5. Directional Drilling

Directional drilling may be used where the drillsite cannot be placed directly over the reservoir, as might be the case where a river or mountain is involved, where no surface occupancy is permitted on the leasehold, or where land use restrictions require centrally located drillsites.

There are limits both to (1) the degree that the well bore can be deviated from the vertical and, (2) the horizontal distance the well can be drilled from the wellsite to the target zone. Generally, it is not possible to drill directionally to reach a target zone more than ½ to 1 mile of horizontal distance from the drillsite. However, technology could be developed over the next 15 years allowing a greater horizontal reach. The limit of horizontal distance is also affected by depth of the target zone, characteristics of the rock formation to be penetrated, and the additional costs of directional drilling. These factors are all considered before applying this technology.

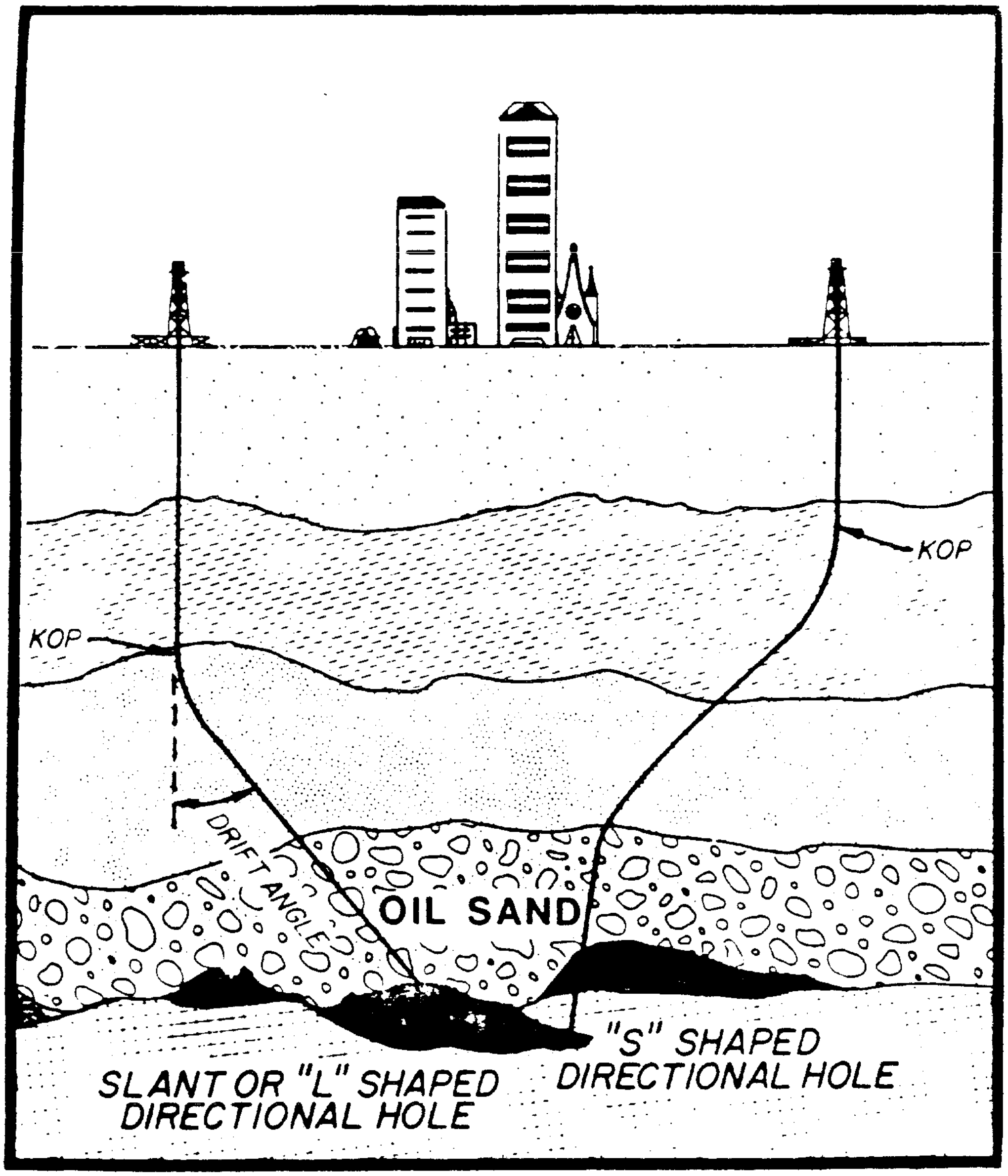

FIGURE 3: An Illustration of Directional Drilling.

6. Oil and Gas Discovery

As stated earlier, at the completion of drilling, the well is evaluated to determine if hydrocarbons can be commercially produced. A "drill stem test" is conducted to directly measure the fluid content (water, oil, or gas) of the formation and the amount of flow and shut-in pressure of the well. The well is "logged" by measuring the electric resistivity which provides information as to the porosity of the rock, the kind of fluids present, and fluid saturation level of the rocks. These physical characteristics of the rock formations and associated fluids are measured and recorded. If it is determined, based on the well production tests, that the well can be economically developed for production, the well is readied for production, and connected to a gathering system.

C. FIELD DEVELOPMENT (PHASE 3)

The completion of a wildcat well as a commercial producer generally sparks additional drilling interest in the area. Should one or two additional confirmation wells be drilled, an operator will generally proceed with field development.

1. Approval of Field Development Plans

After discovery of oil and gas and prior to the development of a field, the lessee/operator must receive approval of the Applications for Permits to Drill (APD's) and the Drilling and Surface Use programs that make up the Drilling plans. A Field Development Plan consists of a coordinated collection of site-specific drilling and surface use proposals for individual wells as required by Onshore Oil and Gas Order No. 1. The lessee/operator is required to submit the plan when sufficient information is available to project a reasonably foreseeable development of the field. Sufficient information is usually not available until one or more confirmation wells have been drilled to delineate the characteristics of the reservoir. The limits of a field located on a structural trap can be determined more easily than a stratigraphic field based on the information obtained from drilled wells and geophysical data. The proposed field development is subject to environmental analysis prior to approval or rejection of the APD.

The Drilling Plan includes information on existing roads, the proposed location of the access roads, the proposed and existing wells, pipelines, tank batteries and other ancillary facilities; the proposed location and type of water supply; the proposed waste disposal methods; plans for reclamation of the surface; and other information deemed necessary.

The geological information required to be submitted includes (a) occurrence and anticipated depths of fresh water aquifers, (b) expected depths of possible oil or gas productive zones above or below the zone already discovered, (c) other mineral bearing formations, (d) the potential for entering highly permeable formations in which the drilling mud might be lost, (e) the anticipated pressures in the formations to be drilled, and (f) the potential for encountering other geologic conditions which could cause drilling problems,and other information as rquired by Onshore Order No. 1. This information is obtained to determine whether the proposed drilling program is adequate, and to insure the drilling mud, pressure control, casing, cementing, testing, well logging, and completion programs adequately protect the surface and subsurface environments, protect other subsurface resources, and provide safe working conditions.

2. Well Spacing Pattern

Before development of an oil and gas field can begin a well spacing pattern is established to allot a spacing unit for each well that will be drilled in the discovery area. Oil well spacing patterns in the United States normally range from 2 acres per well to 640 acres per well. Spacing units established for oil production are usually closer than gas well spacings and are generally in multiples of 40 acres, i.e., 40, 80, 160, 320, 640, up to 1280 acres in horizontally drilled prospects. Gas well spacing patterns in the United States range from 40 to 1,440 acres per well. Most Montana spacing patterns at the present time allow for production of gas based on 640 acres per well during initial field development.

The well spacing pattern established for an oil and gas field is the primary factor that determines the amount and intensity of human presence and associated activity during the development and operation of an oil and gas field and the amount of surface disturbance and land area required to accommodate surface facilities. The wider the well spacing pattern, the lower the intensity and concentration of human activity and the less overall surface disturbance occurs within the oil and gas field. Well spacing is determined by how much of the reserves can be produced by any one well; the producer will attempt to maximize production using the fewest number of wells possible.

3. Unitization

Surface use in an oil and gas field is affected by *unitization* of the leaseholds, or consolidation of leases. In areas involving Federal lands an exploratory unit is formed pursuant to 43 CFR Subpart 3180 through Subpart 3186. The area enclosed within an exploratory unit is based on available geologic data. These units may also include state and privately held minerals.

A unit agreement provides for (a) development and operation of the field as a single, consolidated unit without regard to separate lease ownerships; and (b) the allocation of costs and benefits according to terms of the agreement. "Exploratory Units" are also formed to share the cost of drilling exploratory wells to test geologic structures. Unit agreements involving more than 10% federal participation require BLM approval.

Field development under a unit agreement reduces the surface use requirements because all wells within the unit boundaries are operated as though they are located on a single lease. Development and operations of the field are planned and conducted by a single unit operator and, therefore, duplication of field processing equipment and facilities is minimized. Oil or gas field development under a unitization plan may also involve a wider well spacing pattern and fewer wells than a field developed on a lease-by-lease basis.

In accordance with unitization provisions, if drilling commences prior to the end of the primary term of any lease committed to the unit, then that lease's term may be extended for up to two years at the contraction or termination of the unit. The lease term also remains in effect as long as oil or gas is produced in paying quantities.

