the acceptable noise standard is 50 dBA, the noise from the compressor would be out of compliance.

Low Frequency Noise—Low frequency noise is experienced by some landowners who live near oil and gas facilities. Low frequency noise does not have a consistent definition, but it is commonly defined as noise that has a frequency between 20 and 100 - 150 Hz (in other words, sound waves are vibrating between 20 and 150 times per second).

Low frequency noise can be generated by numerous sources during oil and gas production.[231]

- Low frequency noise is produced by machinery, both rotational and reciprocating, and all forms of transport and turbulence. Typical sources include pumps, compressors, and fans.
- The firing rate of many diesel engines is usually below 100 Hz, so road traffic noise can be regarded as low frequency.

- Combustion turbines are capable of producing high levels of low frequency noise. This noise is generated by the exhaust gas.[232]
- Burners (and flares) can emit broadband low frequency flame roar.

Low frequency noise creates a potential for
. It is well established, however, that the annoyance due to a given noise source is perceived very differently from person to person. For many humans, their ears are not very sensitive to low levels of low frequency sound. At low frequencies, however, noise may not be perceived as sound but rather may be "felt" as a vibration or pressure sensation.[233]

For those who are sensitive to low frequency sound the effects can be dramatic.[234] Complainants often describe the noise as:

- Humming or rumbling
- Constant and unpleasant
- Pressure in ears
- Affects whole body
- Sounds like large, idling engine
- Coming from far away

Researchers have conducted field measurements and laboratory studies of people who have complained of low frequency noise in their homes. Studies have found that:[235]

- Problems tend to arise in quiet rural or suburban environments
- The noise is often close to inaudibility, and is heard by a minority of people
- The noise is typically audible indoors and not outdoors
- The noise is more audible at night than day
- The noise has a throbbing and rumbly characteristic
- The complainants have normal hearing

FIGURE I-29. VENTING OF GAS WELL CAN BE PIERCINGLY LOUD.

Despite the fact that the World Health Organization has stated that, "The evidence on low frequency noise is sufficiently strong to warrant immediate concern," few noise regulations in the United States address low frequency noise. Some counties in northern Michigan have developed ordinances that reference low frequency noise as a separate than other noise issues.[236] Most of the research and regulation related to low frequency noise has taken place in European countries and Japan. See Chapter V for resources related to Low Frequency Noise.

Health Effects of Noise

There are adverse physical and mental effects from noise. For example, prolonged periods of exposure to 65 dBA can cause mental and bodily fatigue. Furthermore, noise can affect the quantity and quality of sleep; cause permanent hearing damage; contribute to the development or aggravation of heart and circulatory diseases; and transform a person's initial annoyance into more extreme emotional responses and behavior.[237]

According to the World Health Organization:[238]

> Noise annoyance is a *global phenomenon. A definition of annoyance is "a feeling of displeasure associated with any agent or condition, known or believed by an individual or group to adversely affect them."*

> *. . .apart from "annoyance", people may feel a variety of negative emotions when exposed to community noise, and may report anger, disappointment, dissatisfaction, withdrawal, helplessness, depression, anxiety, distraction, agitation, or exhaustion.*
>
> *. . . Social and behavioural effects include changes in overt everyday behaviour patterns (e.g. closing windows, not using balconies, turning TV and radio to louder levels, writing petitions, complaining to authorities); adverse changes in social behaviour (e.g. aggression, unfriendliness, disengagement, non-participation); adverse changes in social indicators (e.g. residential mobility, hospital admissions, drug consumption, accident rates); and changes in mood (e.g. less happy, more depressed).*

The World Health Organization also reports that "a large proportion of low-frequency components in noise may increase considerably the adverse effects on health." In an epidemiological survey of sufferers from low frequency noise, the following health effects were documented:[239]

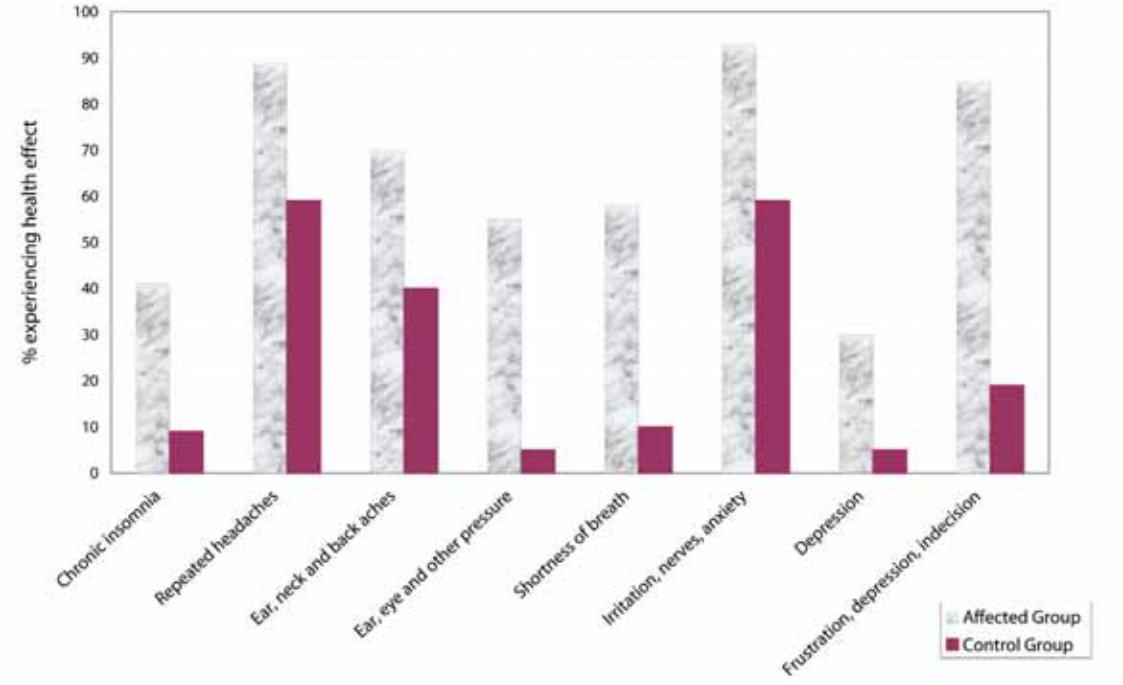


FIGURE I-30. HEALTH EFFECTS OF LOW FREQUENCY NOISE
Source: Mirowska, M. and Mroz, E. 2000.[240]

The above health effects were felt by people experiencing low frequency noise in their homes. The New Mexico Game and Fish states that even for human beings in a recreational setting, low frequency noise has been shown to cause stress reactions including raised blood pressure and increased muscle tension.[241]

Unfortunately, many of the health effects of noise due to oil and gas operations have not been scientifically documented. The lack of scientific study does not mean, however, that noise issues related to oil and gas are insignificant. The loud, continuous noise during the drilling phase; the loud short-term noises from flaring or hydraulic fracturing; the intermittent whine of poorly maintained pump jacks and other equipment; and the loud or low frequency noise from compressors are common complaints related to oil and gas development. Numerous citizens have reported disruption of sleep and increased anxiety caused by noise from oil and gas developments.[242]

To illustrate the frustration with noise generated by compressors, here is one landowner's experience:

> *Now comes the second phase. The dreadful noise generated by a nearby large compressor station. Noise that was so loud that our dog was too frightened to go outside to do his business without a lot of coaxing. Noise that sounds like a jet plane circling over your house for 24 hours a day. Noise that is constant. Noise that drives people to the breaking point. My neighbor called the sheriff, state officials and even the governor and was told nothing could be done about the noise. Like I said, the noise drives people to the breaking point, and my neighbor fired 17 rifle shots toward the station.*
>
> —Excerpted from CBM Destroys Retirement Dream.
> The full story from this landowner can be found in Chapter IV.[243]

For more landowner stories related to noise, see Chapter IV. See the section on Alternative Technologies and Practices later in the chapter for information on how to decrease noise levels.

CONTAMINANTS ASSOCIATED WITH THE OIL AND GAS INDUSTRY

The following table summarizes the types of wastes that are generated during the various stages of oil and gas development.

Of these wastes, there are some that pose more serious concerns for landowners than others. These include specific air emissions; hydrocarbon wastes; produced water; and naturally occurring radioactive materials (NORM). These are discussed in more detail on the following pages.

	Air Emissions	Waste Water	Residual Wastes	Oil and Gas Industry Contaminants That Are Hazardous to Human Health
Well Drilling and Completion	• fugitive natural gas • other volatile organic compounds (VOCs) • polyaromatic hydrocarbons (PAHs) • carbon dioxide • carbon monoxide • hydrogen sulfide • methane	• drilling muds • organic acids • alkalis • diesel oil • crankcase oils • acidic stimulation fluids (hydrochloric and hydrofluoric acids)	• drill cuttings (some oil-coated) • drilling mud solids • weighting agents • dispersants • corrosion inhibitors • surfactants • flocculating agents • paraffins	• arsenic • benzene • cadmium • chlorinated paraffin waxes • chromium • carbon monoxide • 1,2-dichloroethane • dichloromethane • ethylbenzene • hexachlorobenzene • hydrogen sulfide • lead • nickel • polycyclic aromatic hydrocarbons (PAHs) • polychlorinated dibenzodioxins • polychlorinated dibenzofurans • radon and radium • toluene • trichloroethylene • uranium • volatile organic compounds • xylene
Production	• fugitive natural gas • other VOCs • PAHs • carbon dioxide • carbon monoxide • hydrogen sulfide • methane migration • fugitive BTEX (benzene, toluene, ethylbenzene, and xylene) from natural gas conditioning	• produced water possibly containing: arsenic, sulfur, metals (e.g., lead, nickel, zinc, antimony, barium), radionuclides (uranium, radon, radium), dissolved solids, and high levels of salts (e.g., sodium, chloride, potassium, magnesium) • produced water also may contain additives such as biocides, lubricants and corrosion inhibitors • wastewater containing glycol, amines, salts, untreatable emulsions, and hydrocarbons (e.g., benzene, toluene and naphthalene)	• produced sand • elemental sulfur • spent catalysts • separator sludge • tank bottoms • used filters • sanitary wastes	
Maintenance	• volatile cleaning agents • paints • other VOCs • hydrochloric acid gas	• completion fluid • wastewater containing well-cleaning solvents (detergents and degreasers), paint and stimulation agents	• pipe scale • waste paints • paraffins • cement • sand	
Abandoned Wells, Spills and Blowouts	• fugitive natural gas • other VOCs • PAHs • particulate matter • sulfur compounds • carbon dioxide • carbon monoxide	• escaping oil produced water brine	• contaminated soils • sorbents	

Adapted from: Sittig, 1978; EPA Office of Solid Waste, 1987. [244]

AIR EMISSIONS

As seen in the table below, there are several types of air emissions in the drilling and production process. The following table provides information on air quality concerns related to oil and gas in different parts of the country.

Some of the key sources of air emissions include the following:

Regional Air Quality Concerns from Oil and Gas Development

Pollutant or Impairment	Gulf Coast	North Slope	San Joaquin Valley	Rocky Mountain Region	California Coast
Visibility	A concern	An issue	Serious impairment in summer & winter	Degradation a serious concern	A possible concern
Sulfur dioxide, sulfate				A concern	
Ozone	A serious concern		A serious concern	An serious issue in some areas; a potential in others	A concern
Acid Deposition				A new issue and serious concern	
PM-2.5; PM-10 (particulate matter 2.5 or 10 microns in diameter)	A concern		A serious concern	Potentially an issue	A potential concern
Carbon Monoxide		A concern			

Adapted from: the U.S. Department of Energy [245]

1. Fugitive emissions from leaking tubing, valves, tanks, and open pits, or intentional venting of natural gas may release volatile organic compounds (VOCs)[246] and hydrogen sulfide.
   - VOCs are carbon-containing substances that readily evaporate into the air. They can combine with nitrogen oxides to form ground-level ozone, which can cause respiratory ailments such as asthma, and decreased lung function (see following page for more information). Examples are benzene and toluene.
2. Particulate Matter is essentially small particles that are suspended in the air and settle to the ground slowly. These particles may be re-suspended if disturbed. The most common sources of particulate matter from oil and gas operations are dust or soil entering the air during pad construction or from traffic on access roads; and diesel exhaust from vehicles or engines used at oil and gas facilities.
   - PM_{10} particles (with diameters less than 10 micrometers or μm) are small enough to be inhaled and can cause adverse health effects.
   - $PM_{2.5}$ particles (with diameters less than 2.5 μm) can lodge deep within the lungs and cause serious health problems. $PM_{2.5}$ particles are the main cause of visibility impairment (haze). Secondary particles are formed through chemical reactions involving gases and other particles in the atmosphere. Particles formed in this manner are fine particles (< 2.5 μm). The most common precursor gases involved in these reactions are nitrogen oxides (NOx), sulphur dioxide (SO_2), volatile organic compounds (VOCs) and ammonia (NH_3).[247] SO_2, NO_x and VOCs are all emitted during oil and gas operations.
   - For residents living along unpaved roads or near well pads, dust can penetrate their homes causing a nuisance and health problems such as hay fever and allergies. Crops

Studies over the last 15 years show that low levels of ozone, most certainly at 50 to 60 parts per billion (34-24 ppb below the federal limit) are detrimental to health.

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and vegetation near unpaved roads can be covered with the airborne dust stunting their growth due to the shading effect and clogging of the plant's pores. As a result, cattle and wildlife may avoid this vegetation. For motorists using the unpaved roads the traffic-generated dust can reduce visibility and cause driving hazards.

Dust Suppression

WATER is probably the oldest of all dust suppressants. Typically, it is applied by spraying it over the road surface.
Drawbacks: Water's dust suppressing capacity is very temporary because of evaporation. Heavy applications of water can create soft mud or penetrate the road to the sub-base and causing major road failure. Consequently, several light applications are preferable to one heavy application.

CHLORIDE COMPOUNDS such as calcium chloride ($CaCl_2$), magnesium chloride ($MgCl_2$) and the less popular sodium chloride ($NaCl_2$) are used because they attract and absorb moisture from the atmosphere and retain it for extended length of time, which significantly reduce the evaporation of moisture from the road surface. Thus, they are more effective dust suppressants than plain water.
Drawbacks: Chloride compounds have the disadvantage of dissolving in water, and therefore can be washed out during wet weather conditions. They are also corrosive.

LIGNIN DERIVATIVES include a variety of industrial waste products, animal fats, and vegetable oils; the most popular is ligninsulfonate, which is a waste product from the paper-making industry. When used as dust suppressant, the lignin polymers act as glue binding the soil particles together. According to the New Mexico State University Molecular Biologic Program, a by-product of the soybean crushing process, called soapstock, is now being used as dust suppressant on dirt and gravel roads throughout the Midwest. This alternative is said to be more environmentally safe in places where runoff is a concern, and supposedly lasts longer than most other alternatives.[248]
Drawbacks: Ligninsulfonate dissolves in water, and so it is easily washed away during wet weather conditions.

