Appendix R

OIL AND GAS OPERATIONS

Introduction

This appendix describes, in general terms, the various activities involved in exploring for oil and gas on BLM-managed public lands; the process of acquiring oil and gas leases; and the process of developing, producing, and abandoning oil and gas wells on Federal leases. The descriptions of these activities are for the Kremmling Field Office (KFO) Draft Resource Management Plan (DRMP/) Draft Environmental Impact Statement (DEIS), and apply, primarily, to Jackson County.

Geophysical Exploration

Oil and gas can be discovered by direct or indirect exploration methods (such as the mapping of rock outcrops, seeps, borehole data, and remote sensing data). In many cases, indirect methods (such as seismic, gravity, and magnetic surveys) are required in order to delineate subsurface features that could contain oil and gas. Geophysical exploration could provide information that increases the chances of drilling a discovery well, as well as information that could discourage drilling, and the associated surface disturbance. More sophisticated geophysical techniques [such as three-dimensional (3D) seismic surveys] could supply enough information to model a reservoir, and optimize drilling in order to prevent excess wells, and the associated surface disturbance.

Gravity Surveys

Gravitational prospecting detects micro-variations in gravitational attraction caused by the differences in the density of various types of rock. Gravity data are used in order to generate anomaly maps from which faults and general structural trends can be interpreted. Generally, these surveys are not considered definitive due to the many corrections required (such as those associated with terrain, elevation, and latitude), and the poor resolution of complex subsurface structures. The instrument used for gravity surveys is a small portable device called a gravimeter. Generally, measurements are taken at many points along a linear transect, and the gravimeter is transported either by backpack, helicopter, or off-road vehicle (ORV). The only surface disturbance associated with gravity prospecting is that caused by a vehicle, if used.

Geomagnetic Surveys

Magnetic prospecting is commonly used for locating metallic ore bodies and, to a limited extent, in oil and gas exploration. Magnetic surveys use an instrument called a magnetometer in order to detect small magnetic anomalies caused by mineral and lithologic variations in the Earth's crust. These surveys can detect trends in basement rock, and the approximate depth to those basement rocks; however, in general, they provide little specific data to aid in petroleum exploration. Many corrections are required in order to obtain reliable information. The generated maps lack resolution, and are considered rudimentary views of subsurface geology. Magnetometers vary greatly in size and complexity, and most magnetic surveys are conducted from the air by suspending a magnetometer under an airplane. Magnetic surveys conducted on the ground are nearly identical to gravity surveys, and surface disturbance is minimal to non-existent.

Seismic Reflection Surveys

Seismic prospecting is the best, and most popular, indirect method for locating subsurface structures and stratigraphy that might contain hydrocarbons. Seismic energy (shock waves) is induced into the Earth using one of several methods. As these waves travel downward and outward, they encounter various rock strata, each having a different seismic velocity characteristic. As the wave energy encounters the interface between rock layers (where the lower layer is of lower seismic velocity), some of the seismic energy is reflected upward. Sensing devices, commonly called geophones, are placed on the surface in order to detect these reflections. The geophones are connected to a recording truck that stores the data. The time required for the shock waves to travel from the shot point down to a given reflector and back to the geophone is related to depth, and this value is mapped to give an underground picture of the geologic structure.

There are many methods available today that an Explorationist can use in order to induce the initial seismic energy into the Earth. All methods require preliminary surveying and the lying of geophones. The thumper and vibrator methods pound or vibrate the ground in order to create a shock wave. Usually, several large trucks are used in tandem, each equipped with vibrator pads (about 4 feet square). The pads are lowered to the ground, and vibrators on all trucks are triggered electronically from the recording truck. Information is recorded, and then the trucks proceed a short distance, and the process is repeated. Less than 50 square feet of surface area is required to operate the equipment at each test site. The trucks are equipped with large flotation type tires, which reduce the impact of driving over undisturbed terrain.

The drilling method uses truck-mounted drills that drill small-diameter holes to depths of 100 feet to 200 feet. Four (4) to 12 holes are drilled per mile of line. Usually, a charge of explosive is placed in the hole, covered, and detonated. The detonated explosive sends a shock wave below the Earth's surface that is, subsequently, reflected back to the surface from various subsurface rock layers. In rugged topography, a portable drill is sometimes carried in by helicopter. Charges are placed in the hole, as is done in a truck-mounted drilling operation. Another portable technique is to transport the charges in a helicopter to the source-point locations. The charges are placed on wooden sticks, or lath, approximately 3 feet above the ground. Usually, 10 charges in a line are detonated at once. In remote areas, where there is little known subsurface data, a series of short seismic lines might be required in order to determine the subsurface geology. Subsequently, more extensive seismic lines are arranged in order to obtain the greatest amount of geologic information.

Seismic information can be obtained in two-dimensional (2D) or 3D configurations. In order to obtain 3D seismic information, the seismic sensors and energy source are located along lines in a grid pattern. This type of survey differs from the more common 2D surveys due to the large volume of data, and to the intensive computerization of the data. The results are expensive to obtain; however, it gives a more detailed and informative subsurface picture. The orientation and arrangement of the components in 3D seismic surveys are less tolerant of adjustments to the physical locations of the lines and geophones; however, they are also more compact in the area they cover. Alignment can be fairly critical; however, spacing of the lines can often be changed in order to significantly increase the information collected. The depth of the desired geologic information dictates the spacing of the grid lines, with smaller spacing detailing shallower formations. The 3D surveys are very expensive, and are, usually, conducted after 2D surveys or drilling has delineated a geologic prospect that will justify the extra cost. Extensive computer processing of the raw data is required in order to produce a useable seismic section from which geophysicists can interpret structural relationships to depths of 30,000 feet or more. The effective depth of investigation and resolution are determined, to some degree, by which method is used.

A typical drilling seismic operation can use 10 people to 15 people operating 5 trucks to 7 trucks. Under normal conditions, 3 miles to 5 miles of line can be surveyed each day using the explosive method. The vehicles used for a drilling program include several heavy truck-mounted drill rigs, water trucks, a computer recording truck; and several light pickup trucks for the surveyors, shot hole crew, geophone crew, permit man, and party chief.