4. Drilling Procedures

The drilling of development wells is essentially the same as the drilling of a wildcat well. Roads and other facilities are planned and constructed for long term use.

5. Surface Use Requirements

Surface uses associated with oil and gas field development wells include access roads, wellsites, flowlines, storage tank batteries, and facilities to separate oil, gas, and water. In remote locations, worker camps may be required. Access roads are planned, located, and constructed for long term use as opposed to roads built for short term use to drill wildcat wells.

6. Surface Use and Construction Standards

The minimum standards for design, construction, and oil and gas operations are set forth in the "Surface Operating Standards for Oil and Gas Exploration and Development, Third Edition - U. S. Forest Service and Bureau of Land Management." The publication prescribes the minimum operating standards for oil and gas operations on Federal lands. The objective of the standards is to minimize surface disturbance, effects on other resources, and to retain the reclamation potential of the disturbed area. Additional site-specific construction and design standards may be required depending on the proposed activities and conditions encountered at the construction site.

The locations for wellsites, tank batteries, mudpits, pumping stations, roads, and pipelines are selected to minimize to the extent possible the long term impacts to other resources and disruption of other land uses. Ideal locations for oil and gas activities are seldom available and it is not always possible to avoid damage to surface resources. Wellsites are constrained by the geologic target to be drilled; pipelines, because of their linear nature, cannot always be located to avoid all environmentally sensitive areas. In the selection of sites special attention is given to avoiding construction on steep topography and unstable soils, near streams and other open water areas, on cultural resource sites, and in threatened, endangered, or sensitive species habitats. It is not possible or practical to avoid all situations and special construction techniques may be needed to minimize the impacts.

Wellsites are usually located on the most level location available that accommodates the intended use consistent with reaching the geologic target. The drillsite layout can also be oriented to conform to or fit into the topographic conditions at the drillsite. However, safety considerations in a hydrogen sulfide (H_2S) area may be an overruling factor when determining the topographic setting and providing adequate escape routes for the drill crew. Onshore Oil and Gas Order No. 6 sets forth hydrogen sulfide gas regulating considerations and requirements (43 CFR 3160). In general, steeply sloping locations which require deep nearly vertical cuts and steep fill slopes are avoided or appropriately mitigated. The wellsite is also reviewed to determine its effect in conjunction with the location of the access road. Advantages gained on a good wellsite or tank battery location may be negated by adverse effects from the location of the access road.

Wellsite Construction Standards - Construction of the wellsite must conform to the approved wellsite and layout plan in the Surface Use Plan of Operations and excavation of the cut and fill slopes of the wellsite are guided by information on the surveyed construction stakes. Generally all surface soil materials ("topsoil") are removed from the entire construction area and stockpiled. The depth of topsoil to be removed and stockpiled is determined at the predrill inspection and stated either in the proposed surface use plan of operations or specified as a condition of approval. In order to avoid mixing topsoil with subsurface materials during construction and reclamation topsoil stockpiles are located at specified locations, out of the way of construction activities.

Fill materials are to be compacted to minimize the chance of slope failure. Terracing may be used on both cut and fill slopes to reduce the land area occupied by the wellsite, to prevent excessive water accumulation, slope failure, and erosion. If excess material needs to be excavated, the excess material is to be disposed of or stockpiled at approved locations. Snow and frozen soil material cannot be used in the construction of fill areas or reserve pits.

The area of the well pad that actually supports the drilling rig substructure must be level and capable of supporting the weight of the rig. The drilling rig, tanks, heater-treater, etc., are not placed on uncompacted fill material. The area used for mud tanks, generators, mud storage, and fuel tanks, etc., is usually slightly sloping to provide surface drainage from the work area. Runoff water from off site areas is diverted away from the wellsite by ditches, waterbars, or terraces up-slope from the drilling and wellsite.

The reserve pit is to be located and constructed entirely in cut material. If this is not possible, at least 50 percent of the reserve pit must be constructed below original ground level to prevent failure of the pit dike. Pit dikes constructed of fill material are to be adequately compacted.

Pits improperly constructed on slopes may leak along the plane between the natural ground level and the fill. There is a significant potential for pit failure in these situations.

Lining of reserve pits may be required to prevent contamination of ground water and soil. Bentonite, plastic, or other synthetic liners may be used. Fencing of reserve pits is usually required to keep out wildlife or livestock. In some environmentally sensitive areas or where topography limits the size of the wellsite, a "self-contained mud system" may be required. The drilling fluids, mud, and cuttings are stored in metal tanks and transported to approved offsite disposal areas or disposed in a much smaller onsite pit.

A closed mud system and safety "surge tank" may be used in lieu of a reserve pit at locations such as areas with limited space in which to locate a drillpad, high water table area, or other situations where a reserve pit cannot be accommodated. The surge tank is used to contain the spent downhole fluids, muds, and cuttings from the wellbore. Since there is no reserve pit in which to dispose of the cuttings and spent drilling fluids they must be periodically trucked from the drillsite during the drilling of the well and disposed of at an approved location. The removal and disposal of the wellbore cuttings and spent drilling fluids is very expensive and closed mud systems, although not infrequently used, are not employed as a standard drilling practice. A combination of closed mud system and normal reserve pit is more commonly used. Water conservation and limited drilling space are primary considerations.

Roads and Access Ways - It is Forest Service policy that existing roads be used for access when they are available, when they meet Forest Service standards for the intended use, and when there are no significant conflicts with other uses. When access involves use of existing agency roads, the oil and gas operator may be required to contribute to the road's maintenance. Usually this use is authorized by a joint use agreement in which each user's prorated share of the road maintenance costs are assessed.

New road construction, or reconstruction, by the operator must be consistent with the goals of the Forest's transportation plan and must meet Forest Service standards established for the intended road use.

Proper road location is critical for the engineering success and mitigation of the environmental effects of road construction. The surface and subsurface conditions of a proposed road location also determine the cost to survey, design, construct, and maintain a road. The following factors are considered when determining road locations: (1) the intended use of the road, planned season of use, and type of vehicles to be used; (2) the Forest's transportation plan which may already identify feasible routes for the area; and (3) existing data, including maps and aerial photos, of administrative, biological, physical, and cultural conditions of the area.

A field reconnaissance during the predrill inspection of the proposed and alternative routes is made to determine type of excavation, landslide areas, subgrade conditions, the need for surfacing, potential cut slope problems, surface or subsurface water problem areas, suitability of fill material, potential gravel pits or quarries for road aggregate, and potential borrow and waste sites.

When steep slope areas, erosion hazard areas, visual resource areas, stream crossings, and other areas of high environmental sensitivity cannot be avoided, special road design and construction techniques may be required.

Both the BLM and the Forest Service require that all permanent roads constructed by nongovernment entities across public or National Forest System lands be designed by, or constructed under the direction of, a licensed professional engineer. The design and construction requirements depend on the site conditions, planned use of the road, seasons of use, amount and type of traffic, and whether use will be short- or long-term. These factors are also used to determine the class of road built to accommodate the intended use(s).

The specific design specifications and requirements depend on whether the road class is (1) short term, (2) local, (3) collector, or (4) arterial road. Each road class is based on a transportation need and must meet certain design criteria. Other factors, unique and directly applicable to the oil and gas industry, considered include:

- The prevailing wind direction in relation to the potential for encountering sour gas (H_2S) and the need for a clear escape route from the drillsite.

- The potential for year round operation: drillsites and producing locations may require all-weather access and special maintenance considerations for snow removal.

- The potential for exploratory drilling to result in a producing operation. The initial road alignments will allow upgrading to a permanent road if a discovery is made.

When the road location information is submitted to the Forest Service in the surface use plan, the proposed route, and if applicable, alternative routes, road design standards and construction methods, are evaluated. Final approval of the road location, road design standards, and construction standards are made during processing of the surface use plan.

Pipelines Standards - General pipeline construction standards were established to minimize surface disturbance, provide soil stability, and preserve reclamation potential. Pipeline construction usually involves clearing vegetation and leveling a strip of land wide enough to accommodate a pipeline trench, excavated material, and pipeline construction equipment and transport trucks. The width of the area cleared and leveled is kept to a minimum consistent with access and construction requirements. The width of the disturbed area varies depending on the number of lines within a corridor, size of the pipeline, equipment, and topographic setting.

Locating pipeline routes on steep hillsides and adjacent to live watercourses is avoided to the extent possible. However, because of the extended linear nature of a pipeline these situations cannot be entirely avoided. Extensive cuts and fills that destabilize steep slopes are major problems with sidehill locations. Pipelines located adjacent to watercourses increase the risk of petroleum spills and silt entering streams.

Pipeline beds are constructed so they do not block, dam, or change the natural watercourse of any drainage. Pipelines suspended above watercourses must provide adequate clearance for water runoff and waterborne debris, and allow for the passage of wildlife and livestock. Pipelines located on gentle topography usually require less construction and surface disturbance, and are, therefore, inherently more stable and retain greater reclamation potential.

It is a standard practice to stockpile topsoil to the side of the pipeline right-of-way prior to construction and leveling the pipeline bed. The topsoil is segregated and not mixed or covered by excavated material during construction.

Upon completion of construction, the pipeline is graded to conform to the adjoining terrain, the surface soil material returned to the right-of-way, and the pipeline right-of-way waterbarred and revegetated to avoid erosion and minimize the visual intrusion.