RESINOUS ADHESIVES include waste oils, tars, bitumen, and by-products from the plastic industry. Of all these products, cutback asphalt and asphalt emulsions are most widely used as dust suppressants.
Drawbacks: According to the Minnesota Pollution Control Agency, "When applied to roads, waste oil can seep into groundwater, runoff into surface waters or spread into the air with dust particles. Once in ground or surface waters even small amounts of used oil can contaminate large quantities of drinking water. . . Used oil reduces the amount of oxygen in water, damaging fish and other aquatic life."[249] Consequently, waste oils are prohibited from use as a dust suppressant in Minnesota.Very little quantitative information currently exists on the environmental impacts from the use of dust suppressants (other than water). Landowners should be aware that the application of dust suppressants has been noted to cause slipperiness on unpaved roads in wet weather conditions. The water quality effects of the use of dust suppressants are still not entirely known, however the chloride compounds and the lignin additives commonly used contain contaminants such as chlorides, heavy metals and organic compounds that are regulated by the U.S. Environmental Protection Agency.[250]

ALTERNATIVES TO WATER AND CHEMICAL DUST SUPPRESSANTS[251]

LOWERING SPEED LIMITS will decrease the amount of dust stirred up from unpaved roads and pads. Lowering the speed of a vehicle from 45 miles per hour to 35 miles per hour can reduce emissions by up to 22 %. Installation of speed bumps can reduce vehicle speeds.

UPGRADING UNPAVED ROADS (e.g., by improving particle size, shape, and mineral types that make up the surface and base materials) will increase a road's surface strength, and reduce dust emissions. Adding surface gravel can reduce the source of dust emission, but if gravel is added the amount of fine particles (i.e., those smaller than 0.075 mm) should be limited to 10 to 20 %. Also, improving drainage and crown can reduce dust emissions. Paving is the most expensive, but most effective road upgrade option.

Dust can affect human health, and the health of crops, livestock and wildlife.

3. The flaring of natural gas produced from the oil or gas wells may release carbon monoxide, nitrogen oxides, sulfur dioxide, benzene, toluene, ethylbenzene and xylene, polycyclic aromatic hydrocarbons (PAHs) and, in the case of sour gas, hydrogen sulfide and carbon disulfide.
    - Benzene and PAHs are carcinogenic (cancer-causing). Also, benzene has been shown to cause various adverse health effects other than cancer, such as blood disorders,

Studies also show that directional drilling has been successful in a variety of geological formations (e.g., shallow reservoirs, deep reservoirs, tight sands, coal beds, tar sands). Furthermore, if horizontal drilling is used in coal beds, there may be no need to hydraulically fracture the beds, resulting in a decreased potential for groundwater pollution.
Perhaps the greatest benefit to the surface owner is the ability to locate well sites away from residences or other areas that surface owners do not want to be disturbed. It is now possible for companies to access oil or gas from beneath a landowner's property by drilling a well that is miles away from that property.[338]

A major benefit to the companies and mineral owners receiving royalties is increased oil and gas production. Oil- and gas-bearing formations tend to be more wide than they are deep, consequently, wells that intersect a producing formation at an angle or horizontally often can drain more of the oil and gas than purely vertical wells. There are numerous studies showing that directionally drilled wells have been able to extract 2-25 times more oil or gas than vertical wells drilled in the same oil or gas field.[339]

FIGURE I-37. A VERTICAL AND HORIZONTAL WELL DRILLED ON ONE PAD. Photo printed with permission of Vermejo Park Ranch.

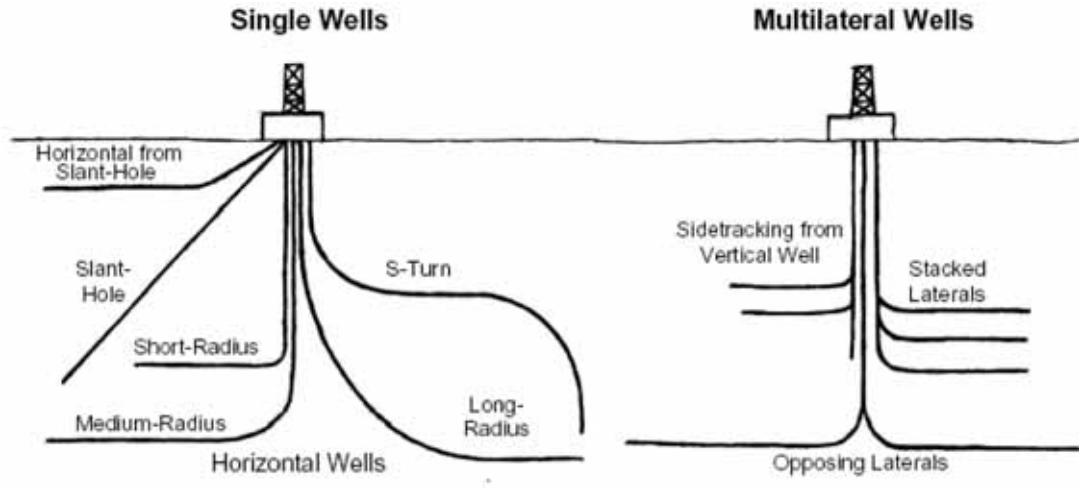


FIGURE I-38. DIRECTIONALLY DRILLED WELLS
Source: Drilling Smarter: Using Directional Drilling to Reduce Oil and Gas Impacts in the Intermountain West.[340]

The drilling of a directional well is more costly than drilling a typical vertical well because it requires specialized equipment; constant attention to the placement of the drill bit; it takes several days longer to drill the wells; and pumping costs may increase because parts may wear out faster. According to the U.S. EPA, however, the increased costs of directional drilling are often more than offset by increased production and the reduced need for drilling multiple wells.[341]

> *In the Dundee Formation of Michigan, as much as 85 % of the known oil remained in the formation after many years of production, but many wells were on the verge of being plugged because daily production had fallen to only five barrels of oil per well. The U.S. Department of Energy co-sponsored a project to drill a horizontal well in the formation. This well produced 100 barrels per day. The program attracted other well developers, and 20 to 30 additional horizontal wells are being drilled in the formation. It is estimated that the application of horizontal drilling to this formation may yield an additional 80 to 100 million barrels of oil.*[342]

4. **Flareless or "green" completions reduce flaring and venting of natural gas.** Before natural gas and coalbed methane wells begin producing gas for sale, the well bore and surrounding reservoir must be "cleaned up" (i.e., any fluids, sand, coal particles, or drill cuttings within the well bore must be removed). The conventional method for doing this is to pump air down the well bore, which lifts the waste fluids and solids out. The solid and liquid waste materials are then dumped into a pit or tank, and any gas that is removed is flared or vented to the atmosphere. In some flareless or green completions, natural gas, rather than air, is pumped down the well bore to clean it out.[343]

   In flareless or green completions the gas that comes to the surface is separated from fluids and solids using a series of heavy-duty separators (sometimes referred to as "flowback units"). The water is discharged to tanks to be reused, the sand is sent to a reserve pit, and the gas is either cycled back through the well bore, or sent to a pipeline to be sold rather than vented or flared. According to the U.S. Environmental Protection Agency (EPA), benefits of this system include: the elimination or reduction in venting or flaring of natural gas; sale of the gas and condensate provides the operator with an immediate revenue stream; there is a reduction in solid waste and water pollution; and the system enables safer operating practices.

   Emissions Reductions: One company, which drilled 63 wells using flareless completions, reported a reduction in natural gas emissions of 7,410 thousand cubic feet per year, which is 70% of the gas that would formerly have been vented to the atmosphere.[344] Another company has been able to reduce flaring by 85-90%.[345]

   Costs and Pay-Back: The capital costs for companies include the use of separators, sand traps and tanks. One company reported these costs as being $180,000. The equipment, however, can be moved from site to site, so if a company were to complete 60 wells per year the annual capital charges would be less than $10,000. Operating costs are less than $1,000 per year. EPA has estimated that "green completions" can pay back their costs in about 1 year.

FIGURE I-39. TYPICAL COMPLETION WITH A FLARE BERM AND WASTE PITS. Photo by Dan Randolph

   An alternative to sending the gas to the pipeline is to send it to a flare tank. Flare tanks

capture and more fully combust the waste gases. The tanks can be carried from site to site. This practice avoids the costs associated with excavating and reclaiming flare pits, and avoids the potential liability associated with cleaning up soils contaminated by flaring.

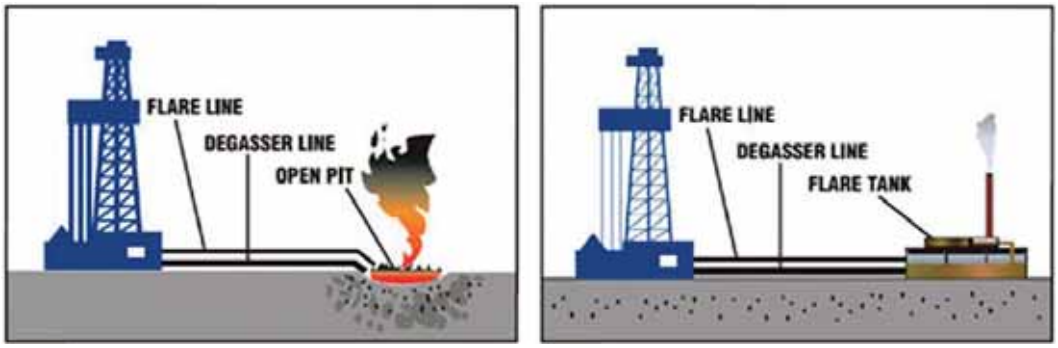


FIGURE I-40. FLARE TANKS REDUCE HAZARDOUS EMISSIONS BY MORE FULLY COMBUSTING WASTE GASES.
Source: Wellco Energy Services, Inc.[346]

5. **Waste minimization during drilling operations.** The state of Texas has produced a document *Waste Minimization in the Oil Field* that provides a general overview of waste minimization techniques for wastes arising from oil and gas operations, including drilling operations.[347] The document also provides case studies of successful waste minimization projects and a bibliography of useful technical references. The document includes dozens of examples of alternative drilling practices, such as:

   - Product substitution. Replacing conventional, toxic products with less toxic, yet effective, substitutes. For example, companies are substituting low toxicity glycols, synthetic hydrocarbons, polymers, and esters for conventional oil-based drilling fluids. The use of these substitutes eliminates the generation of oil-contaminated cuttings and other contamination by the oil-based fluid and decreases concerns related to site clean-up when the well is abandoned. Drilling engineers have published numerous technical papers that describe the successful application of substitute drilling fluids. In many instances, this substitution has resulted in significant cost savings.

     Similarly, companies have designed alternatives to the conventional water- and chemical-based hydraulic fracturing techniques, by substituting carbon dioxide for the more common and more toxic fracing fluids.

   - Process or procedural modifications. For example, in the past few years the drilling industry has improved the technology of slim hole drilling. If feasible, slim hole drilling reduces the volume of wastes (e.g., drilling fluid and the drill cuttings) produced during drilling. The total cost of a slim hole drilling operation may be considerably less than for conventional hole sizes, and smaller casing is required, which may help reduce the total cost of the operation.

   - Reduction in water use. For example, companies can reclaim water from waste drilling fluids by using mechanical or chemical separation techniques such as large bowl centrifuges, hydrocyclones, and/or chemical flocculants. The reclaimed water may then be reused, thus reducing the demand on, and cost of, new water sources. Dewatering of wastes may also result in a reduction of the volume of drilling waste to be managed, thus saving waste management costs, easing site closure concerns and costs, and reducing future potential liability concerns.

   - Preventative maintenance. For example, chemicals and materials should be stored so that they are not in contact with the ground (e.g., stored on wooden pallets), or exposed

to the weather. There should be secondary containment in the case of spills. All drums and containers should be kept closed except when in use. It is very important that all chemical and material containers always be properly labeled so that their contents may be identified at any time. Proper storage and labeling of containers allows quick and easy identification and classification of released chemical or material in the event of a leak or rupture. In some instances, that could save hundreds of dollars in soil sampling and laboratory analysis costs.

- Recycling. For example, the cost of closing a drilling site is increased if waste drilling fluid in a reserve pit must be dewatered and/or stabilized prior to closure. An alternative is to recycle or reuse the waste drilling fluid, e.g., in another drilling project. One company designed a multi-well drilling project where the same drilling fluid was used for drilling each successive well. The result was significant cost savings and greatly reduced waste management concerns. Another cost effective alternative for reuse of waste drilling fluid is in plugging or spudding of other wells.

ALTERNATIVES USED DURING THE PRODUCTION PHASE

1. Minimizing Surface Disturbance

- Well pads are often much larger than they need to be—sometimes exceeding several acres in size. At Ted Turner's Vermejo Park Ranch, however, the well pads are only 0.6 acres. (See Vermejo Park Ranch Coal Bed Methane Project Mineral Extraction Agreement Summary, in Chapter III).
- After the drilling phase if over, the portion of the drilling pad not needed for oil or gas production can be reclaimed. This is known as interim reclamation, and it is required by law in many states. Unfortunately, lack of enforcement by state agencies means that interim reclamation does not occur in many jurisdictions.

FIGURE I-41. MINIMIZING SURFACE DISTURBANCE.
Left to right: Poor Practice: no efforts have been made to reduce surface disturbance at this site. Better Practice: this well site and the road leading to it have been revegetated. The surface owner has 40 additional years of use, and a 40-year head start on reclamation. Photos by Bob Miller.

2. Minimizing Visual Impacts and Noise

- Landscaping can help decrease the visual impacts of wells. For example, soil can be formed into ridges or gentle berms around the well pad, and trees and other vegetation can be planted on the ridges to screen wells so that nearby residents don't see them.
- A low-profile pumping unit can replace the conventional unit, which uses a 30- to 40-foot beam and looks like a giant, bobbing horse's head. The conventional pump is run on a gas- or diesel-powered engine, which is noisy and smelly. Alternatives to this large pump include using a pneumatic pumping device that doesn't require an engine, therefore, produces little or no noise. This pump stands about 10 to 15-feet tall. According to one company, pneumatic pumps will not function correctly if a lot of water is extracted while extracting methane gas.[348] When larger amounts of water are produced, an alterative to the standard beam pump is the progressive cavity pump. These pumps come in different shapes and sizes, and like the pneumatic pump, they can un on electric motors, and therefore, be much quieter than conventional pumps.

FIGURE I-42. PUMPING UNITS
Left to right: Conventional pump "pump jack"; progressive cavity pump; low profile progressive cavity pump.

3. Minimizing Noise

- Noise created by operators constantly driving in and out from the well pad to monitor well production can be mitigated using an automated monitoring system, which allows wells to be monitored remotely, e.g., from the company's office.[349]
- To mitigate noise impacts from engines, a sound barrier made out of four inches of insulation and 18-gauge steel can be used. Sound barriers are placed in an L-shape above the engine, and they extend past the sides of the engine.[350] Some engines can operate at a constant number of revolutions per minute (RPM), which reduces the up-down noise caused by other engines, which speed up and slow down. Mufflers, like those used for automobile engines, can be used to minimize engine noise.[351] To reduce noise in sensitive areas, well-site or field compressors may be enclosed in a sound-insulated building, and equipped with two buried hospital-grade mufflers in series.
- Noise from compressors can be mitigated by treating each significant noise source: gas turbines or engines, compressors, exhaust outlets and air inlets, and cooling and ventilation fans. Abatement may involve changing the blades on fans, which can change the frequency of sound emitted, thereby removing the annoying tones. Engine noise can be muffled using automotive-type mufflers, or by housing the engines in acoustically insulated structures. Also, the entire compressor can be housed in an acoustically insulated building.

