CHAPTER 7

SUMMARY OF STATE AND FEDERAL REGULATIONS

Alabama

Introduction

Alabama produced 8,486,000 barrels of oil, and 11,392.000 barrels of condensate, 137 x 10^9 cubic feet of gas in 1984. Production was from 760 oil wells, 509 conventional gas wells, and 184 coalbed methane wells. Thirteen percent of conventional oil and gas wells are strippers; 52 percent of coalbed methane wells are strippers.

Alabama began limited regulation of oil and gas activities in 1946. Regulations for disposal of drilling wastes were adopted in 1973. Regulations and/or administrative codes have continued to be revised during the forty years of regulation.

Regulatory Agencies

Four agencies regulate oil and gas activity in Alabama:

- Alabama State Oil and Gas Board
- Alabama Department of Environmental Management
- U.S. Bureau of Land Management
- U.S. Corps of Engineers

The Alabama State Oil and Gas Board is "charged with preventing the waste of Alabama's oil and gas resources and protecting the correlative rights of owners." In carrying out its mandate, the Board regulates all oil and gas operations for the issuance of drilling permits through the production phase. The Oil and Gas Board has authority to issue permits for UIC Class II wells. The various permitting requirements and conditions of the Oil and Gas Board are detailed in the Board's Administrative Code.

The Alabama Department of Environmental Management (ADEM) has the authority to issue permits for all UIC wells other than Class II. The Department of Environmental Management also has NPDES authority. The Oil and Gas Board and Department of Environmental Management operate under a 1979 Memorandum of Agreement which requires the Board to forward information regarding actual or proposed discharges to the Department of Environmental Management.

The U. S. Bureau of Land Management authority and regulations for Federally-held mineral rights are discussed separately under Federal Agencies. The U.S. Forest Service retains surface rights (and usually coordinates stipulations with the Bureau of Land Management) in Federal forests and grasslands.

State Rules and Regulations

Drilling

Drilling pits are permitted by the Oil and Gas Board. The Board has certain construction requirements to ensure the integrity of the pit. Pits are closed by dewatering (see below), then backfilling, leveling, and compacting.

No pits are permitted in Alabama's coastal wetlands. The Department of Environmental Management prohibits the use of pits in wetlands in order to insure the protection of surface or groundwater resources. Many of the wetlands area in Alabama fall within the jurisdiction of the Alabama Coastal Area Management Program, which is an enforcement responsibility of ADEM. The Certificate of Consistency which must be issued by ADEM before a permit can be issued by the Board requires use of portable above-ground tanksfor any well drilled in the coastal area.

Drilling muds and pit fluids may be disposed in one of three ways. They may be injected into a formation below underground sources of drinking water. They may be transported to a drilling mud treatment (recycling) facility. In non-wetland areas, the fluids may be applied to the land surface or into an approved landfill if:

- The chloride concentration is less than 500 mg/L
- The Oil and Gas Board is properly notified
- The landowner provides written approval
- It is a one-time-only application
- There will be no discharge to surface body of water

These activities are permitted by the Oil and Gas Board prior to allowing disposal of fluids.

Production Waters

Class II injection wells are used for the disposal of brines produced in association with oil and/or natural gas, for the disposal of non-hazardous waste waters that may be generated during the operation of a gas plant. for the enhanced recovery of oil or natural gas, or for the storage of hydrocarbons which are liquid at standard temperature and pressure. Currently, all of Alabama's 250 Class II injection wells are used for disposal purposes, or for the enhancement of oil or natural gas production.

Rule 400-1-5-.04 requires that "Immediately following the initiation of production in any field or pool, all salt water shall be disposed of into an approved underground formation or otherwise disposed of as approved by the Supervisor where such salt water cannot damage or pollute underground sources of drinking water, oil, gas or other minerals." The permitting of Class II injection wells in Alabama is a two-step process. Step 1 is approval to drill or convert a well for injection purposes and includes: a review of all well constructions within a one-quarter mile radius of the proposed injection well; and the submission of data concerning the construction of the proposed injection well, analyses and estimated volumes of fluids to be injected, anticipated injection pressures, known or calculated fracture pressure of the proposed injection interval, and the lowermost depth of fresh water. All injections shall be through tubing anchored by a packer unless otherwise approved by the Oil and Gas Supervisor. In addition, the operator must provide proof that the injection casing is adequately cemented in order to prevent vertical fluid migration and must test the injection casing at a pressure equal to 2/10th the depth of the mid-point of the injection interval, but not to exceed 1,500 psi.

Following completion of the Board's Step 1 requirements, the applicant may receive approval to begin injection. Once injection begins the operator must submit monthly reports on injection volumes, injection pressures, and tubing-casing annulus pressures. The injection pressure and casing-tubing annulus pressure must be recorded on a daily basis, or computed on a daily average basis from weekly measurements. Also, chemical analyses of injected fluids are to be submitted on an annual basis and a pressure test must be performed at least once every five years.

Produced waters from coalbed methane wells are an exception to the injection requirement. EPA has advised Alabama that coalbed methane production is not covered under the Federal onshore oil and gas regulations. Produced waters from coalbed methane wells may be allowed to accumulate in pits, settle, and then may be discharged directly into live streams. The Department of Environmental Management requires operators to obtain permits for such discharges, and requires such discharges to meet a 600 mg/l in-stream limit.

Plugging/Abandonment

Plugging is required after six months, but wells may be approved for temporary abandonment if future utility can be shown. Thereafter, well status must be reported every six months.

When plugging, cement plugs of not less than 100 feet should be placed above any producing formation, from 50 feet below to 50 feet above the base of fresh water strata, and from 50 feet below to 50 feet above the base of the surface casing. A 25 foot plug should be near the surface, and a steel plate over the casing stub. Intervals between the plugs must be filled with mud-laden fluid.

References

State Oil and Gas Board of Alabama, Submittal to EPA Regarding Onshore Oil and Gas Subcategory, March 1985.

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Alabama Meeting Report. 1985. Proceedings of the Onshore Oil and Gas Workshop, U.S. EPA, Washington, D.C. (March 26-27 in Atlanta, GA).

Personal Communication:

Treena Pizner, Alabama Department of Environmental Management (205) 271-7850.

Alaska

Introduction

Alaska produced 681,309,821 barrels of oil and 316 x 10^9 cubic feet of gas in 1986. During 1986, 608,225.599 barrels of water and 1,066 x 10^9 cubic feet of gas were injected into producing formations for enhanced oil recovery.

Alaska ranked second in U.S. oil production, but twenty-third in the number of production wells (1,191 wells) in 1986. It ranked eighth in U.S. gas production and twenty-fourth in the number of producing gas wells (104 wells)

In 1986 Alaska produced from two oil and gas development regions, the South Central region (including Cook Inlet and the Kenai Peninsula) and the North Slope region. The state contains other prospective regions; but to date no discoveries in these regions have been made. Approximately 663,738,428 barrels of oil and 123 x 10^9 cubic feet of gas were produced from the North Slope in 1986 from two fields (Kuparuk and Prudhoe). The Duck Island unit (Endicott Field) will commence production in early 1988. Production at Milue Point unit is currently suspended for economic reasons.

The Kenai Peninsula produced mostly gas with little associated produced water. In 1986, fields in the South Central region produced 17,571,393 barrels of oil and 193 x 10^9 cubic feet of gas.

Regulatory Agencies

Eight agencies regulate oil and gas activities in Alaska:

- Alaska Oil and Gas Conservation Commission

- Alaska Department of Environmental Conservation
- U.S. Bureau of Land Management
- Alaska Department of Natural Resources
- Alaska Department of Fish and Game
- U.S. Army Corps of Engineers
- U. S. EPA - Region X
- U.S. Fish and Wildlife Service

Alaska Oil and Gas Conservation Commission regulates the production and conservation of oil and gas in Alaska, and is responsible for issuing permits for drilling. The Commission checks well casings to prevent contamination of water, and has primacy for the Class II injection wells. Under Title 31 of the Alaska Statutes, the Commission has the status of an independent quasi-judicial agency. Its three commissioners, appointed by the Governor, must include an expert in petroleum engineering and an expert in petroleum geology.

The Alaska Department of Environmental Conservation is the primary pollution control agency within the State government. The department regulates and permits solid waste disposal, wastewater discharges, and air contaminant emissions. It issues state discharge permits for oil and gas drilling and production operations. The Department also regulates hazardous wastes, oil spill control, and the subsurface disposal of non-hazardous oil and gas wastes (which are not regulated as Class II wastes). Since Alaska does not have responsibility for the NPDES program, DEC coordinates with EPA-Region X, which administers the NPDES program in Alaska.

The U.S.Bureau of Land Management is responsible for all oil and gas activity on Federal and Indian lands (under 43 CFR 3160). There are 370 million acres of land in Alaska, of which more than half are under Federal ownership. There are 150 producing oil and gas wells on Federal leases. Regulatory processes for oil and gas operations are covered in Onshore Oil and Gas Order No.1. More information on BLM regulations can be found in the section on Federal programs.

The Alaska Department of Natural Resources issues surface and subsurface oil and gas leases on State land. Leasing stipulations address environmental concerns, such as requiring that reserve pits be rendered impermeable, at lease award. The Department also approves plans of operations for all oil and gas activity on State lands. The approval letter contains site-specific stipulations developed through inter-agency review. The Department also conducts field inspections of operations and abandonments.

Under the Section 404 program of the Clean Water Act, the U.S. Army Corps of Engineers is responsible for issuing permits for dredge and fill activities on wetlands defined as part of the waters of the United States, and U.S. EPA has review responsibility for such permits. Several other State and Federal agencies also have comment and/or concurrence responsibilities on the Federal permits. Since much of Alaska's drilling and production activity, including that on the North Slope, takes place on wetlands, all pads, roads and facilities have 404 permits. The Corps of Engineers requires all reserve pits to be rendered impermeable.

The U.S. Fish and Wildlife Service, in addition to having comment responsibility on 404 permits, has been conducting research related to the permitted discharge of drilling fluids to the tundra wetlands. The research project currently in progress is designed to determine the deleterious effect of the discharge on wildlife in the wetlands, especially to waterfowl.

State Rules and Regulations

Current regulations for handling of drilling and production wastes in Alaska may be subject to modification. A final draft of proposed amendments to regulations for Solid Waste Management (18 AAC 60) was published by the Department of Environmental Conservation on October 31, 1986. These amendments would impose more stringent requirements on the management of reserve pits and drilling wastes. As of April, 1987, however, these amendments had not yet been adopted. However, the final revisions were expected to be completed and distributed in April. DEC projects adoption of the proposals by July, 1987.

Reserve Pits

The management and disposal of "drilling wastes" primarily involves the proper operation and closure of the reserve pit utilized during drilling operations. The reserve pit often provides the permanent disposal site for solids or solidified wastes from the drilling operation. Although in exploratory drilling, reserve pits may often be used and closed in a single season, on the North Slope many are in continual use, due to the directional drilling of multiple wells from a single pad. There are however, a variety of ways in which drilling wastes are ultimately disposed, such as subsurface injection. (In proposed regulations (18 AAC 60), "drilling wastes" are defined as including "drilling muds, cuttings, hydrocarbons, brine, acid, sand, and emulsions of mixtures of fluids produced from and unique to the operation or maintenance of a well").

State statutes require permits for solid waste disposal facilities. However, prior to 1982, few solid waste permits were issued for reserve pits. As early as 1982, it became policy to require permits for all currently active and new pits in the Cook Inlet area. The same policy was applied on the North Slope beginning in 1985.

Under 20 AAC 25.047, administered by the AOGCC, reserve pits are required "for the reception and confinement of drilling fluids and cuttings, to facilitate the safety of the drilling operation, and to prevent contamination of groundwater and damage to the surface environment." The general construction requirement is that the pits must be rendered "impervious." There is no specific requirement for lining.

The proposed DEC regulations would impose specific construction and performance requirements for reserve pits. The particular requirements would depend on factors such as the proximity of surface water or groundwater which is used for drinking water, the proximity of an existing or developing population, and whether the pit were being built in an area of continuous permafrost. For example, a reserve pit being constructed in a non-permafrost region within 100 feet of a surface water body used for drinking water would require double liner, leachate collection (if no fluid management plan), site inspection and monitoring. A reserve pit in a permafrost region not adjacent to water supplies or population would require a containment structure (possibly lined) designed to prevent the escape of wastes from the reserve pit, site inspection, a fluid management plan, and monitoring.

Under 20 AAC 25.047, administered by the AOGCC, upon termination of operations related to a particular reserve pit, "the operator shall proceed with diligence to dispose of and solidify in place all pumpable fluids, and shall leave the reserve pit in a condition that does not constitute a hazard to ground water." Under 18 AAC 60 and 18 AAC 72, administered by the DEC, solid waste permits are required for closure and wastewater permits for all discharges.

Disposal from Reserve Pits

Reserve pit fluids on the North Slope may be disposed of through injection in dedicated wells. In the Kenai area there have been several permits for centralized disposal of oil field wastes. One of these permitted disposal facilities was operated by an independent concessionaire on Kenai Borough owned land, but DEC cancelled the permit because of contaminants found in monitoring wells.

DEC has issued general permits for discharges to the tundra, for annular injection of reserve pit fluids, and for dedicated injection wells that are not Class II wells, and issues occasional specific permits for road application. Injection into dedicated Class II wells is permitted by the Oil and Gas Conservation Commission. Annular injection is allowed under the permit-to-drill issued by AOGCC.

Surface Discharge to Tundra:

DEC issued a seasonal general permit on May 12, 1986 (expired September 30, 1986) for discharges onto the tundra from reserve pits containing "produced waters, drilling fluids and cuttings, boiler blowdown, rig washing fluids, workover fluids, completion fluids, excess fluids from blowouts and drill pad runoff." Only those pits were eligible which had received no discharges or placements of any materials into thepit since August 1, 1985 (that is, pits which had gone through a one year freeze-thaw cycle to precipitate contaminants). Further, pits must have no visible sheen on the surface. Operators must notify DEC two weeks prior to any discharge, and include information on volumes and analyses for salinity, settleable solids, arsenic and chromium. Written approval must be received from DEC prior to the discharge.The permit applies only to discharges of the clarified supernatant from the pits. The maximum drawdown is 18 inches from pit bottom at point of withdrawal, to prevent solids carry-over. Other management practices, such as injection, must be used for further drawdown. Effluents must be monitored during discharge. The effluent limitations for 1986 were:

COD	200 mg/l
pH	6.0 - 8.5(or

	within 0.5 of receiving water)
Salinity	3parts/thousands
Settleable solids	1 mg/l
Oil and grease	15mg/l
Aromatic hydrocarbons	10ug/l
Arsenic	.05mg/l
Barium	1 mg/l
Cadmium	.01 mg/l
Chromium	.05 mg/l
Lead	.05 mg/l
Mercury	.002 mg/l

These limitations will be reevaluated prior to issuance of the 1987 general permit. Limitations are also being evaluated for copper, zinc, aluminum, and boron. The process of reevaluation after 1985 led to the elimination of an effluent limitation for manganese in the 1986 general permit. DEC figures in the information sheet with the 1986 general permit indicate approximately 36 million gallons of liquid were discharged from 43 reserve pits in 1985, 35 of which exceeded limitations. But 16 of these pits exceeded only the limitation for manganese, which is found at naturally high levels in waters on the slope.

Surface Discharge to Roads:

Permits for road applications of reserve pit fluids, used for dust control during the summer, are issued to individual applicants. Two permits issued to facilities of one company for 1986 were valid from May 15th to December 31st, but specified that discharges must be between June 1st and August 31st unless DEC determined sufficient thaw existed to prevent puddling or runoff.

Unlike discharges to the tundra, road application permits do not require that the reserve pit fluids go through a one) year freeze-thaw cycle before disposal. Application is specifically designated for particular roads and pads. Spraying is prohibited when the surfaces are already wet. Spraying is to be made no closer than three feet from the edge of the shoulder of any pad or road to prevent spraying onto adjacent areas. Compliance with effluent limitations is to be determined at the edge of the road or pad. The required limitations are the same as those for discharge to the tundra, except for the range for pH (6 to 9). Sampling and monitoring reports are required.

Annular Disposal:

Reserve pit wastes are frequently injected down the annulus either of the well being drilled, or of another well on the pad. A general permit for the North Slope for annular disposal was issued by DEC for the period of August 6, 1985 to April 30, 1987. The permit applies to the discharge of "fluids produced from the drilling, servicing or testing of oil and gas exploration, development, service and stratigraphic test wells, including but not limited to drilling fluids, rig washwater, completion fluids, formation fluids, reserve pit meltwaters and domestic wastewaters...."

Discharge must occur below the permafrost zone; the minimum depth must be 1,000 feet. No discharge must be into any zone containing TDS of less than 3,000 ppm. Operators must notify DEC at least two weeks before beginning injection, and must include information on volumes and types of material being injected, the zone and depth of the injection, and the method to be used to seal the injection zone at the completion of disposal. Written approval must be received from DEC. A report must be submitted after closure of the well, stating volumes and types of liquids injected, well location, well designations, date and time of injections, and depth of injection zones.

This option may require that the operator perform annual maintenance on the well to preserve the permafrost.

Injection Wells

The Oil and Gas Conservation Commission has responsibility for Class II UIC wells. The Commission permits the disposal of both oil field waste fluids and produced waters into wells dedicated for disposal of oil field wastes (20 AAC 25.252), and approves injection into wells for enhanced recovery (20 AAC, Article 5). While the numbers continually change, current figures provided in February and March, 1987 were 17 disposal wells (14 North Slope; 3 Kenai) and 387 enhanced recovery wells.

Since more water is injected for enhanced recovery in Alaska than is produced with oil and gas production, produced waters are injected into disposal wells only when they are removed from any enhanced recovery operation. Additional water for enhanced recovery is drawn from both Cook Inlet and the Arctic Ocean.

Injection for enhanced recovery may be carried out under area injection orders (20 AAC 25.460). The Commission may issue orders permitting injection on an area basis, rather than for each individual well, if the wells are essentially similar, within the same field or site or similar area, are operated by a single operator, and are used to inject other than hazardous waste.

Reserve pit fluids may be injected into dedicated disposal wells, or in some instances returned down the annulus to formation.

Injection wells must be cased with safe and appropriate casing, tubed to prevent leakage, and cemented to protect oil, gas, and fresh water strata. At application, information must be provided on all wells within a quarter mile of the injection well which penetrate the injection zone. Adequate evidence must be provided that a proposed injection well will not cause or increase fractures in overlying strata which could allow injected or formation liquids to enter fresh water strata. (Fresh water aquifers may be exempted from the restrictions affecting them if they do not currently and cannot in the future serve as sources of drinking water, are between 3,000 and 10,000 mg/l TDS but cannot be reasonably expected to supply a public water system, or if too contaminated for economic or technologically practical recovery).

Injection wells must be equipped with tubing and packer or other equipment which isolates pressure to the injection interval. Wells must undergo pressure tests for mechanical integrity before operation. The test must be for 30 minutes at 1500 psi or 0.25 psi/ft times the vertical depth of the casing shoe, whichever is greater (but must not exceed 70% of the minimum yield strength of the casing), with a maximum pressure decline of 10%. Thereafter, mechanical integrity must be demonstrated by the operator by monitoring the pressure in the casing-tubing annulus during actual injection. The monitored pressure must be reported monthly.

At present, two applications are pending with the EPA for permits for dedicated, Class I, disposal wells on the North Slope, one for the Prudhoe Bay Unit and one for the Endicott Unit. These wells will be for restricted oil and gas development wastes.Plugging/Abandonment

All wells that have been permitted on a property must be abandoned within one year following cessation of the operator's oil and gas activity within the field where the wells are located. Any well which, after drilling, is not completed, must be abandoned or suspended before removal of the drilling equipment.

The Commission may approve suspension of a well if it has future productive or service use, and if there is justifiable reason for the suspension (e.g., unavailability of production or marketing facilities).

The operator of a suspended well must set a bridge plug 200-300 feet below the casing head and cap with 100 linear feet of cement. Additional plugging requirements for a suspended well would be determined on a site-specific basis by the Commission.

Abandoned wells must be plugged to prevent movement of fluid into or between freshwater and hydrocarbon sources. Uncased portions of a well must be cased to keep fluids in original strata; cement plugs must be placed from 50 feet below to 100 feet above hydrocarbon strata, and from 150 feet below to 50 feet above the base of the lowest freshwater stratum.

Uncased and cased portions of the well bore must be segregated; various cementing method/plug placement combinations may be used (e.g., plug from 100 feet below to 100 feet above casing shoe, by displacement method).

Cased portions of the well bore must be plugged with cement to confine hydrocarbons and freshwater to original strata. Perforated intervals must be plugged by one of several methods (e.g., cement plugs extending from 100 feet below to 50 feet above the base and from 50 feet below to 100 feet above the top of each interval, or by placing a mechanical bridge with 75-foot cement cap 50 feet over the interval), as must casingstubs within the outer casing (plug from 100 feet above to 100 feet below the stub, bridge plug 25 feet over stub with 75-foot cap, or downsqueeze 150 feet of cement through retainer with additional 50 foot plug).

Surface plugs must seal annular openings in communication with the open hole, and a 150-foot cement plug must extend to within 5 feet of grade elevation.

Cements used for plugging within permafrost zones must be designed to set before freezing and have low heat of hydration. Muds equaling or exceeding density of mud used to drill each interval should fill intervals between plugs.

Final abandonment of the wells and drillsites must also be approved by the Alaska Department of Natural Resources if the site is on State land.

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Regulations, Alaska Administrative Code, Title 18, Alaska Department of Environmental Conservation: Chapter 60 (Solid Waste Managemtent), October 9, 1983; draft revisions, October 31, 1986: Chapter 72 (Wastewater Disposal), January, 1983.

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Title 46, Water, Air, Energy, and Environmental conservation: Chapters 3 (Environmental Conservation; 4, (oil Pollution Control); and 8-9 (Oil and Hazardous Substance Release).

Fristoe, Bradley R. 1985. Letter Communication to EPA. State of Alaska Department of Environmental Conservation.

Alaska Department of Environmental Conservation: General Wastewater Disposal Permits for surface discharges from reserve pits (#8640-DB001; May 12, 1986) and annular injection (#8540-DB001; August 6, 1985); and individual permits for road application (#8636-DB003 & DB004).

Personal Communications:

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ARIZONA

Introduction

Arizona produced 214,000 barrels of oil and 225 MMCF of gas in 1984. Production was from 26 oil wells and 5 gas wells. Approximately 655 bbls/day of brines are produced in the State per day.

Regulatory Agencies

There are five agencies that regulate the oil and gas industry in Arizona:

- Arizona Oil and Gas Conservation Commission

- U.S. Bureau of Land Management

- U.S. Bureau of Indian Affairs

- Arizona Department of Health and Safety

- EPA, Region IX

The Bureau of Land Management has the authority to issue oil and gas drilling permits for Federal minerals. Where Indian mineral rights prevail, oil and gas activity may be governed by both the BLM and the Bureau of Indian Affairs.

The Arizona Oil and Gas Conservation Commission reviews all oil and gas drilling applications and is primarily responsible for approving and enforcing oil and gas activities. The Oil and Gas Commission's regulations pertain to the construction, location, and operation of onsite drilling and production activities.

Arizona does not have NPDES or UIC program primacy. The Department of Health and Safety Coordinates with EPA's Region IX for any surface water discharge or underground injection permit. Region IX administers the UIC program; there are no discharges from oil and gas facilities.

State Rules and Regulations

Drilling

Reserve pits receive drilling fluids and muds, drill cuttings, and any waters produced during drilling. The pits are allowed to evaporate before closure, and then are filled.

Production

All brines produced during the production phase are reinjected, either for enhanced recovery or disposal. Permit approval is required both from EPA-Region IX and the Commission for drilling an injection well. The casing and cementing requirements in the Arizona state regulations are general, requiring "safe or adequate casing or tubing in order to prevent leakage," cemented and set to prevent damage to gas, oil or fresh water strata. Surface casing is required to be pressure tested at 600 psi for 30 minutes, with a maximum allowable drop of 10% in pressure.

Plugging/Abandonment

There are no provisions in the regulations specifying a time limit for plugging after the cessation of production. Decisions are made on a case-by-case basis. In the case of a dry hole, plugging must take place within 60 days after the cessation of drilling, unless permission for temporary abandonment is granted by the Commission.