7. Oil Field Production Development

Production operations in an oil field begins soon after the discovery well is completed. Portable and temporary facilities located on the drillpad are used to initiate the production of oil from the reservoir. As further drilling proceeds and reservoir limits are established, permanent production facilities are designed and installed at centralized locations. The type, size, and number of the facilities are determined by the number of producing wells, expected production rates, volumes of gas and water expected to be produced with the oil, the number of separate leases involved, and whether or not the field is being developed on a unitized or individual lease basis. Development of production on a lease basis requires handling and processing facilities be installed on or near each lease. Unitization generally reduces the number of facilities needed to produce, process, and store the oil prior to marketing. However, these facilities are often larger than those used on an individual lease.

8. Gas Field Production Development

Production operations in a gas field begins when a pipeline to a market outlet is constructed. Market pipelines are not economical unless sufficient gas reserves have been proven to exist by drilling operations. Gas wells are often shut-in after completion for periods of several months or years until a pipeline connection becomes available.

9. Rate of Development

The rate at which development wells are drilled in a newly discovered field depends upon (a) whether the field is developed on a lease basis or unitized basis, (b) the probability of profitable production, (c) the availability of drilling equipment, (d) protective drilling requirements, and (e) the degree to which limits of the field are known. The development of a field that is based on a stratigraphic reservoir may proceed more slowly and yield more dry holes than development of a field located on a structural trap reservoir.

The most important factor when determining how fast field development is undertaken is indicated production potential. If large productive capacity and substantial reserves are indicated, development drilling proceeds at a rapid pace. If there is a question as to whether indicated reserves are sufficient to warrant additional wells, the development drilling occurs at a slower pace. An evaluation period to observe production performance may follow between the drilling of each well.

Development on an individual lease basis proceeds more rapidly than development in a unitized area. When development drilling is undertaken on a lease basis, each lessee drills his own well(s) to obtain production from the field. This creates a competitive situation where the first wells drilled produce the greatest share of oil from the reservoir and quickest and greatest return on investment. When unitized, all owners within the "participating area" share in a well's production regardless of whose lease the well is located on. The development of a reservoir can then proceed in an orderly manner and at a more controlled pace.

10. Protective Drilling

The drilling of a well to prevent drainage of hydrocarbons by a producing well on an adjoining lease may be required in fields which contain a mixture of Federal lands and patented or fee lands. The terms of Federal leases require the drilling of a protective well on the leased tract if an "offset" well is located on adjacent non-Federal lands or on Federal lands leased at a lower royalty rate. An "offset" well is a well drilled at the adjoining location in accordance with the established spacing rule.

11. Pool Discoveries

Discovery of a "new pay zone" within an existing field is a "pool" discovery, as distinguished from a new field discovery. A pool discovery may result in the drilling of additional wells -- often on the same well pads as existing wells, or often sharing the same boreholes or separated only by a few feet. Existing wells may also be drilled deeper to the new pay zone. Each new pay zone developed may require additional flowlines, storage, and treatment facilities if the fluids from the various pools are to be kept separate. Frequently, a new pool discovery means re-entering completed old, plugged and abandoned producers and perforating additional zones in existing producers. Commingling (mixing) of fluids from different formations may be approved depending on the oil or gas characteristics. Some fields contain as many as seven, or more, pay zones all sharing a geologic structure that created the conditions for the accumulation of oil and gas. Commingling, if possible, often eliminates the need for additional surface production facilities.

D. PRODUCTION (PHASE 4)

Production is a combination of operations that includes: (1) bringing the fluids (oil, gas, and water) to the surface; (2) maintaining and/or enhancing the productive capacity of the wells; (3) treating and separating the fluids; (4) purifying, testing, measuring, and otherwise preparing the fluids for market; (5) disposing of produced water; and (6) transporting oil and gas to market.

The production of oil and gas from a single well is usually initiated as soon as drilling is completed and the well is developed for production. In the meantime, other wells may be shut in, in production, being drilled, or exist only in the field development plans. There is also usually little time separation between the activities associated with exploratory drilling, oil and gas field development, and actual production of oil or gas. It may take a few months to many years before a field is fully developed. Therefore, field development activities and those activities normally associated with oil and gas production occur simultaneously during the early life of a field. Drilling of new wells is undertaken periodically throughout the life of a producing field to increase or maintain production from the reservoir. Once a well goes to production, the term of the lease is extended beyond the primary term for as long as production continues or as long as a well is capable of producing in paying quantities.

1. Well Completion Report

A "Well Completion or Recompletion Report and Log" must be filed with the BLM within 30 days after completion of a well for production. The completion report reflects the mechanical and physical condition of the well. Geologic information and, when applicable, information on the completed interval and production is required. Operators must notify the BLM no later than the 5th business day after a well begins production.

2. Well Completions

After a well has been drilled and evaluated for its economic worth and profit, work to set the casing and prepare the well for completion and production begins. The decision to complete an individual well for production is based on the type of oil or gas accumulations involved, the expected future development that may be undertaken during the life of the well, and the economic circumstances at the time that the work is done. Completion equipment and the methods employed varies.

Prior to well completion, production casing is installed and cement is placed between the casing and the open well bore to provide stability and to isolate specific zones, e.g., fresh water aquifers. If the casing is set through the productive horizon, it will be perforated to allow entry of oil and gas into the well bore.

The drilling rig and most of the support equipment are normally moved from the wellsite after the production casing is cemented in place. The pay zone is usually then perforated and stimulated using a much smaller rig (workover rig). Small diameter "production" tubing is then placed inside the casing down to the producing zone. The tubing is connected to the surface equipment and transports the oil and gas from the bottom of the well to the surface. If the pressure is sufficient to raise a column of oil or gas to the surface the well is completed as a flowing well. When pressure is not sufficient, a pumping system is installed. After the well is completed, the well is tested for a period of days or months before another well is drilled.

Temporary storage tanks are normally used to hold any produced oil during testing. A "separator" is required to separate the gas from the oil. The gas separated from the oil may be burned off as waste until a pipeline connection is available. If water is produced with the oil, a "treater" is needed to separate emulsified oil and water. During gas well testing, the gas is either flared or vented.

Horizontal wells are normally completed with steel casing that is installed from the surface through the entire length of the horizontal section. The section of casing in the horizontal portion of the hole already has holes or perforations. Several special tools are installed between the perforated casing and the solid casing to isolate the producing formation from other important and valuable zones above, i.e., other potential producing zones, disposal zones and fresh water aquifers. One of these tools is an inflatable casing packer. This tool does not allow downward movement of fluid in the borehole annulus during cementing operations. Above the packer is a cementing tool which allows fluid (cement) to be diverted from inside the casing to the outside of the casing. With the packer in place and the cementing tool, cement can be circulated or placed in the angle section of the hole and up into the vertical section of the hole. By using a combination of cement tools and other techniques, cementing of casing in horizontal wells provides similar protection as in vertical wells. In some cases, the casing does not have pre-drilled holes for the horizontal section and is completed in a fashion similar to vertical wells, except that the cementing is accomplished in stages to ensure adequate zone isolation.

3. Well Stimulation

"Well stimulation" is employed to enlarge channels or to create new ones in the producing formation rock to enhance oil and gas production. Since oil is usually contained in the pores or cracks of sandstone or limestone formations, enlarging or creating new channels allows the oil or gas to accumulate and move more freely to a wellbore. A well may be restimulated several times during its lifetime to maintain or increase production. There is a short term increase in activity at the wellsite during this process. Generally no new surface disturbance is required to perform these operations. Three basic well stimulation methods have been developed: explosive fracturing, acid treatment, and hydraulic fracturing.

Explosive fracturing is used to enlarge the wellbore, eliminate nearby plugging of the rock pores, and force fluids into the formation, thereby fracturing the rock in the proximity of the well bore to stimulate increased production.

Acid treatment dissolves rock with weak hydrochloric and/or hydrofluoric acid, thereby enlarging existing channels and opening new ones for oil to flow to the wellbore. Reservoir rocks most commonly acidized are limestone (calcium carbonate) and dolomite that exhibit low permeability. Well servicing rigs are used to prepare both new and old wells for acid treatment.

Hydraulic fracturing is used to create or enlarge cracks in sandstone reservoirs in the same manner as acid treatment is used in limestone or dolomite reservoirs. Hydraulic pressure is applied against the formation by pumping fluid, gas, or foam (either water or diesel-base) under high pressure into the well. This pressure splits and cracks the rocks to improve the productivity of the well, or increase the rate fluids can be injected into disposal wells. The fracturing fluid is normally mixed with uniform sand grains that prop open the created fractures. The fracturing fluids are usually recovered over a period of time, as they flow back into the well bore. Most well pads are of sufficient size to accommodate the trucks and other equipment needed to complete a "frac" job, however, a second pad and additional surface disturbance may be required for safety considerations and to accommodate the large amount of equipment needed to perform special "massive fracture" jobs.

4. Oil Wells - Wellhead Facilities

The "wellhead" is the equipment installed to maintain control of the well at the surface and to prevent well fluids from "blowing" or "leaking" at the surface. The pressures encountered in the well determine the type of wellhead equipment needed. This varies from a simple assembly to support the weight of the production tubing in the well to a high-pressure wellhead to control reservoir pressures. Pressures in these reservoirs are usually great enough to result in a "flowing" well. However, after reservoir pressures are depleted, some type of artificial lift is usually required to bring the oil to the surface. In addition to the wellhead stocktanks, heat treating facilities, separators, and a water disposal pit may be required for both flowing and artificial lift wells.