FIGURE I-43. SOUND CONTROL
Left to right: Pump jack with sound abatement walls and muffler at lower right. The "barn" houses a compressor station. By treating each noise source, the company achieved its design goal of 40 dB at 300 feet from the station. The barn-like building was designed to fit into the rural countryside; source: ATCO Noise Management. [352]

FIGURE I-44. SOUND CONTROL
Left to right: Sound is directed up; sound is directed away from a house, but is not absorbed; sound is effectively reduced with absorbing panels to 1 decibel above ambient.

4. Minimizing Air Pollution

- If the control valves on a pump's separator unit, which separates the methane and water, are replaced with better valves, methane emissions to the atmosphere can be reduced. This will have positive environmental benefits, as methane is a powerful greenhouse gas that contributes to global warming. By replacing 3,300 controllers on 2,760 wells in Colorado and New Mexico, the Colorado Oil and Gas Conservation Commission expects that methane emissions will be reduced by 12,000 tons per year in the San Juan Basin.[353] According to an engineer with the company BP, replacing valves not only has a positive benefit with greenhouse gases, it also has a positive economic benefit for that company.[354]
- Emissions can be reduced by monitoring and pinpointing fugitive emissions, and then sealing the leaks; using lower heater treater temperatures; connecting storage tanks to flare systems; converting gas-driven chemical pumps to electric-, air- or nitrogen-driven pumps; compressing casing gas and shutting down line pigging. Also, air emission may be decreased by installing: no-bleed or low-bleed pneumatic devices; vapor recovery units; high efficiency flares; closed-loop skimmers on water tanks; and separator pumps and evacuators on pipeline bleeders.[355]
- Wellhead compressors that are powered by natural gas emit NO_X and VOCs (which contribute to ground-level ozone) and carbon monoxide. According to the federal Bureau of Land Management, there are add-on technologies, such as catalytic converters, that can reduce these emissions by as much as 95%.[356]
- Cavitation baffle systems (large storm sewer concrete pipe) can be used to reduce flare height and contain the majority of coal dust during coalbed methane cavitation operations.[357]

- Barrett Resources Corporation has minimized odors generated at natural gas production sites, a common source of complaint by surface owners, by using combustion units designed to destroy vapors released by condensate tanks and glycol dehydrators. These units also reduce emissions of methane (a greenhouse gas), and other hydrocarbons that can affect visibility.

Capture Gas Instead of Flaring It

The federal Department of Energy and the Interstate Oil and Gas Compact Commission are involved in a project to reduce greenhouse gases and NO_x emissions and increase oil production and in California. Gas that would otherwise be flared, and shut-in gas from California's oil-fields will be used to generate electricity. Several types of conventional and new microturbine generators will be tested at selected sites from among California's 21,000 marginal wells.

Petroleum Technology Transfer Council[358]

- Standard glycol dehydrators which are used to remove water from natural gas, typically vent water and hazardous gases directly into the atmosphere. Glycol dehydrators are a major source of benzene emissions within the oil and gas industry.[359] Fatalities from human exposure to high concentrations of benzene have been documented since the early 1900s, and studies have shown correlations between workplace exposure to benzene and the onset of certain forms of leukemia.[360] The issue of air emissions from glycol dehydrators has only been identified in the past few years. Most of the glycol dehydration units are installed in rural environments; they are typically left unattended, and emissions are not regularly monitored.

  In 1995, the Canadian government announced that it would be limiting benzene releases through various measures including controlling emissions of benzene from natural gas dehydrators. A Canadian Working Group composed of industry, government, and public interest groups produced a document, *Best Management Practices for Control of Benzene Emissions from Glycol Dehydrators*,[361] which outlines methods for minimizing benzene emissions in new and existing plants; and provides more information on alternatives to glycol dehydration. These include: methanol or glycol injection; separator packages; line heaters; solid desiccant/molecular sieve plants; membrane technology; and other commercial processes.

  Emissions from glycol dehydrators can be reduced by: optimization of operations; equipment modifications or replacement; and/or, addition of emission control equipment. Emission controls such as condensers, flare stacks, and incinerators for still column vent vapors have been installed by industry at some locations. Research by the U.S. EPA has indicated that operators of glycol dehydrators often maintain a circulation rate that is at least two times higher than is needed to remove enough water from the gas. Therefore, companies can reduce their glycol use by performing simple calculations to determine the minimum circulation rate needed. By doing so, they will lose less methane to the atmosphere; improve the dehydrator unit efficiency; and decrease fuel pump use. EPA has calculated that by doing so, the potential savings for a dehydrator unit can range from $260 to $26,280 per year.[362]

RECONNECTING THE SURFACE AND MINERAL ESTATES

In some states, mineral rights revert to the surface owner under certain conditions such as death, failure to obtain production, or passage of a specified period of time. It is important to be aware that these types of laws may exist in your state, and they may provide surface owners with the opportunity to take possession of the mineral rights beneath their land. Several states have laws to this effect.

- In Louisiana, if the minerals are not used (e.g., no exploration or production has occurred) within 10 years, the surface owner becomes the owner of the minerals.[377]
- In North Dakota and Ohio, if minerals have lain dormant for 20 years the surface owner can claim them.[378]
- In Michigan, a law that passed in 1998 provides landowners with the opportunity to petition the state to purchase the state-owned minerals beneath their land. They can do this only if there is no pending lease or development. Upon request from surface owners, the state must sell the minerals to them at fair market value, unless the state wants to reserve minerals to prevent damage in environmentally sensitive areas, or there is some other legitimate reason to keep the minerals in state ownership. A deed restriction then will be added to the property that prohibits the minerals from being severed in the future.[379]
- Recent attempts to pass similar laws in Colorado and Montana have failed.

HOW TO DETERMINE OWNERSHIP

If a landowner is unsure of whether or not he or she owns the mineral estate, it is a question that should be answered, especially if the land is owned or leased in a region with oil and gas development.

- If you own the minerals beneath your land, you have considerable opportunity to benefit from and influence the course of oil and gas development.
- If you do not own the minerals beneath your land, that means that other people or entities possess certain rights that may hinder your ability to shape oil and gas development on your property.

There are a number of methods for determining who owns the oil and gas beneath your land.

1. **Read your property deed and research the land title records.**
   If you want to find out who owns the minerals beneath your land the first step is to find the deed to your property. The deed may state that ownership of your property is fee simple absolute. This may mean that you own both the surface property and the underground mineral resources.

   If you can't find your copy of your deed, contact your county government. Surface deeds are almost always recorded in the county government's Recorder of Deeds (or some equivalent) office in the county where the property is located.

   It may be necessary to search the property's historical deeds all the way back to the 1800s. (Be aware that older mineral deeds may not be recorded in any government office.) A phrase in an old deed such as "oil and gas excepted and reserved" means that the surface was sold separately from the oil and gas estate at that time. If you find such a statement in an old deed, the oil and gas is probably not yours to lease or develop.[380]

2. Research mineral deeds, grants and reservations.
Go to the county and federal government offices to find out if there are mineral deeds, grants or reservations related to your property. You will need a legal description of your land (this can be found in your deed or in the title document for your land).

The federal Bureau of Land Management maintains Surface and Mineral Land Status maps, which can be purchased for a nominal fee. These maps are color-coded to show ownership status (i.e., federal, state or private ownership), but the maps do not show private land owner names.

Depending upon where you live, there will be different county officials (e.g., county recorders, register of deeds, county clerk) charged with recording mineral, oil and gas transaction documents such as mineral deeds. To obtain addresses and phone numbers for the appropriate office, contact your county government, or visit the web site: *http://royalty-deeds.com/courthouses/.*

Some county assessor offices track minerals because they are taxed at the county level if they are producing (or they are taxed if non-producing but severed from the surface). You should contact your assessor's office to determine if they track mineral ownership.

3. Have a title search conducted by a land title/abstract or title insurance company.
There are two main types of companies that provide information on property ownership: one that will create an abstract of title, and a second that provides title insurance. In both cases, these companies can research the legal history of property and perform extensive searches of public records including deeds, mortgages, contracts, civil court records, probate court records, federal court records, and tax records. They may be able to assist you, if your own search attempts have not provided you with adequate information.

When you purchased your property, you may have hired a company to provide you with title insurance to prove that you had clear title to the land. In Colorado, title insurance companies are now required by law to inform the title insurance purchaser if the mineral estate has been either leased or severed from the surface estate. The title companies must also inform the purchaser that there is a substantial likelihood that a third party holds some or all interest in oil, gas, other minerals, or geothermal energy in the property; and that such mineral estate may include the right to enter and use the property without the surface owner's permission.[381]

For residents of other states, be aware that title searches may not include information on whether or not you own the minerals. In many states, it is common for title companies to exclude research on mineral rights, mining claims, water rights, and other issues of concern. If you have already done a title search for your property, refer to the exclusion section of the title policy. If mineral rights are mentioned as exclusions, then it is unlikely that this document will provide you with the information you need.

Make sure you find a company that will (and knows how to) include mineral rights in a title search. Not all title companies have personnel trained in examining mineral ownership, so it is important to ask if they are qualified to examine this type of property. The companies should also be willing to "stand behind" their findings. Having a title company insure a mineral title examination may be difficult, however, so find out in advance whether or not the company is willing to provide insurance. Alternatively, you can ask for a mineral guarantee, which will disclose any mineral reservations found in the "chain of title" (i.e., the list of all people/entities who have held title to the property) since the land was first patented. As mentioned above, a mineral reservation indicates that the ownership of the minerals has been severed from ownership of the land. The interpretation of the mineral report, howev-

er, can be complicated. Usually, if you order a mineral guarantee report from a title/abstract company, you will need to take that information to an attorney who can provide you with an opinion based on the findings in the report. If you get mineral title insurance, you do not normally need to get the legal opinion.

Be aware that title searches can be expensive. One Montana titles searcher quoted his hourly fee for producing a mineral report at $126.[382] And there may be attorney fees on top of that.

4. **You may want to consider hiring a landman.**
While landmen typically work for oil and gas companies, determining mineral ownership is a large component of their work, and experienced landmen should have significant expertise in determining mineral ownership. Also, landmen may be more affordable than title companies, but unlike title companies they may not be able to guarantee their findings.

5. **Find out if the minerals have been dormant, and for how long.**
As mentioned above, several states have laws that allow surface owners to claim minerals beneath their lands if those minerals have been dormant for a certain period of time. There may be other states that also have similar laws. Again, you will want to consult an attorney to determine whether the dormant minerals now belong to you, or what steps you need to take to re-claim these rights.

Mineral Versus Surface Rights

If someone owns or leases the mineral rights to oil and gas beneath your land, he or she has the right to enter your property and search for minerals; and, if minerals are discovered, the owner then has the right to remove those minerals.

Depending upon the state that you live in, some or all of the following "rights" may be included in the search for and removal of minerals:

- the right to enter upon the surface for exploration and production of oil and gas
- the right to conduct geophysical exploration and seismic tests on the surface
- the right to mine caliche (dirt, gravel, etc.) for constructing roads, drill pads, etc. from the premises

The Rights

"In Manistee County, the Michigan Department of Environmental Quality (DEQ) has allowed drilling in residential areas of natural gas wells that contain high concentrations of hydrogen sulfide, a poisonous chemical. DEQ officials defend their action on the basis that the rights of mineral and lease holders "must be respected." In effect, they appear to be determining that the drillers' rights are more important than the rights of residents."

— Schneider, Keith.[383]

To find out which statutes and regulations apply to oil and gas in your state, contact the government agencies listed in Chapter V. For a list of federal statutes that apply to oil and gas, see the publication *Preserving Our Public Lands* (to obtain a copy, see Chapter V).

The following sections provide examples of various state, federal and county or municipal statutes and regulations that provide some protections for surface owners.

Before reading about the potential regulatory protections for surface owners, it is important to note that even though there are statutes and regulations on the books, it does not guarantee that these protections will occur. Companies may fail to follow the laws, and their infractions may go unnoticed by the government enforcement agencies. Or governments may turn a blind eye when companies break the law — either for political reasons, or because the agencies do not have the staff to properly enforce the laws. Therefore, it is important for landowners to learn as much as they can about the laws and regulations governing oil and gas in their region. If landowners see that laws are being broken, they can pressure government agencies to enforce the laws.

STATE REGULATIONS

The oil and gas industry is regulated primarily at the state level. Whether the state, the federal government or a private party owns the minerals, generally the mineral operator must adhere to state laws and regulations governing oil and gas development.[394]

Even though there are laws or regulations on the books, it does not guarantee that these protections will occur.

Most states have agencies with the specific mandate to oversee oil and gas development. For example, many states have oil and gas commissions, which are empowered by the state government to regulate the industry. Also, natural resources or environmental quality departments may have the ability to regulate certain aspects of the oil and gas industry, such as discharge of wastes. (A table of state regulatory agencies and contact information can be found in Chapter V.)

The following section provides information on how various states treat some issues that are of concern to surface owners. Selected examples are given of state regulations and requirements. It is not possible to include all regulations for all states in this guide. The purpose of the examples is to provide the reader with an idea of the way in which different states regulate oil and gas development.

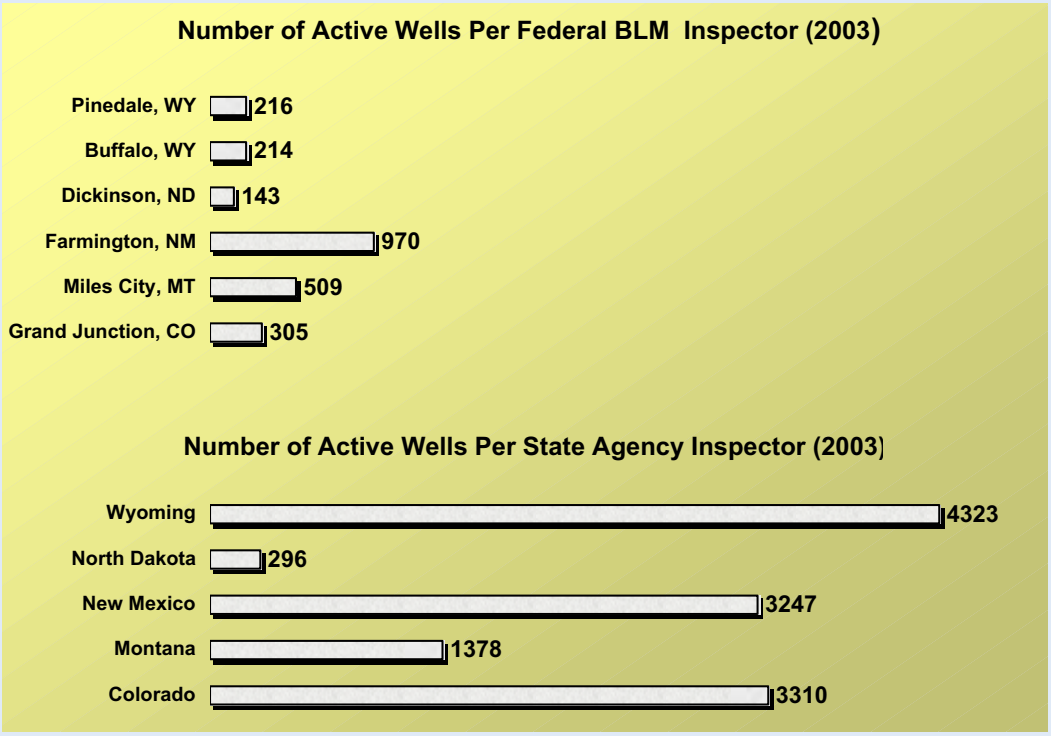
Leasing

The direct notification of individual surface owners typically does not occur when leasing of state or federal minerals occurs. Consequently, surface owners often do not realize that the mineral rights have been leased to a company that may develop oil and gas on their land. Some states do have processes for posting notices about lease sales on state lands. For example, the state agency in Montana will post notices on its web site, in local newspapers and they will send information about leases to a mailing list.[395]

The Interstate Oil and Gas Compact Commission has produced a table that summarizes state oil and gas leasing information, including how the state agencies notify the public about lease sales. This table is available at: http://www.iogcc.state.ok.us/STATELANDLEASINGINFO.htm

Shortage of State and Federal Oil and Gas Inspectors

A 2004 review of inspection and enforcement programs in five western states found that although the number of active oil and gas wells in those states increased by 14% between 2000 and 2004, the number of state oil and gas inspectors generally did not increase. On the federal level, Bureau of Land Management (BLM) field office inspectors conducted 33% fewer inspections in 2003 than they did in 1999. The chart below shows the average number of active wells per state and federal inspectors for the year 2003. From the chart, it is clear that in most jurisdictions inspectors cannot possibly have time to inspect all active wells every year – given the fact that each inspection involves driving to the well site, conducting the inspection, and performing any necessary paperwork and follow-up. Although state agencies have fewer inspectors relative to the number of active wells than the BLM, state inspectors conduct significantly more field inspections than their federal counterparts. State agencies inspect active wells once every 1-3 years, while BLM field office staff inspect active wells every 2-10 years (and inspect active wells for environmental compliance once every 4-5 years).