When a well is plugged, a 50-foot cement plug must be placed immediately above each producing formation, and a continuous cement plug must be placed through, and to 50 feet above, and below all freshwater strata. A 20-foot cement plug must be placed at or near the surface of the well. Intervals between plugs must be filled with heavy mud. An uncased hole must be plugged with heavy mud up to the base of the surface string, at which point a 50-foot plug must be placed in and out of the bottom of the surface pipe.

References

Ray Brady, Deputy State Director, Division of Mineral Resources. Letter to EPA. September 4, 1985.

"Arizona Administrative Code" Chapter 7, Oil and Gas Conservation Commission, Article 1. Oil, Gas and Helium. 1982.

Personal Communications:

Lyndon Hammon, NPDES Permits Section Manager, Arizona Department of Health and Safety. September 29, 1986 (602) 257-2262.

Nate Lau, Director of the UIC Division, EPA Region IX. September 28, 1986 (415) 974-0893.

Arkansas

Introduction

Arkansas produces 19,715,691 barrels of oil and 194,483 MM cubic feet of gas in 1985. Production is from 9,490 oil wells and 2,492 gas wells. The State is divided into two geographical districts. The Arcoma Basin, located in the northwest corner of the State, produces 99 percent natural gas on a volume basis. The Mississippi Embayment in southeastern Arkansas produces approximately 90 percent oil and 10 percent gas.

State Regulatory Agencies

Two agencies regulate oil and gas activity in Arkansas:

- Arkansas Oil and Gas Commission
- Arkansas Department of Pollution Control and Ecology

The Arkansas Oil and Gas Commission, regulates industry practices regarding drilling and production activities of oil and gas wells under the authority of Act 105 of 1939 (the "Oil and Gas Act"), Act 937 of 1979, and Act 523 of 1981. Act 105 created the Oil and Gas Commission, and authorized it to prevent waste of oil and gas resources and to prevent pollution of fresh water supplies by oil, gas or saltwater. Act 937 authorized the Commission to prevent waste in brine production. Act 523 amended the "Oil and Gas Act" to authorize the Oil and Gas Commission to "acquire primary enforcement responsibility either singularly or jointly with the Department of Pollution Control and Ecology for the control of underground injection under the applicable provisions of the Safe Drinking Water Act." Drilling and production practices are regulated under the "General Rules and Regulations" of the Commission (Order No. 2-39). The General Rules and Regulations do not address all aspects of industry practices, and refer the reader to "special rules pertaining to individual oil, gas, or salt water fields and pools." Special rules of any non-emergency nature require a public hearing, and are provided for in Rules A-2 and B-38 of the General Rules and Regulations.

The Arkansas Department of Pollution Control and Ecology (ADPCE) regulates pollution generally, or pollution specifically related to oil and gas drilling and production wastes, under authority of Act 472 of 1949 (the "Arkansas Water and Air Pollution Control Act"), Act 120 of 1961, Act 254 of 1969, and Act 743 of 1975. Act 472 provided authority to ADPCE to establish pollution standards and industrial discharge limits for state waters. Act 120 includes "wells" within the definition of waters of the state, and made it a violation to cause pollution in waters of the state. Act 254 provided a tax penalty for operators allowing saltwater to escape a lease, and required ADPCE to identify the source of pollution and take steps to eliminate it if the chloride level in any stream exceeded 250 ppm. Act 743 of 1975 provided ADPCE jurisdiction to permit disposal of pollutants into wells.

The principal regulations of ADPCE related to oil and gas drilling and production wastes are found in Regulation No. 1: "Regulation for the Prevention of Pollution by Salt Water and Other Oil Field Wastes Produced by Wells in New Fields or Pools." The regulation was promulgated on October 13, 1958, pursuant to the authority provided by Act 472.

ADPCE is currently considering revisions to Regulation No.1 which would be modeled on Louisiana State Order No.29-B. But at the beginning of 1987, timing and outcome of the effort were not yet certain.

Arkansas has primacy for both the NPDES program and the UIC program. The NPDES program is administered by ADPCE. There is a Memorandum of

Agreement (March 25, 1982) governing the division of authority between ADPCE and the Oil and Gas Commission with respect to underground injection wells, but there continues to be some disagreement between the two agencies as to what the agreement actually allows or requires.

Under the agreement, ADPCE has primary responsibility for Class I, III, IV, and V injection wells, except for bromine related brine disposal wells. AOGC is given "administrative management responsibility for the issuance of construction and operating permits for Class II and Class V bromine related disposal wells. AOGC shall be responsible for enforcement in respect to all Class II wells." AOGC is further described as responsible for well integrity and the migration of wastes from the injection strata into actual or potential drinking water aquifers.

But the Memorandum also notes the statutory overlap of jurisdiction which it was intended to resolve. The degree to which this issue is still unresolved is reflected in the introduction, during the current session of the legislature, of a bill drafted by counsel for the Commission which would have established exclusive authority with respect to Class II wells for the Commission and repealed all portions of statutes giving ADPCE any claim to such jurisdiction. The bill failed to get out of committee.

The result of this conflict is that operators do not always comply, or believe they need to comply, with all of the requirements of ADPCE. According to information provided by both the Department and the Commission, operators in the gas fields in the northern part of the state tend to follow the Department's requirements, while those in the older oil fields in the south frequently fail to apply for ADPCE permits or follow their requirements.

State Rules and Regulations

Drilling

The Oil and Gas Commission does not have any specific regulations governing the construction or management of reserve pits or the disposal of drilling wastes, nor does Regulation No.1 of ADPCE impose any requirements on reserve pits. Typical practices include onsite disposal in unlined reserve pits or landspreading in the vicinity of the pit.

ADPCE, however, has been sending out letters of authorization intended to serve as informal permits which stipulate management practices for reserve pits and disposal of drilling wastes. Many of the provision required by the letter are those the Department would like to include in a proposed revision of Regulation No.1. The lack of specific regulations containing the provisions in the letter has resulted in uneven compliance with the letter's requirements by operators. The letter lists conditions which the Department of Pollution Control and Ecology expects to be followed during drilling operations pertaining to reserve pit construction, pit fluid and drilling mud disposal, and drill site reclamation.

Under the letter's requirements, all earthen pits must be lined with a synthetic liner (20 mils thick) or a clay liner (18 to 24 inches thick), and must maintain at least 2 feet of freeboard. Pits must be reclaimed to grade and seeded within 60 days after the drilling rig has been removed from the site.

Reserve pit fluids may be only by State permitted disposal services.

The letter of authorization also states that completion fluids high in total dissolved solids, such as KCL, should be kept separate from the contents of the reserve pit, and recommends that a lined pit be used for this purpose..

Production

Rules C-7 and C-8 of the General Rules and Regulations define the means by which salt water produced from oil and gas wells may be discharged into subsurface formations for disposal or enhanced recovery. The Oil and Gas Commission states that it will consult the State Geological Survey and the State Board of Health, when reviewing an application to inject salt water, in order to protect fresh water supplies.

Wells for disposal and enhanced recovery are to be cased and cemented "in such manner that damage will not be caused to oil, gas or freshwater resources." Injection pressure must be limited to ensure that fractures are not propagated in the confining zones. Injection must be through tubing set on a packer. Information must be provided by the applicant on all wells or dry holes within a half mile of the new or converted injection well.

Section 4 of Regulation No. 1 forbids discharging salt water from any oil or gas well in a manner whereby the salt water may come in contact with "any of the waters of the State, whether by natural drainage, seepage, overflow, or otherwise." Other sections of Regulation No. 1 require the well operator to obtain a permit for a waste disposal system that prevents the wastes from contacting State waters. The regulation provides two alternatives for salt water disposal: subsurface discharge in disposal wells constructed in accordance with the Rules and Regulations of the Arkansas Oil and Gas Commission, and surface discharge into lined earthen pits. Currently, only subsurface disposal is permitted.

The letter of authorization issued by the Arkansas Department of Pollution Control and Ecology states that salt water produced any time during the lifetime of a well will remain the responsibility of the production company, and "shall be stored in a plastic or fiberglass tank above ground and resting on a concrete pad."

Offsite Disposal

Disposal of reserve pit fluids and drilling mud requires a permit from the Arkansas Department of Pollution Control and Ecology. The permit requires that the disposal company provide an analysis of the pit fluids and drilling mud, the amount hauled, and its final destination. A disposal company that is permitted to land apply pit fluid and drilling mud near the well must provide the Department with a copy of the land owner's agreement as well as an analysis of the wastes. An analysis of pit fluid will include tests for chlorides and pH, and a drilling mud analysis will include tests for chromium, zinc, chlorides, and pH.

Plugging/Abandonment

Wells which are not completed as commercially productive after drilling must be abandoned and plugged before the drilling equipment is released from the drilling operation. No time limitation is established in the regulations, however, for temporary abandonment of a properly cased well.

When plugging, a 100-foot cement plug must be placed above each producing stratum, or a bridge plug may be used. A cement plug of 100 feet must be placed 50 feet below the base of the freshwater stratum if surface casing is not cemented below that stratum; if it is, a 100-foot cement plug should be placed inside the base of the surface casing. A plug should be set at the surface of the ground in such way as to not interfere with cultivation. Intervals between plugs should be filled with heavy mud-laden fluid.

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CALIFORNIA

Introduction

California produced 423,900,000 barrels of oil and 493 billion x 10^9 cubic feet of gas in 1985. California ranked fourth in U.S. oil production and sixth in U.S. gas production. Production was from 55,079 producing oil wells and 1,566 producing gas wells. Approximately 55% of the oil production is attributed to enhanced recovery.

Regulatory Agencies

Several agencies regulate oil and gas activity in California:

- California Department of Conservation, Division of Oil and Gas
- California Water Resources Control Board, and the nine Regional Water Quality Control Boards
- California Department of Health Services
- California Air Resources Board, and the county or regional Air Pollution Control Districts
- State Lands Commission
- California Coastal Commission
- Local government agencies
- U.S. Bureau of Land Management
- U.S. Department of Energy

The Division of Oil and Gas of the California Department of Conservation, created in 1915, issues permits for the drilling, reworking and abandonment of oil and gas wells. Under authority delegated by EPA, the Division also issues UIC permits for Class II injection wells. As part of its responsibilities, the Division is responsible for ensuring that the drilling and operation of such wells does not endanger fresh groundwater strata.

The California Water Resources Control Board is generally responsible for protecting the waters of the State, and for preserving all present and anticipated beneficial uses of these waters. EPA has delegated authority to issue NPDES permits to the Water Resources Control Board. This responsibility is implemented through nine Regional Water Quality Control Boards, which issue Waste Discharge Requirements (California's NPDES permits) for point sources of water pollution. The Water Resources Control Board has the authority to adopt statewide water quality policy and water quality control plans for Regional Boards to follow.

The Regional Boards must at minimum implement requirements as strict as those of the State Board. But they have autonomy to develop more stringent requirements within their regions. All discharges of drilling wastes or produced waters to surface impoundments or surface waters are subject to the permitting authority of the Regional Boards. Under a Memorandum of Under/standing between the Regional Water Quality Control Boards and the Division of Oil and Gas, the Regional Boards also have the responsibility for reviewing permits written by the Division of Oil and Gas to ensure the incorporation of the concerns of the Regional Boards.

The California Department of Health Services is responsible for the regulation of hazardous wastes. The Department has responsibility for determining which waste streams and constituents are hazardous under California's laws, including determinations as to the hazardousness of drilling fluids and muds. The Department is also responsible for the regulation of injection wells into which hazardous wastes are being injected. Further, the Department of Health Services shares with the Regional Water Quality Control Boards responsibility for the regulation of hazardous waste landfills and surface impoundments.

For wells on State-owned, onshore lands, the State Lands Commission has joint responsibilities with the Division of Oil and Gas. Their responsibilities are expressed in the provisions of the lease terms.

The California Department of Fish and Game, while not a permitting agency for drilling projects, provides comments and recommendations on methods to mitigate any problems that oil and gas operations may create for fish and wildlife. The Department of Fish and Game coordinates State operations involving any spills that affect fish and wildlife.

Local Air Pollution Control Districts issue permits to operate equipment that emits pollutants into the atmosphere. The equipment includes steam generators used for enhanced oil recovery projects.

The California Coastal Commission issues permits for any development proposed within the coastal zone. This zone extends from the State's 3-mile seaward limit to 1,000 yards inland. Oil and gas projects within this area would need permits, although there are provisions for exemptions.

Cities and counties also issue land use permits for oil and gas operations. Generally, a condition of their permits requires that an operator comply with the regulations of the Division of Oil and Gas.

The Bureau of Land Management approves approximately 400 oil and gas drilling permits per year on Federal lands, and additionally provides permits for wells for reinjection of produced waters. Since operators of these wells must meet the requirements of the state as well as BLM, they are subject to dual permitting. In 1985, there were 6,200 oil, gas and injection wells on Federal lands. The oil and gas wells produced about 22.4 million barrels of water per month, with most going to reinjection and some to evaporation percolation ponds.

The Department of Energy manages the Elk Hills Naval Petroleum Reserves. In 1985, these fields produced approximately 86,000 barrels of water, 128,000 barrels of oil, and 184 billion cubic feet of gas per day. Produced waters have been reinjected or disposed in earthen sumps, but the Department of Energy has been managing a transition to disposal only in injection wells.

State Rules and Regulations

Drilling: Under Article 9 of Title 22 of the California Administrative Code, drilling fluids and drilling muds are listed as wastes which come under the provisions of the regulations for hazardous wastes if they contain a hazardous material. Most muds actually in use in California, however, do not fall under this provision. The Department of Health Services has prepared a list (available to operators on request) of additives and fluids which are non-hazardous if used according to the manufacturer's recommendations. The Department will also review test data submitted by companies on new muds or fluids when requested to do so, in order to determine if they are non-hazardous.

Discharges of drilling muds and cuttings which do not contain halogenated solvents into on-site sumps are specifically excluded from the requirements affecting "Discharges of Waste to Land" (Subchapter 15, Chapter 3, Title 23) under the jurisdiction of the Regional Water Quality Control Boards, provided that the operator takes appropriate measures at the conclusion of drilling operations. The operator must either "(1) remove all wastes from the sump, or (2) remove all free liquid from the sump and cover solid and semisolid wastes, provided that representative sampling of the sump contents after liquid removal shows residual solid wastes to be nonhazardous."

Drilling pits may or may not need to be lined or sealed depending on their location. While the Regional Water Quality Control Boards do not prescribe pit construction conditions, the conditional use permit that a driller obtains from each county may detail the pit requirements. If the fluids contain hazardous materials, the pits would have to have liners.

On Federal lands, drilling fluids are left in the sump until completion of the well. After completion of the well, drilling fluids are hauled to a Class II disposal site for oil field wastes.

Before drilling a well, operators must file an indemnity bond with the Division of Oil and Gas, to ensure that the applicant complies with the permit requirements, and properly abandons or completes the well. After proper abandonment or completion, the Division releases the bond.

Produced Waters

Produced waters may be reinjected for enhanced recovery or disposal, discharged on the surface for beneficial use, placed in lined sumps for evaporation or unlined sumps for evaporation and percolation, or disposed of in sewer systems. In some cases, produced waters ultimately disposed of in sumps are first discharged into watercourses which carry the saltwater to the sumps. The impact and legality of this practice is currently under review. The approximate percentages of produced water disposed of by each method are:

Evaporation in percolation sumps	- 18%
Evaporation in lined sumps	- 6%
Disposal in sewer systems	- 2%
Surface disposal (beneficial)	- 18%
Injection for enhanced recovery	- 41%
Injection for disposal	- 15%

Surface Discharge for Beneficial Use: In cases where the quality of the water is sufficient for beneficial use for irrigation, livestock and/or wildlife, produced waters may be permitted for discharge into surface waters (principally into irrigation canals, dry ditches and ephemeral streams). There are at least 12 such permits in the Fresno office of the Central Valley Regional Water Quality Control Board. Discharge permit limits include the following maximum values:

Oil and grease	- 35 mg/l
Chlorides	- 200 mg/l
Boron	- 1 mg/l
Electrical conductivity	- 1,000 u mhos

Sewer Disposal: The small percentage that goes to sewer systems is predominantly within the Los Angeles County Sanitation District. Production waters entering such sewers must meet applicable pretreatment standards, including a maximum oil and grease content of 75 mg/l, and limits on heavy metals, cyanide, chlorinated hydrocarbons, and sulfides. There is no pretreatment limit for chloride.

Pits: Regulation of all saltwater sumps is under the jurisdiction of the Regional Water Quality Control Boards, which have the authority to regulate discharges to surface impoundments "by issuing waste discharge requirements, including discharge prohibitions, which implement water quality control plans." (Title 23, Chapter 3, Subchapter 15 of the California Administrative Code). But while minimum regulatory standards are established for various classes of impoundments under Subchapter 15, a specific exemption is provided for evaporation ponds and percolation ponds if "the applicable regional board has issued waste discharge requirements, reclamation requirements, or waived such issuance." To be eligible for the exemption, the discharge must also be nonhazardous, comply with the State Board's nondegradation policy, and comply with "the water quality objectives set forth in the applicable water quality control plan...." For example, unlined sumps containing produced waters which could adversely affect freshwater aquifers would not be permitted in locations which could impact such aquifers.

Regional Water Quality Control Boards while they must at least implement the requirements established by the State Board, have the authority to establish requirements more stringent than those established by the State Board. Thus the Regional Boards may establish specific pit construction requirements (e.g., liners to prevent percolation from the sumps) in sensitive areas.

Any sump, other than an operations sump, containing a mixture of oil and water, must be covered with screening to restrain entry of wildlife. If the Department of Fish and Game deems the condition of a sump to be hazardous for wildlife, the Department notifies the Division of Oil and Gas, which requires the operator to abate the condition within 10 days (if an immediate or grave danger) or 30 days.

In addition to discharge to on-site saltwater sumps, substantial volumes of saltwater are discharged to offsite sumps. These are discussed below.

Injection: Over half of produced waters in California are reinjected, either for enhanced recovery or disposal. Authority for management of Class II injection wells is delegated by EPA to the Division of Oil and Gas. The Regional Water Quality Control Boards, under a Memorandum of Understanding with the Division of Oil and Gas, may comment on Class II injection well permits on matters which could affect water quality, including degradation of ground/water.

On Bureau of Land Management leases, operators of Class II wells must obtain permits from both the Division of Oil and Gas and BLM. Many of the injection wells are for enhanced recovery, and therefore could significantly affect BLM's royalty earnings from its leases. As a result, BLM wants to maintain joint signatory authority on UIC permits. BLM and the Division of Oil and Gas are in the process of trying to develop a Memorandum of Understanding on joint permitting.

Injection wells, other than those injecting steam, air, or pipeline quality gas, must be equipped with tubing and packer set immediately above the approved zone of injection. Exceptions may be granted where there is no evidence of freshwater-bearing strata, where more than one string of casing is cemented below the base of freshwater, or where the operator can demonstrate that freshwater and oil zones can be protected without tubing and packer. The pressure in the well must not be sufficient to fracture the zone of injection.

To obtain approval from the Division of Oil and Gas, operators must file plans, geologic analyses, evaluations of the impact of the planned well on other wells in the area, monitoring program, the source and analysis of the water being injected, and analysis of water in the injection zone. A new chemical analysis of the water being injected must be filed whenever the source of the water is changed or as requested by the Division. Mechanical integrity tests are carried out annually, except for thermal enhanced recovery wells and wells with special conditions. In these cases, MIT's are performed on varying schedules - usually every three years.

Some disposal of saltwater in California also takes place in combination with other oil field related nonhazardous wastes in Class V wells; regulation of Class V wells has not been delegated to the state.

Any wells into which wastes defined as hazardous under California regulations are being injected, regardless of the Federal classification, would become subject to the requirements established in the Toxic Injection Well Control Act of 1985, which are generally more stringent than Federal requirements. These requirements are under the jurisdiction of the Department of Health Services.

Offsite Facilities

Central Sumps for Produced Waters: On the western side of the San Joaquin Valley, a series of large percolation/evaporation sumps receive produced water discharged to them through natural watercourse drainage. The Department of Energy has ordered the closure of two of these sumps, which are on the property of the Elk Hills Naval Petroleum Reserve; the two sumps no longer receive produced waters, and are in the process of closure. The remaining sumps are still operating. Some of the wells discharging to the sumps, and some of the watercourses through which the discharges go, are on Federal lands managed by the Bureau of Land Management. Currently, most of the sumps either operate under requirements dating from more than two decades ago, or have no requirements at all.

While this disposal method is currently allowed, the Central Valley Regional Water Quality Control Board is con/sidering whether these produced waters should be regulated under the requirements for California "designated" wastes (if they contain pollutants which exceed water quality objectives or could cause degradation of the waters of the state). There is also a question as to whether this method of disposal is in accordance with 435.32 of 40 CFR, since the discharge to the sumps is through natural watercourses, and the discharged waters generally do not meet the requirements for agriculture and wildlife use.

Waste Disposal Facilities for Drilling Wastes: Drilling wastes may be transported offsite for disposal. If hazardous by California's definition, the wastes must be disposed of (as required by Section 2521, Subchapter 15, Chapter 3, Title 23) in Class I waste management units (requiring double liners and no migration). If classified as "designated" wastes, they may be disposed of in Class II facilities (single liners, no migration, and design and construction "for the containment of the specific wastes which will be discharged") or Class I facilities. If non-designated, alternative uses would be permissible.

Transport: An invoice for an undesignated waste is required for trucks hauling brine. If being trucked to a central injection facility, the Division of Oil and Gas requires that the trucker carry a ticket designating the volume and source of the fluid. The operator of the central facility collects a copy of the ticket and files it.

Plugging/Abandonment

Under Section 3237 of the Public Resources Code, suspension of activity and removal of drilling activity is evidence of desertion of a well after six months. Removal of production equipment is evidence of desertion after two years. The Supervisor of the Division of Oil and Gas <u>may</u> order the plugging of a well which has been deserted. But the Division of Oil and Gas generally exercises its discretion for previously producing wells (particularly those which were permitted prior to the existence of a bonding requirement), actively communicating with operators about plugging with respect to wells which have been out of production for five years.

When a well is plugged, it is generally required that cement plugs be placed across specified intervals to protect oil, gas, and usable water zones. The district deputy may allow cement to be mixed with or replaced by other substances with adequate physical properties. Intervals which are not plugged are to be filled with mud fluid of "sufficient weight and consistency" to prevent movement of other fluids into the well bore.

At the surface, the hole and all annuli must be plugged with at least a 25-foot cement plug. In an open hole, a cement plug must be placed from at least 100 feet below the bottom to at least 100 feet above the top of each oil or gas zone, and at least a 200-foot plug must be placed across all fresh-saltwater interfaces. Where the hole is open below the shoe, a cement plug is required from 50 feet below to 50 feet above the shoe.

In a cased hole, all perforations must be plugged with cement, and a plug must extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, or the oil or gas zone, whichever is highest. If cement is behind casing across fresh-saltwater interface, a 100-foot cement plug must be placed at the interface inside the casing. If the top of the cement behind the casing is below the top of the highest saltwater sands, squeeze-cementing is required through perforations to protect the freshwater, in addition to a 100-foot plug inside the casing.

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Scott Smith, Central Valley Water Quality Control Board (209) 445-5116.

Chong Rhee, L.A. County Sanitation District (213) 699-7411.

Greg Williams, Department of Health Services, (916) 322-0453

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COLORADO

Introduction

Colorado has a long history of regulating oil and gas activities. As far back as 1889, Colorado passed a bill prohibiting the discharge of oil, petroleum, or other substances into any waters of the State. In 1927, a second bill was passed that included provisions for well plugging. In 1951, the Oil and Gas Conservation Act was passed. The Solid Wastes Disposal Sites and Facilities Act was passed. The Solid Wastes Disposal Sites and Facilities Act (Title 30-20-Part 1, C.R.S. 1973, as amended) also has jurisdiction.

In 1985, Colorado produced 30,552,685 barrels of oil from 5,287 wells; 275,684 million cubic feet of gas were produced from 4,665 gas wells. Mud and air drilling are both encountered.