Flowing Wells - The surface equipment at the head of a flowing well is limited to a series of valves, or "Christmas tree," and a fenced service area ranging from 15 by 15 feet to 50 by 50 feet around the wellhead. A service area may also contain a small (1 by 2 by 3 feet) gas powered chemical pump and "guy line" anchors for servicing units brought in for well repairs. Chemical pumps used to inject emulsion breakers, corrosion inhibitors, or paraffin solvents into the well or flowline.

Artificial Lifts (Pumping) - When a well is completed, the natural reservoir pressure drives the fluid to the surface. At some time during the life of an oil well, the pressure is depleted and some form of artificial lift is used to raise the fluid to the surface. The most common methods of artificial lift are sucker rod pumps, centrifugal pumps, hydraulic pumps, and gas lift. All of the pump systems require some type of surface equipment and a power system. All power systems generate noise; however, the noise level ranges from almost none for electric motors to high noise levels for single cylinder gas engines.

Beam Pump - The pumping unit is the most visible and recognizable piece of production equipment within oil fields. Pumping jacks, or Beam pumps, vary in size from 4' to over 25' in height depending on depth of well. The principle of the beam pump is the same as that of the common hand pump used to lift water. A series of rods (sucker rods) and a valve move up and down through a "stuffing box" in the well to bring the oil to the surface. These sucker rods are connected to a mechanical pump at the bottom of the well. The stuffing box is regularly maintained to prevent oil leaks from the wellhead. Failed packing in stuffing boxes is a common cause of oil spills. The rod is connected to a reciprocating pumping unit or pump jack. Surface pumping units are usually powered by electric motors, however, internal combustion engines are used when electric power is not available. Single-cylinder engines operate at very high noise levels, whereas multi-cylinder engines operate at lower noise levels and electric motors at a very low noise level.

Centrifugal Pumps - Centrifugal submersible oil well pumps consist of a stack of 25 to 300 electric powered small pumps located inside the well casing. Centrifugal pumps require little equipment above the ground and generate no noise at the surface. Surface equipment requirements include a switch or control cabinet, the wellhead, a spool for the cable used to transmit electricity to the pumps, and an electric powerline.

Hydraulic Pumps - The pumping unit of a hydraulic system is located inside the well and is powered by oil under high pressure. The equipment required on the surface includes a storage tank for the power oil, a pump to pressurize the oil, an electric motor or internal combustion engine to power the oil pump, power oil regulating valves and pressure gauges, hydraulic pump and the oil wells. The total surface area used for this type of facility may be greater than for other pumping systems if a centralized power system and additional oil pressure lines are used to carry the power oil from the pump to the wellheads. The noise level created at the wellhead depends on whether an electric motor or internal combustion engine is used to power the oil pump.

Gas Lift - Gas lift is commonly used where low-cost, high pressure natural gas is available and where pressure in the petroleum reservoir is sufficient to force the petroleum part of the way up the well. In this system natural gas under pressure is injected into well casing. The gas forces the fluids up the production tubing to the surface. The gas pressure maintained inside the casing creates a flowing well. The surface equipment used for gas lift includes gas compressor, oil storage tank, and separator. The system is quiet if the compressor is powered by electric motor and little physical space is required at the wellhead.

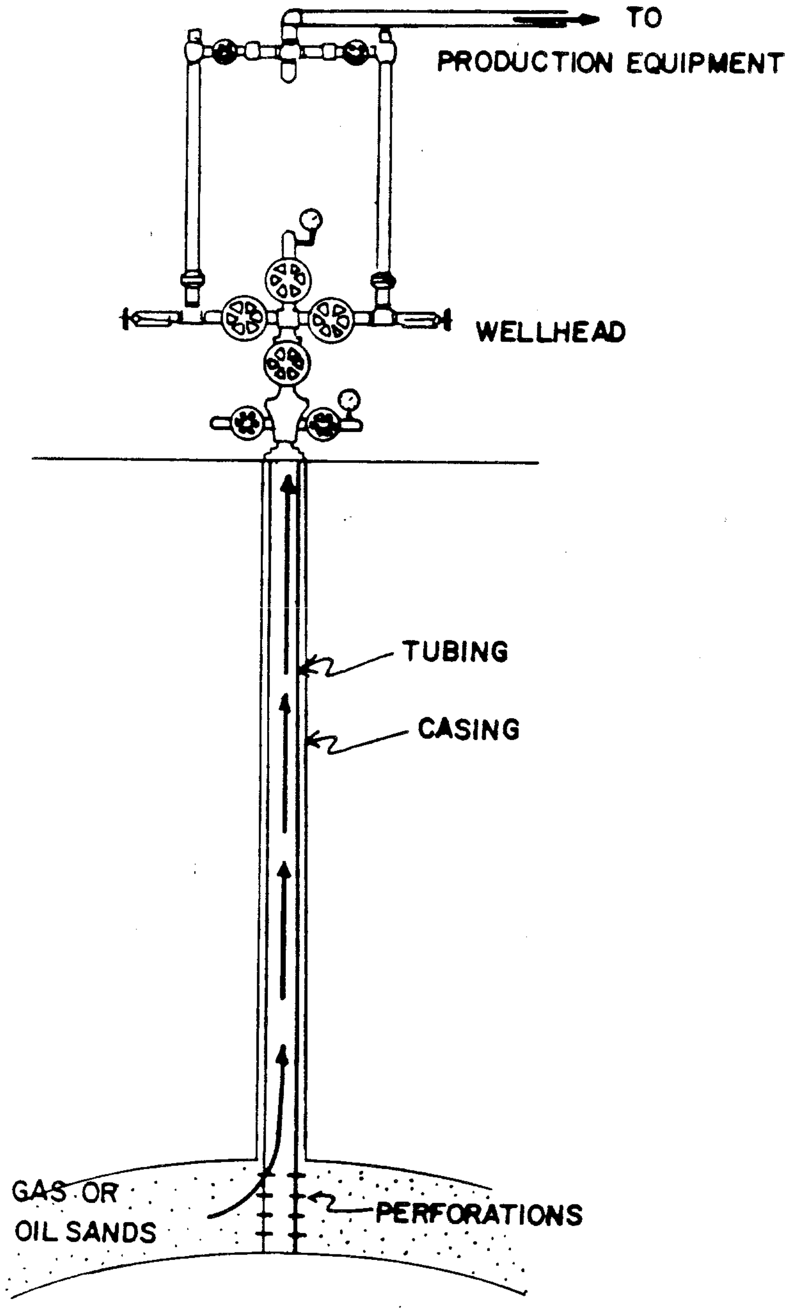

FIGURE 4: An illustration of the wellhead of a free-flowing gas or oil well.