Public and existing private roads and vehicle routes are used. Cross-country off-highway vehicle (OHV) travel might be necessary in order to carry out tasks. Motor graders and (or) dozers might be required in order to construct access to remote areas. Concern about unnecessary surface disturbance has caused government and industry to more carefully plan surveys. As a result, earth-moving equipment is now only rarely used in seismic exploration work. Several trips a day are made along a seismograph line, which usually establishes a well-defined 2-track vehicle route. The repeated movement back and forth along the line (especially the light pickup trucks) defines the vehicle route. Spreading vehicles out so that vehicle routes are not straight, and so that vehicles do not retrace the same route has, in some cases, prevented the establishment of new vehicle routes, and has reduced impacts. Drilling water, when needed, is usually obtained from the nearest source.

Each of the foregoing exploration methods has inherent strengths and weaknesses, and Explorationists must decide which method is the most practical with regard to surface constraints (such as topography) that will still produce useful information. Economics and past information also play a role in determining the method used. Reconnaissance-type surveys of gravity and geomagnetic can be run in areas where there is limited information (with the attendant lower costs and less impact). More expensive, and higher impact, seismic surveys are run when more detailed information is required.

GEOPHYSICAL MANAGEMENT (PERMITTING PROCESS)

Geophysical operations on, and off of, an oil and gas leases are reviewed by the appropriate Federal Surface Management Agency (SMA) [such as the BLM, the Bureau of Reclamation (BOR), or the U.S. Forest Service (USFS)]. Effective administration and surface protection can only be accomplished through close cooperation between the Operator and the affected agency. The responsibilities of the Geophysical Operator and the Field Manager are as follows [U.S. Department of the Interior (DOI) H-3150]:

- **Geophysical Operator --** An Operator is required to file with the Field Manager a “Notice of Intent to Conduct Oil and Gas Exploration Operations.” The Notice of Intent should include a map showing the location of the line, all access routes, and ancillary facilities. The party filing the Notice of Intent should be bonded. A copy of the bond, or other evidence of satisfactory bonding, should accompany the Notice. For geophysical operation methods involving surface disturbance, a Cultural Resources Survey is also required. A pre-work field conference may be conducted. Earth-moving equipment should not be used without prior approval. Upon completion of operations, including required rehabilitation, the Operator is required to file a “Notice of Completion of Oil and Gas Exploration Operations.”

- **Field Manager --** The Field Manager should contact the Operator after the Notice of Intent is filed, and apprise the Operator of the practices and procedures to be followed before commencing operations on BLM-managed public lands. After the operations are completed, as specified by the Notice of Completion, the Field Manager should complete a final inspection, and notify the Operator if the terms and conditions of the Notice of Intent have been met, or if additional action is required. Consent to release the bond or termination of liability should not be granted until the terms and conditions have been met.

- **State Standards --** The Operator is required to register with the Colorado Oil and Gas Conservation Commission (COGCC). The COGCC standards for plugging shot holes and personnel safety will be followed.

- **Mitigation Measures --** Seasonal restrictions are imposed in order to reduce conflicts with wildlife, watershed damage, and hunting activity. When possible, geophysical exploration is conducted during the winter, when frozen ground and snow cover help to reduce impacts to sensitive resources (such as wetland or riparian areas and cultural resources sites). The most critical management practice is compliance monitoring during and after seismic activity. Compliance inspections during the operation ensure that stipulations are being followed. Compliance inspections upon completion of work ensure that the lines are clean, and that the drill holes are properly plugged.

Oil and Gas Leasing

The Mineral Leasing Act (MLA) of 1920, as amended [30 United States Code (USC) Section 181 et seq.] provides that all public lands are open to oil and gas leasing unless a specific order has been issued to close an area. Based upon the Federal Onshore Oil and Gas Leasing Reform Act (FOOGLRA) of 1987 (30 USC Section 181 et seq.), all leases must be exposed to competitive lease sales. Lands for which bids are not received at the lease sale will be available for non-competitive leasing for a period not to exceed 2 years. Competitive sales will be held at least quarterly and by oral auction. Competitive and non-competitive leases are issued for a 10-year term, or for as long as oil and/or gas are produced. The Federal government receives yearly rental fees on non-producing leases, and royalties on leases in production. Royalty is received at the rate of 12.5 percent of the total saleable production. [This revenue is split between the Federal government and the State(s) in which the royalties are generated.] [NOTE: Recent provisions by Congress have changed the distribution of royalties from an equal split (50 percent to the Federal government and 50 percent to the State) to 52 percent to the Federal government and 48 percent to the State.]

RMPs identify oil and gas planning decisions, such as areas closed to leasing, open to leasing, or open to leasing with major or moderate constraints (lease stipulations) based upon known resource values and Reasonably Foreseeable Development (RFD) Scenarios. In some areas, however, additional planning and analysis may be necessary prior to new oil and gas leasing due to changing circumstances, updated policies, and new information.

A Master Leasing Plan (MLP) is a mechanism for completing the additional planning, analysis, and decision-making efforts that may be necessary for some areas. A MLP will analyze likely development scenarios and varying mitigation levels, but at a less site-specific level than would typically be conducted where a development plan has been fully defined by an Operator. (The MLP process is discussed in detail in Appendix V.)

Normally, the oil and gas industry proposes parcels for sale, which may then be offered in the quarterly lease sales. Parcels may also be proposed for sale by individuals, or may be posted for sale by the BLM. Lease stipulations may be attached to each parcel, and may become part of the lease after sale. Initially, stipulations from various databases are attached to parcels by the BLM State Office leasing section. The parcel list is segregated and then sent to Field Offices that have parcel lands in their areas. In the Field Office, the parcels are reviewed by a group of Resource and National Environmental Policy Act (NEPA) Specialists in order to ensure that lands in the parcels are in conformance with RMPs, that the stipulations are correct, and that any missing stipulations are included. A Determination of NEPA Adequacy (DNA) or an Environmental Assessment (EA) is then prepared for the nominated parcels. This completes the review process, and allows the parcel to be included in a sale package.

The Authorized Officer has the authority to relocate, control timing, and impose other mitigation measures under Section 6 of the Standard Lease Form. This authority may be invoked whether or not lease stipulations are attached to the lease, when new resources are discovered on a lease. (Lease stipulations are conditions of lease issuance that provide protection for other resource values or land uses by establishing authority for delay, site changes, or the denial of operations within the terms of the lease contract.) The stipulations are specified for each applicable parcel in the Notice of Competitive Oil and Gas Lease Sale, and are intended to inform interested parties (potential lessees, Operators) that certain activities will be regulated or prohibited unless the Operator and the SMA arrive at an acceptable plan for mitigating anticipated impacts. Lease stipulations may be applied to specific portions of a lease or to the entire lease. Lease stipulations are based upon the perceived resource requirements and land uses specified in RMP and NEPA documentation. New science, comprehensive documentation of resource requirements, land pattern interference, and ongoing monitoring of the effectiveness of a stipulation may allow granting of a waiver, exception, or modification to a stipulation. (A lease stipulation “waiver” is a permanent exemption to a lease stipulation. An “exception” is a one-time exemption to a lease stipulation, and is determined on a case-by-case basis. A “modification” is a change to the provisions of a lease stipulation, either temporarily, or for the term of the lease.)