State Regulatory Agencies

Three agencies share regulatory authority for oil and gas wastes in Colorado:

- Department of Natural Resources-Oil and Gas Conservation Commission

- Department of Health

- U.S. Bureau of Land Management

The Oil and Gas Conservation Commission has primary responsibility for the management of oil and gas exploration, development and production activities in Colorado. The Commission is responsible for the conservation of oil and gas, the protection of the rights of all parties, and has general authority to protect the environment from pollution by oil and gas activities on the site of drilling and production operations. The Commission is also responsible for regulation and permitting of central disposal facilities operated by the producing companies.

The Colorado Department of Health, and specifically the Water Quality Control Division/Commission and the Waste Management Division, has statutory and regulatory authority over solid waste disposal sites and facilities and NPDES permits, and is generally concerned with endangerment of public health and the environment. Commercial disposal facilities for wastes from oil and gas production operations are subject to the Department's permitting and regulation. In addition, the Department is responsible for permitting of discharges for beneficial use for agriculture and wildlife.

Because the two agencies shared certain areas of responsibility under their statutes, they developed a Memorandum of Understanding in 1971 to specifically allocate responsibilities. Under this agreement, the Water Quality Control Commission of the Department of Health designated the Oil and Gas Conservation Commission as "its authorized representative to exercise authority for the administration of water pollution prevention, abatement and control required to protect the waters of the state from conditions and activities arising from the drilling, production and plugging of wells and all other operations for the production of oil and gas." This relationship has subsequently been clarified in the regulations of both agencies. The Department of Health regulations specify that the Department:

"...will consider oil and gas liquid waste impoundments to be in compliance with these regulations if:

A. The disposal facilities are regulated by the Oil and Gas Conservation Commission,

B. There is no imminent or substantial endangerment to the public health or the environment from the disposal facilities, and

C. Compliance with the Certificate of Designation requirement is not required by the County within which the site is located (for central disposal facilities only)."

The U.S. Bureau of Land Management has jurisdiction over Federally-owned mineral rights. The U.S. Forest Service retains surface rights on Federally-owned forests and grasslands. EPA retains responsibility for approving underground injection wells on Indian land. The requirements of these agencies are discussed separately under Federal Agencies.

State Rules and Regulations

Drilling

Pit Requirements: Oil and Gas Conservation rules require that "before commencing to drill, proper and adequate slush pits shall be constructed for the reception and confinement of mud and cuttings and to facilitate the drilling operation. Special precautions shall be taken to prevent contamination or pollution of state waters."

According to information provided by the Oil and Gas Conservation Commission, most wells are drilled using tanks rather than reserve pits;

the reserve pits are used primarily when the mud is displaced during the running of pipe. While there are no rules prohibiting the discharge of produced waters into a reserve pit, this is not commonly done. If the volume of produced water exceeded five barrels/day, this would make the reserve pits subject to the construction requirements and reviews in Rule 325. Otherwise, pits "for temporary storage and disposal of substances produced in the initial completion and testing or workover of wells drilled for oil and/or gas for a period of time not in excess of ninety (90) days" are excluded from application of many of the provisions of the Rule.

Most drilling fluids and muds in Colorado are bentonite and fresh water based. Very few oil-based drilling fluids are used, and those are moved from operation to operation until disposed of into an approved landfill.

Pit Closure/Discharge: If the well is a dry hole and is abandoned, backfilling of pits and reclamation of the land must be completed within six months, unless an extension is granted for unusual circumstances (Rule 319(a)(8)).

Generally, after decanting of the lighter fluids in the reserve pits, reserve pit sludges may be dried out and disposed of on the surface by tilling into the ground. The sludge may be removed to a different location before land disposal. The sludge may also be buried when the pit is backfilled. The Commission has permitted one facility for land discharge of wastes with limitations on total suspended solids, total dissolved solids, oil and grease, and chemical oxygen demand.

Produced Waters

Produced water is disposed of through reinjection (c. 85%), placement in storage and disposal pits (c. 15%), and discharge for beneficial use for agriculture and wildlife (<1%).

Disposal and Storage Pits: The Oil and Gas Conservation Commission regulates all produced-water storage or disposal pits except for the commercial disposal facilities regulated by the Department of Health. This includes both on-site pits and central pits. A central pit is a storage or disposal pit serving several leases or batteries in a field, and operated by one of more oil and gas operators, under a field operators agreement approved by the Commission.

Both central and on-site pits are subject to the requirements of Rule 325, which specifies informational, construction and operating requirements. Minimally, such pits are required to have adequate storage capacity for the volume of produced water expected, and to be kept free of surface accumulations of oil or other hydrocarbons which could impede evaporation. Certain of the other requirements in the Rule do not apply where the volume of water to be disposed does not exceed 5 barrels per day on a monthly basis.

Generally, applicants for permits to construct produced-brine disposal pits must provide substantial information on surface waters and groundwaters, geology and soil types in the area of the well. The application must also indicate the source and expected volume of water to be produced daily, and a chemical analysis of the water, assessing all factors related to salinity. If a pit is located over permeable soil, and will receive, at full capacity, in excess of 100 barrels of fluid/day with a TDS content of 5,000 ppm or more, the operator must provide a plan for lining the pit and detecting leaks. Liners may be required where water placed in the pit has a higher TDS content than underlying aquifers hydrologically connected, regardless of the amount of water delivered to the pit.

The Commission makes case-by-case determination on lining require/ments for all produced-water storage and disposal pits on the basis of site-specific evaluations. According to information provided by the Commission, 90% of the pits for wells producing more than 5 barrels per day of water are required to be lined (approximately 2/3 with clay and 1/3 with synthetic liners). Of the remaining pits, either the received water is fresh and is allowed to percolate, or the pits are over impervious shales and the water evaporates.

Injection: Produced water is reinjected into Class II wells both for enhanced recovery (667 wells) and disposal (134 wells). The UIC Class II injection program has been delegated to the Oil and Gas Conservation Commission.

Wells used for injection into oil or gas producing disposal zones must have "safe and adequate casing or tubing so as to prevent leakage, and shall be so set or cemented that damage will not be caused to oil, gas or fresh water resources." Detailed reports on fluids received and injected must be filed monthly.

Mechanical integrity tests must be performed on new injection wells before starting injection, and every five years thereafter. The test pressure must be 300 p.s.i. or the minimum injection pressure, whichever is greater, and not more than the maximum injection pressure, with a pressure variance of no more than 10%. Monthly injection reports are submitted which list volumes injected and injection pressures. All injection facilities are inspected by the Commission staff on a routine basis.

Discharges for Wildlife and Agricultural Use: A few facilities in the states have permits from the Department of Health for effluent discharges under the BPT Wildlife and Agricultural Use Subcategory. The effluent limitations are:

pH	-	6.0 to 9.0
Total suspended solids	-	30 mg/l (30-day average) 45 mg/l (1 day maximum)
Oil and grease	-	10 mg/l
Total dissolved solids	-	5,000 mg/l (30-day average) 7,500 mg/l (1-day maximum)

Offsite Disposal

Commercial off-site produced water evaporation or evaporation/ percolation pits are regulated by the Division of Waste Management of the Department of Health. According to information provided by the Department of Health, there are currently eight commercial disposal pits, of which half are lined. Lining requirements are determined by classifications of impoundments. Class I facilities (in recharge area for drinking water aquifer, where seepage from impoundment would impair use of the groundwater) require double liners with leak-detection systems. Class II impoundments (where seepage would damage a freshwater aquifer if no liner were used) require single liners and monitoring systems. Class III impoundments (located outside a recharge area, or competent bedrock between the surface and the aquifer, or impairment would not result from unrestricted seepage) require no liners.

Truckers transporting produced brines to offsite impoundments or injection wells must file monthly reports on the source, volume and recipient of the waters hauled. Similar records must be kept by the receiving facility. These records will be subject to computerized cross-tabulation.

Plugging/Abandonment

Wells that have ceased production or are incapable of production are to be abandoned within six months, unless granted an extension by the Director of the Oil and Gas Conservation Commission (Rule 319(b)). In practice, if a well is shut down for economic reasons, the Commission will not require a formerly producing well to be plugged. If, however, the operator of the well has numerous wells which are closed down for economic reasons, and is operating all such wells under a single blanket bond, the Director may require the provision of individual bonds for each well. The operator must file a status report every six months indicating plans for future operations.

Wells must be plugged so as to confine oil, gas, or water to original strata. The operator must obtain approval of plugging method from the Commission prior to plugging operation. Surface casing may not be removed from the well unless approved by the Director. Generally, cement plugs are required 50 feet above and below each permeable zone, a 100-foot plug at the base of the surface casing, and a cement plug at the top of the surface casing. The operator may plug above perforated zones, or may squeeze with cement prior to abandoning the well or before recompleting into another formation..

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Florida

Introduction

Florida produced 14,090,000 barrels of oil and 15×10^9 cubic feet of gas in 1984. Production was from 165 oil wells; there are no producing gas wells. Virtually all drilling fluids as well as produced fluids are reinjected.

Regulatory Agencies

Four agencies are responsible for regulating the oil and gas industry in Florida:

- Florida Department of Natural Resources, Division of Resource Management, Florida Geological Survey
- Florida Department of Environmental Regulation
- Florida Regional Water Management Districts
- U.S. Environmental Protection Agency, Region IV

Primary regulatory responsibility rests with the Department of Natural Resources (DNR). DNR is the permitting agency for oil and gas wells, including approval to dispose of waste fluids by subsurface injection. The DNR regulates the exploration, drilling, and production of the oil and gas industry with respect to reporting, spacing, safety, and construction.

The Department of Environmental Regulation oversees the industry with respect to water quality standards and dredge and fill requirements (for pits) if oil and gas activities occur in wetlands of the State.

Florida's Regional Water Management Districts, which are separate regulatory groups on a local level, regulate oil and gas activities with regard to water use. Consumptive use permits are issued if applicable.

Other State agencies may be involved on a case-by-case basis. These agencies are most commonly the Florida Game and Freshwater Fish Commission, the Department of Community Affairs, and the Department of Transportation.

The State of Florida does not have primacy for Class II UIC program wells. The State operates a separate program for injection wells with a State permit and State inspections. A driller wishing to inject fluids underground must apply for permit to do so from two separate governmental entities, the U.S. Environmental Protection Agency Region IV and the State, and undergo two sets of inspections.State Rules and Regulations

Drilling fluids are put into pits during operation but then disposed of by reinjection. Pits are nearly dry when they are backfilled. They are lowered as fast as possible by pumping down the well bore prior to plugging the well. All produced waters are reinjected.

The DNR is governed by Chapter 377, Florida Statutes, and its implementing rules, Chapters 16C-25 through 16C-30, Florida Administrative Code. Part of Chapter 377s specific purpose is to "require the drilling, casing, and plugging of wells to be done in such a manner as to prevent the pollution of fresh, salt, or brackish waters on the lands of the State." And Section 377.371 further states that, "No person drilling for or producing oil, gas, or other petroleum products shall pollute land or water ; damage aquatic or marine life, wildlife, birds, or public or private property."

UIC permits are issued pursuant to Chapter 403, Florida Statutes and Chapter 17,28, Florida Administrative Code. If, applicable, dredge and fill activities are regulated under Chapter 403, Florida Statutes, and Chapter 17-12 Florida Administrative Code. Water standards are issued under Chapters 17-3 and 17-4, Florida Administrative Code. Water management licenses (consumptive use) are issued under Chapter 373, Florida Statutes, by the regional Water Management Districts.

Plugging/Abandonment

Each request for temporary abandonment will be considered on a case-by-case basis. But the requirements for temporary abandonment are not significantly different than those for abandonment. Only the placement of a surface plug and the restoration of the surface area are not required.

When plugging an abandoned well, perforated intervals require cement retainers 100 feet above the interval, a 100-foot plug placed at the top of the retainer, and cement squeezed into the interval, or they require a 200-foot plug extending 100 feet above and below the interval. With respect to open hole below casing string, a plug must be placed 100 feet above and below the casing shoe. A plug must be placed 100 feet above and below the casing stub if the casing is cut. Annular space must be plugged with a minimum 100-foot plug at the top of the casing. In uncased holes, 200-foot plugs must be placed opposite hydrocarbon formations, and at contact points between saline and fresh water zones. Additional plugs must be placed in the casing of smallest diameter (25-foot on dry land; 150-foot for wetlands).

References

Lloyd Wise, Region IV NPDES permit writer, Summary of EPA Workshop presentation, Onshore Oil and Gas Workshop Meeting Report. July 1985.

Lynn Griffin, Environmental Specialist, Department of Environmental Regulation. Letter to W.A. Telliard, EPA, March 22, 1985.

State of Florida Regulatory and Review Procedures for Land Development. Chapter 14. November 1, 1984.

Personal Communication:

Lynn Griffin, Environmental Specialist, Department of Environmental Regulation, October 2, 1986 (904) 488-8615.

David Curry Florida Department of Natural Resources (904) 487-2219.

ILLINOIS

Introduction

Illinois produced 28,873,000 barrels of oil and 15 x 10^9 cubic feet of gas in 1984. Production is from 28,920 oil wells and 157 gas wells. Nineteen barrels of brine are produced for every barrel of oil. Seven thousand injection wells are operating in the State.

State Regulatory Agencies

Principally one agency regulates the oil and gas industry in Illinois:

- Department of Mines and Minerals, Division of Oil and Gas

The Department of Mines and Minerals operates under an Act in Relation to Oil, Gas, Coal and Other Surface and Underground Resources. Section 8A of the Act provides the Department with the power and authority to regulate the disposal of salt- or sulphur-bearing water and any oil field waste produced in the operation of any oil or gas well, and to adopt proper rules and regulations relative thereto. Section 8B provides that no person shall drill, convert or deepen a well for the purpose of injecting gas, air, water, or other liquid into any underground formation or strata without first securing a permit therefor. Section 8C(A) states that no person shall operate an oil field brine transportation system without an oil field brine transportation permit. Section 8G(3) specifies that the permittee shall not dispose of oil field brine onto or into the ground except at locations specifically approved and permitted by the Mining Board. No oil field brine shall be placed in a location where it could enter any public or private drain, pond, stream or other body of surface or ground water.

The Division of Oil and Gas has UIC program primary for Class II wells. There are Federal lands in Illinois but there is no drilling or production on Federal lands currently. The Illinois Environmental Protection Agency has been delegated NPDES authority but no surface water discharges from the oil and gas industry are allowed.

State Rules and Regulations

Drilling

Before commencement of drilling a new well, the operator must execute a bond of $2,500 unless the operator already has a blanket bond of $25,000. The bond is cancelled only after the well has been plugged, and all related restoration activities have been completed.

There are no State requirements that drilling pits be permitte or lined. Fluids from the pits may be disposed in a dry drill hole. When the pit mud dries, the pit is back-filled and reclaimed. Pits must be reclaimed within 6 months after drilling ceases.

Production

Produced waters go into lined holding-evaporation ponds or are reinjected into certified injection wells. If pits are used, the lining must be an impermeable material which will prevent seepage. Most requests are for fiber glass or concrete lined pits. Earthen lined pits have been substantially eliminated during the past 5 years. The Department of Mines and Minerals has been reducing the number of old pits by removing and injecting the brines, stabilizing the contents, applying topsoil, and vegetating the pit area.

Neither road spreading nor land farming is allowed.

Seven thousand injection wells for disposal or enhanced recovery are operating in Illinois, of which the majority are water flooding wells. Permits for injection wells must be obtained from the Division of Oil and Gas. The permit application must include the location and depth of any existing wells within a half-mile of the proposed new or converted injection well, and information to show that injection into the proposed zone will not initiate fractures through the overlying strata which would enable injection or formation fluids to enter fresh water strata. Injection must be through adequate tubing and packer.

A mechanical integrity pressure test must be carried out before initiation of injection. Thereafter, the well must be tested at least every five years (or, alternatively, monthly records of actual injection pressure in the casing tubing annulus may be reported annually). Test pressures for new wells must be at the the greater of 300 psi or the maximum authorized injection pressure; the same range applies for newly converted wells or on retests, except the ceiling is 1,000 psi.

Offsite/Commercial Disposal

Use is not made of offsite or commercial pits in the state of Illinois.Brines may be transported offsite to injection wells. Transporters must have oil field brine hauling permits. Well operators must maintain detailed records of all brine removed from their leases, and of the haulers with whom they contracted for the removal.

Plugging/Abandonment

A well must be plugged within 30 days of the cessation of drilling operations if no production casing has been run. Wells at which there have been no production operations for six months must be plugged, unless the operator has been granted an extension. Requests for extensions will be granted by the Mining Board for good cause so long as all casing remains sound and in the well. The length of the extension is at the discretion of the Board. When an extension is granted, if no bond covering the well is in effect, a bond is required from the operator, which remains in effect until the well is plugged. If, at expiration of the extension, Mining Board denies a further extension, the well must be plugged and abandoned.

When plugging, cement plugs must be placed opposite any producing formation and extend 20 feet above the formation. Cement plugs must also be placed from 50 feet below to 100 feet above any coal seam thicker than 30 inches, from 20 feet below to 20 feet above the casing seat of the oil string, and from 10 feet below to 15 feet above the base of the surface casing. If surface casing was not used, a 25 foot plug must be used below the surface with a one foot mushroom cap. Where surface casing was used, the casing must be cut off three feet below the ground and a one foot cap added. Mud must fill the remainder of the well. There are no specific provisions for plugs over zones with potable water.

References

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The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

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State of Illinois. 1984. An Act in Relation to Oil, Gas, Coal and Other Surface and Underground Resources. Revised Edition.

State of Illinois. 1984. Rules and Regulations. Department of Mines and Minerals, Division of Oil and Gas. Revised Edition.

Personal Communication:

George R. Lane, Division of Oil and Gas (217) 782-7756.

INDIANA

Introduction

Indiana produced 4,758,609 barrels of oil and 367,084,000 cubic feet of gas in 1986. Production was from 7,600 oil wells and 806 gas wells.

State Regulatory Agencies

Two agencies principally regulate oil and gas activity in Indiana:

- Indiana Department of Natural Resources, Division of Oil and Gas

- U.S. Environmental Protection Agency, Region V

The Indiana Division of Oil and Gas regulates the industry through Rule 310 IAC 7-1. No discharge to surface waters is allowed so that any involvement of the Indiana Department of Environmental Management would occur as a result of improper disposal of oil and gas wastes. Concerns that owners of Federal lands may have regarding oil and gas surface treatment are satisfied thorough conditions of the respective lease agreements.

The Oil and Gas Division does not have primacy for UIC program Class II wells. The State is in the process of attaining such status. Currently, however, anyone interested in underground injection must obtain two permits--one from the State, and one from the U.S. Environmental Protection Agency.

State Rules and Regulations

Drilling

Adequate pits for muds or wastes associated with drilling operations are required. Drill pits must be reclaimed within 60 days after drilling has stopped. Fluids associated with such drill pits generally can be classified as fresh-water and are mixed with bentonite clays. When a pit is closed, the practice is to pump the small amount of fluid in the pit to the surrounding land, bury the drill cuttings and other pit muds, and reclaim the land.

Production

Pits used for gathering production fluids and storing them until reinjection must be lined with impervious clay or an artificial liner. All production fluids must be reinjected underground. Evaporation pits were disallowed by the State two years ago.

Plugging/Abandonment

Any well which is not producing must be capped and sealed immediately. If not placed back in production within two years, the operator may be required to plug and abandon the well, to recase the well, or to demonstrate (through pressure testing or other approved method) that the well casing is in good condition and there is no commingling of fluids.

When the well is plugged, cement plugs are required from 50 feet below (or from the bottom of the well) to 100 feet above any stratum with oil, gas, or commercial deposits of coal. Where insufficient casing is set or surface casing was not cemented to surface, production casing should be removed from 50 feet below the deepest aquifer containing potable water, and a cement plug placed from the remaining production string to three feet below the surface. In the case of a dry hole which has not encountered coal, a similar surface plug may be placed after filling the hole from the bottom with mud. The use of bridges is prohibited.

References

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Personal Communications:

Mike Nickolaus, Indiana Division of Oil and Gas (317) 232-4055.

KANSAS

Introduction

Kansas produced 75,723,000 barrels of oil and 466.6 x 10^9 cubic feet of gas in 1984. Production is from 57,633 producing oil wells and 12,680 gas wells. Kansas ranks seventh in both U.S. oil production and U.S. gas production. There are 11,000 injection wells in the State.

Oil was found in Kansas in the 1860s, but it was not commercially developed until 1895. Oil and gas regulation began in 1935.

State Regulatory Agencies

One agency regulates oil and gas activities in Kansas:

- Kansas Corporation Commission

On July 1, 1986, by passage of House Bill 3078, the Kansas Legislature transferred the Department of Health and Environment's regulatory responsibilities for oil and gas activities to the Kansas Corporation Commission. Prior to July 1, 1986, the Department of Health and Environment had responsibilities related to lease maintenance, emergency pits, drill pits, burn pits, storage ponds and Class II oil field brine and enhanced recovery injection wells. Under Kansas' Statutes (Chapter 55, Article 10, 55-1003) plans and specifications for the disposal of oil and gas brines and mineralized waters were to be submitted to and approved by both the State Corporation Commission and the Secretary of Health and Environment. Subsequent to the 1988 legislative action, the Secretary of Health and Environment no longer is a party to such action.

There are few Federal lands and little involvement of Indian Tribes in the Kansas oil and gas industry. The State informs neither party directly when an application for a permit to drill has been received. Such information is published as a routine matter in local news outlets, and if there are specified requirements by the Bureau of Land Management or Indian Tribes, they are communicated directly to the driller through lease agreement condition or by other legal means.

State Rules and Regulations

Regulation of the industry is through the issuance of drilling and well operation permits. A compliance or surety bond is not required. With the recent departmental transfer of responsibilities, the Corporation Commission is in the process of revising and proposing regulations pertaining to those activities formerly administered by the Secretary of Health and Environment.

Pit Requirements: Drilling pits and burn pits have been permitted and regulated, without requiring a separate permit application, under a general rule for a maximum period of 365 days unless the operator requests and receives approval for an extension. Drilling pits may be used to temporarily confine "salt water, oil or refuse resulting from oil and gas activities during the drilling, completion or testing of any oil, gas, exploratory, wildcat, service or storage wells." Permits are required for emergency pits.

Liners are not required for drilling pits unless the Commission determines a liner to be necessary to protect soil or water resources in geologically or hydrologically sensitive areas. In such areas liners or portable pits can be required. In areas with sandy soils, for example, drilling pits are required to be lined. In the heavy clay region of the north-central portion of the state, however, such pits would most likely not be lined.

Pit Closure: On-site burial, after evaporation or mechanical dewatering, is the primary method of pit closure. After May 1, 1987, backfilling is required "as soon as practical or as required by the commission" after abandonment. Most lease agreements already contain such a requirement. Landfarming is prohibited. In geologically or hydrologically sensitive areas, in situ disposal of drilling pit contents can be prohibited.

Produced Waters

Injection: Ninety-nine percent of produced water is disposed of into injection wells for enhanced recovery (9,399 wells) or for salt water disposal (5,536 wells). The Kansas Corporation Commission has primacy for the UIC Class II program. Operators may inject produced saltwater into enhanced recovery or disposal wells after receiving approval of their applications from the Commission. Water injected into disposal wells may be returned to any horizon from which produced, or to other subsurface waterbearing formations which contain or previously produced saltwater or appreciably mineralized water.

All injection and disposal wells requiring wellhead pressure to inject fluids must inject through tubing under a packer set immediately above the uppermost perforation or open-hole interval. The annulus between the tubing and the casing shall be filled with a corrosion-inhibiting fluid or hydrocarbon liquid. Packerless or tubingless pressure completions may be authorized under special conditions. (For example, injection through tubing without a packer must, among other requirements, have no surface wellhead pressure). Wells must be cased and cemented in such manner as to prevent damage to hydrocarbon sources or fresh and usable water sources.

Mechanical integrity tests must be conducted before injection begins, and at least every five years thereafter. Packerless wells shall be tested using a retrievable plug immediately above the uppermost perforation or open-hole zone. The test pressure must be 100 psi or the authorized injection pressure, whichever is greater. No time period or pressure variance for the test is specified in the regulations.

Other Storage/Disposal Practices: Spreading of salt water on roads under construction is not prohibited if approval is received from the Kansas Department of Health and Environment.