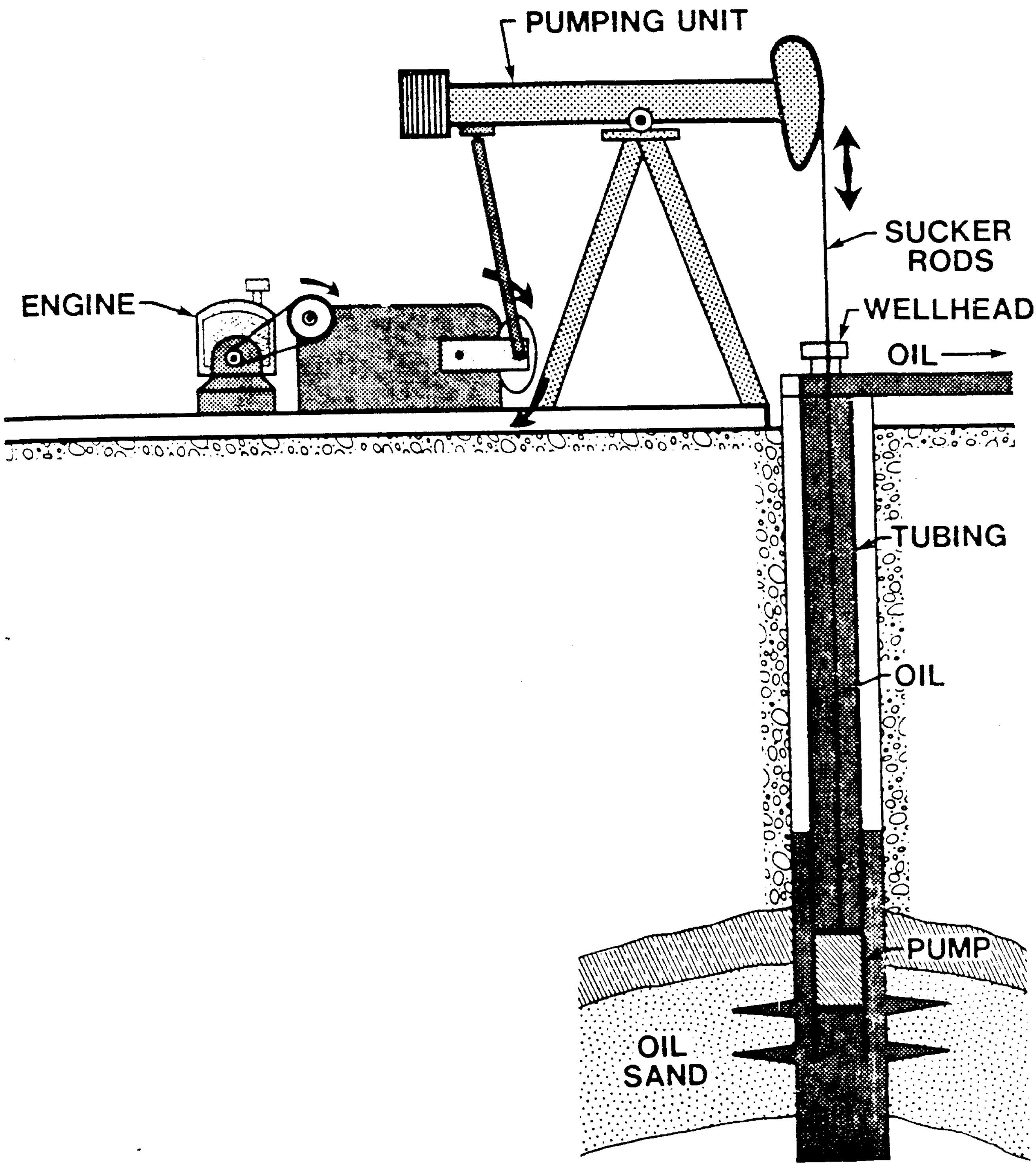

FIGURE 5: An illustration of an oil pumping unit.

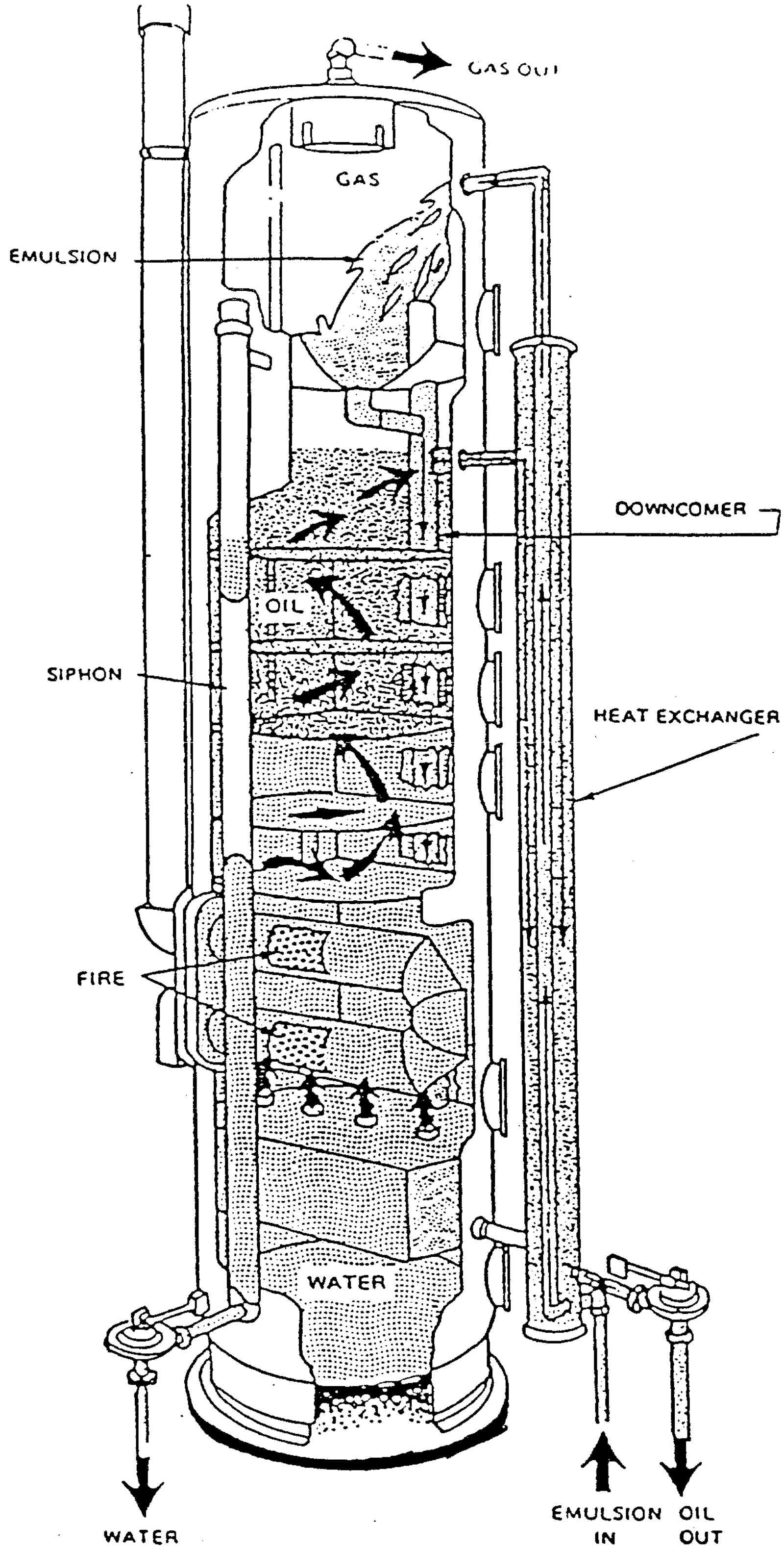

FIGURE 6: An illustration of a vertical heater treater.

5. Gas Wells

Most gas wells produce by normal flow and, in most cases, do not require pumping. Surface use at a flowing gas well is usually limited to a 50-foot by 50-foot fenced area. Water may enter a gas well and cause production to cease due to the hydrostatic pressure. A pump is then installed to pump off the column of water. The pumping requirement varies from periodic to almost continuous. The typical gas wellhead facilities are similar to those of a flowing oil well, consisting of a relatively unobtrusive wellhead "Christmas tree." Other equipment may be required depending upon the gas quality and location of the measurement facilities. Additional equipment may include a separator, dehydrator, gas meter house, and a compressor.

6. Oil Field Gathering Systems

Crude oil may be transferred in small diameter pipelines called "flowlines" from the wells to treatment facilities and a central tank storage battery before it is transported from the lease. The flowlines may be constructed with 2, 3 or 4 inch diameter steel pipes, but plastic pipe is more commonly used. Flowlines are usually buried, however, under certain circumstances, may be elevated above the ground. The installation of flowlines is similar to small scale pipeline construction. Generally, a level bed is constructed to provide for vehicle access, trenching, and burial of the flowline. Flowlines are often installed in, or adjacent to, a roadbed to reduce surface disturbance and facilitate its installation. After the oil is gathered from the field and is treated, measured, and tested, it will be transported from the lease by pipeline or trucked to market. In some instances oil will be pumped directly into a storage tank at the wellhead and trucked off location. This is typical with high volume producers.

7. Gas Field Gathering Systems

Natural gas is often sold at the wellhead and transported directly off the lease. If processing and conditioning are required to remove liquid hydrocarbons, "acid gases," and water, the gas may be transferred to a central collection point and treating facility through flowlines prior to sale. Gas gathering systems generally include equipment for (1) conditioning and dehydrating the gas; (2) compressing the gas so that it flows through the pipelines; and (3) controlling, measuring, and recording its flow.

8. Oil and Gas Separating, Treating, and Storage Facilities

Fluids produced from a well normally contain oil, gas, and water. The oil, gas, and water are separated or treated before the oil is stored in the tank battery. The treating facilities may be located at the wellhead, but in a fully developed field, they are usually located at the tank battery site. If enough "natural gas" is produced with the oil after separation, it will be compressed, dehydrated, and pipelined directly to the market.

Enough condensate, also called "casinghead gasoline" or "drip gas", may be produced in the field to make it economical to process it for marketing. A treatment or processing plant may then be built in the area to remove natural gasoline, butane, and propane. Some of the residue gas may be used to fuel the processing facility, gas compressors, pump engines, and heat the separating and treating vessels. The remainder of the gas, usually methane, is marketed as "natural gas". The oil and water produced from a well are usually in the form of an emulsion. Water is separated and removed after the gas is removed. The type of treatment facilities used depends on the amount of emulsification. If emulsification is high, chemical and/or heat treatment is used to separate the oil and water. Heat is applied in a facility called a "heater-treater" (Figure 6) which breaks the oil in water emulsification. The heat is supplemented in most cases by chemical emulsion breakers. The oil and water, when not highly emulsified, may be separated by gravity in a tall settling tank called a "gun barrel." Conditioning equipment such as separators, (Figure 7) heaters, dehydrators, and compressors may be located at the wellhead where the oil and gas first reach the surface or at the tank batteries and/or gas compressor stations in the field.