Drilling Permit Process

A Federal lessee, or the Operator of record, is governed by procedures set forth by the Onshore Oil and Gas Order No. I, “Approval of Operations on Onshore Federal and Indian Oil and Gas Leases,” issued under 43 CFR 3164. These procedures cover approval of operations. Other Onshore Orders and Notices to Lessees prescribe practices relating to developing a lease, including drilling, measuring oil and gas, and disposing of produced water. In the initial permitting process, the Operator selects the location of a proposed drill site. This selection is based upon COGCC spacing requirements, the subsurface geology, the topography, and avoiding known protected surface resource values.

Spacing requirements are established by the COGCC in order to protect the correlative rights of offsetting mineral owners, and in order to efficiently recover the resource. This applies to all mineral ownership (such as fee, State, and Federal minerals). The spacing requirements are to be applied to the subsurface point of production. Wells must be drilled within 200 feet of the center of a legal subdivision (such as a quarter section), depending upon the spacing assigned to the particular area. A proposed location may be moved beyond the designated tolerance by a spacing exception granted by the COGCC. A spacing exception requires notification of the offsetting mineral lease owners. If there is a protest, the matter must be presented at a public hearing with full evidence of the need to relocate the well before a decision can be made by the COGCC.

The Planning Area for this DRMP/DEIS is subject to State spacing COGCC Rule 318, which for wells deeper than 2,500 feet would be approximately 40 acres. This does not mean that all wells can be approved at 40-acre spacing. For wells shallower than 2,500 feet, the wells must be spaced at least 300 feet from the nearest well, and a distance of at least 200 feet from the lease boundary. Forty (40) acres is not a probable future spacing for the entire Planning Area, except in specific instances, because spacing is based upon the most efficient recovery of the reserves. The probable maximum subsurface density of wells is 160 acres throughout most of the Planning Area, with certain areas having a subsurface density of 40 acres, based upon the currently projected recovery efficiencies and economics. Spacing of 640 acres per well is not unrealistic in the case of deep, expensive wells that can recover the reserves in an efficient manner; and, in the case of coalbed methane (CBM), wells that may use a pinnate drilling pattern [a drilling pattern resembling the veins of a leaf, with 2 closely-spaced (within 20 feet) vertical wells, with the first well serving as an air injection well early in the project, and then as a producing well; and the second well serving as the horizontal and service well bore].

Surface density of wells would be a variable based upon the surface resource conflicts, the economics of directional drilling, the accessibility within the checkerboard (surface locations on fee land to access Federal minerals within resource conflict areas), and the subsurface density. Occasionally, the BLM could require that a lessee drill a well on a lease if it is determined that federally owned minerals are being drained by an adjacent well on private or State-owned lands that could cause conflicts in areas of sensitive surface resources. If the economics are not sufficient to drill a directional well from a location on the Federal lease, drainage protection might require compromising the sensitive surface resource after a thorough environmental review. Economic conditions dramatically affect drilling activity. (More information on drilling and production trends for the Planning Area can be found in the Reasonably Foreseeable Development (RFD) Scenario created for the DRMP/DEIS).

Permitting

After the Operator makes a decision to drill, the well, access road, and pipeline can be surveyed and staked without notifying the BLM. Cultural Resource Inventories can also be obtained without notice. However, no drilling operations or related surface-disturbing activities may be initiated without an approved Application for Permit to Drill (APD).

Notice of Staking

The Operator may choose to submit a Notice of Staking (NOS) prior to submitting an APD. The NOS is an abbreviated Notice that consists of an NOS Form, a staked location map, and a sketched Site Plan. This NOS is posted in the BLM Field Office for a 30-day public review period, which meets the public notification period that is required before a Federal APD can be approved. The NOS triggers the onsite inspection of the proposed well, which determines whether there are any conflicts with critical resources, and provides the preliminary data necessary in order to assess what additional items are necessary to include in the APD. Submission of an NOS is optional; however, if properly coordinated early in the process, it may expedite final permit approval because it allows the Operator the opportunity to gather information and better address site-specific resource concerns while, at the same time, preparing the APD package. When employing the NOS process, a completed APD is later submitted for review and approval.

Application for Permit to Drill

The Operator may choose to submit an APD without submitting an NOS. When an APD is provided by an Operator, the BLM posts the APD for 30-days and, concurrently, determines whether the APD package is complete. Once an APD is determined to be complete, the BLM has 30 days to prepare an environmental analysis of possible impacts to surface resources and to review the “down-hole” aspects of the proposed Drilling Plan. Prior to any surface-disturbing activity or drilling operations the APD must be approved by the Field Manager.

If the APD option is used, an APD is submitted to the Field Manager, and a field inspection is held with the Operator and any other interested parties. The purpose of the onsite field inspection is to evaluate the Operator’s plan, to assess the situation for possible impacts (surface and subsurface), and to formulate resource protection stipulations. In order to lessen environmental impacts, a site can be moved, reoriented, or resized (within certain limits) at the onsite inspection. The proposed access road or pipeline can also be re-routed. If necessary, site-specific mitigation measures are added to the APD as Conditions of Approval (COAs) for the protection of surface and subsurface resource values in the vicinity of the proposed activity. The Field Office is responsible for preparing the environmental documentation necessary in order to satisfy the NEPA requirements, and to provide any mitigation measures needed in order to protect the affected surface resource values.

Consideration is also given to the protection of subsurface water resources. When processing an APD, a BLM Geologist is required to identify the maximum depth of usable water, as defined in Onshore Oil and Gas Order No. 2. (Usable water is defined as water containing 10,000 parts per million or less of total dissolved solids.) Usually, water of this quality is to be protected by surface casing and cement. Determining the depth of fresh water requires specific water quality data in the proposed well vicinity, or geophysical log determination of water quality, depending upon existing well proximity and log availability. If water quality data or logs from nearby wells are not available, the area within a 2-mile radius of the proposed well is checked for water wells. If wells exist, surface casing is required to be set below the deepest fresh-water zone found in these wells, or below a depth reasonably estimated for future water wells. Within the Planning area, usable water can be available to great depths and beyond the surface casing setting point. In this case, surface casing is set through the fresh surface waters, and cement is required in order to protect the remaining useable water from the underlying non-useable water. The depth of the casing is specified to be below a depth reasonably anticipated for future useable water recovery.