Requests for a surface pond permit are granted unless denied by the Commission within 10 days. According to proposed Rule 82-3-600, the Commission, in approving applications for surface pond permits, shall consider the protection of soil and water resources from pollution. Each operator of a surface pond shall install observation trenches, holes, or wells if required by the Commission, and seal the pond with artificial material if the Commission determines that an unsealed condition will present a pollution threat to soil or water resources. Surface drainage is to be prevented from entering the pond. During the past two years, it has become a practice, on a case-by-case basis, to require monitoring wells in association with surface ponds and emergency pits in areas of shallow groundwater supply.

There are approximately 25 permanent pits, receiving a total of 30 barrels of brine a day, mostly in the Southeast corner of the State where there are no groundwater or seepage problems and where TDS concentrations of the produced waters are less than 10,000 ppm. Surface discharges of produced brine are not allowed nor is pit disposal allowed.

Upon the permanent cessation of the flow of fluids into any surface pond, all fluids resulting from oil and gas activities shall be removed to a disposal well approved by the Commission, or used for road maintenance or construction if approved by the Commission. Pond solids may be transported to a permitted solid waste landfill or to an approved offsite disposal area. Either action requires a permit from the Department of Health and Environment under the Kansas Solid Waste Statutes.

Offsite and Commercial Pits

Use is not made of offsite or commercial pits.

Plugging/Abandonment

Kansas Statute 55-156 states that prior to abandonment of any well which has been drilled, is being drilled, or may hereafter be drilled, the operator shall protect usable groundwater or surface water from pollution, and from loss through downward drainage, by plugging the well in accordance with the rules and regulations adopted by the Commission. Failure to comply with these rules and regulations shall be a class E felony.

Within 90 days after operations cease on any well, the operator must plug the well or give notice of temporary abandonment. If no production has begun after a year, the operator must either reapply for temporary abandonment status or plug the well. Extensions are given for good cause, which means primarily for economic reasons.

Cement plugs of at least 50 feet in length shall be placed above each present or past productive formation, and both above and below any freshwater horizons. Intervals between all plugs shall be filled with approved heavy mud-laden fluid.

References

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Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

General Rules and Regulations, the State Corporation Commission of the State of Kansas (Effective May 1, 1986).

Personal Communication:

Jim Schoff, Kansas Corporation Commission (316) 263-3238.

Rick Hesterman, Kansas Corporation Commission (316) 263-3238.

Kentucky

Introduction

Kentucky produced 7,788,000 barrels of oil and 61.5 x 10^9 cubic feet of gas from 8,798 gas wells, 19,334 oil wells, and 283 combination wells in 1984.

State Regulatory Agencies

Five agencies regulate oil and gas activity in Kentucky:

- Kentucky Division of Oil and Gas
- Kentucky Department of Natural Resources and Environmental Protection
- U.S. Bureau of Land Management
- U.S. Army Corps of Engineers
- U.S. Environmental Protection Agency, Region IV

The Kentucky Division of Oil and Gas in the Department of Mines and Mining, issues drill permits and provides well casing and well plugging requirements. The State is seeking primacy but does not yet have primacy for the UIC Class II well program.

The Kentucky Department of Natural Resources and Environmental Protection has NPDES - delegated authority. The Department issues permits for holding pits containing production fluids and instructions, pursuant to regulations, for pit construction.

The U.S. Army corps of Engineers becomes involved in oil and gas activities on lands maintained for water management projects.

State Rules and Regulations

Drilling

Pursuant to Kentucky regulation 401 KAR 5:090, there can be no discharge from a pit without an NPDES permit. Pits used to contain drilling muds or fluids associated with drilling activities have a permit by rule (unde Title 401, Chapter 47 - Solid Waste Facilities) for construction and operation , provided that the pit life is not longer than 30 days after completion of exploration or drilling activities. Where the pit life is longer than 30 days beyond completion of exploration or drilling activities, the pit is defined as a holding pit, and a facility-specific permit is required. When a pit no longer is in service, it must be backfilled and the land restored. There are no liner requirements for a drilling pit.

Production

A holding pit is a pit "designed to receive and store produced water at a facility." A holding pit must have a permit and must be lined with a synthetic material of 20mil minimum thickness. The State may grant an exemption to the lining clause for pits that pre-existed the date of regulatory enactment. Construction requirements include at least 1 foot of freeboard and a 2-foot berm above ground around the pit. Surface waters must be divertied from the pit.

No NPDES permits have been issued for discharges from holding pits. However, the Department of Natural Resources and Environmental Protection recently was sued and entered into a consent decree which specified a water quality criterion of 600 mg/l chlorides as appropriate for receiving water quality. It is anticipated that there will be a number of requests for NPDES permits to discharge produced fluids.

Some holding pits are used as produced water storage pits until a contract hauler transports the fluids for well injection or other purposes. There is no manifest system per se, but there is reporting of the producer, the amount of the fluid and its destination following transportation. Most of the fluid goes into injection wells.

There is no roadspreading or landspreading of produced fluids in Keentucky. Some use is being made currently of mechanical evaporation.

Plugging/Abandonment

A well may be temporarily abandoned for cause for two years, on a renewable basis. The well must be capped in such a way as to prevent escape of oil, gas or water from the well, or entrance of foreign materials into the well.

When a well not drilled through a coal-bearing stratum is abandoned, it must be securely plugged "by placing above the oil-producing sand a plug of pine, poplar or some other material that will prevent the well from becoming flooded." After 7 feet of clay or sediment above the plug, another plug of the same kind should be set. A similar combination of plugs and clay should be placed with the lower plug 10 feet below the casing. [Sec.353.180] Additional requirements are imposed for wells drilled through coal-bearing strata, including the use of cement plugs.[Sec.353.120].

References

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Personal Communications:

Brian C. Gelpin, Kentucky Division of Oil and Gas (606) 257-3812.

Brad Lambert, Kentucky Department of Natural Resources and Environmental Protection (502) 264-3410.

LOUISIANA

Introduction

Louisiana produced 449,545,000 barrels of oil and 5,867 x 10^9 cubic feet of gas in 1984. Louisiana ranks third in U.S. oil production and second in U.S. gas production. Over half of Louisiana's 25,823 oil wells are strippers. More than two-thirds of Louisiana's 14,436 gas wells are marginal (produce less than 60 thousand cubic feet of gas per day.) Eighty five percent of all produced fluids is salt water.

State statutes have regulated drilling operations since 1940. On January 20, 1986, the Office of Conservation promulgated amended rules and regulations regarding "the storage, treatment, and disposal of non-hazardous oilfield waste."

State Regulatory Agencies

Four agencies regulate oil and gas activity in Louisiana:

- Louisiana Department of Natural Resources, Office of Conservation

- Louisiana Department of Environmental Quality

- U.S. Bureau of Land Management

- U.S. Corps of Engineers

The Louisiana Department of Natural Resources Office of Conservation regulates all subsurface and surface disposal of oil- and gas-associated wastes. These powers are delegated to the Office of Conservation under

Title 30 of the Louisiana Revised Statutes of 1950. The Office of Conservation has been granted primacy for all classes of UIC wells.

The Office of Conservation does not coordinate with EPA on NPDES permits, but does coordinate with the Louisiana Department of Environmental Quality, Office of Water Resources, on any problem discharges originating from oil and gas activities. The Office of Water Resources also permits discharges of brine and reserve pit fluids. The effluent standards incorporated in the permits represent DEQ-OWR policy; the proposed effluent regulations for oil and natural gas development have not yet been adopted. The regulatory basis for that policy is found in rather general rules (January 27, 1953) of the Stream Control Commission, and a subsequent order (July 1, 1968) of the Commission.

The Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are federally held. Surface rights in Federal forests and grasslands are retained by the U.S. Forest Service. These rules, regulations, and orders are discussed in a separate section, Federal Agencies. The Bureau of Indian Affairs has some jurisdiction in limited areas of Louisiana.

State Rules and Regulations

Drilling

Pit Construction/Management: Reserve pits utilized in the drilling of oil and gas wells do not have to be lined. However, Louisiana Statewide Order No.29-B contains stringent operational requirements for reserve pits, including segregation of the drilling wastes in reserve pits from produced water or waste oil, protection from surface waters by levees, walls and drainage ditches, and maintenance of 2-foot freeboard.

Pit Closure/Discharge: Reserve pits must be emptied of fluids and closed within six months of completion of drilling or workover operations. Prior to closure, and for all closure and onsite and offsite disposal techniques except subsurface injection of reserve pit fluids, wastes must be analyzed for pH, oil and grease, and a number of metal and salinity parameters. (An exemption to the testing requirement is granted for reserve pit fluids from wells drilled to less than 5,000 feet using fresh water "native" mud with limited amounts of bentonite, barite or caustic soda). Disposal of drilling and workover waste fluids at pit closure may be accomplished through annular injection, injection down another newly-drilled well which will be plugged, onsite land treatment, solidification and burial onsite, mixing waste with native soil and burial onsite, wastewater discharge, or offsite disposal at permitted commercial facilities.

The Water Pollution Control Division issues a standard permit to oilfield service companies to discharge wastewater from treated drilling site reserve pits and abandoned or inactive production pits in order to facilitate pit closure. This permit allows the discharge of fluids meeting the following maximum effluent limitations:

Oil and Grease	-	15 mg/l
Total Suspended Solids	-	50 mg/l
Chemical Oxygen Demand	-	125 mg/l
Total Chromium	-	0.5 mg/l
Zinc	-	5.0 mg/l
Chlorides	-	500 mg/l
pH	-	6.0 to 9.0

There are provisions for dilution of the wastewater to meet the chloride limitation provided all other parameters are met (predilution chloride concentrations must be less than 2000 mg/l in freshwater areas and less than four times ambient chlorinity in brackish and saline areas).

Reserve pit fluids may be disposed of onsite providing applicable technical criteria are met. For either land treatment, burial or trenching, waste/soil mixture must not exceed:

pH	-	6-9
Arsenic	-	10 ppm
Barium	-	2,000 ppm
Cadmium	-	10 ppm
Chromium	-	500 ppm
Lead	-	500 ppm
Mercury	-	10 ppm
Selenium	-	10 ppm
Silver	-	200 ppm
Zinc	-	500 ppm

Onsite land treatment may be used for closing pits containing only nonhazardous oilfield wastes by mixing wastes with soil from pit walls or levees and adjacent areas, providing the resultant waste/soil mixture meets the above criteria, has an oil and grease content no greater than 1% (dry weight), and meets additional parameters in freshwater wetlands not normally inundated and in uplands:

Electrical conductivity (EC)	-	< 8 mmhos/cm (wetlands)
		< 4 mmhos/cm (uplands)
Sodium absorption ratio (SAR)	-	<14 (wetlands)
		<12 (uplands)
Exchangeable sodium % (ESP)	-	<25% (wetlands)
		<15% (uplands)

Pits may be closed by mixing the waste with soil and burying the mixture onsite if it meets the above pH and metals limits, has moisture content <50% by weight, EC 12 mmhos/cm, and oil and grease content 3% by weight. The top of the burial site must be at least 5 feet below ground level and covered by native soil, and the bottom at least 5 feet above the seasonal high water table.

Pits may be closed by solidification and onsite burial, using the same cover and depth requirements, if they have a pH of 6-12, and do not exceed the following limits in leachate tests:

Oil & grease	-	10 mg/l	Lead	-	0.5 mg/l
Arsenic	-	0.5 mg/l	Mercury	-	0.02 mg/l
Barium	-	10 mg/l	Selenium	-	0.1 mg/l
Cadmium	-	0.1 mg/l	Silver	-	0.5 mg/l
Chromium	-	0.5 mg/l	Zinc	-	5 mg/l

The solidified material must also meet permeability, compressive strength and wet/dry durability criteria.

Injection of drilling and workover waste fluids (including reserve pit fluids) may only be done at the well where used, and must not endanger underground sources of drinking water. Surface casing annular injection may be authorized if the surface casing is set and cemented at least 200 feet below the base of the lowest underground source of drinking water. Injection may be through perforations in the intermediate or production casing if that casing is set and cemented at similar depth. Surface casing open hole injection may be approved if, in addition to meeting the 200-foot requirement, there is a cement plug of at least 100 feet across the uppermost potential hydrocarbon zone.

Production:

Pits: All production pits must be lined such that the hydraulic conductivity of the liner does not exceed 1×10^{-7} cm/sec. Liners may consist of clays, soils mixed with cement or clays, synthetics (at least 10 mil thickness), or any combination meeting the 1×10^{-7} cm/sec limitation. Production pits located within inland tidal waters, lakes bounded by the Gulf of Mexico, and saltwater marshes are exempted from the liner requirement provided they are part of an approved treatment train for removal of residual oil and grease. Natural gas processing pits and compressor station pits which collect and store process water and stormwater runoff are also exempted.

Surface Discharge: The current policy of the Office of Water Resources is that discharge of produced water is permitted into brackish and saline areas, with a discharge limit for oil and grease of 72 mg/l (monthly sample). A report is required on monthly volumes discharged and on oil and grease, and an annual report on chlorinity (though no limit is established). The discharge must be to an open flowing water body of sufficient volume to prevent stratification and significant buildup of ambient salinity. The actual regulatory requirement states that "saltwater may be disposed of in normally saline waters, tidally affected waters, brackish waters or other waters unsuitable for human consumption or agricultural purposes.

Exceptions to the restriction against discharges in fresh water bodies are given for the Mississippi River and its distributaries below Venice, and the Atchafalaya River below Morgan City.

New regulations in November, 1985 required for the first time that all of the above discharges be permitted. A mailing was sent out in 1986 requiring filing of information and permit applications for current discharges. When these are received and evaluated, discharges actually occurring in fresh water areas not covered by the above exceptions would be required to end.

Injection: Over two-thirds of produced water is reinjected for enhanced recovery or disposal, both onsite and commercial. Injection wells must be equipped with tubing set on a mechanical packer, set no higher than 150 feet above the top of the disposal zone. Surface casing must be set through the deepest underground source of drinking water and cemented back to the surface. Long string casing must be cemented above the injection zone.

Mechanical integrity tests must be carried out at least every five years. Test pressures should be at the maximum permitted injection pressure, but within the interval of 300 - 1,000 psi. The test interval should be 30 minutes, with no greater than a 5 psi variance.

Offsite Disposal

Reserve pit contents can be transported offsite to permitted commercial land treatment or pit disposal facilities. Produced water can be transported to commercial underground injection wells.

Louisiana requires a substantial degree of financial commitment from commercial facility operators. Applicants for permits for commercial facilities must provide evidence of sufficient financial capability to ensure both adequate coverage of any liability incurred, and a guarantee of funding for proper closing of the facility. A bond or irrevocable letter of credit must be provided for closing, based on closing costs estimated in the facility plan. Insurance against any liabilities which may be incurred must be provided through certificates of insurance, letters of credit, or other acceptable financial instruments. Required minimums are $1 million for commercial facilities operating open pits; $500,000 for commercial facilities that store treat or dispose of nonhazardous oilfield solids; $250,000 for commercial saltwater underground injection/closed storage systems; and $100,000 for transfer stations operated in conjunction with permitted commercial facilities.

Commercial facilities may use lined pits for temporary storage, not permanent disposal, of nonhazardous oilfield wastes. Such pits must be located on the site of the permitted treatment system, must not exceed 50,000 barrels capacity, and must have maximum hydraulic conductivity of 1×10^{-7} cm/sec.

Commercial land treatment facilities must be isolated from contact with water supplies, and are subject to extensive and continuous monitoring and sampling requirements. Limitations on concentrations and other parameters are established as maximums at any time in the treatment zone (a), at the time of closure in the treatment zone (b), and in surface runoff water from the facility (c):

	(a)	(b)	(c)
pH	6.5 - 9	6.5 - 9	6.5 - 9
Oil & Grease	5%	3%	15 ppm
EC	10 mmhos/cm	10 mmhos/cm	0.75 mmhos/cm
SAR	12	12	10
ESP	15%	15%	
TSS			60 ppm
COD			125 ppm
Chloride			500 ppm
Arsenic	40 ppm	10 ppm	0.2 ppm
Barium	3,000 ppm	3,000 ppm	undetermined
Cadmium	10 ppm	10 ppm	0.05 ppm

Chromium	1,000 ppm	1,000 ppm	0.15 ppm
Lead	1,000 ppm	1,000 ppm	0.1 ppm
Mercury	10 ppm	10 ppm	0.01 ppm
Selenium	10 ppm	10 ppm	0.05 ppm
Silver	200 ppm	200 ppm	
Zinc	500 ppm	500 ppm	1 ppm

Commercial facilities may also receive permits to produce reusable materials from nonhazardous oilfield waste. Such materials may be used as daily cover in sanitary landfills, or as construction fill (subject to case-by-case review by the Commissioner). The oil and grease and metals leachate test limits are identical to those for leachate tests for solidification (above); the ESP, SAR and pH limits are the same as those for treatment zones at commercial land treatment facilities; EC is 8 mmhos/cm.

A complete manifest system to track the transportation and disposal of wastes taken to offsite commercial facilities is enforced.

Plugging/Abandonment

Wells must be plugged within 90 days of notice in "Inactive Well Report" unless the operator submits a plan describing the well's future use, and the well is then classified as having future utility.

When plugging, a cement plug of 100 feet must be placed above or across the uppermost perforated interval. Where production casing was not run or was removed, a cement plug shall run from 50 feet below to 50 feet above the shoe of the surface casing. If freshwater strata are not protected by casing, a cement plug must extend from 100 feet below to 150 feet above the deepest freshwater stratum, and a plug shall be placed from 50 feet below to 50 feet above the shoe of the surface casing. A

30-foot plug must be placed at the top of the well. Additional plugs must be placed to contain high pressure oil, gas, or water sands. In wells completed with screen or perforated liners which cannot practically be removed, a 100-foot cement plug must be placed with its bottom as near as practical to the top of the liner or screen. Mud-laden fluids must fill those portions of the well not filled with cement.

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MARYLAND

Introduction

Maryland produced 20 million cubic feet of gas from 6 gas wells, and no oil, in 1986.

State Regulatory Agencies

Two agencies regulate oil and gas activities in Maryland:

- Department of Natural Resources, Geological Survey
- Department of Health and Mental Hygiene, Office of Environmental Programs

The Department of Natural Resources regulates oil handling, storage, and transportation. It issues drilling permits and regulates site erosion.

All wastewater regulation is managed by the Department of Health. Section 6-104 of the public general laws of Maryland provides that a person may not dispose of any product of a gas or oil well without a permit issued by the Department. The Department has both NPDES delegation and UIC program authority.

State Rules and Regulations

Drilling and Production

Drilling and production wastes are managed by the Department of Health, Office of Environmental Programs. There is no differentiation between pits that are associated with drilling or production activities.

A pit may be lined with an impervious material such as clay or a plastic to prevent groundwater pollution. Fluids introduced to lined pits generally are transported to a brine disposal facility or to a sewage treatment plant, or they may be transported out of State for disposal purposes. There are no requirements on thickness or type of pit liners. There is no manifest system associated with transporting gas wastes unless such wastes are defined as hazardous.

Pits that are not lined must have a groundwater discharge permit issued under Code of Maryland regulations. The requirements associated with pit contents that would meet permit conditions for groundwater discharge are determined on a site-by-site basis. If there is surface discharge from a pit, an NPDES permit would be required.

Due to the absence of facilities, the State currently has neither issued an NPDES permit for surface discharges nor a UIC permit for underground injection. There is a groundwater discharge gas storage extraction facility in the western part of the State that is permitted to discharge about 1 million gallons per year. The permit requires that the first of a series of ten ponds be lined. There are periodic monitoring requirements for the ponds and in a nearby stream, but there are no monitoring limits and no monitoring wells.

Offsite and Commercial Pits

The only offsite pit used in the State is the one in Western Maryland described above. Some transported production fluids are received by this facility.

Plugging/Abandonment

There are no specific requirements in the regulations relating to the time within which a well must be plugged.

Injection: Over half of produced waters in California are reinjected, either for enhanced recovery or disposal. Authority for management of Class II injection wells is delegated by EPA to the Division of Oil and Gas. The Regional Water Quality Control Boards, under a Memorandum of Understanding with the Division of Oil and Gas, may comment on Class II injection well permits on matters which could affect water quality, including degradation of ground/water.

On Bureau of Land Management leases, operators of Class II wells must obtain permits from both the Division of Oil and Gas and BLM. Many of the injection wells are for enhanced recovery, and therefore could significantly affect BLM's royalty earnings from its leases. As a result, BLM wants to maintain joint signatory authority on UIC permits. BLM and the Division of Oil and Gas are in the process of trying to develop a Memorandum of Understanding on joint permitting.

Injection wells, other than those injecting steam, air, or pipeline quality gas, must be equipped with tubing and packer set immediately above the approved zone of injection. Exceptions may be granted where there is no evidence of freshwater-bearing strata, where more than one string of casing is cemented below the base of freshwater, or where the operator can demonstrate that freshwater and oil zones can be protected without tubing and packer. The pressure in the well must not be sufficient to fracture the zone of injection.

To obtain approval from the Division of Oil and Gas, operators must file plans, geologic analyses, evaluations of the impact of the planned well on other wells in the area, monitoring program, the source and analysis of the water being injected, and analysis of water in the injection zone. A new chemical analysis of the water being injected must be filed whenever the source of the water is changed or as requested by

When plugging, the well must be filled with mud, clay, or other nonporous material from the bottom (or from a bridge 30 feet below the lowest stratum) to 20 feet above the lowest oil, gas or water-bearing stratum, at which point a cement plug should be placed. Similar filling and cementing steps should be taken for each oil, gas or water stratum. A plug should be anchored about 10 feet below the bottom of the largest casing in the well, and the remainder of the well filled with nonporous material to within 2 feet of the surface.

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Bob Creter and David Fluke, Department of Health, Office of Environmental Protection (301) 791-4787.

MICHIGAN

Introduction

Michigan produced 29,140,000 barrels of oil and 152,840 MMCF of gas in 1985 from 1,380 flowing wells and 4,480 pumping wells. In 1984, the State ranked twelfth in U.S. oil production and thirteenth in U.S. gas production. Oil and gas production in Michigan peaked in 1980 and has been on a slight decline for the past 5 years.

The first successful Michigan oil well was drilled in 1886. The first oil and gas drilling permit was issued in 1927.

Regulatory Agencies

Five agencies regulate oil and gas activities in Michigan:

- Michigan Department of Natural Resources.
- Michigan Department of Commerce, Public Service Commission
- U.S. Forest Service.
- U.S. Bureau of Land Management.
- U.S. Environmental Protection Agency.

The Michigan Oil and Gas Act of 1939 (PA 61) established the Supervisor of Wells and designaed the Director of the Department of Natural Resources to that office. The Director, as authorized, appointed the Chief of the Geological Survey Division as the Assistant Supervisor of Wells to act on his behalf. The prime regulator of the oil and gas industry is the Assistant Supervisor of Wells and herein shall be referred to as the Supervisor. The Supervisor has authority to subpoena, to establish well spacing requirements, to develop orders without legislative interference, and to control disposal of solid and liquid wastes from drilling. The Oil and Gas Act provides the Supervisor broad authority to regulate the industry from "cradle to grave"; it stresses "prevention of wastes" from exploration to well abandonment. The State requires a bond, an environmental assessment, spacing minimums, and approves of well construction design.

The Water Resources Commission Act of 1929 (PA 245) regulates discharges to and the pollution of any waters of the State; it is under Act 245 that National Pollution Discharge Elimination System (NPDES) permits are issued. Michigan is an NPDES delegated State with such permits issued by the Surface Water Quality Division of the Bureau of Environmental Protection in the Department of Natural Resources. No NPDES permits are issued for oil and gas wastes.

The Solid Waste Management Act of 1978 (PA 641) provides for the licensing of solid waste disposal sites.

The State of Michigan does not require NPDES or landfill permits for disposal of liquid or solid oil field drilling wastes; these activities are regulated by the Supervisor of Wells. Other divisions of the Department of Natural Resources provide assistance to the Geological Survey Division in enforcing the Act by providing liaison with the Attorney General and with county prosecutors for action by the local courts through cooperative efforts of Department of Natural Resources law enforcement conservation officers. Where a groundwater problem has been identified through investigation and monitoring by the Geological Survey Division, and groundwater restoration is required, an NPDES permit by the Water Quality Division is issued on the restored water.

The Air Quality Division of the Department of Natural Resources regulates gaseous emissions to the atmosphere. The Michigan Public Service Commission regulates the production of gas from dry natural gas reservoirs and safety of gas pipe line construction.