The above information comes from a report entitled *Law and Order in the Oil and Gas Fields – A Review of Inspection and Enforcement in Five Western States*. It was produced by the Western Organization of Resource Councils in November, 2004.[396]

Financial Assurance (Bonds)

Typically, if oil and gas operators walk away from their operations (e.g., by declaring bankruptcy), the management of these orphan sites falls to the state or federal governments. Nearly all states require that companies post a bond or another form of financial assurance with the state to cover the costs related to plugging and abandonment of wells. These funds are collected to provide the state with some "insurance," in the event that a company is no longer willing or able to perform the plugging and restoration. The funds are released back to a company if it properly plugs and abandons its well. Proper abandonment typically includes the restoration of surface lands.[408]

State	Financial Assurance Per Well	State-wide Blanket Bond
Alaska	$100,000	$200,000
California	$15,000 (wells < 5,000' deep) $20,000 (wells 5,000 – 10,000') $30,000 (wells > 10,000')	$100,000 (50 or fewer onshore wells) $250,000 (more than 50 onshore wells) $1 million (all onshore and offshore wells)
Colorado	$5,000	$30,000 (less than 100 wells) $100,000 (more than 100 wells)
Illinois	$1,500 (well < 2,000' deep) $3,000 (well = or > 2,000' deep)	$25,000 for up to 25 wells $50,000 for up to 50 wells $100,000 for all wells in state
Kansas	$50 refundable fee (if operator has an acceptable record of compliance) $0.75 per foot drilled (for all the operator's wells)	$5,000 (1-5 wells that are <2,000' deep ; this increases to $20,000 for 25 or more wells at this depth) $10,000 (1-5 wells that are >2,000'; this increases to $30,000 for 25 or more wells)
Kentucky	$500 (wells = or < 500' deep) $5,000 (wells > 4,000' deep)	$10,000
Montana	$1,500 (well < 2,000' deep) $5,000 (2,000' – 3,500' deep) $10,000 (3,501' or deeper)	$50,000
New Mexico	$5,000 - $7,500 (well < 5,000' deep) $7,500 - $10,000 (5,000' – 10,000' deep) $10,000 – $12,500 (well > 10,000' deep)	$50,000
Ohio	$5,000	$15,000
Oklahoma	None.	$25,000 OR financial statement showing operator net worth of at least $50,000
Pennsylvania	$2,500 (this amount may be adjusted every two years; different rules apply for wells drilled prior to 1985)	$25,000 (this amount may be adjusted every two years; different rules apply for wells drilled prior to 1985)
Wyoming	$10,000 (wells < 2,000' deep) $20,000 (wells > 2,000' deep)	$75,000 for all wells < 2.000' deep

FIGURE II-6. VARIATIONS IN FINANCIAL ASSURANCE REQUIREMENTS FOR PLUGGING AND SITE RESTORATION. [409]

Well depth and geographic location are two factors that play into the amount of financial assurance that state agencies require for plugging and restoration of individual wells. The amount varies with well depth in fourteen states (Alabama, Arizona, California, Illinois, Kansas, Kentucky, Michigan, Mississippi, Missouri, Montana, New Mexico, New York, Utah and Wyoming).[410] Geographical differences in financial assurance are evident by comparing bond amounts in Kentucky and Alaska. In Kentucky a single bond for a well 500 feet deep or less is $500, while the minimum per well amount in Alaska is $100,000. This may reflect the higher costs of reclaiming Alaskan well sites.

In most states, companies are allowed to post state-wide or blanket financial assurances with the state government. These blanket bonds are supposed to demonstrate a company's financial capability of plugging and restoring all of its wells in that state. The states vary greatly on the amount of financial assurance required in a blanket bond. The amounts range from as low

as $5,000 in Kansas to as high as $1 million in California.

The cost of plugging and reclaiming a single orphaned well site in the western states can range from $19,000 to $75,000.

A recent study indicates that the costs of plugging and reclaiming a single orphaned well site in the western states can range from $19,000 to $75,000.[411] Based on these numbers, it appears that in most states financial assurance bonds are inadequate to cover the costs of properly plugging and restoring well sites.

A striking example of the inadequacy of bond amounts comes from Wyoming. In 2001, the state of Wyoming and the federal Bureau of Land Management (BLM) were left with an estimated $4 million in liability to plug and reclaim 120 wells abandoned by Emerald Restoration & Production. The government collected $125,000 in bonds from the company, which went toward plugging 56 wells on private land. The state Oil and Gas Commission used $2 million from the state's Conservation Fund to meet plugging costs that the bond did not cover. There are still more than 60 of Emerald's wells on federal and state lands yet to be plugged.[412]

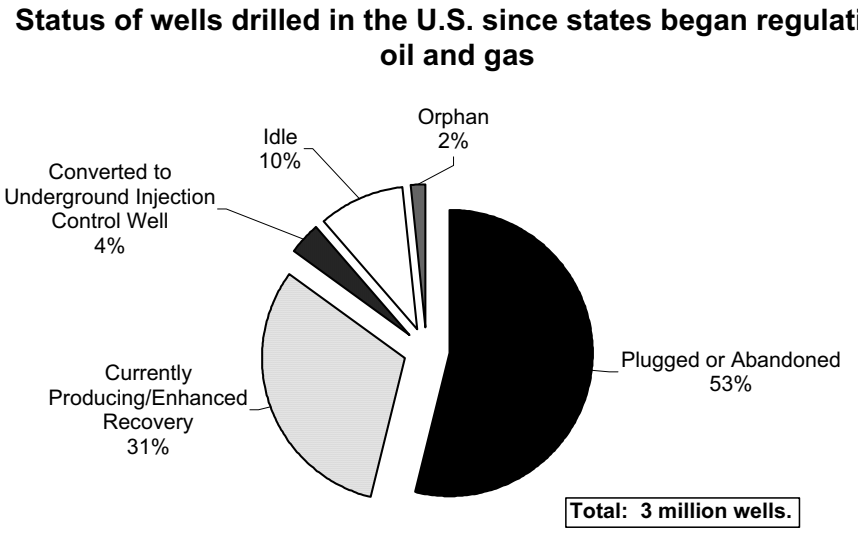


FIGURE II-7. STATUS OF THE THREE MILLION WELLS drilled in the U.S. since states began regulating oil and gas. Source: *Produce or Plug: A Summary of Idle and Orphan Well Statistics and Regulatory Approaches.* [413]

According to industry statistics, approximately 2 % of the three million wells (i.e., 60,000 wells) that have been drilled in the United States are considered orphaned.[414] As already mentioned, it can cost between $19,000 and $75,000 to properly plug and abandon a single orphan well. That means that at the present time $1.1 billion to $4.5 billion of taxpayers' money will have to be spent to properly plug and abandon all of the orphan wells in the U.S.[415]

In some situations it can cost far more than $75,000 to properly plug and abandon a single orphan well. To date, the Colorado Oil and Gas Conservation Commission (COGCC) has spent more than $400,000 trying to plug an orphan gas well in La Plata County, Colorado. Unfortunately, COGCC's efforts have not been successful, and the failure to plug the well has had near tragic consequences.

> *On February 12, 2005, Charles Yoakum turned on his stove. All four walls of his trailer blew apart and the roof blew into the air. An orphan gas well, located about 250 feet from Yoakum's trailer, is the likely source of methane that fueled the --.*[416] *The orphan well has a long history of leaking methane and fouling the groundwater in the Bondad area of La Plata County. In 1994, the Colorado Oil and Gas Conservation Commission (COGCC) spent*

$200,000 trying to plug the well. After the explosion, the COGCC pledged to spend $200,000 more to identify the exact location of the well and of another orphan well in the area, and identify any abandoned pipelines, utility corridors, or other potential conduits for gas migration. [417]

FIGURE II-8. REMAINS OF A TRAILER IN LA PLATA COUNTY, CO. The trailer exploded due to methane that most likely came from an inadequately plugged orphan well. Photo Credit: Yodit Gidey, Durango Herald.

Clearly, if states do not have enough money to put toward plugging all orphan wells, the wells can become environmental problems and present health hazards to nearby residents. (See box entitled "Bankrupt Companies Walk Away from Oil Wells in Texas.") It is important, therefore, for surface owners to: 1) encourage governments to require adequate bonds, and/or 2) include a financial security provisions in Surface Use Agreements. With these measures in place, there will be some assurance that companies —not the surface owners or the public— will bear the cost of adequately plugging and cleaning up well sites.

Chapter III

Tips for Landowners

III

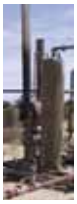
WHAT TO DO WHEN THE LANDMAN COMES CALLING
This section provides surface owners with suggestions on how to respond to the initial visits from oil and gas companies.

SURFACE USE AGREEMENTS
One of the tools available for protecting surface property and surface owner quality of life is the Surface Use Agreement. This section examines the pros and cons of negotiating these agreements, and provides samples of what others have been able to negotiate.

LEASING
The information in this section is geared toward those fortunate enough to own mineral rights. Mineral owners have the option of leasing or not leasing the minerals to oil and gas companies. If they choose to lease, there are some tips contained in this section to help ensure that the lease meets their needs and protects their interests.

OTHER ACTIVITIES LANDOWNERS MAY WANT TO CONSIDER
The final section of this chapter provides additional strategies and tools for surface owners confronted with oil and gas development. Some of these strategies include pushing for reform of oil and gas laws and regulations, taking companies to court, and working with other landowners to pressure companies and governments to carry out responsible oil and gas development.

What to do When the Landman Comes Calling



What is a landman?
A landman is the name given to a man or woman who serves as the company's contact person with the public who may be an employee or contractor with the oil or gas company. Some of the tasks that landmen perform include: researching courthouse records to determine mineral ownership; locating mineral/landowners and negotiating oil and gas leases and other agreements with them; and conducting surface inspections before drilling.[449]

What to do if contacted by a landman

1. When interest develops in your minerals, you may be approached by phone, mail, or in person. The landman or lease broker may determine your interest in leasing by quoting you an offer. You should write the offer down or get it in writing.
2. Do not sign or agree to anything (e.g., a lease or surface use agreement) without understanding the terms of the agreement or getting professional advice. You may want to contact an attorney or organizations that work with landowners. You may want to talk with your neighbors and others who have been in negotiations with oil or gas companies. It may be helpful for you to read through the landowner profiles that are scattered throughout this document. The lessons learned by others may help you to figure out your own strategy for dealing with oil and gas company representatives.

3. Stand your ground. Some landmen may use intimidation tactics or threats to pressure you into signing an agreement. For more information on intimidation tactics, see the story "Threats and Intimidation: This is Negotiation?" and also Peggy Hocutt's story, in Chapter IV.
4. Put together a list of issues important to you before you begin negotiating with the landman. Remember, everything except your name and the legal description of the property is negotiable.
5. At any meeting with a landman, document as much as you can. Take notes, or better yet, tape record your meetings. Or have someone else sit in as a witness.
6. Understand who it is you are dealing with. Research the oil or gas company's track record. Talk with neighbors and other landowners who have had to deal with the same company. Find out, if you can, details of agreements reached between the company and other surface owners (e.g., if they offered to test your neighbor's well water, they should do the same for you).
   - The Colorado Oil and Gas Conservation Commission (COGCC) maintains a database of incidents and complaints. You can look up information on a specific company, e.g., how many violations they have had, and how the company responded to complaints. Also, the database has information on inspections, notices of alleged violations, and spills. It can be found at the COGCC website, under "Database." (http://oil-gas.state.co.us/). There may be similar databases in other states. Contact your state agencies to find out.
7. Consider signing a lease or negotiating a Surface Use Agreement (both are discussed below). If you are going to sign a lease, consider negotiating the Surface Use Agreement either before or at the same time that you negotiate the lease.

Knowing Your Landman

You may want to ask your landman if he or she is a certified landman, and whether or not he or she belongs to any professional landmen associations, the largest one being the American Association of Professional Landmen (AAPL). Many of these associations have codes of ethics that landmen agree to follow. For example, the AAPL Code of Ethics state that:

> *The Land Professional, in his dealings with landowners, industry parties, and others outside the industry, shall conduct himself in a manner consistent with fairness and honesty, such as to maintain the respect of the public.*

If you believe that the land professional has used intimidation tactics, or has lied to you during the negotiations, you should call the landman's association and report the incident. For example, the AAPL has an Ethics Committee to which you may direct complaints. Their address is: American Association of Professional Landmen. Ethics Committee. 4100 Fossil Creek Blvd. Fort Worth, TX 76137. Phone: 817-847-7700.

ment payments. For example, they might be willing to pay a percentage overriding royalty to split estate owners, if it were in lieu of surface damage payments.

- Some companies recognized that the actual implementation of the surface use agreement was a potential area of conflict. Some felt that giving the landowner a single, local point of contact for the agreement would be good. Others did not necessarily provide for this in the agreement, yet said that they believed that landowners prefer companies who have a local office or point of contact. Some company representatives also stated that more authority should be given to local company staff to resolve disputes.