When final approval is given by the BLM, the Operator can commence construction and drilling operations. Approval of an APD is valid for 2 years from the date of approval, as long as the lease does not expire during that time. If drilling does not begin within 2 years, an APD may be extended for up to 2 years, at the discretion of the BLM and the SMA, if a written request is filed before the 2-year expiration date. The COAs can also be revised before an APD is extended.

Surface Disturbance Associated With Exploratory Drilling

Upon receiving approval to drill the proposed well, the Operator moves construction equipment over existing roads to the point where the access road to the well's location will begin. Generally, the types of equipment include dozers (track-mounted and rubber-tired), scrapers, and motor-graders. Moving equipment to the construction site requires moving several loads (some over-weight and over-width) over public and private roads. Existing roads and vehicle routes are improved in places and, occasionally, culverts and cattle guards are installed as specified in the approved APD.

The length of the access road varies. Generally the shortest feasible route is selected in order to reduce the haul distance and construction costs. Environmental factors, mitigation measures designed to meet Visual Resource Management (VRM) standards, and/or the landowner's preference might dictate a longer route. In rough terrain, the type of construction is side-casting (using the material taken from the cut portion of the road in order to construct the fill portion), where slightly less than one-half of the roadbed is on a cut area, and the rest is on a fill area. Generally, roads are constructed with l4-foot (single lane) or 24-foot (double lane) running surface (in relatively level terrain). Soil texture, steepness of the topography, and moisture conditions might require surfacing the access road. The total acreage disturbed for each mile of access road constructed varies significantly with the steepness of the slope.

Well locations are constructed by one of three different general types of construction; however, in every case, all soil material suitable for plant growth is first removed and stockpiled in a designated area. Usually, sites on flat terrain require slightly more than removing the topsoil material and vegetation. Drilling sites on ridge tops and hillsides are constructed by cutting and filling portions of the location. The majority of the excess cut material is stockpiled in an area that will allow it to be easily recovered for rehabilitation. It is important to confine extra cut material in a stockpile rather than to cast it down hillsides and drainages, where it cannot be recovered for rehabilitation. The amount of level surface required for safely assembling and operating a drilling rig varies with the type of rig, and the depth and type of the well. The amount of level surface required is approximately 300 feet by 400 feet, and should be constructed so that the drill rig can be placed on the cut surface instead of fill material in order to prevent the derrick from leaning or toppling as a result of the settling of uncompacted soil.

In addition to the drilling rig footprint, a reserve pit is constructed. It is usually square or oblong; however, it can be constructed in another shape in order to accommodate topography. Generally, the reserve pit is 8 feet to 12 feet deep; however, it could be deeper in order to compensate for smaller length and width or deeper drilling depths. Normally, reserve pits should be constructed entirely in the cut-portion of the well pad; however, in locations where this is not possible, at least 50 percent of the reserve pit should be constructed below original ground level in order to help prevent failure of the pit dike. Depending upon the relationship of the location to natural drainages, it might be necessary to construct water bars or diversions. The area disturbed for construction depends largely upon the steepness of the slope. For reserve pit construction on sloping sites, it is preferable to locate the pit on the drill pad next to the high wall. Depending upon the soil permeability, pits can be lined with an impermeable material in order to contain the drilling fluids. If water is encountered while digging the reserve pit, a closed mud system (consisting of steel tanks) could be required. Closed systems are mandatory for oil-base mud, and the mud and cuttings must be recycled or disposed of in an approved manner.

Typically, drilling activities begin within 1 or 2 weeks after the location and access road have been constructed. The conventional drilling rig, and associated equipment, are moved to the location and erected. Moving a drilling rig might require moving 10 truckloads to 25 truckloads of equipment over public highways and private roads. The derrick, when erected, is roughly 160 feet high. Drilling rigs for coal-bed natural gas (CBNG) wells are smaller, require fewer loads, and are less structurally imposing.

Water for drilling is hauled to rig storage tanks. Generally, water sources are wells or commercial water sources. Occasionally, water supply wells are drilled on, or close to, the site. The Operator must obtain a permit from the Colorado State Engineer for the use of surface or subsurface water for drilling, and any applicable BLM surface use permits. When drilling commences, and as long as it progresses, water is continually transported to the rig location. Roughly 5,000 barrels (or 210,000 gallons) of water are required to drill an oil or gas well to the depth of 9,000 feet. More water would be required if circulation is lost, or permeable zones that cannot withstand the pressure of the drilling fluid are encountered.

Issuance of Rights-of-Way

Rights-of-way (ROWs) are required for all facilities, tank batteries, pipelines, powerlines, and access roads that occupy federally owned land outside the lease or unit boundary. When a third party (someone other than the Operator) constructs a facility or installation on BLM-managed public lands, or off of the lease, a ROW is also required. The ROW is issued by the BLM.

Drilling Operations

This section describes more conventional or traditional drilling operation techniques. The BLM encourages the use of new, alternative construction and drilling techniques and technologies that are designed to limit environmental impacts.

Rotary Drilling

Initially, drilling proceeds rapidly because of the less competent nature of shallow formations. Drilling is accomplished by rotating the drill string and putting variable weights on the bit located at the bottom of the string. While drilling, the derrick and associated hoisting equipment bear a majority of the drill string’s weight. The combination of rotary motion and weight on the bit causes rock to be gouged away at the bottom of the hole. The rotary motion is created by a square or hexagonal rod (called a Kelly), which fits through a square or hexagonal hole in a large turntable (called a rotary table). The rotary table sits on the drilling rig floor, and as the bit advances, the kelly slides down through it. When the kelly has gone as deep as it can, it is raised, and a new piece of drill pipe (approximately 30 feet in length) is attached in its place. The drill pipe is then lowered, the kelly is re-attached, and drilling recommences. When the bit becomes dull, it is necessary to “trip” the drill string and replace the bit. This is a time-consuming process of withdrawing 90-foot sections of the drill pipe until the bit is out of the hole. This process requires a large part of the total drilling time, and could result in other down-hole problems. New bits, constructed with modern metals and manufactured polycrystalline diamonds, along with down-hole mud motors, have revolutionized drilling operations, whereby thousands of feet of hole can be drilled with one bit run.