When drilling occurs on Federal lands, Federal review of the drilling applications depends on whether Federal ownership is restricted to surface rights, or includes both surface and mineral rights. When only surface rights are owned by the Federal government, a copy of the drilling application is sent to the Federal agency involved, generally the U.S. Forest Service. Two separate investigations then follow: one by the Geological Survey, and one by the U.S. Forest Service, which involves fish and wildlife, geological, and other Federal experts. A Federal surface use permit then is issued. The drilling application is not approved by the State until all reviews have been completed and pertinent comments made a part of permit conditions. When both surface and mineral rights are Federally owned, a copy of the drilling application is sent to both the U.S. Forest Service and Bureau of Land Management.

The U.S. Environmental Protection Agency administers the UIC program for the State (40 CFR 147.1151)

State Rules and Regulations

Drilling: Pit Construction/Site Management Requirements. According to Instruction 1-84 (effective February 1, 1985) of the Supervisor of Wells, liners are required for mud pits when drilling with saltwater based drilling fluids, or when drilling through salt formations or brine-containing formations. While case-by-case exceptions to the requirement for lined drilling pits may, in principle, be approved in cases where a well is to be drilled which will only encounter fresh water (as in the southern part of the peninsula), such an exception is rarely requested.

Liners for mud pits must be of an impervious material that will meet or exceed the specifications for 20 mil virgin PVC. Liners of other than 20 mil virgin PVC must be approved by the Supervisor. Liners must be installed in a manner which prevents vertical and lateral leakage, and must be one piece or with factory-installed seams. Mud pits may not be built where the groundwater table is observed at the depth of the proposed excavation. In such cases steel tanks are used and the drilling muds disposed of at an approved offsite location.

Instruction 1-84 restricts the use of mud pits to "drilling muds, drilling fluids, cuttings, native soils, cementing materials and/or approved pit stiffening materials." No salt cuttings from drilling may be released to the pit as solids; they must be screened out and dissolved before being released (via a closed system) to the pit.

Instruction 1-84 also requires that cellars be sealed, and rat holes and mouse holes equipped with a closed-end steel liner or otherwise sealed or cased in such a manner that all fluids entering the cellar, rat hole and/or mouse hole shall not be released to the ground but shall be discharged to steel tanks, the lined reserve pit, or the mud circulation system. Aprons of 20 mil virgin PVC or other equivalent material shall be installed under steel mud tanks and overlapping the mud pit apron, and in ditches or under pipes used for brine conveyance from cellars to pits or to steel mud tanks.

Pit Closure: At closure, all free liquids above the solids in the mud pits shall be removed to the maximum extent possible and either reused or disposed. The remaining mud pit solids may be required to be stiffened (mixed with earthen materials). In any event the residue is encapsulated and buried on site or removed to an approved waste disposal site. For on-site disposal the edges of the pit liner must be folded over the pit, and a separate piece of 10 mil virgin PVC used to entirely encapsulate the pit. The top of the cover must be buried at least 4 feet below grade. The Supervisor may require additional measures under special circumstances.

For abandoned pits, or pits used prior to Special Order 1-81 issued in 1981 and not meeting its specifications, no action is taken unless a contamination problem has been detected. When a potential contamination problem exists, the site is investigated by the Survey's groundwater unit. If it can be shown that an identifiable entity is responsible, damages may be sought administratively or through the courts.

Disposal: Free liquids from the mud pits must be pumped off prior to encapsulation, either for disposal or for use in the drilling of additional wells. Fluids may be disposed in Class II injection wells.

Two additional options are specified in Special Order 1-85. The Supervisor may authorize disposal of fluids on-site to dry holes as part of plugging operations. Under rare conditions, where production casing is run, fluids generated during drilling of the well may be injected in the annular space. In both cases, drilling fluids must be injected in permeable formations isolated below fresh water horizons.

Prior to Special Order 1-85, pit fluids were allowed to be spread on roads for dust and ice control. A 1983 estimate showed that 22 million of the 28 million gallons of pit fluids generated during the year were spread on roads. Special Order 1-85 prohibited use of pit brines for ice control on March 29, 1985, and prohibited their use for dust control as of September 1, 1985.

Offsite disposal in approved lined landfills with leachate collection systems is also permitted.

Produced Fluids

Injection: Over 90% of Michigan's produced brines are now disposed of by injection into Class II wells. Such wells must have a surface string of casing which is cemented and completely isolates the fresh water aquifers from the down hole disposal zone.

The wells must be "cased and sealed to prevent the loss or injection of brine into any unapproved formation." Wells must be equipped with tubing and packer. Since Michigan does not have delegated UIC authority, EPA's Region V directly implements the mechanical integrity test program. Wells are required to meet a standard pressure test of 300 psi for 30 minutes, with 3% allowable bleed-off.

Annular disposal of produced brines is prohibited. Although exceptions are technically allowed under the regulations, none has ever been requested.

Surface Disposal: Produced brines were formerly used for both ice and dust control in Michigan. Special Order 1-85, issued on March 29, 1985, immediately banned the use of brine for ice control. The use of brine for dust control may continue through September 12, 1987 (provided the brines meet specifications for benzene, toluene, and xylene content). Annual one year extensions may be granted that would allow continued use of brine for dust control. Such one year extensions may continue until a 3 year DNR environmental impact study has been completed. The decision to whether to allow continued road application of brine will be based on the results of this study.

Offsite Facilities Disposal

Solid drilling wastes may be disposed of in an approved, licensed solid waste landfill, with the agreement of the landfill operator, where the landfill is lined and has a leachate collection system, a groundwater monitoring system, and a treatment process prior to the discharge of waste leachate.

Road disposal of produced brines remains temporarily available for dust control; producers may provide brine to a hauler if the hauler can verify in writing the authorization to receive brines on behalf of a governmental unit.

Plugging Abandonment

Plugging operations must commence within 60 days after completion as a dry hole, or within a year after cessation of production. Extensions may be granted by the Supervisor if there are sufficient reasons for retaining the well.

Oil, gas, brine and fresh water shall be confined to the strata in which they occur by use of muds, cement, or other suitable materials; both the materials and methods of placement must be specified and approved by the Supervisor. The surface pipe is abandoned with the hole and must be cut off below plow depth and sealed with a cement plug or other approved material.

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MISSISSIPPI

Introduction

Mississippi produced 31,879,000 barrels of oil in 1984 from 3,569 oil wells; 210×10^9 cubic feet of gas were produced from 715 gas wells.

State Regulatory Agencies

Four agencies regulate the oil and gas activity in Mississippi:

- State Oil and Gas Board
- Mississippi Department of Natural Resources, Bureau of Pollution Control
- Department of Wildlife Conservation
- U.S. Environmental Protection Agency, Region IV.

The State Oil and Gas Board regulates the oil and gas industry "to prevent the pollution of freshwater supplies by oil, gas or saltwater" and to promote, encourage, and foster the oil and gas industry (Section 53-1-17, *State Statutes*). *The Oil and Gas Board does not have UIC* program authority.

The Department of Natural Resources, Bureau of Pollution Control, is responsible for the investigation of water pollution and for the issuance of NPDES permits. No NPDES permits are issued for drilling fluids, completion fluids, workover fluids, or produced brines generated by the onshore oil and gas industry.

The Department of Wildlife Conservation is responsible for the maintenance of fish and wildlife within the State.

The U.S. Environmental Protection Agency, Region IV, issues UIC program Class II injection well permits for Mississippi. In this activity area, the State Oil and Gas Board maintains a separate well injection permitting program; a well operator must obtain an injection permit both from the State and Federal Governments.

A 1982 memorandum of Agreement among the Department of Natural Resources, Department of Wildlife Conservation, and the State Oil and Gas Board coordinates the activities of the three State agencies related to the oil and gas industry. The Agreement ensures that the Mississippi Commission on Wildlife Conservation has an opportunity to review the drill plan, as drilling may impact the sensitive environmental nature of the State's wetland resources. The Agreement further allows for suspension of a lessee's operations by the Oil and Gas Board where any signatory agency determines such operations to be in violation of applicable laws or regulations.

State Rules and Regulations

Drilling

The use of drilling reserve pits, or mud pits, does not require a special permit; the permit to drill constitutes the permit for the drilling reserve pit. Reserve pits must be constructed to prevent pollution of surface or subsurface fresh waters. The only specific construction requirements in the regulations are that the pit must be protected from surface waters by dikes and drainage ditches, and that no siphons or openings may be placed in the walls or dikes that would permit contents of the pit to escape.

The reserve pit must be emptied of fluids, backfilled and compacted within three months of the completion of drilling operations. Exceptions may be granted if warranted, and the reserve pits may be used as test pits, with agreement of the Board's field representative, if they meet the conditions for well test pits.

When closing the reserve pit, there are several options for disposing of the drilling muds. Where the well is a dry hole, the muds may be pumped back into the hole before plugging and abandonment, provided the surface casing has been set to a point below the base of the USDW. They may be landfarmed if they will "not . . . cause contamination of soils." The muds may be hauled to a commercial disposal facility designed to handle drilling muds. Or the muds may be treated in the pit with flocculants to aid in precipitation, coagulation and sedimentation. The supernatant water is then sampled in place to determine that it does not exceed the following limits established by the Department of Natural Resources in its "Reserve Pit Discharge Policy:"

Chlorides	-	500 mg/l
pH	-	6 - 9
Suspended solids	-	100 mg/l
Specific conductance	-	1000 umhos/cm
COD	-	250 mg/l
Zinc	-	5 mg/l
Chromium	-	0.5 mg/l
Phenol	-	0.1 mg/l

If the fluids meet this limit, they may be discharged. These discharges are considered to be part of the policy covered by the drilling permit, and do not require a separate discharge permit. The Oil and Gas Board is in the process of incorporating these limits formally into their pit regulations (in Rule 63, Section III.E.9). After the discharge, the dewatered muds are covered in place and the pit is closed as noted above.

Production

Pits: The regulations of the State Oil and Gas Board contain a provision, now a decade old, requiring that earthen pits "be phased out and discontinued, except as hereinafter provided." The regulations further specify limited conditions under which specific types of pits may be used, and the requirements which must be met in their construction and management. When permits are issued for pits (other than reserve pits), the longest permit period is two years. In addition to reserve pits, permits are issued for four types of pits:

Temporary saltwater storage pits: The Board's regulations stipulate that this type of pit will be "permitted only if no other means of storing or disposing of saltwater is available" (e.g., in remote areas). When permitted, these pits must be lined with an impervious material, must have no siphons or openings in the walls or dikes, and must be protected from surface waters by dikes and drainage ditches. Only produced waters should be placed in the pit (after separation), and fluid levels should never rise to within one foot of the top.

Emergency pits: Produced water should never intentionally be placed in such pits, but only in the event of an emergency such as a saltwater disposal or water injection system failure. A field representative of the Board must be notified within 72 hours. Within two weeks after the emergency period, the pit must be emptied so as to contain no more than two feet of water. The fluid level must never rise to within one foot of the top of the pit; there must be no siphons or openings in the walls of the pit; and dikes and drainage ditches should be used to protect the pit from surface water.

Burn pits: This may be used to burn tank bottoms and other refuse products. the burn pit must be place at least 100 feet away from the facilities for storing and/or treating the oil or gas, must be constructed to prevent escape of contents or ingress of surface water, must never have fluid levels closer than two feet to the top of the pit walls, and must not be used for noncombustible fluids (except as these are naturally associate with the combustible wastes).

Well test pits: These are small pits used in testing producing wells for short periods of time. Well test pits must be placed at least 100 feet away from the facilities for storing and/or treating the oil or gas, must be constructed to prevent escape of contents or ingress of surface water, and must maintain a 2-foot freeboard.

When any of these pits is abandoned, it must be empties of fluids, backfilled, leveled and compacted.

There are areas where even this use of pits is prohibited. In areas where public water supplies, or recreational, wildlife, or fishery resources would be adversely affected (e.g., coastal wetlands), "impervious containers shall be used . . . [and] the contents removed and properly disposed of within ninety days following usage."

Injection: Annular disposal of produced saltwater is permitted. The Board's policy is that disposal in the annulus is allowed only where the operator can make an absolute showing of no endangerment to the environment or fresh groundwater, and can demonstrate that there is no economic alternative. The applicant is required to provide the Board an economic study of the well and of the economics of alternative methods of disposal. Generally, the economic showing could only be made in a setting where there was no well which could be converted to an injection well; this would likely be in remote, small fields. The applicant would be required to provide the Board with a radioactive tracer survey to prove that the injected fluid was not leading through the casing and was entering the correct zone.

As note above, Mississippi does not have delegated authority for regulation Class II wells. But the state issues permits for all injection wells, and operators must obtain permits both from EPA and the State Oil and Gas Board. The state regulations require information on wells within 1/4 mile of the proposed injection well, injection pressure limited to 75% of estimated fracture pressure of the target formation, injection through tubing and packer set no more than 150 feet above the injection zone, and mechanical integrity tests before initial injection and every five years thereafter. Test pressures are required to be at the greater of maximum authorized injection pressure or 300 psi (for a new well), with a ceiling of 500 psi (for a converted well).

Offsite and Commercial Pits

Except for two commercial pits in southern Mississippi, both of which are phasing down, use is not made of offsite and commercial pits within the state.

Plugging/Abandonment

All wells which are drilled and found dry must be plugged within 120 days, unless an extension is granted by the Supervisor. A production or service well which ceases to operate must be listed, after six months, on the Inactive Well Status Report. The operator must classify the well as having future utility or having no future utility. If the "future utility" designation is accepted, no further action is necessary. If the well is designated as having no future utility, it must be plugged within 120 days.

When plugging a well in which production casing has been set, if the production casing is not to be pulled, a cement or bridging plug must be placed near the bottom of the casing string to protect any producible pool. If the production casing is to be pulled, a cement or bridge plug should be placed at the bottom of the production string, a 100-foot cement plug about 50 feet below all freshwater-bearing strata, additional plugs to protect freshwater sands, a 100-foot plug at the bottom of the surface pipe, and a plug at the surface. The remainder of the hole must be filled with mud.

When plugging an uncased hole, 100-foot plugs must be placed to protect each producible pool. Additionally, 100-foot plugs must be placed approximately 50 feet below all fresh water bearing strata, and at the bottom of the surface pipe. A plug must be placed at the surface of the ground in a manner so as not to interfere with soil cultivation.

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Richard Ball, Mississippi Department of Natural Resources, Bureau of Pollution Control (601) 961-5171.

MISSOURI

Introduction

Missouri produced 131,000 barrels of oil from 557 oil wells in 1984. There is no commercial gas production. The State has 9 evaporation pits and 229 injection wells. In 1984, Missouri had a total of 2.6 million barrels of produced waters, most of which were injected. The reason for injection exceeding production is that two major steam operations import fresh water to steam out the oil, which results in an increased quantity of injectable fluids. Missouri has not had commercial gas production since 1977.

State Regulatory Agencies

Three agencies regulate oil and gas activities in Missouri:

- Department of Natural Resources, Division of Geology and Land Survey

U.S. Bureau of Land Management

The State Oil and Gas Council was formed by Rule 10 CSR 50-1.010 and is composed of the executive heads of the Division of Geology and Land Survey, Division of Commerce and Industrial Development, Missouri Public Service Commission, Clean Water Commission, the University of Missouri, and two persons knowledgeable of the oil and gas industry, appointed by the Governor with the advice and consent of the Senate. The State Geologist who serves as Director of the Division of Geology and Land Survey, is charged with the duty of enforcing the rules, regulations, and orders of the Council. The State has primacy for UIC program Class II wells.

Federal lands in Missouri are confined to U.S. Air Force bases, but there is drilling on these lands. When a request for a permit to drill is received, the Bureau of Land Management prepares the draft permit, which is issued by the State Oil and Gas Council.

The Department of Natural Resources, Division of Environmental Quality becomes involved only when there is a breach of a pit dike, and a spill of fluids occurs. Appropriate action under the Division of Environmental Quality regulations then occurs.

State Rules and Regulations

Drilling

Rule 10 CSR 50-2.040 provides requirements during the drilling of wells to prevent contamination of either surface or underground fresh water resources. There is a bonding requirement before commencing oil or gas drilling operations, and all wells must be plugged when abandoned.

There are no regulations related to drill pits. Drill pits are not lined. When pit muds dry, the muds are buried on site.

Produced Waters

There are no regulations related to construction of evaporation - percolation pits for produced waters. About 32,370 barrels of produced waters were put in such pits in 1984.

The remainder of produced waters are injected into Class II wells for disposal or enhanced recovery. Injection wells must be completed with strings of casing properly cemented at sufficient depths to protect any fresh water strata. The specific casing and cementing requirements will be based on the depth to the base of lowest underground drinking water source, the nature of the fluids being injected, and the hydraulic relationship between the injection zone and the base of the underground source of drinking water. Maximum injection pressure must be established by the state geologist to avoid fracturing the confining zone.

All injection wells must be tested for mechanical integrity before initiating injection, and at least every 5 years thereafter. Procedures may include a pressure test, monitoring of annulus pressure after an initial pressure test, or other methods deemed effective by the state geologist.

Offsite Disposal

Some of the produced fluid is trucked to other injection sites. There is no manifest required for the transportation of produced brine.

Plugging/Abandonment

Notification is required within 90 days after operations cease, and the Council may require temporary plugging to prevent pollution of freshwater strata. After 6 months, the operator must plug and abandon the well, unless granted an additional 6 month extension for good cause. Further 6-month extensions may be granted, up to a limit of two years.

Plugging must assure that all fluids remain in their original strata. Cement plugs must be placed from the bottom of any oil or gas stratum to at least 25 feet above the top of that stratum. Appropriate means must be taken to prevent migration of surface water into a plugged well. Casing must be cut off below plow depth.

References

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Missouri Meeting Report. 1985. Proceedings of the Onshore Oil and Gas State/Federal Western Workshop. U.S. Environmental Protection Agency, Washington, D.C. (December 1985).

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Personal Communications:

Kenneth Deason, Missouri Oil and Gas Council (314) 364-1752.

MONTANA

Introduction

Montana produced 20,079,819 barrels of oil and 52,981,382 billion cubic feet of gas in 1984. Production is from 4,665 oil wells and 2,152 gas wells. A total of 622 wells were drilled for oil and gas in 1985. About 320,000 barrels of brine per day are produced from the approximately 1,600 full producing oil wells. The remaining stripper wells produce about 40 barrels each of brine per day.

Responsible Regulatory Agencies

Four agencies regulate oil and gas activities in Montana:

- Montana Department of Natural Resources and Conservation, Oil and Gas Conservation Division

- Montana Department of Health and Environmental Sciences, Water Quality Bureau

- U.S. Environmental Protection Agency, Region VIII

- U.S. Bureau of Land Management.

the Oil and Gas Conservation Division issues drilling permits and regulates the oil and gas industry in Montana. There is a compliance bond. Montana does not have primacy for the UIC program, but the Board of Oil and Gas Conservation is planning to negotiate with EPA on assumption of privacy..

The Montana Department of health and Environmental Sciences, Water Quality Bureau, controls water quality issues. the Bureau has primacy for the issuance of NPDES permits.

Region VIII of the Environmental Protection Agency issues UIC permits for the injection of brines in Montana.

The Bureau of Land Management uses their own form for drilling permits; thus, a driller must obtain a State as well as a Federal permit to drill for oil or gas on Federal lands. The Board of Oil and Gas Conservation has a cooperative agreement with the Bureau of Land Management concerning spacing of wells and field rules on Federal lands. BLM issued the permits to drill on Indian lands. The Board has no jurisdiction over Indian lands but does maintain files on those wells if the operation chooses to file the permit requests and reports that would be required on other wells.

State Rules and Regulations

Drilling

Permits are not required for drilling pits. The regulations of the Oil and Gas Conservation Division (36.22.1005) require the operator to "contain and dispose" of drilling operation wastes either by removal from the site or burial at least three feet below the surface of the land. further, the operator is required to "construct his reserve pit in a manner adequate to prevent undue harm to the soil or natural water in the area. When a salt base mud system is used as the drilling medium, the reserve pit shall be sealed when necessary to prevent seepage."

The lining requirement for reserve pits is decided case by case, based upon soil composition, slope, drilling, fluids, and proximity to water sources. Fluids may be removed from reserve pits by several methods. One method is to remove fluids by truck and haul them to another drill site or disposal facility. No manifest is required for transporting fluids. Another method is to allow fluids, other than oil, to remain in a reserve pit for up to a year for evaporation.

Alternatively, the fluids may be treated chemically so that they may be used for beneficial purposes. After the fluids have been removed, the remaining solids are left to dry before backfilling. If a plastic liner has been used, it is folded into and buried in the reserve pit.

Produced Waters

Full producing wells in Montana produce approximately 200 barrels per day of brine; strippers about 40 barrels per day. Most produced water is reinjected, but some is disposed of by evaporation, and a small amount by discharge for beneficial use.

Rule 36.22.1227 of the Board of Oil and Gas Conservation states that salt or brackish water may be disposed of by evaporation when impounded in excavated earthen pits which may only be used for such purpose when the pit is underlaid by tight soil such as heavy clay or hardpan. At no time shall salt or brackish water impounded in earthen pits be allowed to escape over adjacent lands or into streams.

Rule 36.22.1228 allows salt water to be injected into the stratum from which produced or into other proven saltwater-bearing strata. Injection is also permitted to producing formations to enhance production of oil and gas. The UIC program, however, is administered by EPA - Region VIII.

NPDES discharge permits are issued by the Water Quality Bureau of the Montana Department of Health and Environmental Sciences for 18 facilities under the beneficial use provision of the wildlife and agricultural use subcategory with a total permitted discharge of 0.6 million gallons per day. Of those issued, only about two of the permitted facilities discharge. Discharges are to a closed basin in the northern part of the State. Discharge limits include total dissolved solids of less than 1,000 mg/l and an oil and grease of 15 mg/l absolute with an average of 10 mg/l. Other discharge limits including phenols and metals are imposed.

Plugging/Abandonment

Once a well is no longer being used for the purpose for which it was drilled, it should be plugged. But a well can remain idle on a field with other producing wells, while being held for possible future use (unless causing damage to oil, gas, or freshwater strata). But at the point that other wells in that field cease to produce because of depletion of the reservoirs, the operator must commence drilling and abandonment operations within 90 days. Before plugging work begins, the operator must submit forms laying out the specific plans for plugging. After approval by the Petroleum Engineer, plugging may proceed.

References

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Personal Communications:

Charles Maio, Administrator, Board of Oil and Gas (406) 656-0040.

Abe Horpestad, Water Quality Bureau (406) 444-2459.

NEBRASKA

Introduction

Nebraska produces 6,470,000 barrels of oil and 2,347 MM cubic feet of gas each year. Production is from 2.072 oil wells and 18 gas wells. Most of the State production is in two areas: the five county area in the Denver Bsin, and Red Willow and Hitchcock Counties. Strippers account for about 85 percent of the State production.

Regulatory Agencies

Three agencies regulate oil and gas activity in Nebraska:

- Nebraska Oil and Gas Conservation Commission
- Nebraska Department of Environmental Control
- U.S. Bureau of Land Management

The Nebraska Oil and Gas Conservation Commission regulates industry practices and procedures with regard to construction, location, and operation of onsite drilling. The Commission issues permits for oil and gas drilling and UIC Class II wells. The Commission has three members who are appointed by the Governor. At least one member must have experience in oil or gas production.

Nebraska is an NPDES - delegated State. The Nebraska Deparetment of Environmental Control issues all NPDES permits and regulates all other classes of UIC wells.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands. The Bureau is addressed in a separate section.

State Rules and Regulations/Drilling

When drilling is complete, the supernatant in mud pits is allowed to evaporate. The muds in use are generally fresh water gels. After the mud pit has dried, the residues are land spread, and the pit is backfilled.

Production

Under Rule 3.002, "No salt water, brackish water, or other water unfit for domestic, livestock, irrigation, or general use shall be allowed to flow over the surface or into any stream or underground fresh water zone." Brine may be disposed by evaporation pits, road spraying, or injection.

Pits:

Generally, evaporation pits are used in the panhandle, where net evaporation is as high as 60 inches annually. Under Commission Rule 3.022, retaining pits must be permitted. The Commission approves or disapproves the pit upon receipt of the application. The pits are required to be lined or constructed with impermeable material when the underlying soil conditions would permit seepage to reach subsurface fresh water zones. They must have the capacity for at least three times the average daily fluid influx into the facility.