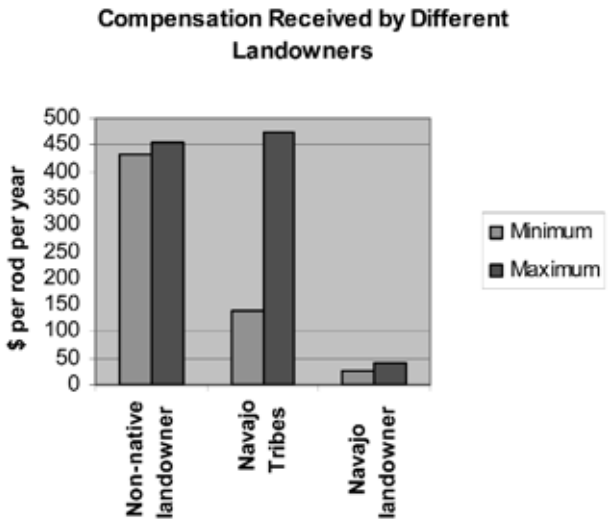
How to Determine Reasonable Compensation

Often, there is no equality in the amount of compensation received from one landowner to the next, or from one region to the next. Also, it is not always easy to find out how much you should be asking for. Often, there are clauses in surface use agreements that prohibit surface owners from disclosing the details of their agreement. This makes it extremely difficult for landowners who are negotiating a surface use agreement to know what is reasonable, or to try to negotiate agreements similar to what their neighbors have negotiated. Still, that should not prevent landowners from talking with other landowners or attorneys, and trying to find out what level of compensation others have been able to receive.

Navajo landowners not receiving the "fair market value" for leased land

Many natural gas pipelines that originate in the San Juan Basin of Colorado and New Mexico cross lands owned by Navajo tribes, individual Navajo landowners, and non-Native landowners. In August of 2003, it was brought to light that some Navajo tribes and individuals in the region were not being compensated for pipeline rights-of-ways at the same rate as private landowners. A report released by a court-appointed investigator revealed that the U.S. Department of the Interior leased Navajo land to oil and gas pipeline companies for as much as 20 time less than the amounts paid to nearby private landowners. "It is doubtful," wrote the investigator, Alan Balaran, whether Navajos "are receiving 'fair market value' for leases encumbering their land. It is certain they are denied the information necessary to make such a determination."[458]

On an annual basis, private landowners who leased their land to oil and gas companies received between $432 and $455 per rod (16.5 feet) of land leased; Navajo Tribes negotiated payments of between $140 and $475 per rod; and individual Navajo landowners only received from $25 to $40 per rod. Using these figures, over the 20-year life of the leases, individual Navajo landowners could receive $11,000 less than their private landowner neighbors. According to a Denver Post article, because the Interior Department did not provide translators for the pipeline right-of-way negotiations, "some of the individual Navajos put their thumbprints on dubious leases they couldn't read and never had explained to them."[459]



The government in Alberta, Canada, has prepared information for surface owners on how to determine adequate compensation payments.[460] Alberta is a major oil and gas producing region, and oil and gas companies that operator there are required to negotiate a "surface lease" with the surface owner (similar to the mineral lease that is negotiated with a mineral owner). In fact, companies are not allowed on a surface owner's property, except to conduct the land survey, until the lease has been negotiated, signed, and the first-year compensation paid. Although prepared for Alberta landowners, the guidelines below may provide landowners in the United States with a starting point for assessing how much to ask for in compensation.

The dollar amounts are in Canadian dollars ($1 Canadian = approximately $0.83 U.S.).

Entry Fee	The entry fee is $500 (approximately $415 U.S.) per acre of land granted to the company, to a maximum of $5,000 when 10 or more acres are used. The minimum entry fee is $250, paid when the area is half an acre or less. • For example, if a company uses 4.25-acres, the entry fee would be: 4.25 acres x $500 = $2,125 *Note: the entry fee for many U.S. states is higher than this amount. For example, in Wyoming the initial payment, which is akin to this entry fee, is closer to $2,000 (US) per acre.
Land Value	The value of the land used by the company is determined by the price expected if the land were sold on the open market by a willing seller to a willing buyer at the time when the lease was prepared. The value is also based on the highest approved use (agricultural, industrial, residential) for the land. • The per acre value for the well site is determined by dividing the value of the titled unit by the number of acres required.
Initial Nuisance, Inconvenience and Noise	This payment is for nuisance during the first year of the lease. • For example, in the first year landowners likely have to spend time dealing with a company's representatives and surveyors, preparing documentation, negotiating with the company and/or seeking advice from government agencies or lawyers. There may also be noise and inconvenience related to construction. The company should pay reasonable compensation to you for nuisance. Keep a record of all time spent, phone calls made and expenses incurred.
Loss of Use of the Land	The company pays an annual compensation for loss of the normal use of the well site area during the well site's life. The amount should approximate the value of the gross annual production reasonably expected from the area. • To calculate the amount, use the greater of yield and price averages from the past five years, or today's street price. For example, assuming canola production at 35 bushels per acre on a well site and access road occupying four acres, the loss would be 4 x 35 = 140 bushels. At $8.50 per bushel, the total annual loss would be $1,190.
Adverse Effect	This payment is related to inconvenience, nuisance and extra costs on the rest of the quarter section where the well site is located. • For instance, farming around the well site may require constantly turning corners, which can cause overlaps, extra strain on machinery, soil compaction, loss of seed and grain, and extra field and labor costs. Other factors related to adverse effect can be noise, dust, odor, additional traffic on the land, and proximity to a residence or farm site.
Other Relevant Factors:	If there are other considerations specific to a landowner's situation, they should be included when negotiating compensation.

FIGURE III-1. ISSUES TO CONSIDER WHEN DETERMINING SURFACE DAMAGE COMPENSATION PAYMENTS.

Reported Compensation Amounts

The following information comes landowners, real estate brokers, attorneys, mineral royalty associations, and community organizations.[461] This information is meant to provide surface owners with an idea of what others have been able to negotiate in various parts of the country. The chart is by no means comprehensive — undoubtedly, some surface owners in these areas receive more or less compensation based on their particular circumstances.

Location	Item	Compensation
Sublette County, WY	Surface damage payment per well	$2,500
Wyoming	Initial payment per well site (1/2 acre) Annual payment Use of existing roads	$1,000 $1,000 $1,000
Wyoming	Initial payment per well Roads and pipelines 4” pipeline – initial payment 4” pipeline – annual payment 8” pipeline – initial payment 8” pipeline – annual payment	$1,000 - $1,500 $5-$10/rod (1 rod = 16.5 feet) $8/rod $4/rod $16/rod $8/rod
Weld County, CO	Surface damage payment per well site (2 acres) 4” pipeline	$4,000 - $5,000 $33/rod
La Plata County, CO	Surface damage payment per well (well site 6/10 acre), plus payments for roads, pipelines and compressor sites 16” inch pipelines	$5,000 - $35,000 $1-$86/rod
Las Animas County, CO	Well site (7/10 acre) Access road	$2,000 - $2,500 $25/rod
Oklahoma	Payment for well pad and access road (appraised value)	$7,500 - $8,600
Kansas	Well site damages 8” pipeline	$5,000 - $10,000 $30-$35/rod

FIGURE III-2. EXAMPLES OF COMPENSATION PAID TO SURFACE OWNERS IN VARIOUS PARTS OF THE U.S.

The following chart (Figure III-3) contains information gathered by the Powder River Basin Resource Council. It shows compensation amounts that some Wyoming landowners were able to negotiate for lands affected by coalbed methane development in the year 2000.[462]

Item	Compensation
Right-of-way easements	$3.00 - $3.50 per rod (1 rod = 16.5 feet; 320 rods = 1 mile)
24-inch diameter pipeline	$13 - $25 per rod
8-, 10- or 12-inch diameter pipelines	$13 - $15 per rod
4- or 6-inch diameter pipelines	$6 - $8 per rod
Small waterlines, e.g., 2-inch diameter	$0.00
Trenches/electrical between well-heads	$0.00
Above-ground power lines and poles	Same as the power company's going rate
Pod Building - meters production, 10 x 12 feet and 8 x 12 feet	$1000/year
Screw compressors – 20 x 40 feet (1 per 8 wells), rented by the acre	$2150/acre for the first year, and then $1200 - $1500/acre for every year thereafter
Large Compressors This example is for a compressor on a 3.67-acre compressor site.	Chain link fence, gravel road to site. Road - $5 per rod per year Compressor - $1300 per acre/year (for five years), with an increase of $500/acre for each additional 5-year renewal period. Reseeding - $325/acre – landowner pays for seed and uses own equipment
Receipt Stations – where production is metered. These stations may include several buildings taking up a 15-foot x 35-foot area.	$1500 per year, paid 5 years in advance. Rental fee is tied to Consumer Price Index, so the initial rental is $7500 after the first 5 years are over. The agreement reflects that $1500 per year is the least the landowner will be paid.
Wells	$500 - $1500 per well for the first year. Every year after that, landowner receives an annual payment of $700 to $1000.

FIGURE III-3. EXAMPLES OF COMPENSATION RECEIVED FOR SURFACE DAMAGE RELATED TO COALBED METHANE DEVELOPMENT.

How much does compensating surface owners affect a company's "bottom line"?
According to the Landowners Association of Wyoming:

> *Surface Owner Accommodation legislation, whether enacted by a ballot initiative or by the legislature, will have no significant impact on revenues generated by Wyoming's oil and gas industry. It may require some additional monies to be spent by the oil and gas industry to compensate the private landowner for losses due to their activities, but those losses are currently being borne by the private landowners—individuals who in no way caused the losses. Currently, Anadarko Production, a top 15 producer, voluntary grants a 1-3% royalty interest in the production to the surface owners on the Union Pacific lands in Wyoming's southern corridor. Clearly, compensating landowners for damages caused by oil and gas activities can go hand-in-hand with being a prudent and successful oil and gas operator.*
>
> *An average well on the Pinedale Anticline in Sublette County costs $2.5 million to drill and complete. Currently companies operating in that area offer $2,500 per well location for a surface damage payment which equates to 1/10th of 1% of the cost of that well going to the affected surface owner. If negotiations ensured by this legislation result in a higher surface damage payment – say even 10 times higher in the extreme case – the surface damage payment would still be less than 1% of the total cost of drilling that well. In this example, the total surface damage payment of $25,000/location would be 3/4 of one day's revenues of a well that is estimated to produce for 20 years. Looking at this another way, the overall IRR (internal rate of return) for this well would be reduced to 25.0% from 25.5% as a result of this higher surface damage payment.*[463]

Examples of Surface Use Agreements

The following are some examples of Surface Use Agreements, which will not only provide you with some guidance on what to ask, but also will help to familiarize you with the language used in these sorts of agreements. The first agreement is a copy of a surface use agreement from Wyoming, which includes clauses that might not be present in the standard agreements that companies ask surface owners to sign. This agreement comes from the Powder River Basin Resource Council web site. This web site also has sample pipeline and right-of-way agreements (see Chapter V for details).

The second agreement is a Mineral Extraction Agreement (MEA) between Ted Turner and El Paso Production Corporation. While not perfect, there are clauses in the Vermejo Park Ranch MEA that are prime examples of how a company can minimize the impact of coalbed methane development on landowners' lives and lands. Ted Turner managed to achieve this agreement without owning the mineral beneath his land. He does, of course, have the financial leverage to negotiate this very landowner-friendly agreement. But this fact should not prevent other landowners from attempting to negotiate similar provisions in their surface use agreements.

FIGURE III-4. CASTLE ROCK, VERMEJO PARK RANCH. Directionally drilled wells access gas beneath this important elk habitat. Photo used with permission from Vermejo Park Ranch.

analysis indicates that a project would exceed the exposure limits in the event of an accident, the township would deny the required land use permit. 2) Implement an effective emergency warning system. 3) Inform the township about hazardous materials used on the site.

- **Colorado communities gain some ability to regulate oil and gas**

  In Colorado, courts have ruled that local governments, as well as the state government, have the ability to regulate oil and gas companies. The Colorado Appeals Court decided in 2002 to uphold a trial court ruling in a case between the town of Frederick and the oil and gas operator North American Resources Co. (NARCO). The town had passed an ordinance requiring gas and oil companies to obtain a special use permit to drill in town, and pay an application fee of $1,000; as well as requiring certain setbacks, and noise and visual impact mitigation, among other things. NARCO went ahead and drilled a well without getting a permit from the town. The town initiated a court action, and the trial court stopped the operation of the well and ordered the company to either remove the well or get the required permit from the town. The case went to the Colorado Appeals Court. The Appeals Court ruled that Colorado communities, including counties, can regulate oil and gas wells, as long as the regulations do not conflict with state laws.[475] The court acknowledged that town's ordinances may delay drilling, but upheld the regulatory scheme as a whole because the ordinances did not allow the town to prevent drilling entirely or to impose arbitrary conditions that would materially impede or destroy the state's interest in oil and gas development.[476]

  Examples of conflicts between town ordinance and state laws:

  - the regulations of setback requirements, noise abatement, visual impact of oil and gas operations, and the authority of the town to assess additional penalties for violation of state rules.

  Examples of acceptable community ordinance provisions:

  - requiring companies to obtain a special use permit. The court said that this did not conflict with the state's objectives even though it could result in a delay in drilling.
  - requiring an inspection fee and a $1,000 application fee, because there was no state rule on the amount a local government could charge for these fees.
  - requiring building permits for above-ground structures, access roads, and emergency response and fire protection plans and costs, again because there was no state rule that created an operational conflict with the town's rule.

The state of Colorado fails in its bid to limit local regulation of oil and gas

In 2002, the state agency that oversees oil and gas development, the Colorado Oil and Gas Conservation Commission (COGCC), amended a rule saying that state drilling permits would take precedence over any county permit or land-use approval process. This amendment was challenged in court by La Plata, Archuleta, Las Animas, Routt and San Miguel counties.

In September, 2003, the Colorado Court of Appeals ruled 2-1 that the COGCC overstepped its authority with the amendment, which the court said pre-empted county land-use rights; and the amendment was declared invalid. The two appeals court judges who ruled in favor of the counties wrote that counties "have a legally protected interest in enacting and enforcing their land-use regulations governing the surface effects of oil and gas operations."

Colorado Court of Appeals, September 25, 2003.[477]

- **Residents of Matunuska Susitna Borough in Alaska press for, and get, progressive local regulations on mineral leasing and development.**

  In 2003 Evergreen Resources purchased coalbed methane leases in the Matanuska Susitna (Mat-Su) Borough area of Alaska. Property owners were alarmed to find that State law allowed for permitting of these leases with no public notice. Citizens in the region took it upon themselves to became more and more educated on CBM development, inviting OGAP to Alaska to deliver landowner workshops. Eventually, public outcry against the leasing practices of the state led the Alaska Department of Natural Resources to hold a series of public meetings for the purpose of developing operating standards for the leases.

  After more than a year of controversy surrounding the CBM leases, Pioneer Natural

Resources announced that the Mat-Su leases acquired through its merger with Evergreen Resources would be relinquished to the State. Despite the return of the leases, the Mat-Su Borough Assembly took steps to prevent a situation of this magnitude happening in the future. Members of the Borough Assembly traveled to the lower 48 to visit areas with CBM development and talk with local governments about oil and gas regulations. In the fall of 2004, the Borough Assembly passed a CBM ordinance with several progressive provisions, for example, requiring ground and surface water monitoring plans, and allowing a surface owners to deny access until a surface use agreement is signed. The Mat-Su ordinance is available on-line at: http://www.matsugov.us/Assembly/documents/04-175AMor.pdf

Industry Will Try to Push Back

Citizens and local governments must anticipate that industry may object to any additional regulations that impose a perceived burden on the way that they do business. There have been many cases where citizens have made some strides in surface owner and environmental protection, only to have the industry use their clout to have the protections removed.