The mud motor is a turbine driven by high-pressure mud, and is placed at the top of the bit in order to enable more rotational power to be transmitted to the bit and, thereby, increase penetration rates. Drilling mud is circulated through the drill pipe to the bottom of the hole, through the bit, up the annulus of the well (the space around a pipe in a well bore), across a screen that separates the rock chips, and into holding tanks from which finer sediments settle from the mud before it is pumped back into the well. The mud is maintained at a required weight and viscosity in order to cool the bit, reduce the drag of the drill pipe on the sides of the hole, seal off any porous zones, contain formation fluids to prevent a blowout, and bring the rock chips to the surface for disposal. Various additives are used in maintaining the mud at the appropriate viscosity and weight. Most of the mud consists of bentonite. Some of the additives are caustic, toxic, or acidic; however, these hazardous additives are used in small amounts during the drilling operations, and are later contained within the reserve pit.

Within the Planning Area, drilling is usually accomplished with water or light mud to depths within approximately 1,000 feet of the prospective formation. Water and natural clays recovered during the drilling operation (light drilling mud) allow fast drilling rates and the attendant reduction in mud chemicals. Once the bit reaches the target depth, the mud system is gradually made more sophisticated by adding bentonite, chemicals, and natural weight materials in order to reduce water loss to the potential producing zones, and to control the subsurface pressure. In almost all cases, the subsurface pressure is higher than an equivalent water column, and it is necessary to increase the mud weights to control the pressure and to prevent a blowout or uncontrolled flow of formation fluids. Many wells are drilled in an underbalanced condition, whereby the mud pressure is slightly less than the formation pressure, which increases penetration rate and reduces the time on the well or in the formations of interest. Drilling in this condition also reduces the potential of damaging the formation, with the attendant loss of flow capacity and recovery. The wells are always overbalanced for safety requirements when a bit trip is made, the well is logged, or the casing is installed.

Drilling operations are continuous, 24 hours a day, 7 days a week. Generally, crews work three 8-hour shifts or two 12-hour shifts a day. Pickup trucks or cars are used for workers' transportation to and from the site. On remote isolated sites, a camp might be established in order to house the crews, which will reduce travel requirements. Other operations, such as cementing, running casing, and rig maintenance, will require road travel, sometimes with heavy equipment.

Upon completing the drilling, a determination is made regarding the productive potential of the well. If oil or gas is not discovered in commercial quantities, the well is considered dry. The Operator is then required to follow BLM procedures to properly plug the dry hole. The drill site and access road are then rehabilitated in accordance with the stipulations attached to the APD and the plugging approval. If the well is a producer, drilling rig operations continue until the production casing is cemented into the well before removing the drilling equipment from the location.

Logging

Geophysical logs are obtained by running various instruments into the hole on a wire cable. Usually, logs are run at a depth point where casing will be installed. A log is not usually run before surface casing is set; however, in most instances, a log recording natural gamma radiation is run through the surface casing in order to determine the geology of that section. The logs can determine water resistivity, hydrocarbon saturations, natural gamma radiations, porosity of the rock by density, nuclear receptivity and sonic measurements, permeability, pressure, temperature, hole geometry, and subsurface track. Logs are used in order to evaluate whether the well is dry or whether it has the potential for a satisfactory completion. Logs also delineate the various geologic horizons; hydrocarbon zones; fresh, usable, and unusable water; and sands, shales, limestones, coals, and other minerals. Usually, the hydrocarbon intervals are randomly situated in each well, and logs are required to specify these intervals so that they can be perforated and stimulated during the completion program. Normally, within the Planning Area, logs recording resistivity, and combined porosity logs of density and nuclear receptivity, are run in the well. The dual porosity logs are a direct indicator of gas because the measured values can be compared in order to provide contrasting porosities.

Casing

Various types of casing are placed in the drilled hole in order to enhance completion operations and safety. (Casing is a string of steel pipe composed of approximately 30-foot lengths of pipe that are threaded together.) Casing is cemented into the well in order to protect against migration of fluids within the hole, and to isolate the productive zones so that they can be completed and produced without interference from other zones containing hydrocarbons or water. Hole deviation, depth, bore hole environment, centralizers (if any), and a myriad of other factors, affect the integrity of the casing and cement job, and must be considered in the original design.

Surface casing that is properly set and cemented also protects surface aquifers from contamination resulting from drilling and production operations. Surface casing should be set to a depth greater than the deepest fresh water aquifer that could be reasonably developed. Usable water could exist at great depths; however, these aquifers are not normally considered to be important water sources. Surface casing is designed to be large enough in order to allow subsequent strings of smaller casing to be set as the well is drilled deeper. Cement is placed in the annulus of the surface casing from casing shoe to ground level. The surface casing is the first string on which blowout prevention (BOP) equipment is installed. (The BOP equipment allows the well to be shut in at any time that conditions warrant, protecting against unanticipated formation pressures, and allowing safe control of the well.) The BOP equipment is tested and inspected regularly by both the rig personnel and the inspection and enforcement branch of the BLM. Minimum standards and enforcement provisions are part of Onshore Order No. 2. Well-trained rig personnel are a necessity for proper blowout prevention.

Usually, only the bottom few thousand feet of intermediate or production casing is cemented, which often leaves several thousand feet of open hole behind some casing strings. Within the Planning Area, the annulus (the space around a pipe in a well bore) is required to be filled with sufficient cement in order to provide adequate protection from interzonal migration of unsuitable water and hydrocarbons. Production casing or production liner is designed to provide isolation of oil and gas formations, and a high-pressure conduit to the hydrocarbon zones that allows stimulation of these intervals to improve the productivity.

During completion operations, the production casing or liner is perforated into zones containing the oil or gas. Within the Planning Area, the low permeability character of the productive formations requires these zones to be “fracked” or stimulated by treated fresh water and large quantities of sand, which improves the productivity to an economic rate. Generally, 2, and up to 5, stimulation treatments can be accomplished in each well. Roughly 50 percent of the stimulation fluid is produced within a couple of days, and the rest over an extended period at low rates. Radioactive tracers show the fracs stay within the zone, which is important in order to maximize the fracs' productivity (because a frac length is the primary factor in successfully stimulating a productive interval). After completion, operations are finished, and wellhead equipment (consisting of various valves and pressure regulators is installed in order to control the oil or gas flow to the production facilities, and to safely shut-in the well under any conditions.