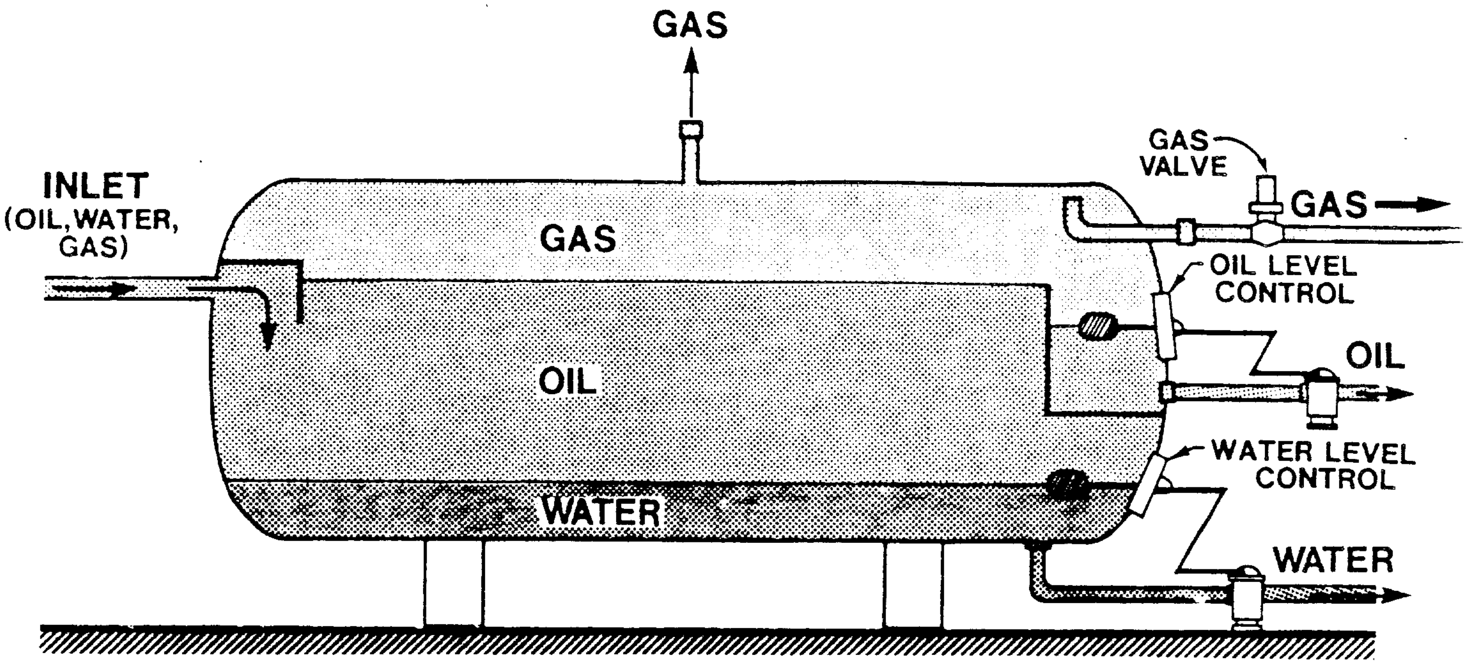

FIGURE 6: Cross section of a horizontal separator.

After the oil and water are separated, the oil is piped to storage tanks (tank batteries). The tank batteries are usually located on, or in the vicinity of, the lease. The number and size of tanks vary with the rate of petroleum production from the field. Small leases may contain only one storage tank; large leases or units may contain several, each with its own separating, treating, and storage facilities. Tank battery sites may occupy from 1 to 5 acres depending on associated facilities and number and size of tanks.

Although natural gas is produced in varying quantities with the crude oil, in many fields the primary or sole production is the natural gas itself. The process to upgrade the gas for transportation and marketing consists of two primary treatments. The first is to separate the natural gas from crude oil and/or other liquid condensates including free water. In this process the gas is run through "separators" and a "heater" to separate the liquids from the gas. The gas is then run through a "dehydration unit" to remove the remaining water vapor. The removal of the water vapor is important since in the presence of natural gas or other hydrocarbons it will form "hydrates" which precipitate out and cause blockage of pipelines. The treatment of the gas is done either at the wellhead or at a centralized field facility located at the tank battery site or at a compressor plant. No gas is stored at these facilities but is entered directly into a marketing pipeline after treatment.

Hydrogen sulfide (H_2S) and carbon dioxide (CO_2) are "acid gases" commonly produced with the natural gas. H_2S is extremely toxic, heavier than air, is highly corrosive to certain metals and may cause eventual failure of the metal. Unless these gases are present in very small quantities they must be removed from the natural gas. There are several processes used to remove "acid gases." The most common is the alkanolamine process in which the acid gas is absorbed in an alkanolamine solution. The solution is then heated and the amine solution is recycled. The hydrogen sulfide is used as a fuel gas and the carbon dioxide may be gathered and sold as dry ice or as compressed gas.

To facilitate marketing, compressors are used to compress the gas up to, or in excess of, a hundred times the normal atmospheric pressure. Large reciprocating compressors driven by gas engines are used, but centrifugal units driven by gas turbines or electric motors are also used. Large compressor stations along the pipeline often use natural gas from the pipeline for fuel. Compressor stations operate at a high noise level and are normally housed in large metal buildings. Storage and maintenance facilities for the gas field's operations are usually located at the compressor station. Compressor stations are the largest and most visible features in a gas field and are the center of most of the human activity.

9. Disposal of Produced Water

After water is separated from oil at the tank battery, it is disposed of under BLM approval and supervision. Although most produced waters are brackish to highly saline, some produced waters are fresh enough for beneficial surface use.

Produced water from oil and gas operations is disposed of by subsurface injection, lined pits, or other methods acceptable to the BLM, in accordance with the requirements of Onshore Order #7: titled: "Disposal of Produced Water," or an applicable Onshore Oil and Gas Order. Disposal of produced water by disposal/injection wells requires permit(s) from the primacy State or Environmental Protection Agency (EPA). Approval of surface use by the Forest Service is also required. The state of Montana has primacy for the surface disposal of produced water and the EPA has authority for underground injection disposal. The state of Montana does permit surface pit disposal (evaporation) of produced water.

When produced water is disposed of underground, it is introduced or injected under pressure into a subsurface horizon containing water of equal or poorer quality. Produced water may also be injected into the producing zone from which it originated to stimulate oil production. Dry holes or depleted wells are commonly converted for saltwater disposal. Occasionally new wells will be drilled for this purpose.

The EPA, in Montana, requires that all injection wells be permitted under the Underground Injection Control (UIC) program. Permission is also required from the BLM per Onshore Order #7. Under the UIC approval process, the disposal well must be pressure tested to ensure the integrity of the casing. The disposal zone must also be isolated by use of tubing and mechanical plug called a packer. The packer seals off the inside of the casing and only allows the injected water to enter the disposal zone. The tubing and packer are also pressure tested to ensure their integrity. These pressure tests confirm the isolation of the disposal zone from possible usable water zones. The tests are repeated at periodic intervals established by the EPA.

10. Enhanced Recovery of Oil

Oil, gas, and water are typically trapped within rock pore space and fractures under high pressure in the reservoir. Because of the high pressures, much or all of the gas is dissolved in the oil. Expansion of pressurized water and gas in solution forces oil out of the rock pores into the well and up to the surface. This is known as the "primary drive" or "primary recovery." Oil flowing out of the rock drains energy from the formation; pressure in the reservoir begins to slowly decline; primary drive diminishes and the production rate falls. The oil cannot be produced unless pressures within the reservoir are maintained or restored to cause displaçement of the oil being held in the rock and to drive it to the wellbore. Usually, only 15 to 20 percent of the oil is recovered from a reservoir during primary production. As reservoir pressures continue to drop, gas in the oil escapes, forming bubbles in the rock pores. This retards the flow of oil and, over time, oil production ceases. Installation and implementation of an enhanced recovery system significantly increases a field's productivity and longevity. Many reservoirs are developed for secondary and tertiary recovery early in the life of a field.

Secondary Recovery Methods - Fluid injection is a secondary recovery operation in which a depleted reservoir is restored to production by the injection of liquids or gases (from external sources) into the wellbore. In essence, this injection restores reservoir pressures and moves the formerly unrecoverable oil through the reservoir to the well. Fluids are injected into selected wells at, or near, original pressure levels to achieve maximum recovery efficiency. Two of the more common fluid injection methods are waterflood and saltwater disposal.

The installation of a secondary recovery system involves drilling of injection wells and new recovery wells or conversion of production wells to injection wells. Fluid injection lines are installed and additional water separation and storage facilities constructed to implement the secondary recovery system. Secondary recovery results in a significant increase in the amount of water produced. Additional surface disturbance may be needed to accommodate water supply facilities, water storage and treating facilities, water injection pumps, and waterlines to wells. Drilling and construction and other human activities intensify in the oil field during installation of a fluid injection system.

Waterflood - The most commonly employed form of secondary recovery is waterflooding. Water is injected into the reservoir under pressure to drive additional oil to the producing wells. On the average, a successful waterflood doubles the amount of oil recovered from a reservoir. In some fields, water for waterfloods is injected into depleted existing wells. In other cases, additional wells may need to be drilled for water injection. Most waterfloods are difficult to operate on a lease basis, so entire fields, if not already being operated under a unitization agreement, are usually unitized before flooding. If unitization precedes a waterflood, there is little or no duplication of secondary recovery facilities. However, additional surface area may be used for the water supply facilities, water storage and treating facilities, water injection pumps, and waterlines to injection wells. If the injection well is a converted producing well, the waterline replaces the producing flowline. If the injection well is a converted dry hole or a new well drilled for the waterflood, the water injection line is the only addition to the pipeline system and requires the same amount of land as a flowline for a producing well.

Gas Injection - Gas injection is a secondary recovery technique that is generally used only in oil and gas reservoirs which have an existing gas cap. Natural gas is injected under pressure to restore and maintain reservoir pressures to displace and move oil to the producing wells.