- **Exploratory wells allowed in a sensitive watershed, despite community opposition.**
  In 2002, in Delta County, Colorado, local citizens groups such as the Grand Mesa Citizens Alliance, worked hard to organize old-time farmers, ranchers, fruit growers and others to convince county commissioners to reject well applications that threatened the water supply in their county. County commissioners denied four of five applications by Gunnison Energy to drill exploratory coalbed methane gas wells. One Delta County Commissioner said that the wells were denied because they were in the middle of the county's watershed. The one well that was approved was located in a remote end of the county where domestic water supplies would not be threatened. The decision went against an earlier decision by the state Oil and Gas Commission, which approved the exploratory drilling.[478] The county also imposed a moratorium on drilling, pending further study of impacts on the water supply, largely due to the efforts of the Western Slope Environmental Resource Council.[479] Legal actions were initiated by Gunnison against the county, and Delta county against the Colorado Oil and Gas Conservation Commission. In 2003, a Denver District court ruled that the county did not have jurisdiction to deny the permits on the basis of water quality or quantity concerns, and Gunnison was issued its permits.

- **Oil and gas industry tries to remove ability of local governments to regulate oil and gas in Kentucky."**
  In early 2003, the oil and gas industry drafted a bill to remove virtually all ability for Kentucky counties to adopt any ordinances related to oil and gas development. At the time, the law gave counties broad powers to protect public health, safety and the environment, as long as the county's regulations did not conflict with state laws.

  The issue that prompted the bill was that Letcher County, Kentucky was considering passing an ordinance regulating the placement of "gathering lines" used to gather gas and oil from wells, due to abuse of landowners' rights. Rather than suggesting that the state implement a program to address the issue of gathering lines (e.g., make the industry accountable to surface landowners for the damage caused when gathering lines are located), the oil and gas industry simply proposed a bill to remove local government authority over all aspects of the industry.

  In February, 2003, the Kentucky Legislature passed the bill, despite citizens' attempts to stop it.[480] Continued citizen action helped to force some amendments to the bill, and in March, 2003, the Senate passed an amended bill that allows local communities to adopt ordinances that regulate oil and gas exploration, production, development, gathering and transmission, if they do so through community planning and zoning processes. The Senate

opment in their backyards. This is why we are one of the founding members of the Michigan Energy Reform Coalition. MERC has provided our township with a statewide view of things, and has given us the access to information and expertise vital to making intelligent decisions.

One of the main reasons our township has been instrumental in MERC is because the issues surrounding oil and gas development are too big to confront alone. MERC shares our goal -- to create a cooperative partnership with the oil and gas industry that will insure reasonable industrial development in our neighborhoods.

It comes as no surprise that some members of the oil and gas industry are loudly complaining that the proposed legislation will put them out of business, and that MERC's hidden agenda is to stop oil and gas development. We have heard these ridiculous accusations before. And we have learned our lesson, which is to let reality take its course, to stick to the truth, to be patient, and with time, our reasonable demands will be met.

The days of letting the oil and gas companies and the GSD behave like dictators are over. The days of companies ignoring the people who live and work amongst their projects are over!

The bills currently under consideration by the Legislature are for minimum changes that are long overdue. They are just the start of a process of insuring that townships, counties, and citizens have a say in the health, safety, and quality of life in their communities. We hope our legislators see that these bills become law.

15. LAURA AMOS: HYDRAULIC FRACTURING

FAMILY'S WATER WELL WAS CONTAMINATED AFTER HYDRAULIC FRACTURING NEAR THEIR HOME.

By Laura Amos

My husband Larry, our daughter Lauren and I live south of Silt in the heart of what we call Encana's Industrial Wasteland. We were among the first in our area to have natural gas drilling on our property. We are among the unfortunate who do not own the mineral rights under our property. The "Good Faith Negotiations" required by the Colorado Oil and Gas Conservation Commission addressed none of our concerns. Encana sent to our home a nice old gentleman who sat at our kitchen table and told us more or less, "I feel for you, but you own the surface, we own the minerals, and we're coming in to drill. Here's the Surface Use Agreement, you can sign it, but you don't have to. If you sign it you get a check for $3000. If you don't sign you get no financial reimbursement for any damages that may occur." We hesitated to sign for a couple of weeks until we learned that what he was telling us was accurate—the law provided us no protection, no mediation, and no real power to negotiate. It also now appears that others who do not own the mineral rights under their land were also bullied.

In May 2001 while fracturing four wells on our neighbors' property (less than 1000' from our house on what's known as the G33 pad), the gas well operator 'blew up' our water well. Fracturing created or opened a hydrogeological connection between our water well and the gas well, sending the cap of our water well flying and blowing our water into the air like a geyser at Yellowstone.

Immediately our water turned gray, had a horrible smell, and bubbled like 7-Up. Water production dropped drastically from 15 gallons per minute to nothing or near nothing. Tests of our water showed 14 milligrams (mg) per liter of methane. That's almost as much methane that water will hold at our elevation. But the Colorado Oil and Gas Conservation Commission (COGCC) claimed that the methane was "transient" in nature. We were assured that methane is safe, that in fact our bodies produce it naturally, and that there are no known health effects. We were warned, however, to make sure there were no closets or pockets in our home where the gas could build up and explode. They tested the water in our well a couple more times that summer, ending in August 2001.

In the spring of 2003 I became very ill. I spent months in doctors' offices and hospitals. I was eventually diagnosed with Primary Hyper Aldosteronism, a very rare condition of a tumor in my adrenal gland. None of my doctors had any idea of how I could have acquired such a rare disease. The tumor and my adrenal gland had to be removed. As a result, I am concerned that my immune system is now compromised, as well as the other endocrine related systems that are linked with the adrenal glands.

For more than two years my husband and I felt more or less abandoned by the COGCC. We resolved nothing. In January 2004 I had had enough and decided to become better informed and make others aware of my predicament. I started my 1st letter-writing campaign. The gas commission came back, tested again, and again found 14 mg of methane per liter in our water. They determined that it was Williams Fork Formation gas, a Notice of Alleged Violation was issued to Encana, but no fine was administered by the COGCC.

In August 2004 I came across a memo written to the US Forest Service and BLM Regional offices in Delta County, describing the health hazard posed by a chemical used in fluids that are injected underground to enhance the release of methane. Dr. Theo Colborn of Paonia, Colorado submitted the memo in response to decisions that were being made in Delta County by the government officials to allow gas exploration and development on the Grand Mesa. Colborn is the President of the Endocrine Disruption Exchange, Inc (TEDX) and for over 10 years directed the World Wildlife Fund's Wildlife and Contaminants Program. She has been honored worldwide for her focus on the effects of synthetic chemicals on human and wildlife health. The focus of Colborn's memo was on a chemical called 2BE, used in fracturing fluids.

The following information was taken from Colborn's report: "2BE is a highly soluble, colorless liquid with a very faint, ether like odor." She wrote that at the concentration to be used in Delta county 2BE might not be detectable through odor or taste. "2-BE has a low volatility, vaporizes slowly when mixed with water and remains well dissolved throughout the water column." "It mobilizes in soil and can easily leach into groundwater." "It could remain entrapped underground for years." She noted it is readily absorbed by the skin and can easily be inhaled as it off-gasses in the home. Colborn cited the Agency for Toxic Substances and Disease Registry Profile that listed the following effects of 2-BE: kidney damage, kidney failure, toxicity to the spleen, the bones in the spinal column and bone marrow, liver cancer, anemia, female fertility reduction, embryo mortality, and the biggie that got my attention…elevated numbers of combined malignant and non-malignant tumors of the adrenal gland.

Of course that sent up a huge red flag! I have had no peace of mind ever since. Remember that from August 2001 until January 2004 no testing was done on our water. Our daughter was only 6 months old when fracturing blew up our water well. I bathed her in that water every day. I also continued breast-feeding her for 18 more months until she was 2 years old – during the time the tumor was developing in my adrenal gland. If there was a chemical in my body causing my tumor, she was exposed to it as well. She was in contact with the chemical through every possible exposure pathway.

After reading Colborn's memo, I tried to find out if Encana used 2BE in fracturing. Encana's spokesman, Walt Lowrey, assured several of our neighbors, and my husband and me that 2BE was NOT used. In addition, Lowrey told many reporters in western Colorado, Denver and the Associated Press that 2BE was not used on the pad, or anywhere in this area.

However, on January 31, 2005, I learned that the industry had not been telling the truth to all of us. In June 2001, five weeks after the operator and the COGCC knew that there was a connection between the gas well and my water well, they proceeded to fracture wells on the G33 pad again. It was reportedly an experimental fracture, a new idea to fracture into the Wasatch formation, the same formation that our water comes from. They fractured 2000 feet below the surface, and they DID use 2BE. Encana is now delivering us alternative water for use in our home, but we are concerned that our well water may never be safe again.

I am ONE MAD MOTHER who intends to continue to challenge the system that allows average citizens to be ignored and trampled on, without consideration for their health, their children's health, and life-long investments. I am ONE MAD MOTHER who believes it is the role of government to protect the average citizen. I believe that I should have the support and concern of the COGCC, but that is far from the case. Instead, it is obvious that the COGCC is continuing to be more concerned with corporate interests. In fact, Brian Macke, director of the COGCC recently told a CBS News Bureau Chief in Washington D.C. that I am crazy, and that my exposure to 2BE may have come from Windex!

Surface owners need some protection and some power in dealing with huge corporations who care only about profit. I am not the only person who believes her health has been compromised because of gas development in Garfield County. There are many others out there who feel that they have been violated. Giving surface owners some legal rights to protect themselves and their property is critical in order to prevent more situations like mine.

16. COMPANY'S THREAT TO BOND AND DRILL IS NOT *NEGOTIATING IN GOOD FAITH.*

THE FOLLOWING LETTER WAS WRITTEN TO ASK COLORADO LEGISLATORS TO SUPPORT A BILL THAT WOULD PROVIDE PROTECTIONS FOR SURFACE OWNERS.

By Bruce Thomson

I'm writing in hope that my story of working with BP Amoco will help persuade you to support the Curry Surface Owners Compensation Bill.

My background is as a CPA, small business owner, and sometimes real estate developer. Along with my wife, I own 157 acres about 15 miles east of Durango that we plan to develop. The land has been conceptually approved by La Plata County for 10 residential lots.

In 2000, we received notice from BP Amoco of their intention to drill another gas well on our land (there was one on the property when we bought it). I specifically asked to work directly with whomever was authorized to make final decisions regarding well placement, pad size, noise mitigation, compensation, etc. I was told that Ralph Chamberlain of Timberline Land Corporation was the man for me to work with. After many hours of work and numerous walks on the land, Ralph and I agreed to a pad location and size with specific protection for about a dozen very nice, large Ponderosas.

Then I got a call from BP Amoco, from the man for whom Ralph was working. This company representative said that what Ralph and I had agreed to had no standing and that BP Amoco and I

would have to begin all over again on working through well placement, pad size, etc. In my mind, this was an egregious breach of good faith. If I had been working with a building contractor in an arm's length transaction, I would have severed the relationship immediately and refused to do business with them.

But as I was reminded by BP Amoco in every phone conversation, letter, and meeting at that time, I had no choice but to do business with them and if I didn't cooperate, they didn't need to do business with me and they would simply 'bond and drill'. 'Bond and drill' became the gun to my head that made me realize that I could only ask for or resist very little and then I'd better shut up.

As it turned out, BP Amoco drilled the well in approximately the location that Ralph and I had agreed to, but with a much bigger pad size so that we lost those dozen or so Ponderosas closest to the gas well that we had hoped to protect. I can't tell you specifically what compensation or promises of mitigation my wife and I got from BP in our Surface Use Agreement because I am legally bound to confidentiality by the agreement itself, but I can tell you that the money doesn't come close to compensating us for the damage to the surface and the promises of mitigation are pretty much non-existent.

I was opposed to the agreement confidentiality provision because I would like to be able to share the experience I had with BP Amoco with other landowners facing the same situation and perhaps help them, but again BP Amoco held the gun to my head and I was forced to leave the confidentiality provision in the agreement. My relations with BP Amoco were and continue to be very cordial, but there's always the implicit understanding that the game is rigged in their favor and I'd better cooperate or else.

I am a businessman and I believe in the free market. I believe that BP Amoco has the right to profit from their mineral rights, but I also believe that I have the right to enjoy and profit from my surface rights. By drilling a gas well on my land without adequately compensating me for surface destruction or protecting against noise or other pollution related to the gas well, I have been denied a portion of my surface rights.

The 10 lots that I will develop on my land will now all have a reduced value because of the proximity of the gas wells and it will be my family and not BP who suffers that financial loss.

I ask you to please support the Curry Surface Owners Compensation Bill to help level the playing field between gas well operators and land owners.

Don't let gas well operators continue to exploit their mineral rights at the expense of land owners' surface rights.

Thank you,

Bruce M. Thomson

17. WYOMING LANDOWNERS FACE CONDEMNATION OR LOSS OF HOMEOWNERS' INSURANCE

By Dan and Barbara Renner

Under the current laws of the State of Wyoming, Landowners who own their surface but not the minerals lying underneath (commonly referred to as split estate) face a desperate decision: Either agree to allow a seismic company to place explosives on your property and detonate them, or be condemned under eminent domain.

But wait, there's more...Should the landowner agree to allow the explosive seismic testing to take place in order to avoid condemnation, they may lose their homeowners' insurance. So, what do you do? You call the Governor, right?

In June 2004 the residents of Clark, WY, a small community on the outskirts of Yellowstone Park, received notification of a pending 3-D seismic testing project in a 47 square mile area that encompassed much of the Clark community. Quantum Geophysical, Inc., based in Houston, TX, was contracted to perform the 3-D seismic testing and proposed 3,420 seismic shotholes in and around Clark. This proposed activity is unusual in that Clark is a residential community encompassing approximately 350 private landowners and this activity will take place in their front yards!

In addition to the seismic testing, Windsor Wyoming, LLC, an oil and gas developer based in Oklahoma City, has applied to the BLM and the State of Wyoming for permits to install approximately 20 miles of pipeline across public and private lands, as well as the Clarks Fork River, and construct a gas separation plant in Clark. Again, this exploration and development activity, will take place in the front yards of Clark's residents. Such activity is not unknown in the area — Windsor has taken over the operation of an abandoned well site that sits just one-quarter mile of 5 homes. But residents in the area had not realized until recently that all of this activity, particularly explosive seismic testing, places them jeopardy when it came to homeowners' insurance.

Much of the private land in the Clark area overlies minerals owned and leased by the federal government. Under Wyoming law, the mineral owner (or the mineral lessee) holds a superior position to that of the surface owner. Surface owners in Wyoming are required by law to allow open access to their lands by the oil and gas industry for the purposes of exploration and development. Attempts to block or inhibit that access will result in condemnation procedures against the surface owner.

In January 2005 Quantum Geophysical began to contact, via telephone and mail, residents in the Clark area regarding the not yet permitted seismic testing they had been hired to conduct. One of the residents, Dan Renner, questioned Quantum,s representative (Bruce Fulker) regarding the possibility of unexploded ordnance remaining on his property following the testing and who is liable should that ordnance explode at a later date. He also requested information regarding the type of explosive to be used, how often misfires occur and how long it would take any unexploded ordnance to deteriorate. The representative could not readily answer the questions, but assured Mr. Renner he would obtain the answers.