Oil and Gas Exploratory Units

Surface use in an oil or gas field could be affected by unitization of the leaseholds. In areas of Federal and mixed mineral ownership, an exploratory unit can be formed before a wildcat exploratory well is drilled. The boundary of the unit is based upon geologic data, and attempts to consolidate the interests in an entire structure or geologic play. The developers of the unit enter into an agreement to develop and operate as a single entity, regardless of separate lease ownerships. Costs and benefits are allocated according to agreed-upon terms. Development in a unitized field can proceed more efficiently than in a field composed of individual leases. This is because competition between lease Operators, and drainage considerations, are not a primary concern. Unitization also can reduce surface use requirements because all wells are operated as though under a single lease, and operations can be planned for more efficiency. Duplication of field processing facilities is eliminated, and consolidating facilities into more efficient systems is probable. Unitization can also involve wider spacing than usual, or spacing based upon reservoir factors rather than upon a set rule (which could result in fewer wells and higher recovery efficiency). Usually, through planning, access roads are shorter and better organized, facilities are consolidated, and well efficiency is maximized to a degree not seen in individual lease operations.

Field Development

New field development is analyzed in an EA or in an Environmental Impact Statement (EIS) after the sufficient confirmation wells are drilled. Generally, the Operator can estimate the extent of drilling and disturbance required to extract and produce the oil and gas at that time. Many fields go through several development stages. A field can be considered fully developed, and can produce for many years, when it is determined that a well can be drilled to a deeper pay zone, or a new interval is discovered to be economically attractive. In this case, there is typically less new disturbance because the old well bores, or the old well pads, are used for the new completions. A new stage of field development (such as infill drilling) can lead to increases in roads and facilities. All new construction, reconstruction, or alterations of existing facilities, including roads, flow lines, pipelines, tank batteries, or other production facilities, must be approved by the BLM, and could require a new environmental analysis document. Throughout field development, partial restoration and rehabilitation is required in order to reduce the surface impacts to the minimum required to produce the resource.

The most important factor in further developing an oil or gas field is the economics of production. When an oil or gas discovery is made, a well spacing pattern can be established before development drilling begins. This pattern is dependent upon the current State-wide or area-wide spacing. Well spacing is regulated by the COGCC, and factors considered in the establishment of a spacing pattern include data from the discovery well that translate into recovery efficiency. These data include porosity, permeability, pressure, composition of reservoir and fluids, depth of formations, well production rates, and the economic effect of the proposed spacing on recovery. These data are relatively sparse in the initial phase of development; extended production permits refining these values. These data are so tentative that the COGCC tends to define large spacing until the data are more conclusive. Usually, spacing for oil wells varies from 40 acres to 320 acres per well; however, spacing can be as small as 2.5 acres. Generally, spacing for gas wells is from 160 acres to 640 acres per well; however, it can be as small as 10 acres if reservoir recovery efficiency dictates that spacing. Spacing requirements can pose problems in selecting an environmentally sound location, or in the cumulative impacts of well drilling. Reservoir characteristics determine the most efficient spacing to achieve maximum recovery. If an Operator determines that a different spacing is necessary in order to achieve maximum recovery, the State (with input from the BLM) may grant exceptions to the spacing requirements.

Production

Gas, oil, and water are being produced within the Planning Area by means of natural flow (plunger lifts) and artificial lift (gas and electric pumping units and submersible pumps).

Gas Production

A typical gas well facility consists of methanol injection equipment (in order to keep production and surface lines from freezing), a separator (which separates gas, oil, and water), a dehydrator (that uses glycol or calcium chloride in order to extract entrained water in the gas), and an orifice meter. An intermitter is sometimes used to either shut-in the well to build up pressure, or to blow the well down if it is being loaded with fluid. If the gas well is producing some oil or condensate, oil tanks are used in order to store the oil or condensate until it is sold and transported off-site by truck or pipeline. Pipeline quality gas at the wellhead requires a minimum of processing equipment. As the quality of gas decreases with the increased presence of water, solids, or liquid hydrocarbons, the amount of processing equipment increases. Water or liquid hydrocarbons in the gas are removed before the gas is sold, usually in the separation equipment near the wellhead. If liquid hydrocarbons are present, storage facilities (tank batteries) are required in order to store the liquids until they accumulate in sufficient quantities to be hauled out by large trucks. Gas dehydration equipment might also be required onsite in order to remove water entrained in the gas to a water content defined by pipeline specifications. (Gas production data can be found in the RFD Scenario for oil and gas that was developed for this DRMP/DEIS.)

Gas that occurs with oil is separated by venting that gas at the tank battery, or it can be collected into feeder lines leading to compressors that boost the pressure to the transportation system. If enough casinghead gas is separated to make it economical for marketing, a plant can be constructed in order to process the gas, or a pipeline can be constructed in order to carry the product to an existing plant. If the volume of casinghead gas is insufficient to warrant treatment in a gas plant, it is usually used as fuel for pump engines in the field, or as heating fuel for the heater-treaters. Gas is flared or vented into the atmosphere if the quantity exceeds the fuel requirements on the lease but is not recoverable in commercial quantities. Gas may also be flared if pipelines are unavailable to transport the gas off-site.

Oil Production

Generally, within the Planning Area, oil is produced using artificial lift methods (pump units). The oil production equipment (such as heater-treaters, tank batteries, and holding facilities for production water) are either placed on a portion of the location (on cut rather than fill) and located a safe distance from the wellhead, or placed as a centralized facility that services a number of wells with pipeline connections. The heater-treater and tanks are surrounded by earthen dikes designed to contain accidental spills. Either all of the facilities or only the produced water pit (if present) will be fenced. Production facility colors are required to be from the standard color chart, and are specified in the APD's COAs.

Production from several wells on one lease can be carried by pipeline to a central tank battery. Use of a central tank battery can depend upon whether the oil is from the same formation, the same lease ownership, or multiple lease ownerships and formations; or whether a commingling agreement is approved. Due to the nature of the oil, adequate separation of oil and water is only obtained through applications of heat. The fluid stream arrives at a separator point where the flash gas is taken off. In most cases, this flash gas is used for lease operations. The remainder of the flash gas is either compressed and sold, or flared. (Flash gas is defined as solution gas liberated from the oil through a reduction in pressure.) Water and oil are also being separated at this point by gravity segregation. The oil is sent to storage tanks, and the water is sent to a disposal or injection facility. Within the Planning Area, the 2 main methods of oil measurement are lease-automatic-custody-transfer-units and tank gauging. Measurement is required by 43 CFR 3162.7-2 and by Onshore Order No. 4 in order to ensure proper and full payment of Federal royalties. Oil wells can be completed as flowing (those wells with sufficient underground pressure to raise the oil to the surface) or, if the pressure is inadequate, they are completed with the installation of subsurface pumps. Usually, the subsurface pumps are mechanically powered by a pumping unit. (Pumping units come in a variety of sizes, the larger ones reaching a height of 30 feet to 40 feet.) The units are powered by internal combustion engines or electric motors. Fuel for the engines may be casinghead gas or propane. In cases where large volumes of water are produced with the oil, electric submersible pumps can be installed. These pumps could produce up to 6,000 barrels of fluid per day at an oil cut of one-half of 1 percent oil. (Oil production data can be found in the RFD Scenario for oil and gas that was developed for this DRMP/DEIS.)