Saltwater Disposal - Although not a secondary recovery process, *per se*, saltwater disposal is a common form of fluid injection. Its primary purpose is simply to dispose of the saltwater produced with crude oil. A typical system is composed of collection centers in which saltwater from several wells is gathered, a central treating plant in which corrosion-forming substances are removed, and a disposal well. The saltwater is injected into the originating zone and used to pressurize and drive the oil towards the borehole of a producing well. (See Disposal of Produced Water.)

Tertiary Recovery Methods - Tertiary recovery methods increase the amount of oil produced and recovered from an oil reservoir beyond that obtained from primary and secondary methods. Tertiary oil recovery techniques employ chemicals, water, gases, and heat singly, and in combination, to reduce the factors that inhibit oil recovery. Considerable technical and financial risk is involved because of the large investment in equipment and the unknown factors or characteristics of the oil reservoir that may affect the success of a tertiary recovery method. There are three broad categories of tertiary recovery methods currently used: (1) thermal enhancement, which primarily involves injecting high pressure steam into the oil reservoir to reduce oil viscosity and increase its ability to flow; (2) miscible flood, in which propane, butane, natural gas, CO_2, or other gases are injected into the reservoir to dissolve and displace the oil; and (3) chemical enhancement, which includes injecting polymers to thicken injected waters which increase uniformity of oil displacement in the reservoir or injecting detergents ("surfactants") that essentially "wash" the oil from the reservoir rocks.

As with secondary recovery systems, additional land surface is required to accommodate the injection and oil recovery systems. This includes additional wells, injection lines and flowlines, roads, storage, and treatment facilities, pumps, and injection equipment. There is also an increase in construction and drilling activities during the installation of all enhanced recovery systems.

11. Transportation Pipelines

A transportation pipeline is needed in order to transport natural gas and oil to market or refineries. In most cases, oil is transported to the refinery via a pipeline, although trucks may be used to transport oil from isolated fields or new fields to pipeline terminals or the refinery.

Oil is moved through the pipeline by pumps. Pump stations are located either at gathering stations or trunkline stations or a combination of both. A gathering station is located in or near an oil field and receives oil through a pipeline gathering system from the operators' tanks. From the gathering station, oil is relayed to a trunkline station, which is located on the main pipeline, or trunkline. The trunkline station relays the oil to refineries or shipping terminals. To maintain pressure, booster pumps are spaced along the trunkline. Tank batteries located along the line receive and temporarily store the oil before it continues.

Months and sometimes years of engineering studies and surveys of potential gas reservoirs and markets precede the final decision to build a pipeline.

Construction of a large transportation pipeline may involve as many as 250 to 300 workers in a normal operation and up to 500 workers in a very large operation. The amount of construction equipment needed depends on the variety and difficulty of terrain. Stream crossings, marshes, bogs, heavily timbered forests, steep slopes, or rocky ground can require different types of equipment and construction practices. About 250 to 300 workers can move at a rate of 3 miles a day with a distance of sometimes 10 or 15 miles separating the beginning of the work crew from the end.

In practice, a strip of land from 50 to 75 feet wide is cleared depending on the size of the pipe and the type of terrain. The clearing crews open fences and build gates, cattle guards, and bridges. Salable timber cut by clearing crews is stacked; the rest is cut and disposed of. A roadway capable of supporting vehicle access is graded and completed adjacent to the pipeline. The cleared area needs to be wide enough for the pipeline trench, the largest side-boom tractor, and transportation of pipe and equipment. In rocky terrain, a machine equipped with a ripper that extends several feet into the ground is often used to loosen rocks for removal before the ditching operation begins.

A ditch is made by loose-dirt ditching machines or by wagon drills suspended from side-boom tractors. Dynamite blasting is used for very hard rock surfaces. Pipe is transported to the ditching sites where the pipe is coated, double jointed, welded, and lowered into the ditch. The pipe must be buried deep enough to ensure that it does not interfere with normal surface uses. The Department of Transportation requires a minimum of 36 inches of cover. The trench is backfilled, compacted, and the cleared area waterbarred, and revegetated.

12. Well Servicing and Oil and Gas Field Maintenance

Producing wells in active oil and gas fields periodically require repair and workover operations. Operations involving no new surface disturbance to redrill, deepen, and plug-back require prior approval of the authorized officer of the BLM. In some cases, these operations require the approval of the Forest Service.

No prior approval or subsequent report is required for well cleanout work, routine well maintenance, bottom hole pressure survey, or for repair, replacement, or modification of surface production equipment provided no additional surface disturbance is involved.

When prior approval is required, the operator must submit a Sundry Notice, or APD, as applicable. A detailed written statement of the plan of work must be provided to the authorized officer with the appropriate form. When additional surface disturbance will occur, a description of any subsequent new construction, reconstruction, or alteration of existing facilities, including roads, damsites, flowlines and pipelines, tank batteries, or other production facilities on any lease, must be submitted to the authorized officer for environmental reviews and approvals. On National Forest System lands, the BLM coordinates with the Forest Service to obtain their approval on the surface disturbing activities. Emergency repairs may be conducted without prior approval provided the authorized officer is promptly notified.

The servicing of individual wells to improve or maintain oil and gas production is an activity that extends throughout the life of the field. This work is usually performed with the use of a well servicing unit or self propelled workover rig which is similar to a scaled down oil rig. Both the workover rig or well servicing unit carry hoisting machinery that is used to pull sucker rods and tubing from the wellbore. The most common well servicing operations conducted are cleaning out the well, changing pumps, repairing rod string and tubing, changing the producing and reestablishing oil producing intervals, installing artificial lift, and repairing casing and other downhole equipment. There is an intense, but short term, increase in human and motorized activity at the wellsite during servicing.

Construction, reconstruction, and normal maintenance work continue throughout the field's life. Flowlines, pipelines, pumping units and other oil and gas field equipment which is no longer functional because of corrosion, metal fatigue, wear, or because it has become outdated and inefficient is replaced, upgraded, or abandoned and removed. Major and minor maintenance activities are a normal part of the operations during the life of the oil and gas field.

13. Pollution Control

All spills or leakages of oil, gas, produced water, toxic liquids or waste materials, blowouts, fires, personal injuries, and fatalities must be reported by the operator to the BLM and the surface management agency in accordance with the requirements of Notice to Lessees 3A (NTL 3A), "Reporting of Undesirable Events," or an applicable Onshore Oil and Gas Order. The BLM requires immediate reporting of all Class I events (more than 100 barrels of fluid/500 MCF of gas released or fatalities involved). A "spill prevention, control, and countermeasure plan" is required by the Environmental Protection Agency under 40 CFR Part 112 and any discharge of oil (oil spill) must be reported immediately to the National Response Center, EPA (See 40 CFR 110).

Firewalls/containment dikes must be constructed and maintained around all storage facilities/batteries. The containment structure must have sufficient volume to contain, at a minimum, the entire content of the largest tank within the facility/battery, unless more stringent site-specific protective requirements are deemed necessary by the authorized officer.

14. Inspection and Enforcement

The BLM and Forest Service have developed procedures to ensure that leaseholds which are producing or expected to produce significant quantities of oil or gas in any year, or have a history of noncompliance, are inspected at least once a year. Other factors such as health, safety, and environmental concerns, and potential conflict with other resources also determine inspection priority. Inspections of leasehold operations ensure compliance with applicable laws, regulations, lease terms, Onshore Oil and Gas Orders, NTL's, other written orders of the authorized officer, and the approved plans of operation. The administration of oil and gas operations on National Forest System lands is conducted in accordance with 36 CFR 228.111 through 36 CFR 228.114 and Bureau of Land Management oil and gas regulations 43 CFR 3160.

E. ABANDONMENT (PHASE 5)

All abandonments, whether they involve one wildcat well, a well no longer productive, or an entire leasehold, require the approval and acceptance of the abandonment of the individual well(s) by the BLM and the Forest Service. An acceptable abandonment includes (1) the plugging of the wellbore and (2) reclamation of the land surface to a stable and productive use.

1. Approval of Abandonment

Well abandonment operations may not be started without prior approval of a "Sundry Notices and Reports on Wells" by the authorized officer of the BLM. The Sundry Notice serves as the operator's Notice of Intent to Abandon (NIA). In the case of newly drilled dry holes, failures, and in emergency situations, oral approval may be obtained from the authorized BLM officer followed by written confirmation. In such cases, the surface reclamation requirements will have been discussed with the operator and be included in the approved APD. Additional surface reclamation measures may be required by the Forest Service. For older existing wells, not having an approved surface use plan of operations, a reclamation plan must be submitted with the NIA. Reclamation requirements are part of the approval of the NIA. The operator must contact the BLM prior to plugging a well to allow for approval and witnessing of the plugging operations.

Plugging of Wells - The purpose of plugging a well is to prevent fluid migration between zones within the wellbore, to protect other minerals from damage, and to prevent escape of well gas or fluids to the surface.

Plugging requirements vary with the characteristics of the rock, geologic strata, and well design. Each plugging and surface reclamation program will be unique. The following are some of the most common regulations and plugging practices. They should not be considered all-inclusive.