This rule does not apply to burn pits or emergency pits. Burn pits are required to be a safe distance from any other structure, and must be constructed to prevent any materials from escaping the pit, or surface water from entering the pit. Open pit storage of oil is not allowed unless during an emergency or by special permission from the Director of the Commission.

Road Spraying:

Road spraying of brine is considered on a case-by-case basis. When allowed, spraying must be done with a spreader bar and in such a way as to prevent runoff.

Injection:

In southwest Nebraska, most brines are reinjected, either into disposal or enhanced recovery wells. There are about 500 Class II wells in Nebraska, and most are used for enhanced recovery. Injection wells must be completed, maintained and operated to confine injected fluids to approved formations, and to prevent pollution to fresh water or damage to sources of oil or gas. Information must be submitted with injection well applications on other wells within a half-mile of the proposed injection well, as well as a demonstration that injection will not lead to vertical fractures allowing injection or formation fluids to enter fresh water strata. Injection must be through adequate casing or casing and tubing. Mechanical integrity tests must be at the greater of 125% of the maximum authorized injection pressure or 300 psi. (Alternately, for wells without tubing and packer, the operator shall record actual injection pressure weekly, and report it monthly).

Plugging/Abandonment

There are no specific time requirements related to plugging of a well. State policy is to encourage operators not to permanently plug wells with any further potential for secondary recovery operations.The operator must notify the Director before plugging of the specific plans for plugging, but the regulations make no specific mention of requirements for positive approval or witnessing of plugging. The well must be plugged with "mud-laden fluid, cement, mechanical plug, or some other suitable material" so as to prevent migration of oil, gas, or water from the strata of origin.

References

Nebraska Oil and Gas Conservation Commission, Rules and Regulations, December 1985.

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

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Nebraska Meeting Report. 1985. Proceedings of the Onshore Oil and Gas State/Federal Western Workshop. U.S. EPA, Washington, D.C. (December 1985).

NEVADA

Introduction

During 1984, Nevada produced 1,953,000 barrels of oil from a total of 34 oil wells. There are no producing gas wells in this State. All of these wells are on Federal land and most use reserve pits to evaporate drilling fluids. Reinjection is applied to produced waters. Between 200,000 and 500,000 barrels per year of brine are produced in Nevada's major production area (the Carbonate Belt). Reinjection of these waters is accomplished collectively into some 5-9 injection wells. No produced waters are discharged under the beneficial use subcategory. Nevada has NPDES primary, but is currently negotiating for UIC primacy.

Regulatory Agencies

Four agencies regulate the oil activity in Nevada:

- Nevada Department of Minerals

- Nevada Department of Conservation and Natural Resources, Division of Environmental Protection

- Bureau of Land Management

- EPA, Region IX, Underground Injection Section

The Nevada Department of Minerals, created as a single State department by the State legislature in 1983, regulates the industry on the State level with respect to construction, location, and operation of onsite drilling and production, and issues all operation permits. Operators must obtain permits both from the Department and from BLM.

The Division of Environmental Protection in the Department of Conservation and Natural Resources has adopted Underground Injection Control Regulations governing the use of all types of injection wells. As of April, 1987 the U.S. Environmental Protection Agency had not yet granted delegation of the program to the State. However, it is expected that by october, 1987 the State will be administering the program.

The Division also regulates the disposal of solid waste and supervises the cleanup of any major spills of any pollutants. The discharge of any produced brines during the exploration and testing phase is also regulated. Depending on the quality of the discharge waters and the nearby surface and ground waters, discharge to the surface may or may not be allowed.

The Division has jurisdiction over all waters of the State, both surface and ground waters, and regulates activities on State and Federal lands.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands. For such drilling, the Bureau of Land Management handles all Applications to Drill. The Bureau requires extensive environmental documentation, including environmental assessments, and develops environmental impact statements for drilling on Federal land.

U.S. EPA - Region IX regulates the underground injection of wastes from oil wells under the UIC program. The applicable regulations are found in 40CFR 144 and 146. Operators must obtain permits both from U.S.

EPA and from the Division of Environmental Protection. Upon delegation of the UIC program to the State, EPA will no longer issue permits.

Further discussion of BLM and U.S. EPA UIC regulations can be found in the section on Federal regulations.

State Rules and Regulations

The Regulations and Rules of Practice and Procedures under Chapter 522 of the Nevada Revised Statutes of the Oil and Gas Conservation Law were adopted by the Department of Minerals on December 20, 1979. Section 200.1 of these rules states that, "Fresh water must be protected from pollution whether in drilling, plugging or producing oil or gas or in disposing of salt water already produced." The regulations govern the "drilling, safety, casing, production, abandoning and plugging of wells." The regulations do not include a provision for allowing or disallowing discharges nor is their mention of a discharge allowance. Section 308, however, states that all excavations must be drained and filled and the surface leveled so as to leave the site as near to the condition encountered when operations were commenced as practicable. Section 407 further states that "Oil or oil field wastes may not be stored or retained in unlined pits in the ground or open receptacles except with the approval of the Division." Section 600.1 states that, "The underground disposal of salt water, brackish water, or other unfit for domestic, livestock, irrigation or other use, is permitted only upon approval of the Administrator."

Plugging is required for wells with production casing which have not been operated for a year, and for wells without production casing in which drilling operations have ceased for 30 days. Six-month extensions may be granted for good cause. Plugging is required with cement and heavy mud to seal hydrocarbon or water formations.

References

Proceedings of the Onshore Oil and Gas State/Federal Western Workshop. Summary of presentation given by Scott McDaniel, Nevada Department of Minerals. December 1985.

Nevada Department of Conservation and Natural Resources, Division of Mineral Resources. Regulations and Rules of Practice and Procedures. Chapter 522. December 20, 1979.

Personal Communications:

Cathy Loomis, Engineering Technician, Nevada Department of Minerals, September 26, 1986 (702) 885-5050.

Dan Gross, Division of Environmental Protection, Department of Conservation and Natural Resources, September 26, 1986 (702) 885-4670

Ellis Hammett, Permit Processor, Nevada Bureau of Land Management, September 26, 1986 (702) 784-5123.

Nate Lau, Director, UIC Division, EPA Region IX, September 26, 1986 (415) 974-0893.

NEW MEXICO

Introduction

New Mexico produced 78,500,000 barrels of oil and 893.3 x 10^9 cubic feet of gas in 1985, ranking fourth in U.S. gas production and eighth in U.S. oil production. Production is from 21,986 oil wells and 18,308 gas wells. Twenty percent of oil production is from the stripper well category.

State Regulatory Agencies

The following agencies have responsibilities for regulating oil and gas activities in New Mexico:

- New Mexico Energy and Minerals Department, Oil Conservation Division

- New Mexico Oil Conservation Commission

- New Mexico Water Quality Control Commission

- U.S. Bureau of Land Management

The Oil Conservation Division of the Energy and Minerals Department is responsible for regulating the oil and gas industry. It regulates exploration and drilling, production and refining with respect to protection of water quality.

The Oil Conservation Commission has "concurrent jurisdiction and authority with the division to the extent necessary for the commission to perform its duties as required by law." The three members of the

Commission are the Commissioner of Public Lands, the Director of the Oil Conservation Division, and the State Geologist. The Commission serves as an appeal body for permit applicants who object to decisions of the Division; the applicant must seek review from the Commission before going to court. The Commission may also initiate rules and orders to be administered by the Division, as in the case of Orders R-3221 and R-7940, which restrict surface discharges of produced water in areas of the state with vulnerable aquifers (see below).

New Mexico has relatively few statewide specific regulations relating to fresh water protection from oil and gas discharges because of the diversity of the climate, diversity of the geology, and diversity of the quantity and type of waste that is produced. Statewide rules require that all fresh surface and ground waters be protected from contamination. Statewide UIC rules have been adopted and there is a plugging bond requirement that endures until well abandonment has been approved by the Division.

But the Oil and Gas Act also allows the adoption of special rules or orders tailored to the particular characteristics of a production area. As a result, rules controlling specific disposal practices in differing geographic areas of the state have been adopted.

The U.S. EPA has the responsibility for NPDES permitting in New Mexico; however, the Environmental Improvement Division of the New Mexico Health and Environment Department certifies those permits. No NPDES permits have been issued for the New Mexico oil and gas industry drilling and production facilities.

The Water Quality Control Commission (WQCC) is an interagency commission with members from several state government agencies, including the Environmental Improvement Division and the Oil Conservation Commission. The WQCC is responsible for the development of water quality control standards and water pollution regulations. It delegates the administration of the regulations it develops to constituent agencies. WQCC is prohibited from taking any action which would interfere with the exclusive authority of the Oil Conservation Commission over all persons and things necessary to prevent water pollution as a result of oil or gas operations.

The Oil Conservation Division administers WQCC regulations at oil refineries and natural gas processing facilities. The Environmental Improvement Division administers and enforces WQCC regulations at brine manufacturing operations, including all brine production wells, holding ponds and tanks. The Oil Conservation Division regulates brine injection through its Class II UIC program if the brine is used in the drilling for or production of oil and gas.

The U.S. Bureau of Land Management takes the lead on oil and gas drilling activities on Federal and Indian lands. Where drilling on Federal land occurs, the BLM issues a drilling permit, but concurrence by the State is required. The State maintains primacy in waste disposal activities associated with any such drilling or production activities.

Issues with drilling on Indian lands currently remain unresolved. Some Tribes have issued regulations concerning oil and gas drilling and production activities. Some Tribes have applied for UIC program delegation. The State has not waived jurisdiction in regard to regulating the oil and gas industry on Indian lands, however. Where Tribe regulations go beyond those of the State, the Tribe regulations prevail.

State Rules and Regulations

New Mexico has developed many of its rules in response to problems identified or anticipated in particular production areas in the state. In the southeast, contamination now is being detected related to oil and gas activities which occurred three or four decades ago. These cases may be related to improper casing, pit construction, improper plugging or any number of practices. Contamination includes increases in chlorides and total dissolved solids, dissolved aromatic and phenolic hydrocarbons, and natural gas.

In northwest New Mexico, contamination has mainly been natural gas seeping into water wells. An active plugging program for old abandoned wells is in effect. Little groundwater monitoring has been performed in northwest New Mexico, so the extent of contamination from casing leaks or unlined pits is unknown. In many areas, contamination is unlikely due to deep ground water, thick, low permeability vadose zones, and small volume discharges. Additional investigation is being carried out by the Division in shallow groundwater areas.

Drilling

There is a general regulatory requirement that the operator provide a drilling pit sufficient for accumulation of drill cuttings, and that drilling fluids and drill cuttings must be disposed of at the well site in a manner to prevent contamination of surface or subsurface waters. There are, however, no specific rules on construction of such pits. The District Supervisor would have the responsibility of making a determination if there were a potential problem in vulnerable areas.

No drilling fluids are authorized to be discharged to surface waters. Land application is generally not done, although there are no specific statewide rules on landfarming. The reserve pits are generally dried out through evaporation, and the dried muds buried in the pits. The areas of New Mexico in which there is oil and gas drilling have significant net evaporation. In the southeast, annual rainfall averages 14-17 inches, with 80 inches evaporation. In the northwest, rainfall averages 7-12 inches annually, and evaporation is 40-50 inches.

Removal of drilling fluids or drill cuttings for offsite disposal must be approved by the appropriate District Supervisor.

Produced Waters

Storage/Disposal Pits: Regional Orders determine the requirements for saltwater storage or disposal pits in the most important areas of the state for oil and gas production. In 1967, Order No.R-3221 prohibited most surface disposal of produced waters in a four-county area in southeastern New Mexico. In 1985, another set of regional regulations (Order No.R-7940) was established, effective January 1, 1987, for areas with potentially vulnerable aquifers in the northwestern part of the state.

In the southeast, Order R-3221 prohibits the disposal of produced water onto the ground or into unlined pits due to the presence of shallow groundwater which could be adversely affected by the brine. An exemption is made for pits receiving no more than one barrel/day per 40 acre tract, with a maximum of 16 barrels/day for any pit. An amendment to the Order (R-3221-B) excepted areas in the four counties where the only water present was already highly saline.

In the northwest, Order R-7940 defines areas where aquifers are vulnerable to the effects of produced brine, and prohibits unlined pits in such areas. Exemptions are made (so long as groundwater depth is at least 10 feet) if a pit receives no more than 5 barrels per day of produced water, and the water is less than 10,000 mg/l TDS, or if the pit receives no more than 1/2 barrel per day.

Lined pits may be permitted in areas where unlined pits have been prohibited. Order R-3221-C states that "the utilization of lined evaporation pits is feasible and in the interest of good conservation practices, provided they are properly designed, constructed and maintained." Order R-7940 authorizes administrative approval of lined pits or below grade tanks within the Vulnerable Area "upon a proper showing that the tank or lined pit will be constructed and operated in such a manner as to safely contain the fluids to be placed therein and to detect leakage therefrom."

Operators must obtain approval from the Division for lined pits, and appropriate requirements for pit construction are found both in R-3221-C and in "Guidelines for the Design and Construction of Lined Evaporation Pits." R-3221-C requires that the pit provide at least 600 square feet of evaporative surface for each barrel deposited in the pit on a daily average basis throughout the year, and that the lease or leases served by the pit should have an even or decreasing rate of water production. Header pits must be provided to prevent oil from reaching the evaporation pits. Pits must be lined with an impervious material at least 30 mil in thickness, and have leak detection capability.

Other Surface Discharge: No NPDES permits are issued for discharges of produced waters, and no discharges to surface waters are allowed. However, individual farmers may contract for use of produced water as drinking water for cattle (although not for irrigation). Agreement must be obtained from the District Supervisor. No specific limits are placed on produced water used for this purpose, nor does the approval of the District Supervisor constitute certification as to the quality of the produced water for such purpose.

Injection: Over 90% of produced water is reinjected into wells for enhanced recovery (3,508) or saltwater disposal wells (363). The Oil Conservation Division has responsibility for the Class II UIC injection permitting program.

Generally, disposal of produced waters into zones containing waters of 10,000 mg/l or less TDS will not be permitted except after notice and hearing, unless the water being injected is of higher quality than the native water in the zone. But the Division may establish exempted aquifers for such zones where such injection may be approved administratively.

Regulations impose the general requirement that injection wells be cased with safe and adequate casing or tubing to prevent leakage, and the casing or tubing must be set and cemented to prevent the movement of formation or injected fluid from the injection zone into any other zone or to the surface around the outside of any casing string.

Failure of any injection well must be immediately reported. Where injected fluids have not been confined to the authorized zone or zones, the wells may be restricted as to volume or pressure of injection, or shut-in, until identification and correction of the failure.

Before injection, wells must be tested to assure the "initial integrity of the casing and the tubing and packer, if used, including pressure testing of the casing-tubing annulus. "Tests should be for 15 minutes at pressures in the range of 250-300 psi, with a maximum variance of 10%. Additional tests are required at least every 5 years.

Offsite Disposal

Production and drilling wastes are sometimes sent to commercial or centralized surface disposal or collection facilities. Commercial facilities are those receiving compensation. Centralized facilities are non-commercial facilities "receiving produced water, drilling fluids, drill cuttings from any off-well-site location for collection, disposal, evaporation, or storage in surface pits, ponds, or below grade tanks." The Commission issued Order No.R-7940-A in 1986 to regulate such offsite facilities in the northwest. For commercial pits, the Division may approve use of lined or unlined pits, so long as they are constructed adequately to protect fresh water. For proposed centralized pits, applications must be filed with the Division, unless the facility will never receive more than 16 barrels/day in a 24-hour period and is at least 10 feet above groundwater, or serves emergency purposes during drilling for periods not exceeding 10 days. Applications are required in any case where the pits receive drilling or completion wastes.

Where pits are required to be lined, they must be lined according to the provisions of the "Guidelines" for lined evaporation pits. The "Guidelines" require that the pit must provide the minimum evaporative surface necessary for the maximum yearly volume of water to be discharged to the pit. It should have adequate freeboard to protect against wave action, and levees at least 18 inches above the ground. It must have a double liner system, with a leak detection system between the top and bottom liners. Synthetic liners must be at least 30 mil thick. Skimmer ponds or tanks must be used to separate any oil from the water prior to discharge to the evaporation pit.

Transporters of oil field wastes must register, but need keep no records of source, destination and volumes of the specific wastes hauled.

Plugging/Abandonment

Wells may not be temporarily abandoned for more than six months unless a permit for temporary abandonment has been approved by the Division. The maximum period of the permit is one year, with an additional possible one year extension. The Division may waive this limitation and grant further extensions in the case of a remote or unconnected gas well, a presently non-commercial gas well which could become commercial in the foreseeable future, or a currently non-producing well with commercial potential in a field where secondary recovery has been demonstrated to be commercially feasible. Such further extensions are limited to two years, but are renewable.

Before a permit for temporary abandonment can be granted, evidence must be furnished that the condition of the well will not allow damage to producing zones or the contamination of fresh water. A one-well plugging bond may be required for any well under extension for temporary abandonment.

Specific well-plugging plans must be approved by the Division. The general regulatory requirement is that plugging must "confine all oil, gas, and water in the separate strata originally containing them. This operation shall be accomplished by the use of mud-laden fluid, cement and plugs, used singly or in combination as may be approved by the Division."

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Order of the Oil Conservation Commission of the State of New Mexico, Order No's. R-3221, and R-3221-A through C.

Order of the Oil Conservation Commission of the State of New Mexico, Order No's R-7940 and R-7940-A

Memorandum, R. L. Stamets, Director, Oil Conservation Commission, regarding Hearings for Exceptions to Order No. R-3221, dated October 22, 1985.

Personal Communications:

David Boyer, Hydrogeologist, New Mexico Oil Conservation Division, (505) 827-5812.

NEW YORK

Introduction

New York is one of the pioneer states for oil and gas production and use. Proven oil reserves were documented in 1627, and drilling began in the late 1800s. Since then it is estimated that 30,000 to 50,000 wells have been drilled in New York.

New York produced 1,071,000 barrels of oil from 4,621 wells in 1985. Thirty-five billion cubic feet of natural gas was produced from 4,818 gas wells in 1985.

Regulatory Agencies

Background

In 1963 the New York legislature passed laws regarding oil and gas operations. A working permitting system was instituted in 1966 under the purview of the Department of Environmental Conservation. The regulations have been revised fairly often over the last twenty years. In fact, further revisions are expected in the next year or two as a result of a Generic Environmental Impact Statement scheduled for completion in late 1987.

Agencies

Oil and gas activities in New York are regulated by:

- NY Department of Environmental Conservation

- Bureau of Land Management (Federally-held mineral rights only)

- U.S. Forest Service (surface activities in U.S. forests)

Most oil and gas activities in New York are regulated by the Department of Environmental Conservation. The Department of Environmental Conservation is authorized to regulate the "development, production, and utilization of natural resources of oil and gas . . . in such a manner that a greater ultimate recovery of oil and gas may be had." the Department also has authority for "prevention of pollution and migration." New York is NPDES-delegated, with the Department of Environmental Conservation responsible for the program. New York does not have UIC primacy.

An Oil, Gas, and Solution Mining Advisory Board (with 11 members, a majority of whom are industry representatives) meets a minimum of twice a year, and is charged with providing DEC with its recommendations on developing rules and regulations which could impact the oil and gas industry.

The U.S. Bureau of Land Management has regulatory authority for oil and gas activities when mineral rights are Federally held. Their regulations are discussed in a separate section, Federal Agencies.

The U.S. Forest Service has jurisdiction over surface activities on federal forest lands even when mineral rights are held privately.

The Water Quality Division, Fish and Wildlife Division, Regulatory Affairs, Law Enforcement, and Lands and Forests provide instrumental manpower and enforcement actions, when applicable.

Rules and Regulations

Drilling

The Division of Mineral Resources in the Department of Environmental Conservation issues all oil and gas drilling permits. The Mineral Resources Regulations establish a general objective that must be incorporated in all permits: "Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited." Each permit requires that the fluids generated by drilling be "hauled away and properly disposed of." The regulations do not provide specific direction regarding what practices constitute proper disposal. Rather, the operator must submit and receive approval for a plan for the "environmentally safe and proper ultimate disposal of such fluids."

If drilling muds are freshwater natural clay-based muds, they are considered non-polluting and are specifically excluded from this requirement. Muds contaminated with oil or other pollutants must be disposed in a certified landfill. Drilling pits are dewatered and the fluid disposed of properly prior to reclamation. During reclamation, pit liners are shredded or removed and the rock cuttings disposed in situ. After drying, the cuttings are buried.

Other drilling wastes must be disposed or discharged in a manner acceptable to the Department considering the environmental sensitivity and geology of the area. Historical experience with drilling operations in the same area may also be used in considering an application. Permits may be required for disposal or discharge of drilling wastes (excluding drilling muds) in addition to the drilling permit.

DEC has required that all drilling pits be properly constructed, sized, and lined since 1982. It is a permit condition on all wells. The only exception has been the closely observed, pitless drilling experiments associated with some air-drilled wells.

DEC has noted that the majority of wells in new York are drilled with air and there is very little associated fluid associated with the drill cuttings in the drill pit. As a result, there has been some experimentation with pitless drilling, which DEC reports "creates a temporary dust problem and some vegetation is killed by the associated brine, but less than would be killed by clearing the land for a drilling pit."

Brine and salt water generated during drilling are considered "polluting fluids" in the Mineral Resources Regulations. These fluids, and other polluting fluids, may be stored in watertight tanks or lined pits for up to 45 days after drilling ends prior to disposal. An extension may be granted if the operator plans to use the fluids for later activities. The disposal alternatives for brines and salt water generated during drilling would generally be the same as those for waters generated during production.

The Department is also responsible for well construction and spacing requirements.

Produced Water

Part 556 of the Mineral Resources Regulations addresses operating practices applicable to oil and gas wells. Section 556.5 prohibits pollution of the land and/or surface or ground fresh water resulting from producing, refining, transportation, or processing of oil, gas, and products. Brine (i.e., produced water) may be stored in water-tight tanks or in lined pits prior to disposition. Although specific construction requirements are not described in the regulation, pits must be constructed and lined to prevent percolation into the soil, over or into adjacent lands, streams, or bodies of water.

The only disposal alternative described in the regulation is injection. The Department of Environmental Conservation has procedures for application and approval of permits to inject brines; since New York does not have primacy for the UIC program, an operator would have to obtain a permit from EPA-Region II as well.

According to DEC, the predominant method of disposal of the dilute brines associated with oil production in the old waterflooded fields of New York is under SPDES permits. Road spreading is the predominant brine disposal method for the concentrated brines associated with the state's gas wells. Road spreading is conducted on a manifest system under a separate permit. Criteria for road spreading are established on a case-by-case basis, and include such requirements as time of day, use of spreading bar, prohibition on spreading during rain storms, and concentration limits.

The Department of Environmental Conservation allows "processing [of brines] at sewage disposal plants, permitted onsite discharges, and hauling to other states with approved disposal facilities." DEC allows brine discharges from stripper wells under permits with the following limitations:

- oil and grease	15 mg/l
- pH	6 to 9
- benzene	10 micrograms/l
- toluene	10 micrograms/l
- xylene	10 micrograms/l

Sampling is done infrequently on any given well. Annular disposal is not allowed.

Offsite Pits

New York regulations do not address the use of offsite pits for long term storage or disposal.

Plugging/Abandonment

Wells which are commercially producible may be shut-in for one year, and may be granted additional one-year extensions (renewable) for good cause. Wells may only be temporarily abandoned for 90 days without specific permission, but extensions for a "reasonable time period" will be granted, and renewed, for good cause.

The wellbore must be filled with cement from the bottom of the well to 15 feet above the shallowest formation from which production was every obtained in the vicinity. Alternatively, a bridge topped with 15 feet of cement may be placed above each formation from which production was ever obtained. If casing is left in the well, 15 foot plugs must be placed at top and bottom. If casing extending below deepest potable water is not to remain, a 15 foot plug must be placed 50 feet below that water level. If the surface casing is withdrawn, a 15-foot plug should be placed immediately below where lower end of casing rested, and the well filled with cement from that point to the top. Intervals between plugs must be filled heavy mud-laden fluid. If casing left in the hole was never cemented, it must be perforated and cement squeezed into the annular space. Additional requirements to ensure proper abandonment are added by permit condition.