The events that have taken place subsequent to Quantum,s phone call have made it abundantly clear that Mr. Renner and other surface owners in his situation are caught in an untenable position: If they allow seismic testing to place and permit explosives on their property, they risk losing their homeowner's insurance; If they oppose the testing in order to maintain adequate insurance coverage, they risk condemnation by the seismic testing company via the eminent domain laws in the State of Wyoming. A full explanation of the events follows:

Mr. Fulker replied, in writing, to Mr. Renner that the explosive his company would be using is Seis-

gel, that approximately 1% of the charges would misfire and that the sleep time for Seis-gel is two years (after which it would begin to deteriorate until it eventually became completely inert). Mr. Fulker did not address the liability issues.

However, Mr. Renner had begun to conduct some research on his own. He phoned his insurance company, advised them of the proposed explosives and seismic exploratory operations and asked about his liability coverage. He was promptly advised that should such activity take place on his property, his homeowner,s insurance would either be cancelled or would not be renewed on the next renewal date.

Mr. Renner's next call was to the Wyoming Insurance Commissioner's office. He posed the same questions and was told that the commissioner's office would have to investigate the matter and would get back to him in about a week. Approximately an hour later, Mr. Renner received a call from the Insurance Commissioner's office advising that they could not be of any assistance to him. He was referred to Eric Nelson, an attorney with the Wyoming Oil and Gas Conservation Commission (WOGCC).

A message was left for Mr. Nelson which resulted in a phone call from Mr. Don Likwartz, State Oil and Gas Supervisor with the WOGCC. Mr. Renner was advised that the issue of homeowner,s liability coverage during and after seismic testing had never come up before and questioned Mr. Renner as to why he had contacted his insurance company. Mr. Likwartz said he did not have any answers at that moment but would look into the matter. The last contact from Mr. Likwartz was approximately a week later. He advised that the WOGCC still didn't have any answers.

Mr. Renner contacted a local insurance agency and asked that they attempt to find an insurer who would be willing to cover him under the seismic testing circumstances. The insurance agent responded about a week later advising Mr. Renner that he had contacted four companies (that would insure ranch property of his type) and was told that "with the possibility of undetonated explosives on his property, they would not be willing to write a policy which would include liability."

Further research led Mr. Renner to Mr. Bob Hartwig, Senior Vice President & Chief Economist with the Insurance Information Institute (NY). Mr. Hartwig stated that he knew of no underwriter who would write a policy for liability insurance under the proposed circumstances. He further advised that if a landowner signed the seismic agreement to allow testing involving explosives to take place without notifying his insurance provider, he had significantly changed the conditions of his coverage; his insurance provider could potentially deny any claim based on that change in conditions. On the other hand, if the homeowner notified his insurance carrier of the seismic activities, he would most likely be cancelled, or at the very least, not renewed on the next renewal date. Mr. Hartwig went on to say, however, that the issue could certainly be resolved, although not quickly. He offered a series of solutions, including legislative changes that would be required, which are attached. Mr. Renner forwarded Mr. Hartwig's email response to Ryan Lance, Office of the Governor, State Planning Office, Cheyenne, WY.

Governor Freudenthal's office, through Mr. Lance, has been supportive to the surface owners in Clark who find themselves faced with a no-win situation and has tried to come up with a quick and adequate solution for all involved. The WOGCC, on the other hand, has taken the approach of "they will sign on the dotted line, or they will be condemned." The BLM has maintained that the issue of insurability on private lands does not fall under their purview and that the issue of insurability on public lands "should not be problem."

The Governor's office issued a final statement to the residents of Clark during a community meeting on February 16: The issue is a private party issue that has to be resolved between the two parties. His office offered to assist in finding a solution, but advised that the surface owner and Quantum would have to resolve the issue on their own. "We can't have the heavy hand of the State

involved in a private property issue," said Mr. Lance. (Billings Gazette, February 22, 2005)

The problem with that solution is that it isn't a "private party" issue. If the parties fail to come to an agreement it becomes a State issue with the seismic company using State eminent domain laws to condemn private property and permit seismic testing to go forward. At that point the landowner is right back where he started with the risk of becoming uninsurable.

Furthermore, the issue is much more far-reaching than an agreement between a landowner and a seismic company in Clark, Wyoming. It affects similarly situated landowner's throughout the State and possibly throughout the U.S. It affects lenders who hold the mortgages on such property and have insurance requirements that must be met by the borrower. It affects the ability of insurers to write insurance in Wyoming and other states where explosive seismic activity is involved.

One has to ask has this administration become so unconscionable when it comes to oil and gas development that they would not only allow, but support development in subdivisions, next to schools, alongside churches, and in people's front yards? Better yet, has the quest for development become so outrageous that the State would allow people's land to be condemned if they do not agree to allow seismic activity in order to maintain their homeowners insurance?

Chapter V

Sources of Information

Oil and Gas at Your Door?

A Landowner's Guide to Oil and Gas Development

Second Edition

OIL & GAS ACCOUNTABILITY PROJECT

P.O. Box 1102 • Durango, Colorado USA 81301
Phone: 970-259-3353 Fax: 970-259-7514
www.ogap.org

Chapter V
Sources of Information

RESOURCES ON THE OIL AND GAS DEVELOPMENT PROCESS

U.S. Environmental Protection Agency
October 2000. *Profile of the Oil and Gas Extraction Industry.* EPA Office of Compliance Sector Notebook Project.
http://www.epa.gov/compliance/resources/publications/assistance/sectors/notebooks/oil.html

Baars, D.L., Watney, W. Lynn, Steeples, Don W., and Brostuen, Erling A. 1993.
Petroleum: A Primer for Kansas. Educational Series 7. Kansas Geological Survey.
http://www.kgs.ukans.edu/Publications/Oil/

Natural Gas—from wellhead to burner tip. http://www.naturalgas.org

Pembina Institute
This Canadian institute is an independent, not-for-profit environmental policy research and education organization. Pembina Institute has developed a series of primers on Environment and Energy in the North. While these primers are geared for northern environments, they also contain a lot of excellent general information on the oil and gas development process.
http://www.pembina.org/publications_item.asp?id=168

Centre for Energy
A Canadian energy industry web site that has some basic overviews of the development process for conventional and nonconventional oil and gas sources. http://www.centreforenergy.com/generator2.asp?xml=/silos/ong/UNGOverview01XML.asp&Template=1,1,1

Resources on Oil and Gas Development on Public Lands
See the publication *Preserving our Public Lands* for more information on the federal laws that apply to oil and gas development on public lands. This publication provides citizens with some strategies for protecting public lands from the harmful effects of oil and gas development. To obtain a copy of this publication, contact: the Wyoming Outdoor Council; the Oil and Gas Accountability Project; or download a copy from the Western Resource Advocates web site: http://www.westernresourceadvocates.org/media/pdf/preserv_public_lands_FINAL.PDF

Information on the federal leasing process can be found at the BLM Colorado web site.
http://www.co.blm.gov/oilandgas/leasinstruct.htm

Regulations that govern the BLM's oil and gas leasing program may be found in Title 43, Groups 3000 and 3100 of the Code of Federal Regulations (a publication available in BLM State Offices, law libraries and most public libraries).

Morton, P., Weller, C., Thomson, J., Haefele, M. and Culver, N. 2002.
Coalbed methane and public wildlands: how much and at what cost?
http://www.wilderness.org/Library/Documents/upload/ Drilling-in-the-Rocky-Mountains-How-Much-and-at-What-Cost.pdf

Resources on Impacts to Livestock

Marr-Laing, T. and Severson-Baker, C. 1999. *Beyond "Eco-terrorism": The Deeper Issues Affecting Alberta's Oilpatch.* Pembina Institute for Appropriate Development. Drayton Valley, Alberta. pp. 13-15. This report describes a number of studies that have shown links between oil and gas operations and health effects on livestock.
http://www.pembina.org/pdf/publications/oilpatch.pdf

Resources on Air Emissions

The *Health Effects Notebook for Hazardous Air Pollutants* is an excellent resource for information on specific air pollutants. It can be found on the U.S. EPA's web site.
http://www.epa.gov/ttn/atw/hapindex.html

An excellent report on the impact of hydrogen sulfide emissions from gas wells and related facilities on surface owners is: Schindler, D. 2001. Survey of Accidental and Intentional Hydrogen Sulfide Releases Causing Evacuations and/or Injuries in Manistee and Mason Counties from 1980 to 2001. http://www.mecprotects.org/oilaccidents.pdf

Resources on Oil and Gas Noise

Breul and Kjaer. 2000. *Environmental Noise Handbook.*
http://www.macavsat.org/pdf_files/misc_reports/bk.pdf

Berglund, B., Lindvall, T. and Schwela, D. 1999. *Guidelines for Community Noise*. World Health Organization. http://www.who.int/docstore/peh/noise/Commnoise2.htm

Leventhall, G. 2003. *A Review of Published Research on Low Frequency Noise and its Effects.* Prepared for Department for Environmental Foods and Rural Affairs. (United Kingdom). http://www.defra.gov.uk/environmental/noise/lowfrequency/index.htm

Danish Environmental Protection Agency. 2002. *Danish Guidelines On Environmental Low Frequency Noise, Infrasound And Vibration.*
http://www.mst.dk/transportuk/02030000.htm#vibration

Resources on Oil and Gas Processing, Refining, Pipelines and Liquefied Natural Gas

NaturalGas.org
For more details on the steps involved in processing natural gas, read "Processing Natural Gas" at the NaturalGas.org web site.
http://www.naturalgas.org/naturalgas/processing_ng.asp

Pipeline Safety Trust
The Pipeline Safety Trust promotes fuel transportation safety. This web site has an extensive library with information on pipeline accidents, pipeline policies and regulations, and more.
http://pstrust.org/

Federal Energy Regulatory Commission.
Landowner Guide: An interstate natural gas facility on my land - what do I need to know?
http://www.ferc.gov/about/doing/6513gpo.pdf

Oil spill information research links.
This site provides a listing of government, industry, academic and nonprofit organizational web sites, with descriptions of the information offered on the various sites.
http://www.racerocks.com/pearson/ensy/oils/esoilspl.htm

Liquefied Natural Gas (LNG) Watch
The "LNGwatch" web site has been created by a coalition of citizens and organizations concerned with the health issues associated with LNG. The site contains links to various resources and information on LNG. http://lngwatch.com/

Energy Justice Network
The network works locally (Pennsylvania), nationally, and internationally, focusing primarily on liquefied natural gas issues. The network has also work on combined cycle natural gas power plants and other "dirty energy" issues. Contact Mike Ewall (215-743-4884, catalyst@action-pa.org) or visit their web site. http://www.energyjustice.net

RESOURCES ON "BEST" OR ALTERNATIVE TECHNOLOGIES AND PRACTICES

The authors of this publication do not claim that any specific technologies or practices in the following resources are the "best". The resources are included as potential sources of information on alternative practices in the oil and gas industry. Surface owners will have to decide for themselves what technologies and practices fit best with their needs.

Alaska Department of Environmental Conservation
A pollution prevention opportunities guide for the oil field service industry, from the Alaska Department of Environmental Conservation Pollution Prevention Office.
http://es.epa.gov/program/regional/trade/p2-oppt.html

A Canadian Working Group composed of industry, government, and public interest groups produced *Best Management Practices for Control of Benzene Emissions from Glycol Dehydrators*, which outlines methods for minimizing benzene emissions in new and existing plants; and provides more information on alternatives to glycol dehydration. The document is available on the Small Explorers and Producers Association of Canada (SEPAC) web site
http://www.sepac.ca/Downloads/bmp.pdf

Bureau of Land Management.
The BLM has a program dedicated to techniques used to reduce the visual impacts from surface disturbing projects. Information on this program can be found at
http://www.blm.gov/nstc/VRM/destech.html

Colorado Oil and Gas Conservation Commission
The commission's Outstanding Oil and Gas Operation Awards may give landowners a sense of what some companies have done to set them apart from the rest of the industry.
http://www.dnr.state.co.us/cdnr_news/oil-gas/2001810132249.html

Groundwater Protection Council
For example, they held a Produced Water Conference on Oct 15-17, 2002 in Colorado Springs, CO. Proceedings from this conference can be found at
http://www.gwpc.org/Meetings/PW2002/Post-Meeting-Report.htm

New Mexico Energy, Minerals and Natural Resources Department
In 2000, the Oil Conservation Division of the department released a two volume handbook on Pollution Prevention - Best Management Practices for the Oil and Gas Industry.
http://www.emnrd.state.nm.us/ocd/

Petroleum Technology Transfer Center (PTTC)
Case Studies on various technologies (some of these are highly technical) http://www.pttc.org/case_studies/case_studies.htm, and PTTC Technology Connections: State-of-the-Art Technology Summary http://www.pttc.org/tech_sum/statev8no1.htm

Railroad Commission of Texas
This state regulatory body has waste minimization information for various oil and gas related operations; a guidance document Minimization in the Oil Field Manual; and case histories of waste minimization projects.
http://www.rrc.state.tx.us/divisions/og/key-programs/ogkwast.html

Southwest Pollution Prevention Center, Gas and Oil Hub
This site provides a great deal of information on oil and gas pollution prevention alternatives for all stages of oil and gas development (drilling, well completion, oil and gas processing, oil and gas storage, pipelines, well servicing, oil recovery, transportation and more). Also, the site provides lists of wastes associated with various stages of oil and gas operations
http://p2.utep.edu/hubs/toc.cfm?hub=11&subsec=7&nav=7

U.S. Environmental Protection Agency
Oil and Gas Industry Sector Notebook describes pollution prevention opportunities
http://www.epa.gov/compliance/resources/publications/assistance/sectors/notebooks/oil.html

EPA's Natural Gas STAR Program is a source of information on waste minimization techniques in natural gas treating and processing operations. The program is designed to promote environmental protection through cost-effective measures without regulation, by encouraging natural gas companies to adopt "best management practices" that can reduce methane emissions. More information on the Natural Gas Star Program can be obtain by contacting: U.S. EPA Natural Gas Star Program, U.S. EPA, 401 M Street, SW Washington, DC 20460.
http://134.67.55.16:777/dc/methane/home.nsf/pages/gasstar

The Illinois office of the EPA produced the document *Best Management Practices for Oil Exploration and Extraction.*
http://www.epa.state.il.us/p2/fact-sheets/bmp-oil-exploration.html

Western Governor's Association
The WGA is developing a handbook of best management practices for coalbed methane development. Some of the topics likely to be addressed in their handbook include practices related to planning, landowner relations, land use, water, infrastructure, and fish and wildlife habitat. The handbook should be available in 2004. http://www.westgov.org/

Drilling Waste Management Information System
This is an online resource created by the Argonne National Laboratory and industry. It contains technical and regulatory information on standard and better practices for managing drilling wastes. http://web.ead.anl.gov/dwm/

COALBED METHANE RESOURCES

High Country News
This newspaper produced a special report called *Coalbed Methane Boom*. It can be found on their web site. http://www.hcn.org

ALL Consulting
ALL Consulting has prepared some in-depth material on CBM, including some information on

best practices and mitigation strategies. http://www.all-llc.com/CBM/

Wyoming CBM Clearinghouse
This web site is a clearinghouse of information about coalbed methane (CBM) in and around the state of Wyoming. The CBM Clearinghouse is a joint project of the University of Wyoming and the U.S. Bureau of Land Management. http://www.cbmclearinghouse.info/

East of Huajatolla Citizens Alliance
This group has produced numerous information sheets for citizens dealing with CBM development (including issues such as health and welfare, produced water, impacts on wildlife and livestock, well spacing, and many others). http://ehcitizens.org/cbmgas/index.htm

Montana Department of Environmental Quality
See their information on CBM Environmental and Economic Issues, which contains papers on agriculture, irrigation, water quality, air quality, biological issues, geology and soils, social and economic impacts, and other issues, including a study on *Potential Costs and Benefits to Montanans from CBM Development*. http://www.deq.state.mt.us/CoalBedMethane/index.asp

RESOURCES ON SLAPP SUITS

California Anti-SLAPP Project (CASP)
CASP is dedicated to helping protect and further the rights of Californians to participate in government and civic affairs and to speak freely about public issues. CASP maintains a resource and information center about California SLAPPs. CASP also provides legal assistance and representation to individuals and organizations to defend against SLAPPs.
Phone: 510-486-9123
http://www.casp.net

First Amendment Project (FAP)
FAP is a nonprofit public interest law firm active in two main areas of First Amendment law: anti-SLAPP and open government. FAP provides legal representation to individuals and organizations to defend against SLAPPs.
Phone: 510-208-7744
http://www.thefirstamendment.org

Political Litigation Project, University of Denver School of Law
The Political Litigation Project is run by University of Denver Professors George Pring and Penelope Canan, the leading authorities on SLAPPs. They have a wealth of knowledge about SLAPPs all over the United States, and beyond.
Phone: 303-871-2049

SLAPP Resource Center
http://www.slapps.org

NONPROFIT ORGANIZATIONAL RESOURCES FOR SURFACE OWNERS

For landowners facing gas well development, a number of resources are available. Information on various issues including how to negotiate with an oil and gas company and developing a surface use agreement can be accessed by contacting the nonprofit organizations and/or visiting the websites of the groups listed below. (As well as the groups listed in the Coalbed Methane Resources section.