> *Drilling well or open hole situations* - The plugging of drilling wells or open holes must be in accordance with Onshore Oil and Gas Order No. 2. Minimum requirements specify that cement plugs must extend at least 50 feet above and below zones with fluid which has the potential to migrate, zones of lost circulation, and zones of potentially valuable minerals. Thick zones may be isolated using 100 foot plugs across the top and bottom of the zones. In the absence of productive zones and minerals, the long sections of open hole are plugged with a minimum of 100 foot plugs spaced every 3,000 feet. A 100 foot cement plug is placed across the surface casing shoe (the bottom of the surface casing). This plug must extend at least 50 feet below the shoe and 50 feet above the shoe (inside the surface casing).
>
> All cement plugs must have sufficient volume to fill 100 feet of the hole or casing volume plus an additional 10 percent per 1,000 feet of depth or must be a minimum of 25 sacks if placed through tubing (a 100 foot plug at 5,000 feet would be required to have an additional 50 feet of cement). Certain plugs will be tested by tagging or through pressure. Tagging is accomplished by running into the wellbore with a wireline to verify the location of the cement top or setting some weight of the drillpipe down on the cement plug to establish that a competent plug exists at the depth specified. Pressure testing requires that the wellbore maintain a pressure for a given period of time. Tagging is by far the most utilized plug testing method.
>
> *Depleted producers or cased hole situations* - For cased holes, all perforations must be isolated so as not to allow fluid to migrate up hole or to the surface. The perforations may be isolated by: 1) placing a cement plug across the perforations (50 feet above and below the perforations, if possible) or 2) setting a cement retainer (cement tool that acts like a plug.except that cement can be pumped below the tool but no fluid can pass above the tool) +/- 100 feet above the perforations and pumping a sufficient volume of cement into the perforations, or 3) setting a bridge plug (a tool similar to a

cement retainer except that no fluid can pass in either direction) +/- 100 feet above the perforations and placing of cement on top of the bridge plug.

The production casing may be removed. If the casing is cut and removed, the casing stub (the top of the casing remaining in the hole) must be plugged with a 100 foot cement plug to extend 50 feet inside the casing stub and 50 feet above the casing stub. If casing is removed, the surface casing is plugged as described under open hole situations. If the casing is not removed, the surface casing shoe may be isolated by perforating the production casing near the surface casing shoe. (A cement retainer must be set +/- 100 feet above the perforations and a sufficient volume of cement is pumped below the retainer, through the perforations, and between the outside of the production casing and the inside of the surface casing for a distance of 100 feet). A braden head squeeze may be performed from the surface between the production and surface casing. The annular space may also be filled by running small diameter tubing down the annular space and filling with cement.

All cement plugs must have sufficient volume to fill 100 feet of hole plus an additional volume of 10 percent per 1,000 feet of depth, oor 25 sacks if placed through tubing, 100 foot plug at 5,000 feet would be required to have an additional 50 feet of cement). At the surface, all annular spaces must be plugged with at least 50 feet of cement. No tagging of the surface casing shoe plug is required if the plug was placed through a cement retainer. All cement retainers of bridge plugs must be capped with a minimum of 50 feet of cement.

A permanent abandonment marker is required on all wells unless waived by the Forest Service. This marker pipe is usually 4 inches an diameter and 4 feet above the ground and welded to the production casing or steelcapping plate. The pipe is capped and the well's identity and location permanently inscribed. A small weep hole is placed in the pipe top and through the capping plate so that any leakage can be detected.

Dry wildcat and development wells are normally plugged before the drill rig is removed from the wellsite. This allows the drill rig to plug the hole and avoid the necessity of bringing in other plugging equipment.

Before a lessee/operator abandons a well no longer capable of production, it must be shown that it is no longer suitable for profitable operation. Wells are normally plugged when they are no longer capable of production. However, if a well has potential for use in a secondary recovery program, it may be allowed to stand idle. Truck-mounted equipment is used to plug former producing wells.

Surface Reclamation - A reclamation plan is a part of the surface use plan of operations. Reclamation may be required of any surface previously disturbed that is not necessary for the continued well or other operations. When abandoning a well and other facilities that do not have a previously approved reclamation plan, a plan must be submitted with a Notice of Intent to Abandon (NIA). Additional reclamation measures may be required based on the conditions existing at the time of abandonment. Any additional reclamation requirements are made part of the conditions of approval of the NIA. The general standards and guidelines for reclamation and abandonment of oil and gas operations are set forth in the third edition of the Surface Operating Standards for Oil and Gas Exploration and Development. Additional standards and requirements may be applied to accommodate the site-specific and geographic conditions of the reclamation site.

Prior to the start of reclamation, all equipment and trash must be removed from the wellsite or the area to be reclaimed. When an entire lease is abandoned, the separators, heater treaters, tanks, and other processing and handling equipment are removed and the surface restored. Flowlines and injection lines installed on the surface are removed, but buried lines usually are left in place.

Wellsite Reclamation - Wellsite reclamation must be planned on both producing and abandoned wellsites. The entire site, or portion not required for the continued operation of the well, is reclaimed.

When they are dry, all excavations and mud pits must be closed by backfilling and graded to conform to the surrounding terrain. Waterbreaks and terracing may be installed to prevent erosion of fill material.

Cut and fill slopes must be reduced and graded to blend the site to the adjacent terrain. The wellsite may be recontoured by bringing the construction material back onto the well pad and reestablishing the natural contours where desirable.

The topsoil is replaced on the reclamation area and prepared to provide a seedbed for reestablishment of desirable vegetation. Standard reclamation practices may include contouring, terracing, gouging, scarifying, mulching, fertilizing, seeding, and/or planting.

Reserve Pit Reclamation - All pits must be reclaimed to a natural condition similar to the rest of the reclaimed wellsite area. In addition, the reclaimed pit must be restored to a safe and stable condition. In most cases, if a pit contains a synthetic liner, the pit is not to be trenched (cut) or filled while still containing fluids. Pits must be allowed to dry, be pumped dry, or solidified by adding cement or a solidification compound *in situ* prior to backfilling. The pit area is usually mounded to allow for settling. The mounding allows for positive surface drainage off the reclaimed pit, which lessens the possibility of leaching or lateral movement from the buried pit contents into surface streams or shallow aquifers.

The concentration of hazardous substances in the reserve pit at the time of pit backfilling must not exceed the standards set forth in the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA). All oil and gas drilling-related CERCLA hazardous substances removed from a location and not reused at another drilling location are disposed of in accordance with applicable state and Federal regulations.

Road Reclamation - Roads no longer needed for oil and gas operations and not within the Forest Service Transportation System must be abandoned, closed, and obliterated. Reclamation of abandoned roads will involve one or more of the following techniques: (1) recontouring to the original contour; (2) recontouring to blend with natural contours; (3) recontouring only selected sections of the roadway; and (4) obliteration of the roadway surface with no other modification of the road profile. Reclamation treatments may also include ripping, scarifying, water-barring, and barricading. Stockpiled soil, debris, and fill materials are replaced on the roadbed and the road reseeded in accordance with the approved site-specific reclamation plan.

Pipeline and Flowline Reclamation - Abandonment and reclamation of pipelines and flowlines, similar to the reclamation of abandoned roads involve replacing fill material in the original cuts, reducing and grading cut and fill slopes to conform to the adjacent terrain, replacement of surface soil material, waterbarring and revegetating in accordance with the reclamation plan.

Pipeline trenches are compacted during backfilling and must be maintained to correct backfill settling and prevent erosion. Waterbars and other erosion control devices are repaired or replaced as necessary.

Revegetation - Disturbed areas are revegetated after the site has been contoured, graded, and the soil surface satisfactorily prepared. In order to minimize the soil erosion potentials and provide a stable seed bed, site preparation may include ripping, contour furrowing, terracing, reduction of steep cut and fill slopes, waterbarring, etc. Revegetation involves seeding, planting of containerized plants, or a combination of the two. Native perennial species, or other plant materials specified by the Forest Service are used. The oil and gas operator is advised as to species, methods of revegetation and seasons to plant. Seeding is normally done by drilling on the contour or by other approved methods. Seeding and/or planting is repeated until satisfactory revegetation is accomplished, as determined by the Forest Service. Mulching, fertilizing, fencing, or other practices may also be required depending on site-specific conditions.

Visual Resources - For all activities which alter landforms, disturb vegetation, or require temporary or permanent structures, the operator is required to comply with visual resource management objectives for the area. Site-specific mitigation practices may be required by the Forest Service to avoid or minimize changes in the character of the landscape or minimize the impacts of unnatural intrusions on the landscape.

Additional Requirements - Additional reclamation methods and techniques that reflect local site conditions are required. Technical advances in reclamation practices that may be successfully applied to oil and gas construction are continually being developed.

2. Inspection and Final Abandonment Approval

Final abandonment is not approved until the surface reclamation work required by the APD or NIA is completed and the required reclamation is acceptable to the Forest Service. The operator must file a Subsequent Report of Abandonment (SRA) following the plugging of a well. A Final Abandonment Notice (FAN) which indicates that the site is ready for inspections must be filed upon completion of reclamation.

3. Release of Bonds

If the well is covered by an individual lease bond, the period of liability on that bond is terminated once the final abandonment or phased bonding release has been approved. The principal can request termination of the period of liability from the BLM State Office holding the bond. If the well is covered by a statewide or nationwide bond, termination of the period of liability of these bonds is not approved until final abandonment of all activities conducted under the bond have been approved by both the BLM and Forest Service.