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North Dakota

Introduction

North Dakota produced 45,624,000 barrels of oil and 62 x 10^9 cubic feet of gas in 1986. Production was from 3,595 oil wells and 103 gas wells.

Regulatory Agencies

Three agencies regulate oil and gas activity in North Dakota:

- North Dakota Industrial Commission, Oil and Gas Division
- U.S. Department of Agriculture, Forest Service
- U.S. Bureau of Land Management

The North Dakota Industrial Commission, Oil and Gas Division, has the regulatory responsibility to oversee the drilling and production of oil, protect the correlative rights of the mineral owners, prevent waste, and protect all sources of drinking water. Other responsibilities of the Division are to collect monthly reports on oil, gas, and water; oversee proper disposal of brine; and issue drilling permits. The Division also has primacy for UIC Class II wells and issues such permits.

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands, but the operator must obtain a permit from the Oil and Gas Division. When drilling is to occur on U.S. forestland, no additional permit is needed but additional stipulations are placed by the U.S. Forest Service.

State Rules and Regulations

Drilling

Before a drilling permit is issued by the Commission, the operator of the well must be bonded. Single well bonds are $15,000 a ten-well bond is $50,000, and a blanket bond is $100,000. The Commission will release the bond after site restoration is approved. Before drilling activities, Commission inspectors will survey the site for pit location. The inspectors also decide whether or not to require a pit liner at the site.

Under Commission Rule 43-02-03-19, "Pits shall not be located in or hazardously near, stream courses, nor shall they block natural drainages. Pits shall be constructed in such manner so as to prevent contamination of surface or subsurface waters by seepage or flowage therefrom. Under no circumstances shall pits be used for disposal, dumping or storage of fluids, wastes and other debris not used in drilling operation." Within 1 year after the completion of a well, the pit site must be restored. Pit restoration does require approval from the Commission. Reclamation includes removal of the fluid from the pit and redistributing topsoil that was removed from the site at the beginning of drilling activities.

When drilling is on U.S. forest lands, the U.S. Forest Service has stipulations in addition to those of the Commission. The Forest Service requires a complete survey and design of the drilling site. This survey must be approved before drilling. All reserve pits must be lined with a material that meets the minimum requirement set by the Forest Service. The reclamation plan must also be approved by the Forest Service before implementation.

Production

Under Commission Rule 43-02-03-53, "All saltwater liquids or brines produced with oil and natural gas shall be disposed of without pollution of freshwater supplies. At no time shall saltwater liquids or brines be allowed to flow over the surface of the land or into streams." Surface pits are not allowed for brine storage. Surface tanks are allowed provided they are diked and are leak-proof.

Brine may be disposed by use of injection wells for either enhanced recovery or disposal. When a central tank battery or central production facility is planned to be used, approval must be received from the Commission, or from the Forest Service if on U.S. forest lands. Both methods require permits issued by the Commission. All injection wells must be cased and cemented to prevent movement of fluids into or between underground sources of drinking water. Planning for drilling a well must include an analysis of all other pits within the applicable area of review, the taking of corrective action, if needed, on other wells penetrating the injection zone, and the evaluation of appropriate pressure to avoid generating or spreading fractures in the confining zone. Mechanical integrity tests must be carried out before initiating injection, and at least every five years thereafter (although regular monitoring of annulus pressure or records showing a consistent relationship between injection pressure and flow rate may be used in lieu of later pressure tests). Wells must be pressure tested for at least 15 minutes. Test pressure is dependent upon maximum injection pressure. Allowed pressure variance depends upon the stabilized test pressure and maximum injection pressure.

Offsite Disposal

There are several commercial brine disposal wells in the state, but no pits. The brines hauled onto commercial facilities are stored in tanks.

Plugging/Abandonment

A well may be temporarily abandoned (generally for economic reasons) and no casing pulled with approval of the enforcement officer. A plug must be placed at the top of the casing. Wells which have been shut-in for long periods will be reviewed on a case-by-case basis, including tests of casing integrity. A well where drilling operations have been suspended for six months must be plugged and abandoned unless a permit for temporary abandonment has been obtained.

When wells are plugged, perforations must be squeezed or a cast iron bridge plug set above the perforations and capped with 5 sacks of cement. Cement plugs are set 50 feet in and 50 feet over the top of each productive zone, a 100-foot plug half in and half over the Dakota Formation, and a 10-sack plug at the surface. If the casing is pulled, 100-foot plugs are placed spanning the casing top and the bottom of the surface casing. Field inspectors must witness every plugging.

References

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U.S. Department of Agriculture, Special Forest Service stipulations, September 1986.

OHIO

Introduction

Ohio produced 14,987,592 barrels of oil and 182.2 x 10^9 cubic feet of gas in 1985 from 2,798 full producing oil wells and approximately 26,412 stripper wells producing less than 10 barrels per day, and 31,343 gas wells, almost all of which were stripper wells producing less than 60,000 cubic feet per day.

State Regulatory Agencies

Two agencies regulate oil and gas activities in Ohio:

- Ohio Department of Natural REsources

- Ohio Environmental Protection Agency

The Ohio Department of Natural Resources, Division of Oil and Gas, issues permits for oil and gas drilling and for underground brine injection. The statutes and rules of the Division of Oil and Gas do not contain provisions for effluent discharges. The Division operates on revenues from permit fees and severance taxes on oil and gas. Enforcement activities are dependent primarily upon approximately 50 field staff employees who inspect well sites and conduct investigations. The Division of Oil and Gas has authority to review, investigate, and require corrective action related to all oil and gas drilling and production activities. Compliance bonds are require by the Division.

Ohio has been delegated NPDES authority. NPDES permits are issued through the Ohio Environmental Protection Agency, Water Quality Division;

none is issued for the oil and gas drilling and production industry. The jurisdiction of the Ohio EPA extends to any pollution of the waters of the State. Where brine spills may impair waters of the State, for example, there is coordination between the Ohio DNR and Ohio EPA in damage assessment and corrective measures. When there is potential for groundwater contamination, the Ohio Environmental Protection Agency may assist in the investigation and joint charges may be filed with the Ohio Department of Natural Resources.

A five-member oil and gas Board of Review was created by statute within the Ohio Department of Natural Resources. Members of the Board, appointed by the Governor for five-year terms, consist of representatives of a major petroleum company, the public, independent petroleum operators, and individuals experienced in oil and gas law and in geology. Any person claiming to be aggrieved or adversely affected by an order of the Chief of the Division of Oil and Gas may appeal to the Board for an order vacating or modifying such an order.

On occasion, there is oil and gas drilling on Federal lands. When application for such drilling is filed, the permittee obtains a lease from the appropriate Federal authority prior to requesting a permit from the Division of Oil and Gas. The permitting process then is managed as a standard procedure with no special coordinating efforts.

State Rules and Regulations

Drilling: Earthen pits may be used to contain produced brine, drilling muds and cuttings, fracture fluids, or other substances "resulting, obtained or produced in connection with drilling, fracturing, reworking, reconditioning, plugging back, or plugging operations, but such pits shall be constructed to prevent the escape of brine and such substances." There is no requirement for clay or synthetic liners, unless prescribed on a site-specific basis in an area identified as being hydrogeologically sensitive. When there is a history of groundwater problems associated with an area, a plastic liner requirement is made part of the drilling permit.

The pits must be emptied and backfilled within five months of the commencement of drilling. The regulations specify that "muds, cuttings, and other wastes shall not be disposed of in violation of any rule." In most cases, pit solids are buried on the well site when no environmental harm is expected. Drilling fluids are disposed of either by underground injection.

Produced Waters

Recently enacted laws, which became effective on April 12, 1985, established new standards for well operators and waste brine transporters. Brine disposal has been a major environmental issue in Ohio. Well drillers now are required to submit a brine disposal plan stating the temporary storage method and ultimate disposal method and site for all produced brine.

Operators are required to identify the transporter of the brine including the transporter's address. Anyone who transports brines must pay a $500 one-time fee, provide a $300,000 certificate of insurance for bodily injury and liability, post a $15,000 bond to be used in paying for damages, and provide detailed information. The detailed information includes a daily log that identifies ultimate brine disposal such as time and date of brine loading and amount, road spreading location, disposal well permit number, time and date of brine disposal, etc. The driver is required to maintain a daily log showing driver name, registration certificate number, sites visited, and destination.

Brine production is estimated at 40-50,000 barrels per day. Recent reports indicate that approximately 90% of produced brine is disposed of through injection wells; 10% by surface application and annular disposal.

Storage/Disposal Pits: Under the requirements of the revised rules legislated in April, 1985, "no pit or dike shall be used for the ultimate disposal of brine." Earthen impoundments may be used for the temporary storage of brine in association with a saltwater injection or enhanced recovery well.

Road Spreading: For road or land spreading, a county, township or municipal government must pass a resolution to allow brine disposal that meets several minimum requirements:

- prohibitions on brine application to a water-saturated surface, to vegetation, within 12 feet of bridges or other road surfaces crossing bodies of water or drainage channels, or during night (except for ice control);
- regulations on the rate, amount, and methods of application;
- and a prohibition against discharge by the vehicles making the application at any points other than the surfaces specifically approved.

A resolution with these minimum required specifications will be deemed approved when submitted to the Division of Oil and Gas, without any requirement for further review or approval by the Division.

Injection: Ohio has delegated authority for Class II well injection. Brine injection may be into wells for enhanced recovery (170 wells), into disposal wells (182), or into the annulus of a producing well (c. 4,000 wells). Permits are required for injection into disposal wells or enhanced recovery wells. Notification and approval is required for annular disposal.

For disposal and enhanced recovery wells surface casing must be set at least 50 feet below the deepest underground source of water containing less than 10,000 mg/l TDS or less than 5,000 mg/l chlorides, and must be cemented to the surface. Surface casing must be cemented to surface or properly sealed with prepared clay. Injected fluids must be isolated by the use of casing mechanically centralized and enclosed in cement to a height no less than 300 feet above the top of the injection zone. Injection must be through tubing and a packer set no less than 100 feet above the injection zone.

A variance from some construction requirements may be granted if the injected volume is less than 25 barrels/day at minimal pressures or if the chief determines that the variance sought will result in the construction of an injection well equivalent in its ability to protect freshwater aquifers.

Prior to any injection, the casing outside the tubing must be pressure tested at 300 p.s.i. or at the maximum allowable pressure, whichever is greater, for a period of 15 minutes, with no more than a five percent decline in pressure. The mechanical integrity test must be readministered at least once every five years.

The maximum volumes which may be disposed of with annular injection are 10 barrels per day (if the surface casing is sealed with cement) or 5 barrels per day (if sealed with prepared clay). Annular disposal can only use the force of gravity. Only saltwater and standard well treatment fluids may be disposed of in the annulus. When a well ceases to produce oil or gas, annular disposal must stop and the well must be plugged.

For annular disposal, the surface casing must be sealed with cement or clay, and the sealing material circulated to the surface. The surface casing must be set at least 50 feet below the deepest underground source of water with less than 10,000 ppm TDS or 5,000 ppm chloride. Annular disposal systems must be airtight. Brine may only be disposed of by liquid tight pipeline at an annular disposal well. No trucking of brine is permitted.

Mechanical integrity shall be demonstrated for annular disposal wells at least once every 5 years, using tracer surveys, noise logs, temperature surveys, or other tests approved by the Division.

Offsite and Commercial Disposal

When a groundwater problem history exists, pit solids may be required to be removed and transferred to an Ohio EPA regulated disposal site. Or, if there is a request to move pit solids to an offsite area, an EP-toxicity test for hazardous waste characteristics is required prior to a transfer to a State-approved hazardous or nonhazardous landfill, as appropriate. Abandoned pits are investigated when alleged to be the cause of a groundwater problem. When found to contribute to such a problem, the owner of the pit is required to remove solids and transport them to a State-approved solids disposal facility.

Plugging/Abandonment

Enforcement of plugging regulations is split between two enforcement agencies in Ohio. Wells plugged in non-coal bearing townships must be plugged in accordance with rules adopted in coal bearing townships must be plugged in accordance with rules adopted by the Ohio Department of Industrial Relations, Division of Mines. Plugging rules adopted by the two agencies differ somewhat.

Any operator plugging a well must inform owners of the land on which the well is sited, owners of adjacent land, and mine owners of the intention to abandon the well. Plugging operations for dry holes must begin immediately upon abandonment of the hole. Plugging operations for abandoned production or injection wells must begin "without undue delay after production, extraction, or injection operations have ceased." Temporary abandonment status will be granted for a period of six months if the well poses no environmental threat; remedial action must be taken to correct environmental threats before such status will be granted.

Surface casing may not be pulled from a rotary drilled well. Surface casing may be pulled from a cable tool drilled well if the conductor pipe is left in place. Cement plugs must be placed from a minimum of 50 feet below the base to a minimum of 100 feet above the top of the lowest reservoir rock. If clay is used as the plug, the plug must extend 400 feet above the top of the reservoir. For each succeeding reservoir, until within 100 feet of the bottom of the surface casing, the requirements are identical for cement plugs; for clay plugs the required minimum height above the top of a reservoir is reduced to 200 feet. For freshwater zones, cement plugs must extend from 50 feet below to 100 feet above the zone. A cement plug shall also be placed from 50 feet below grade level to 30 inches below grade level. If a clay plug is used, the plug must extend from 50 feet below the base of the freshwater zone to 30 inches below grade. All portions of the well which are not filled by the plugs are to be filled with mud-laden fluid.

After a well is abandoned, a detailed report containing information about the plugging and the identity of witnesses to the plugging must be filed by the operator with the Division of Oil and Gas.

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OKLAHOMA

Introduction

Oklahoma produced 153,250,000 barrels of oil and 1,996 x 10^{-} cubic feet of gas in 1984. It ranked fifth in U.S. oil production and third in U.S. gas production. Oklahoma had 99,030 producing oil wells and 23,647 producing gas wells. There are approximately 200 million barrels of salt water produced by the oil industry per year. There are about 7,900 saltwater disposal wells and 14,900 enhanced recovery injection wells. Approximately 200 of the disposal wells are commercial facilities.

Regulatory Agencies

Four agencies regulate oil and gas activities in Oklahoma:

- Oklahoma Corporation Commission, Oil and Gas Conservation Division

- Oklahoma Water Resources Board

- Osage Indian Tribe

- U.S. Bureau of Land Management

The Oklahoma Corporation Commission, Oil and Gas Conservation Division, has exclusive jurisdiction over all laws and regulations "relating to the conservation of oil and gas and the prevention of pollution in connection with the exploration, drilling, producing, transporting, purchasing, processing and storage of oil and gas...." Pollution of surface or subsurface water during any well activity is prohibited. Currently, there are 55 inspectors who have the authority to shut down operations if regulations are not followed. Oklahoma has received primacy for the UIC program, and the Division is responsible for the permitting and regulation of Class II wells.

The Oklahoma Water Resources Board is responsible for protection of all surface and ground water to ensure that pollution does not occur The Board has permitting authority for all discharges, which must meet specified water quality standards, including beneficial use limits. However, discharges to water from oil and gas activities are not allowed. The principal role of the Board in oil and gas drilling/production activities is in identifying spills from oil and gas activities and referring them to the Corporation Commission for further action. On occasion, the Board will participate with the Commission in cleaning up the spills.

The Osage Indian Tribe has sole primacy regarding oil and gas operations in Osage County, and has been delegated UIC program responsibility for Class II wells.

The U.S. Bureau of Land Management has primacy where both surface and mineral rights are owned by the Bureau or by an Indian Tribe other than the Osage Tribe. In those cases where mineral rights are owned by the Bureau or an Indian Tribe, but not the surface rights, both the Bureau and the Oklahoma Corporation Commission would become involved and would coordinate the permitting procedures.

State Rules and Regulations

Drilling

Pit Construction/Management: Commission Rule 3-104 establishes a general requirement that "pits and tanks for drilling mud or deleterious substances used in the drilling, completion, and recompletion of wells shall be constructed and maintained so as to prevent pollution of surface and subsurface fresh water." It further requires that deleterious fluids other than fresh water drilling muds from drilling and workover operations be kept separate from the fresh-water muds, and be placed in lined pits (plastic liner of at least 30 mil) or metal tanks for separate disposal.

Emergency pits, burn pits, and circulating, frac, or reserve mud pits used for drilling, reworking or plugging a well may be constructed on-site (serving only the lease or unit on which located) without a permit. Notices of construction must be filed, however, for emergency and burn pits (Rule 3-110.1).

The only requirements, other than the general restriction against pollution, applying to reserve pits as well as other on-site pits are that they must maintain the fluid level at least 18 inches below the lowest point of the embankment, and must be constructed to prevent incursion of outside runoff water.

Pit Closure: Reserve pits must be dewatered and leveled within 12 months of the end of drilling operations. A single 6-month extension may be granted for reasonable cause. Circulating pits must be leveled within 60 days after drilling ceases, and fracture pits within 60 days after completion of fracture operations.

Disposal: Four methods are used for disposing of drilling fluids: annular injection, evaporation followed by burial of pit solids, non-commercial landfarming, or vacuum truck removal to offsite pits. Commercial landfarming is currently prohibited, but is under consideration by the Oklahoma Corporation Commission.

Annular Injection: An operator must apply for approval of on-site annular injection of reserve pit fluids. Surface casing injection (or intermediate casing injection) may be authorized if the surface casing (or intermediate casing) is set and cemented (set) at least 200 feet below the base of treatable water. Injection pressure must be limited so that vertical fractures will not extend to the base of treatable water. (Rule 3-312)

Landfarming: Permits (required) for non-commercial soil farming may only be applied for by the operator of the reserve pit of which the contents are to be landfarmed (Rule 3-110.3). To apply for a soilfarming permit, the operator must have a written agreement from the landowner which is consistent with the regulatory requirements, an analysis of the soil, an analysis of the reserve pit contents, and loading calculations to determine the maximum number of barrels/acre which may be landfarmed. Permits expire 6 months after approval.

Pit contents must be applied uniformly by injection or spray irrigation and incorporated into the soil (within 14 days of application) by injection or disking. The Commission may approve other methods.

An effort must be made to re-establish vegetative cover within 120 days of the completion of soil farming.

Soil farming is limited to water based type muds and the cuttings and accumulated precipitation in the pit of oil based muds. Soil farming of oil based muds is prohibited.

Generally, landfarming is not allowed unless receiving soils are suitable and the hydrology will not lead to pollution of surface or groundwaters.

Specifically, landfarming is prohibited where:

- the land has a slope greater than 5%,
- depth to bedrock is less than 20 inches,
- floods occur more often than once every two years,
- the soil lacks 12 inches of loam, clay, silt, or sand,
- any of the soil is severely saline (>8,000 micromhos/cm),
- a water table is within 6 feet of the soil surface.

When soilfarming is permitted, it must be at least 100 feet away from property line boundaries, freshwater ponds or lakes, and streams designated by Oklahoma Water Quality Standards; at least 50 feet from any natural drainageway; 300 feet from any domestic or irrigation water well; and 800 feet from any active municipal water well.

The maximum application rate for soilfarming is determined by the most limiting of the following parameters:

Total weight of applied materials	400,000 lbs./acre
Total soluble salts	6,000 lbs./acre (less TSS in soil)
Arsenic	80 lbs./acre
Cadmium	5 lbs./acre
Hydrocarbons	100,000 lbs./acre (5%by weight)

If hydrocarbon content is in excess of 20,000 lbs. acre (1% by weight), fertilizer may have to be incorporated with the cuttings and reserve pit effluent from oil based drilling fluids.

Runoff of soil farmed material prior to incorporation is prohibited. Soilfarming may not be practiced in winds gusting over 30 mph, in rain, when the ground is frozen, or when the ground is too highly saturated.

Produced Waters

Injection: Produced waters are injected underground for both enhanced recovery (14,900 wells) and disposal (17,700 onsite and 200 commercial wells). Permits are required from the Commission for all such wells, whether new or converted.

Neither enhanced recovery injection wells nor disposal wells are permitted within 1/2 mile of an active or reserve municipal water supply well unless the applicant can "prove by substantial evidence" that the injection well will not pollute the municipal water supply. In addition, the applicant may be required to provide information on the present status of all active or abandoned wells within 1/2-mile of the enhanced recovery or disposal well, and to identify any abandoned well which was improperly plugged or remains unplugged.

Wells must be constructed and operated to confine injected fluids to the approved intervals, and to prevent pollution of fresh water or damage to oil or gas resources. Surface casing or a stage collar must be installed to at least 90 feet below the surface or 50 feet below any treatable water strata, whichever is lower, and the annular space behind the casing must be filled with cement from the base of the surface casing or stage collar to the surface. (Alternative casing and cementing methods are permissible under some circumstances).

Injection or disposal of any substance must be through tubing and packer. Adequate above-ground extensions shall be installed in each annulus in the well. Appropriate fittings must be provided to allow for measurement of injection pressure.

Before wells for disposal or enhanced recovery can be operated, they must be pressure tested under supervision of the Conservation Division. For new wells, the casing outside the tubing must be tested at the maximum authorized injection pressure or 300 psi, whichever is greater. For converted wells, the test must be at the lesser of 1,000 psi or the maximum authorized injection pressure, but no lower than 300 psi. Test duration is 30 minutes.

With the exception of wells which elect to monitor, each disposal or enhanced recovery well must be pressure tested at least once every five years. The casing-tubing annulus above the packer must be tested at the lower of 1,000 psi or the maximum authorized injection pressure, with a minimum of 300 psi. In lieu of such a casing pressure test, the operator may, each month, monitor and record the pressure in the casing)tubing annulus during actual injection, and report the pressure annually. (Rules 3-206, 3-301 through 3-309, 8-8)

Commercial Offsite Pit

Under Rule 3-110.2, the Oklahoma Corporation Commission permits the use of offsite earthen pits. Such pits must be constructed or sealed with an impervious material, and must be operated in such a way as to prevent the escape of any deleterious material. The operator must provide a bond or irrevocable letter of credit as guarantee that the pit will be emptied and leveled "upon termination of disposal activities."

Some offsite pits service individual wells, in situations where pits are not allowed at the site of the well (e.g., wells within city limits, where city ordinances prohibit such pits). But there are also approximately 100 commercial offsite pits throughout Oklahoma, ranging from less than an acre to ten acres in size. Some offsite pits may contain over 3,000,000 barrels of waste, which calculates to 387 acre feet of fluids.

Commercial pits must have a soil seal at least 12 inches thick, with permeability no greater than 10^{-7} cm/second. If the pit contains deleterious substances, it must be lined according to specifications determined by the Commission. The pit must not contain fluids with a chloride content greater than 3,500 ppm, and may be sampled periodically to enforce that limit. The pit may not be built in a 100-year flood plain, must be built to prevent incursion of outside water runoff, and must be managed to maintain the surface fluid level 24 vertical inches below the lowest point of the embankment. Such pits must be "filled and leveled within one year after abandonment.

"Truckers hauling oil and gas field wastes offsite must hold a Deleterious Substance License, but do not have to report or maintain records on materials and volumes transported.

Plugging/Abandonment

Wells in which neither surface nor production casing has been run must be plugged within 72 hours after drilling or testing is completed. If only surface casing has been run and cemented, plugging must take place within 90 days. In either case, however, if there is any risk of contaminating the environment, oil or gas formations, or treatable water strata, the well must be plugged within 24 hours.

Where production casing has been run, a well must be plugged within one year after the cessation of drilling (if not completed or tested), after the cessation of the latter of completion or testing (if no production), or after the cessation of production. There are, however, numerous exemptions from this requirement. Exemptions include shut-in gas wells, wells for which the Commission has issued an exception to plugging requirements (e.g., where production has ceased for economic reasons), wells located on leases on which other wells are still producing (so long as granted a Temporary Exemption by the Commission). Operators of stripper wells may temporarily plug a well for up to two years.

Plugging shall provide for sealing off each productive formation from the well bore above and below the formation. Cement plugs must extend from 50 feet below to 50 feet above the base of each formation, and from 50 feet below to 50 feet above the top of each formation. Exceptions to these requirements may be granted if: (a) the formation is already sealed off from the well bore with adequate casing, and (b) if the only openings from the productive formation are perforations in the casing, and the annulus between the casing and the outer walls of the well is filled with cement 50 feet below the base and 50 feet above the top of the formation. In such case, a bridge plug capped with 10 feet of cement set at the top of the producing formation is authorized.