Coal-Bed Natural Gas Production

Coal-bed Natural Gas (CBNG) production combines high water production rates of some oil fields with low-pressure operations of some gas fields. Due to the reservoir characteristics of coal, high water production rates are initially required to dewater the reservoir and to allow gas to be liberated from cleat surfaces (the vertical cleavage in coal seams) within the coal. In a coal reservoir, gas is primarily trapped on the face of the coal within the cleat system by molecular attraction. Pressure must be reduced in order to liberate the gas molecules from the coal face. The production history shows that water production rates begin high, with little or no gas. The water rate then drops at a constant rate, with increasing gas rates, until a maximum gas rate is achieved relative to the original gas saturation and reservoir pressures. The gas rate then declines to the economic limit. This process is the exact opposite of that associated with most oil and gas production, which starts at high hydrocarbon rates and low water rates and advances to low hydrocarbon rates and high water rates. Generally, the reservoir depths of CBNG production are shallow (less than 5,000 feet). The depth limit is based upon coal permeability, which is highly sensitive to overburden weight. Usually, a CBNG operation consists of a high-capacity submersible or progressive cavity pump, with water produced out of the tubing, and low-pressure gas produced out of the casing. Centralized facilities collect the gas for compression to pipeline pressures and the water for disposal. Usually, electric power is used to power the well pumps, and is connected to the well by a subsurface cable laid with the water and gas lines. The producing well pad is very small, with only the wellhead and an insulating house to cover the wellhead. The centralized production facilities contain well-header buildings where the individual well gas is measured, and where collection tanks, injection wells, pumps for disposal of the water, and multi-stage compressors that bring the very low pressure gas to sales line pressure are housed. Sometimes, the water can be disposed of in the local drainages, if the Colorado Water Quality Control Division (CWQCD) and the BLM approve this type of disposal. Currently, within the Planning Area, CBNG production is in its infancy, and little history is available regarding its economics and production rates.

Water Production

Water produced with oil, gas, or CBNG is disposed of by trucking the water to an authorized disposal pit, placing the water in lined or unlined pits for evaporation, discharging the water into surface drainages, or through subsurface injection. Water disposal is controlled by the CWQCD for subsurface disposal and secondary recovery purposes. The quality of the water often dictates the appropriate disposal method, and the CWQCD has primacy, through the U.S. Environmental Protection Agency (EPA), to approve surface disposal of this water. Produced water is also used in enhanced recovery projects.

Production Problems

Weather extremes pose problems for producers by causing roads to become impassable; equipment to malfunction; and flow lines, separators, and tanks to freeze up. Other problems producers face in the area are production of hydrogen sulfide (H_2S), carbon dioxide (CO_2), and paraffin; corrosion; electrolysis; and broken flow lines.

Secondary and Enhanced Oil Recovery

Typically, gas reservoirs have no secondary recovery associated with the recovery of gas. This is because natural gas is produced by expansion resulting from the reduction of reservoir pressure. A high reservoir recovery factor can be expected from this expansion process, unless the reservoir is of such low permeability that economics becomes a factor in recovery efficiency. (Economics is a determining factor because of the expense of operating compression facilities in order to reduce the reservoir pressure to the minimum.)

In rare cases where the gas is very rich and contains a large quantity of entrained liquids, secondary recovery uses inert gases (such as nitrogen or dry natural gas) to keep the reservoir pressure above the condensation point in order to produce the maximum amount of liquids. This secondary recovery process requires sweeping the reservoir with undersaturated gas in order to entrain and sweep out the rich gas. When this secondary process is accomplished, especially in dry natural gas secondary recovery operations, the reservoir is depressurized in order to recover the maximum amount of the remaining gas reserves.

A large quantity of CO_2 is available in the northern part of the Planning Area, in the McCallum Field. Praxair, a lessee in the McCallum Field recovers the CO_2, which is trucked to local markets. Praxair is limited in their recovery amount since there are no pipelines from this field to transport the CO_2 . A secondary recovery processes could, potentially, be used in the future if the economics were favorable to construct pipelines.

Typically, an oil reservoir contains oil, gas, and water trapped within the rock matrix under pressure. Due to this pressure, much, or all, of the gas is dissolved in the oil. “Primary drive” is accomplished by expanding gas in solution, which forces oil out of the reservoir into the well and up to the surface. Oil flowing out of the reservoir drains energy from the formation and the primary drive diminishes. In order to keep oil flowing in the reservoir, pressure drawdown is required, and subsurface pumps could be used in order to lift oil to the surface. As reservoir pressures continue to drop, solution gas in the oil escapes, forming bubbles in the pore space. These bubbles further retard the flow of oil, and increase the gas saturation and the flow of solution gas. This process accelerates as the pressure declines, and at some point, production rates become uneconomical, with as much as 80 percent of the original oil remaining in the reservoir. Currently, in the United States, primary oil recovery accounts for less than half of the current oil production. The remaining oil is produced by secondary and enhanced recovery techniques.

Two (2) basic secondary recovery methods are in use: water flooding and displacement by gas. The preferred secondary recovery method is water flooding, which involves injecting water into oil reservoirs in order to maintain or increase pressure. Usually, the process is most efficient when the pressure has not fallen to the point where the reservoir is highly saturated with gas. Reservoir heterogeneity, in the form of fractures, directional permeability, and thin zones, could limit the success of this process.