East of Huajatolla Citizens Alliance in Colorado
This organization has useful information sheets on coalbed methane, and many of these fact sheets are useful for those dealing with conventional oil and gas extraction (e.g., topics such as Surface Use Agreements, Pooling, Force Pooling, Spacing, Citizens Rights and Responsibilities, and many others).
Phone: 719-941-4740 http://www.ehcitizens.org/cbmgas

Northern Plains Resource Council
This Montanta organization has produced a number of publications for surface owners, including *Coal Bed Methane - A guide to protecting your property*, and *Your Lands, Your Rights.*
Phone: 406-248-1154
http://www.northernplains.org

Oil and Gas Accountability Project
This Colorado/New Mexico group has produced this guide, along with various other materials that are helpful for surface owners.
Phone: 970-259-3353
http://www.ogap.org

Powder River Basin Resource Council
Located in Wyoming, this group has a section on their web site "Help for Surface Owners," which includes example legal documents, surface damage agreement checklist and a lot of other great information.
Phone: 307-358-5002 or 307-672-5809
http://www.powderriverbasin.org/helpforsurface_owners.htm

Western Organization of Resource Councils
A Montana-based group with a number of reports and fact sheets that may be useful to landowners (See also CBM resources above). These include: *How to Negotiate; How to Deal With Intimidation* and *Protecting Surface Owners and Promoting Responsible Coal Bed Methane Development*
Phone: 406-252-9672
http://www.worc.org

Michigan Land Use Institute
This organization has a great deal of information on surface owner issues with oil and gas. They also have a *Leasing Packet for Michigan Property Owners*, which includes educational information, tips on negotiating a lease, and model language for a lease addendum. According to the Institute, this packet has helped numerous property owners receive higher royalty rates, and establish protections for their surface land and groundwater. The leasing packet is free to Institute members, and is $15 for non-members.
Phone: 231-882-4723
http://www.mlui.org

GOVERNMENT-PRODUCED LANDOWNER GUIDES AND RESOURCES

A Landowner's Guide to Oil and Gas in Alabama, by Strudwick Marvin Rogers, J.D., and Lisa Lee Mancini. 26 p. 1991. $4.50. Order from Alabama Oil and Gas Board.
http://www.ogb.state.al.us/

Landowners Guide on Oil and Gas Leasing. Ohio Department of Natural Resources. Free Brochure. http://www.ohiodnr.com/mineral/oil/o6.htm

Answers to Typical Questions from the Public and Information for Surface Owners. Colorado Oil and Gas Conservation Commission. http://oil-gas.state.co.us/General.html

Landowners and Oil and Gas Leases in Pennsylvania. Department of Environmental Protection. Fact Sheet. http://www.dep.state.pa.us/dep/deputate/minres/oilgas/fs2834.htm

A Landowner's Guide to Oil and Gas Leasing. New York State Department of Environmental Conservation, Division of Mineral Resources. Brochure. http://www.dec.state.ny.us/website/dmn/Lndownrguide.htm

OTHER LANDOWNER AND MINERAL OWNER RESOURCES

David, Rick D. April 2000. *Conflicts Between Surface Owners and Mineral Lessees.* Internal Paper, Cotton, Bledsoe, Tighe & Dawson, P.C., Attorneys at Law (Midland, Texas). http://www.cbtd.com/news/conflicts.pdf

National Association of Royalty Owners (NARO) is geared toward mineral owners. They have free brochures, and paid publications on mineral deeds, leasing, *How to Survive Force Pooling*, and other topics. http://www.naro-us.org/index.shtml

PETEX Publications. *Land and Leasing*. This manual is for landowners, landmen, lawyers, and investors as well as all oil company employees. It takes a layperson's approach to the legal aspects of land-ownership, transfer, and leasing, privately owned land; state and federal lands; preparations for drilling, producing, and selling; agreements to explore and develop leased properties; and pooling, unitization, and release. It uses examples from Alaska, California, Louisiana, and Canada, Kansas, Michigan, New Mexico, North Dakota, Oklahoma, Texas, and Wyoming. 1984, 287 pp. $21. http://www.utexas.edu/cee/petex/pubs/reference.html

Purdue University Agricultural Economics Department. *Negotiating Oil and Gas Leases on Indiana Farmland.* http://www.agcom.purdue.edu/AgCom/Pubs/EC/EC-564.html

Real Estate Center at Texas A&M University has information for mineral owners and surface owners. Topics include: Negotiating Leases; Scrutinzing Royalty Payments; Recovery of Surface Damages and Remediation Costs; Subdivision Drill Sites, and more. http://recenter.tamu.edu/pubs/catoilg.html

Straube, Michele and Holland, Melinda. March, 2003. *A Conflict Assessment of Split Estate Issues and a Model Agreement Approach to Resolving Conflicts Over Coalbed Methane Development in the Powder River Basin.* Prepared For: U.S. Institute for Environmental Conflict Resolution. http://www.ecr.gov/pdf/CAR.pdf

NONPROFIT ORGANIZATIONS WORKING ON OIL, NATURAL GAS AND CBM ISSUES

NATIONAL AND REGIONAL ORGANIZATIONS

Oil and Gas Accountability Project
OGAP works with citizens and communities from the U.S. and Canada. Visit OGAP's web site for information on: general oil and gas issues; public health and toxics; alternative technologies and practices; federal and state regulatory reform; model local regulations; and surface owner protections.

Durango, Colorado Office
Phone: 970-259-3583
Email: gwen@ogap.org;
bruce@ogap.org;
lisa@ogap.org;
carolyn@ogap.org

Bozeman, Montana Office:
Phone: 505-776-3276
Email: jennifergoldman@ogap.org
http://www.ogap.org

Natural Resources Defense Council
Headquarters: New York
Phone: (212) 727-2700
Email: nrdcinfo@nrdc.org
http://www.nrdc.org

The Wilderness Society
Head office: Washington, DC
Phone: 1-800-THE-WILD
http://www.wilderness.org

Western Organization of Resource Councils
WORC is a regional network of seven grassroots community groups from Montana, North Dakota, South Dakota, Idaho, Oregon, Montana, and Colorado. WORC also has an office in Washington, DC.
Phone: 406-252-9672
Email: billings@worc.org; dc@worc.org
http://www.worc.org

STATE-BASED ORGANIZATIONS

Alaska

Alaska Center for the Environment, Anchorage
Phone: 907-574-3647
Email: cliff@akcenter.org http://www.akcenter.org

Cook Inlet Keeper, Homer
Phone: 907-235-4068
Email: bob@inletkeeper.org
http://www.inletkeeper.org

Denali Citizens Council, Denali Park
Phone: 907-683-2593
Email: leslie@denalicitizens.org
http://www.denalicitizens.org

Friends of Mat-Su (Alaska), Palmer
Phone: 907-746-0130
Email: cbm@pobox.mtaonline.net
http://www.foms.net

Northern Alaska Environmental Center, Fairbanks
Phone: 907-452-5021Email: info@northern.org
http://www.northern.org/artman/publish/coalBed.shtml

Colorado

Grand Valley Citizens Alliance, Parachute
Phone: 970-285-6276

San Juan Citizens Alliance, Durango (works in San Juan Basin)
Phone: 970-259-3583
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Email: pbieber@sensonics.org

Western Colorado Congress, Grand Junction
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Western Slope Environmental Resource Council, Paonia
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Kentucky

Kentucky Resources Council, Frankfort
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Montana

Greater Yellowstone Coalition, Bozeman
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Native Action, Lame Deer
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Email: gsmall@rangeweb.net

Northern Plains Resource Council, Billings
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Surface Owners of the Wolf Mountain Area, Billings
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Utah

Southern Utah Wilderness Alliance
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Wyoming

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Email: dthomas@nemontel.net
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Powder River Basin Resource Council, Sheridan
Phone: 307-672-5809
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Wyoming Outdoor Council, Lander
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STATE REGULATORY AGENCIES

State Oil and Gas Regulatory Agencies		Contact Information
Alabama	State Oil and Gas Board	http://www.ogb.state.al.us Ph: 205-349-2852
Alaska	Oil and Gas Conservation Commission	http://www.state.ak.us/local/akpages/ADMIN/ogc/homeogc.htm Ph: 907-279-1433
	Department of Natural Resources, Division of Oil and Gas	http://www.dog.dnr.state.ak.us/oil/ Ph: 907-269-8800
Arizona	Oil and Gas Conservation Commission	http://www.azgs.state.az.us/OGCC.htm Ph: 520-770-3500
Arkansas	Oil and Gas Commission	http://www.aogc.state.ar.us/ Ph: 501-862-4965
California	Department of Conservation, Division of Oil, Gas and Geothermal Resources	http://www.consrv.ca.gov/DOG/ Ph: 916-445-9686
Colorado	Colorado Oil and Gas Conservation Commission	http://oil-gas.state.co.us/ Ph: 303-894-2100
Florida	Department of Environmental Protection, Geological Survey	http://www.dep.state.fl.us/geology/ Ph: 850-488-4191
Georgia	Natural Resources/Environmental Protection	http://www.dnr.state.ga.us/dnr/environ/ Ph: 404-751-6612
Idaho	Department of Lands, Bureau of Surface and Mineral Resources, Oil and Gas Conservation Commission	http://www2.state.id.us/lands/Bureau/Surface_and_Mineral_Resources/Surface_Minerals_Resource_Mngmnt_Bur.htm Ph: 208-334-0200
Illinois	Illinois Department of Natural Resources, Division of Oil and Gas	http://dnr.state.il.us/mines/dog/welcome.htm Ph: 217-782-7756
Indiana	Indiana Department of Natural Resources, Division of Oil and Gas	http://www.state.in.us/dnroil/ Ph: 317-232-4055
Kansas	Kansas Corporation Commission, Conservation Division	http://www.kcc.state.ks.us/conservation/conservation.htm Ph: 315-337-6200
Kentucky	Department of Mines and Minerals, Division of Oil and Gas	http://dmm.ppr.ky.gov/OilAndGas.htm Ph: 502-573-0147
Louisiana	Department of Natural Resources, Office of Conservation	ttp://www.dnr.state.la.us/cons/conserv.ssih Ph: 225-342-5570
Michigan	Department of Environmental Quality, Geological and Land Management Division	http://www.michigan.gov/deq/0,1607,7-135-3311_4111--,00.html Ph: 517-373-7917
Mississippi	Oil and Gas Board	http://www.ogb.state.ms.us Ph: 601-354-7142
Missouri	Department of Natural Resources, Geological Survey and Resource Assessment Division	http://www.dnr.mo.gov/geology/geosrv/oil.htm Ph: 573-368-2100
Montana	Department of Natural Resources and Conservation, Montana Board of Oil and Gas Conservation	http://bogc.dnrc.state.mt.us/ Ph: 406-656-0040
Nebraska	Oil and Gas Conservation Commission	http://www.nogcc.ne.gov Ph: 308-254-6919
Nevada	Commission on Mineral Resources; Division of Minerals, Oil, Gas and Geothermal	http://minerals.state.nv.us/programs/ogg.htm Ph: 775-684-7040

New Mexico	Energy, Minerals and Natural Resources Department, Oil Conservation Commission	http://www.emnrd.state.nm.us/ocd Ph: 505-476-3440
New York	Department of Environmental Conservation, Division of Mineral Resources	http://www.dec.state.ny.us/website/dmn Ph: 518-402-8076
North Dakota	Industrial Commission, Oil and Gas Division	http://www.oilgas.nd.gov/ Ph: 701-328-8020
Ohio	Ohio Department of Natural Resources	http://www.ohiodnr.com/mineral/oil Ph: 614-265-6633
Oklahoma	Corporation Commission, Oil and Gas Conservation Division	http://www.occ.state.ok.us/Divisions/OG/Og.htm Ph: 405-521-2211
Oregon	Department of Geology and Mineral Industries; Oil, Gas and Geothermal Regulatory and Reclamation Program	http://www.oregongeology.com/oil/oilhome.htm Ph: 503-731-4100
Pennsylvania	Department of Environmental Protection, Bureau of Oil and Gas Management	http://www.dep.state.pa.us/dep/deputate/minres/oilgas/oilgas.htm Ph: 717-772-2199
South Dakota	Department of Environment and Natural Resources, Minerals and Mining Program	http://www.state.sd.us/denr/des/mining/oil&gas/o&ghome.htm Ph: 605-394-2229
Tennessee	Department of Environment and Conservation, State Oil and Gas Board	http://www.state.tn.us/environment/boards/oilandgas.php Ph: 615-532-1500
Texas	Railroad Commission, Crude Oil and Natural Gas	http://www.rrc.state.tx.us/divisions/og/og.html Ph: 512-463-6977
Utah	Division of Oil, Gas and Mining	http://www.ogm.utah.gov/oilgas/ Ph: 801-538-5277
Virginia	Department of Mines, Minerals and Energy, Division of Gas and Oil	http://www.mme.state.va.us/Dgo/default.htm Ph: 276-676-5423
Washington	The Department of Natural Resources, Division of Geology and Earth Resources, Energy (Oil and Gas) Regulation	http://www.dnr.wa.gov/geology/energy.htm Ph: 360-902-1450
West Virginia	Department of Environmental Protection, Office of Oil and Gas	http://www.dep.state.wv.us/item.cfm?ssid=23 Ph: 304-558-6075
Wyoming	Wyoming Oil and Gas Conservation Commission	http://wogcc.state.wy.us/ Ph: 307-777-7434

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