The process of injecting gas is a less popular secondary recovery technique. Historically, produced gas was considered a waste product and was flared (burned) at the point of production. Later, it was recognized that the energy could be conserved, and that the recovery of oil increased if the produced gas was re-injected into the reservoir. Increased production was achieved by maintaining reservoir pressure by injecting the gas into the existing gas cap and also by injecting the gas directly into the oil-saturated zone, creating an immiscible gas drive that displaced the oil. In order to achieve miscibility, the reservoir must have reasonably high pressures and temperatures, and contain high-gravity oil. Many gas-injection projects use the water and gas (WAG) process, which is injecting water and gas alternately in order to achieve better contact with the oil within the reservoir. Currently, the high price and level of demand for natural gas has precluded this type of secondary recovery. The term “enhanced recovery” is used in order to describe recovery processes other than the more traditional secondary recovery procedures. These enhanced recovery methods include thermal, chemical, and miscible (mixable) drives. Currently, no enhanced recovery techniques are being implemented within the Planning Area; however, it is unknown whether these techniques could be applicable in the future based upon economics and new discoveries.

Some reservoirs contain large quantities of heavy oil that cannot be produced using normal or secondary methods. These reservoirs can be stimulated by thermal drive processes in which heat is introduced from the surface or developed in place in the subsurface reservoir. In the surface introduction process, hot water or steam is injected. Raising the temperature of heavy oil reduces the viscosity and makes the oil more mobile. The oils in the Planning Area are not heavy oils; therefore, thermal recovery techniques are not likely to be tried. In the in-situ process, both heavy and light oils can be processed. Spontaneous or induced ignition within the reservoir is created by injected air in order to develop a fire front that burns the hydrocarbons. Evaporation of the lighter ends immediately ahead of the fire front, and later condensation is the primary recovery mechanism. The remaining hydrocarbons are consumed by the fire and are, generally, not considered of any value. These techniques are very expensive, and must have large reserves and thick pay zones in order to be economical. It is unlikely these techniques will be used within the Planning Area in the immediate future unless new discoveries are made. Currently, several chemical drive techniques are in use, including polymer flooding, caustic flooding, and surfactant-polymer injection. These methods attempt to change reservoir conditions in order to allow recovery of additional oil. Caustic and surfactant-polymer flooding have not been economical in the past, and unless a breakthrough in technology is achieved, these techniques will probably not be considered during the life of the Approved RMP (Approved Plan). Polymer flooding is an economically viable process; however, it is used mainly in viscous reservoirs with high permeability. Currently, no such reservoirs exist within the Planning Area; however, discoveries could be made in the future.

Gas Storage

Pipeline-quality gas can be stored in good quality reservoirs with sufficient sealing parameters. This gas is pumped into the reservoir during non-peak, usually lower priced time periods, and then pumped out into the transmission lines at times of peak demand and good prices. The differential in price pays the governmental storage fees for the use of the reservoir and the injection/compression costs required in order to store and retrieve the gas. Gas storage also serves as a buffer for cold periods when demand is high and levels out the summer slack period of production. There are no active gas storage reservoirs within the Planning Area.

Plugging and Abandonment of Wells

The purpose of plugging and abandoning a well is to prevent fluid migration between zones, to protect minerals from damage, and to restore the surface area. Each well must be handled individually due to a combination of factors, including geology, subsurface well design, and specific rehabilitation concerns. Therefore, only minimum requirements can be established, and these must be modified for individual wells. The first step in the plugging process is the filing of the Notice of Intent to Abandon. This Notice is reviewed by both the SMA and a KFO Field Office Petroleum Engineer and Geologist. The notice must be filed and approved before plugging a previously producing well. Verbal plugging instructions can be given for plugging current drilling operations; however, a Notice must be filed after the work is completed. If usable fresh water was encountered while the well was being drilled, the SMA may be allowed, if interested, to assume future responsibility for the well, and the Operator will be reimbursed for the attendant costs. This assumption of responsibility becomes effective after the deeper zones are plugged back to the usable water zone. Usually, the Operator is more than satisfied to remove the surface reclamation liability, and will not charge for the remaining well equipment.

At this stage, the Operator’s plan for securing the hole is reviewed. The minimum requirements, as stated in Onshore Order No. 2, are as follows: in open-hole situations, cement plugs must extend at least 50 feet above and below zones that have fluid with the potential to migrate, zones of lost circulation (this type of zone could require an alternate method in order to isolate it), and zones of potentially valuable minerals. Thick zones may be isolated using cement plugs across the top and bottom of the zone. In the absence of productive zones and minerals, long sections of open hole may be plugged with cement plugs placed every 3,000 feet. In cased holes, cement plugs must be placed opposite perforations and extend 50 feet above and below, except where limited by plug back depth. The length of the plug is 100 feet plus 10 percent per 1,000 feet. (For example, at 10,000 feet the plug will be 200 feet long.)

Cement plugs could be replaced with a cement retainer, if the retainer is set 50 feet above the open perforations, and the perforations are squeezed with cement. A bridge plug could also be used in order to isolate a producing zone, and must be capped, if placed through tubing, with a minimum of 50 feet of cement. If the cap is placed using a dump bailer, a minimum of 35 feet of cement is required. (A dump bailer is an apparatus run on wire line in order to convey the cement to the bottom of the hole.) In the event that the casing has been cut and recovered, a plug is placed 50 feet within the casing stub, and the 100 feet plus 10 percent per 1,000 feet rule is used for the space above the cutoff point. In all cases, a plug is set at the bottom of the surface casing that has a volume of cement using the 100 feet plus 10 percent per 1,000 feet rule. This could require perforating the casing and circulating or squeezing cement behind the production casing if that casing is not removed. Annular space at the surface will be plugged with 50 feet of cement using small-diameter tubing, or by perforating and circulating cement.
If the integrity of a plug is questionable, or the position is extremely vital, it can be tested with pressure or by tagging the plug with the tubing or drill string. (Tagging the plug involves running a pipe into the hole until the plug is encountered, and placing a specified amount of weight on the plug in order to verify its placement and competency.) The surface plug within the casing must be a minimum of 50 feet. The interval between plugs must be filled with mud that will balance the subsurface pressures, and, if this balance point is unknown, a minimum of 9 pounds per gallon is specified. After the casing has been cut off below the ground level, any void at the top of the casing must be filled with cement. If a metal plate is welded over the top of the casing, a weep hole is placed in the plate.

A permanent abandonment marker is required on all wells, unless otherwise requested by the SMA. Usually, this marker pipe is at least 4 inches in diameter, 10 feet long, 4 feet above the ground, and embedded in cement. The pipe must be capped, and the well identity and location must be permanently inscribed. The SMA is responsible for establishing and approving methods for surface rehabilitation, and determining when this rehabilitation has been satisfactorily accomplished. With satisfactorily rehabilitation, a Subsequent Report of Abandonment is approved, and the well bond released.