All fresh water strata in the well must be sealed off by adequate casing from 50 feet below the base of the lowest fresh water stratum to 3 feet from the top of the well bore, and by completely filling the annular space behind such casing with cement. If surface or other casing meets requirements, cement plug may be set 50 feet below base of lowest fresh water stratum to 50 feet above shoe of surface pipe. Top 30 feet of well bore below 3 feet from surface shall be filled with cement. The surface pipe shall be cut off 3 feet from the surface and capped with a steel plate.

Any uncased hole below the shoe of any casing to be left in the well shall be filled with cement to a depth at least 50 feet below the shoe of the casing, or the bottom of the hole, and the casing above the shoe shall be filled with cement to at least 50 feet above the shoe of the casing. If the well is completed with a screen or liner, and the screen or liner is not removed, the well bore must be filled with cement from the base of the screen or liner to at least 50 feet above the top of the screen or liner.

All intervals between cement plugs in the well bore must be filled with mud of not less than 9 lbs. gallon and not less than 36 viscosity.

All plugging operations must be conducted under the supervision of an authorized representative of the Conservation Division.

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OREGON

Introduction

Oregon does not produce oil. Oregon's only producing gas field was discovered in 1979. Thirteen active gas wells produced 4.5 x 10^9 cubic feet of gas in 1986. There is one saltwater injection well for the field. In 1986, approximately 40,000 barrels of brine were injected underground; about 5,000 barrels went to surface land disposal.

State Regulatory Agencies.

Two agencies regulate oil and gas activity in Oregon:

- Oregon Department of Geology and Mineral Industries
- Oregon Department of Environmental Quality.

Oil and gas drilling permits are issued by the Oregon Department of Geology and Mineral Industries. The State Geologist serves as the implementor of rules, orders, and enforcement actions taken by the Department's governing board. The Department is also responsible for regulating Class II wells.

The Oregon Department of Environmental Quality has delegated authority for the NPDES program and issues UIC permits. The State has maintained a permitting program since 1968. No NPDES permits have been issued because there have been no requests to discharge waste to public waters.

None of the gas wells is on Federal lands. If, in the future, drilling were to take place on Federal lands, there would be two separate permitting actions--one by the U.S. Bureau of Land Management and one by the Oregon Department of Geology and Mineral Industries.

State Rules and Regulations

Drilling

Oregon Administrative Rule 632-10-205 requires a surety bond of up to $25,000 for one well, or a blanket bond of $150,000 for more than one well, conditioned upon the faithful compliance by the principal with the rules, regulations, and orders of the Department of Geology and Mineral Industries.

Rule 632-10-140 requires that any fluid necessary to the drilling, production, or other operations by the permittee shall be discharged or placed in pits and sumps approved by the State Geologist and the State Department of Environmental Quality. The operator shall provide pits, sumps, or tanks of adequate capacity and design to retain all mateials. In no event shall the contents of a pit or sump be allowed to:

1. Contaminate streams, artificial canals or waterways, groundwaters, lakes, or rivers.

2. Adversely affect the environment, persons, plants, fish, and wildlife and their population.

When no longer needed, fluid in pits and sumps is to be disposed of in a manner approved by the Department of Environmental Quality and the sumps filled and covered and the premises restored to a near natural state. The restoration need not be done if arrangements are made with the surface owner to leave the site suitable for beneficial subsequent use.

Drilling mud pits are not allowed to hold over winter because of lack of sufficient storage for winter rainfall. If drilling muds dry in the reserve pits before winter occurs, the pit is then closed.

There has not been a problem with abandoned pits; the surety bond provides a mechanism to ensure adequate pit closure.

Production

Rule 632-10-192 of the Department of Geology and Mineral Industries provides that brines or saltwater liquids may be:

1. Disposed in pits only when the pit is lined with impervious material and a Water Pollution Control Facility permit has been issued by the Department of Environmental Quality. Earthen pits used for impounding brine or salt water shall be so constructed and maintained as to prevent the escape of fluid.
2. Disposed by injection into the strata from which produced or into other proved saltwater bearing strata.

3. Disposed by ocean discharge, which may be permitted if water quality is acceptable and if such discharge is approved by the State Department of Environmental Quality through issuance of a National Pollutant Discharge Elimination System Waste discharge permit.

Produced brines are permitted to be spread on dirt roads -- predominantly logging roads -- when such is done in dry weather.

Offsite and Commercial Pits

There are no operational offsite pits. One dump-site has been used as an emergency pit. Operators must dispose of drilling muds in a Department of Environmental Quality approved solid waste disposal site. Such solids may be tested prior to disposal to determine if they contain hazardous materials.

Plugging/Abandonment

The State Geologist may authorize suspension of operations for good cause for whatever time period is stated in the written authorization, and further extensions may be granted upon expiration of the authorization.

Rule 632-10-198: When a well is plugged, producing strata and strata with fluid at greater than hydrostatic pressure must be plugged with cement from 50 feet below to 50 feet above each stratum. A 100-foot cement plug must be placed across the base of the freshwater bearing strata, when it is in open hole. When there is open hole below the base of any casing, a cement plug must extend from 50 feet below to 50 feet above the base of the casing. All casing strings must be cut off at least four feet below the ground, and plugged with cement to a depth of ten feet. Intervals between plugs must be filled with heavy mud-laden fill.

References

Oregon Meeting Report. 1985. Proceedings of the Onshore Oil and Gas State/Federal Western Workshop. U.S. Environmental Protection Agency, Washington, D.C. (December 1985).

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Olmstead, Dennis L. 1985. Letter Communication to EPA. Oregon Department of Geology and Mineral Industries.

Personal Communications:

Dan Wermiel, Department of Geology and Mineral Industries (503) 229-5580.

Kent Ashbaker, Department of Environmental Quality (503) 229-5325.

Pennsylvania

Introduction

Pennyslvania produced 4,825,000 barrels of oil and 166 x 10^9 cubic feet of gas in 1984. Production was from 20,739 oil wells and 24,050 gas wells.

Until 1955, requirements for the oil and gas industry were minimal if not nonexistent. State laws did not require permitting or registration of oil and gas wells. In 1961, the statutes were strengthened to prohibit wasting in production wells, establish spacing, and provide other requirements. It was not unit 1984 that the Coal and Gas Resources Coordination Act and the Oil and Gas Act made sweeping changes in permit review and requirements. There had been little uniformity in Pennsylvania oil and gas laws until then. Combined, these statutes enable Pennsylvania permitting authority to put terms and conditions on permits, and to deny permits. Passage of House Bill 1375 in mid-September, 1986, further strengthens the regulatory management of the oil and gas industry in Pennsylvania, and requires the development of new regulations relating to solid waste management and the disposal of wastes onsite.

The first commercial oil well was drilled near Titusville, PA, 1859.

Regulatory Agencies

Five agencies regulate oil and gas activities in Pennsylvania:

- Department of Environmental Resources, Bureau of Oil and Gas Management
- U.S. Environmental Protection Agency, Region III
- Pennsylvania Fish Commission

- U.S. Forest Service
- U.S. Bureau of Land Management

The Bureau of Oil and Gas Management was created in 1984 to coordinate and combine all related regulatory activities of the oil and gas industry. The Oil and Gas Conservation Law, enacted in 1961, established powers and duties of the Oil and Gas Conservation Commission. Those powers and duties were transferred to the Department of Environmental Resources in 1970. The Oil and Gas Act of 1984 created an Oil and Gas Technical Advisory Board to advise the Department in regulatory activities (Section 216 of 1984 Act). The five member board consists of three representatives of the oil industry, one from the Citizen's Advisory Council, and one from the coal industry.

Section 207(a) of the Act requires that the disposal of drilling and production brines be consistent with the requirements of the Clean Streams Law (which, was first passed in 1937, and most recently amended in 1980). Section 208(a) requires that any well owner who affects the public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternative source. Section 205 prohibits drilling of wells within 200 feet of buildings or water wells without the consent of the owner, within 100 feet of any body of water, or within 100 feet of a wetland 1 acre or more in size. There is a compliance bond conditioned on the operator's faithful performance of the drilling, restoration, water supply replacement, and well plugging requirements of the Oil and Gas Act.

The U.S. Environmental Protection Agency, Region III, issues UIC program permits for underground injection and secondary recovery. The Bureau of Oil and Gas Management has not sought primacy in the UIC program.

The Pennsylvania Fish Commission seeks out pollution of surface waters and takes appropriate action under the Pennsylvania Fish and Boat Code.

The U.S. Forest Service and the U.S. Bureau of Land Management provide requirements they may have in lease agreements. The well driller must demonstrate his notification of landowners and water supply owners of the intent to drill. Mineral rights in the Allegheny National Forest are privately owned. The Bureau of Oil and Gas Management issues drilling permits on Federal lands.

State Rules and Regulations

Drilling

Drilling pits to the present time have been virtually unregulated. Pits typically are unlined. Such pits contain drilling cuttings, contaminated fresh and salt water produced during construction and well stimulation, and various additives used during drilling and well stimulation. Pits are not reclaimed and no permit is required for a drill pit. There is no contingency fund for management of abandoned pits. The Bureau is in the process of developing regulations to further control oil and gas operations. The thrust on drilling pits is to remove liquids to an offsite and commercial treatment and disposal facility and to dispose of solids waste on site with pit reclamation. However, presently many pits remain on-site and may be used for oil/water separation during the production phase.

Production

It has been estimated that Pennsylvania has 17,000 impoundments associated with oil and gas brines. If an impoundment is associated with an individual well, a permit has not been required. Permits are required for offsite and commercial treatment systems. The trend since 1985 has been to move in the direction of centralized treatment facilities for oil and gas waste materials. However, there are still only a few facilities within the State presently operating to solely treat production wastewaters.

There are other production fluid disposal alternatives, which are discussed in the Oil and Gas Operator's Manual published by the Bureau of OIl and Gas Management. As the Manual notes, the practices suggested are options, not regulations. Alternatives include:

- Disposal wells
- Annular disposal
- Treatment and discharge to surface waters
- Onsite treatment and land disposal of top hole water
- Discharge to existing treatment facility
- Road spreading
- Evaporation (through waste heat)

Since these alternatives are not binding regulations, it is largely left to the operator to choose accepatble techniques for disposal.

Offsite and Commercial Pits

Water Quality Management Part II permits and NPDES permits are required for treatment facilities that discharge to waters of the Commonwealth. Treatment afforded production fluids may include flow equalization, pH adjustment (if necessary) gravity separation and surface skimming, retention and settling and aeration. The discharges from several offsite produced-fluids treatment facilities may be covered under a single NPDES permit, if the management of those facilities is under the control of one owner/operator and the geographic area is such as to allow for effective monitoring and surveillance.

The NPDES permit criteria and limits will be governed by receiving water quality standards. Generally, however, total suspended solids will be limited to an instananeous maximum of 60 mg/l and an average monthly of 30 mg/l. Oil and grease will be limited to an instantaneous maximum of 30 mg/l and an average monthly of 15 mg/l. Dissolved iron has an instantaneous maximum of 7 mg/l, and the acidity shall be less than the alkalinity.

Plugging/Abandonment

If wells are certified as having future utility, and are in adequate condition to prevent vertical flow of fluids, contamination of freshwater, or damge of productive zones, a permit can be issued for inactive status. The permit is valid for five years, and is renewable.

While revised regulations on plugging are to be adopted under the new law, current requirements under Act 225 (as amended by Act 265 of 1968) are that: cement plugs of at least 20 feet should be set 20 feet above each stratum which has had oil, gas, or water; a bridge capped with ten feet of cement should be placed 30 feet below the water string of casing, after which the casing may be drawn; a plug should be placed about 10 feet below the bottom of the largest casing in the well; all the spaces between the bottom or top of the well and cement plugs, or between the cement plugs, should be filled with sand pumpings, mud, or other equally non-porous material. Additional plugging requirements are specified for wells passing through workable coal seams, and for wells where the operator wishes to pull the casing. Additional recommendations are made in the Oil and Gas Operator's Manual published by the Bureau of Oil and Gas Management.

References

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The Oil and Gas Act, Act of 12-19-84, P.L. 1140, No.223.

The Oil and Gas Conservation Law, 1961, P.O. 825, No. 359.

Rules and Regulations, Department of Environmental Resources, Chapter 97, Industrial Wastes.

Personal Communication:

Carlyle Westlund, Bureau of Oil and Gas Management (717) 783-9645.

South Dakota

Introduction

South Dakota produced 710,000 barrels of oil and 2.5 x 10^9 cubic feet of gas in 1984. The State has 312 full production and 33 stripper oil wells, and 41 full production and 1 marginal production gas wells.

State Regulatory Agencies

Four agencies regulate oil and gas activities in South Dakota:

- South Dakota Department of Water and Natural Resources
- South Dakota Department of School and Public Lands
- U.S. Bureau of Land Management
- U.S. Environmental Protection Agency, Region VIII

The South Dakota Department of Water and Natural Resources is the primary regulatory agency for oil and gas operations through its Oil and Gas Program in the Division of Environmental Quality. The primary enforcement agency for the UIC program, and non-delegated responsibility for NPDES compliance, is the Department's Office of Water Quality. The Department of Water and Natural Resources also houses the Board of Minerals and Environment, which has power to conduct hearings and take ction on other oil and gas program related enforcement measures.

South Dakota has not been delegated NPDES authority. Two of the active wells have NPDES permits because of beneficial use associated with wastewaters. Draft NPDES permits are prepared by the State and issued by the Water Management Division, U.S. Environmental Protection Agency, Region VIII.

In the event of a desire to drill on Federal lands, two applications for drilling would be filed -- one with the State Department of Water and Natural Resources, and one with the U.S. Bureau of Land Management. The State would defer to the Bureau regarding any pre-drilling permit investigation. Two permits, one from each entity, would be issued to the driller. In the event of a request to inject drilling fluids underground, the Bureau would defer to the State, and the State would issue the injection permit. The Bureau has no means of holding hearings, and the State Board of Minerals and Environment would hold such hearings prior to permit issuance.

The South Dakota Department of School and Public Lands has enforcement powers for lease compliance on State-owned lands and for State-owned minerals.

State Rules and Regulations

Drilling

When drilling operations cease, supernatant in the drilling pit is allowed to evaporate and the mud is allowed to dry. The time interval for this to occur is a various and unknown factor. When the mud has sufficiently dried, the pit is buried and the surface is reclaimed to natural conditions.

The Department of Water and Natural Resources requires a Plugging and Performance Bond for wells, and a Surface Restoration Bond.

Production

Discharge of produced wates is permitted to total retention-evaporation ponds, to Class II UIC wells, and for beneficial use. There are no specific requirements related to pit construction, but the state is currently giving consideration to a proposal to require that pits have liners or be of impermeable construction.

Discharge of brine from oil well production is allowed when a beneficial use of the water can be documented. An NPDES permit is required for such discharge. The two NPDES permitted discharges from wells in South Dakota are used for stock watering. NPDES permits contain not-to-exceed limits for oil and grease of 10 mg/l, total dissolved solids of 5,000 mg/l, and a pH of 6.0 to 9.0. The flow is not to exceed 4,500 gallons per day.

Offsite and Commercial Pits

There are no offsite pits in use, but if there were a request for such usage, the request would be managed through the solid waste permitting process.

Plugging Abandonment

A well may be classified as temporarily abandoned for a period of six months for good cause, and this status may be extended on a case-by-case basis.

Wells must be plugged when they can no longer fulfill the purpose for which they were drilled. Plugging must follow scheduling and requirements approved by the state geologist.

References

Summary of State and Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (December).

Pirner, S. M. 1986. Letter Communication to EPA. South Dakota Department of Water and Natural Resources, Office of Water Quality.

Personal Communications:

Steven M. Pirner, DWNR, Office of Water Quality (605) 773-3351.

Fred V. Steece, DWNR, Supervisor of Oil and Gas Program (605) 394-2385.

Tennessee

Introduction

Tennessee produced about 937,000 barrels of oil from 798 wells in 1984. Only 54 oil wells produced more than 10 barrels of oil per day . Of 507 gas wells, 474 produce less than 60 thousand cubic feet per day.

Regulation of oil and gas drilling operations began in 1968. Wells drilled prior to 1968 do not have to be permitted unless they are deepened, reopened, or reentered.

State Regulatory Agencies

Three agencies regulate oil and gas activities in Tennessee:

- State Oil and Gas Board
- Tennessee Department of Health and Environment
- U.S. Department of the Interior, Bureau of Land Management

The State Oil and Gas Board of the Tennessee Department of Conservation is authorized by the Tennessee Code Annotated (Revised 1982) to regulate activities related to the production of oil and gas in Tennessee. The State Oil and Gas Board regulates the industry according to the General Rules and Regulations (Tennessee State Oil and Gas Board Statewide Order No. 2). The State Oil and Gas Board issues drilling permits and regulates surface disposal.

The Department of Health and Environment is the NPDES authority in Tennessee. They do not currently have UIC primacy, but are working towards being granted primacy by EPA. Discharges of oil and gas wastes are not permitted by the Tennessee Department of Health and Environment.

The U.S. Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are Federally held. Surface rights in Federal forests and grasslands are retained by the U.S. Forest Service.

State Rules and Regulations

Drilling

Much of the drilling in Tennessee is air drilling. The types of wastes most commonly in drilling pits are foaming agents used during the drilling process and spent acids from well treatments.

Before an applicant can complete the permit process and begin to drill, one of the Board's inspectors must approve all pollution control structures, including pits, dikes, diversion drainage ditches, and tanks. In addition, during drilling, inspectors are required to monitor casing programs, particularly with respect to circulation of cement behind the surface casing to reduce the likelihood of groundwater contamination.

The Board requires operators to drain surface pits of water and back fill them with dirt immediately after they are no longer needed for drilling or testing.

Produced Water

Produced saltwater may be disposed of by discharge into an evaporation pit, by annular injection, or by disposal into a dedicated disposal well. In addition, produced water could be used for injection in an enhanced recovery project. The use of evaporation pits is acceptable where both the method and the pit have been approved by a representative of the Board. According to information provided by the Board, it is now the policy of the Board to require the lining of pits, particularly in areas where brine will be the major constituent of the fluids in the pit. The policy was adopted to prevent contamination of groundwater from percolation of pit fluids.

An operator may obtain a permit for annular disposal of produced water for a year. Water injected into the annulus must not be allowed to enter formations with oil, gas, or fresh water.

Plugging/Abandonment

Dry wells must be plugged within six months after drilling is finished, with an extension of 90 days for good cause. Gas wells which pass a deliverability test may be classified as shut-in indefinitely. Wells no longer used for the purpose they were drilled or converted must be plugged. Wells which are neither producing nor plugged must be cased and capped to protect oil, gas, and fresh water. Cash bonds are required for all wells being temporarily abandoned.

When plugged, wells must be filled with sufficient mud to offset the hydrostatic pressure of any formation penetrated. Sufficient plugs must be placed to prevent commingling of fluids and to isolate extractable minerals.

References

Zurawski, Ronald P. "1985 EPA Onshore Oil and Gas Workshop Request for Information on Tennessee Activity and Technology," circa mid-1985.

State of Tennessee - State Oil and Gas Board. "General Rules and Regulations, Statewide Order No. 2," Effective November 1972.

Zurawski, Ronald P. Drilling Waste Conference submittal, circa mid-1985.

State of Tennessee State Oil and Gas Board. "Oil and Gas Laws in Tennessee and Mineral Test Hole REgulatory Act, " Amendments added 1982.

TEXAS

Introduction

In 1985, Texas produced over 830 million barrels of oil from over 210,000 wells. Gas production was 5,805 billion cubic feet from 68,811 gas wells. It is estimated that 75 percent of all active Texas wells are marginally-producing wells.

Regulation of the oil and gas industry in Texas began when the Railroad Commission was assigned jurisdiction over oil and gas activities in 1919.

Regulatory Agencies

The following agencies have jurisdiction over the disposal of oil and gas wastes in Texas:

- Railroad Commission of Texas
- Texas Air Control Board
- Texas Parks and Wildlife Department
- U.S. Corps of Engineers
- U.S. Environmental Protection Agency

Oil and gas activities in Texas are regulated almost entirely by the Oil and Gas Division of the Railroad Commission of Texas. Unlike many State oil and gas commissions, the Railroad Commission is responsible for both prevention of waste and for preventing pollution. Thus one agency is responsible for well spacing, construction requirements (casing, etc.), and most aspects of environmental protection.

In 1985, the Texas legislature amended Section 91.101 of the Natural Resources Code to make explicit the scope of authority of the Railroad Commission with respect to activities related to the exploration, development and production of oil and gas, as well as Section 26.131 of the Water Code. It specified that production activities included all activities associated with the storage, handling, reclamation, gathering, transportation or distribution of oil and gas prior to the refining of the oil or the use of the gas (including activities associated with natural gas and natural gas liquid processing plants). It also specifically included within the jurisdiction of the Commission the drilling of injection-water source wells which penetrate the base of useable quality water. These wells produce water to be used in enhanced recovery injection wells. The major change in the statute was the specification of activities which were to be considered related to "production."

Statewide Rule 8 (governing "water protection") of the Railroad Commission was amended on January 6, 1987 to incorporate these changes in the Natural Resources Code.

The Railroad Commission issues permits for any discharges related to oil and gas exploration, development and production activities. Since the state does not currently have NPDES jurisdiction, such discharges are also subject to EPA permitting.

The Railroad Commission has jurisdiction over Class II underground injection wells. The Railroad Commission is currently evaluating the need for a Class I well program. The Commission has jurisdiction over the injection of gas plant wastes which may need to be injected into a Class I well if they are not sufficiently diluted by produced water to allow injection into a Class II well. Currently, all Class I wells are regulated by the Water Commission, and gas-plant wastes are subject to Class II requirements.

The Texas Air Control Board has jurisdiction over the regulation of oil field activities generating air emissions.

The Texas Parks and Wildlife Department, Pollution Surveillance Branch, investigates fish kills and water pollution complaints and evaluates the effects of discharged wastes on fish and wildlife. The Texas Parks and Wildlife Department has statutory authority to recover the monetary value of damaged fish and wildlife. The Parks and Wildlife Department may also enforce the Texas Water Code when permit violations, discharges in excess of permit limitations, or discharges without a permit occur.

The Texas Railroad Commission has jurisdiction over oil and gas activities on Federal lands in Texas, regardless of who owns the mineral rights.

The U.S. Corps of Engineers has permitting responsibility for any activities which would affect wetlands subject to Section 404 of the Clean Water Act.

State Rules and Regulations

General: Texas Statewide Rule 8 prohibits any "person conducting activities subject to regulation by the [Railroad] Commission" from causing or allowing pollution of surface or subsurface waters in

Texas. With limited exceptions (e.g., landfarming or burial of drilling fluids under specified conditions), "no person may dispose of oil and gas wastes by any method without obtaining a permit to dispose of such wastes." These exceptions are authorized under Rule 8, along with the corresponding conditions which must be met to fulfill the Rule's requirements. The Rule's "authorizations" thus serve the same function as a "general permit" in some other states. Under Statewide Rule 9, permits are required for disposal of oil and gas waste by injection into formations not productive of oil or gas. Statewide Rule 46 requires permits for injection into productive formations.

Drilling

Pit Construction Permits: The Railroad Commission authorizes, by Rule, the maintenance and use without a permit of reserve pits, mud circulation pits, completion/workover pits, basic sediment pits, flare pits, fresh makeup water pits, and water condensate pits, provided that such pits are operated and closed as required by Rule 8. The use of reserve pits and mud circulation pits for oil and gas wastes is restricted to drilling fluids, drill cuttings, sands, silts, wash water, drill stem test fluids, and blowout preventer test fluids.

Permits are required for drilling fluid storage pits (other than mud circulation pits) and drilling fluid disposal pits (other than reserve pits or slush pits), and any other pits not specifically authorized by the Rule. For pits requiring permits, pit locations are evaluated on a case-by-case basis to determine what construction requirements are necessary to prevent waste of oil and gas resources or pollution of surface water or groundwater. Proposed unlined pits which will be continuous use saltwater service are also evaluated to determine whether the pit would cause pollution of surrounding productive agricultural land. The requirements may or may not include liners.

Pit Closure: The Railroad Commission requires that pits be dewatered, backfilled and compacted for closure. Backfill requirements (for all types of pits) vary according to the type of pit and the chloride concentration of the pit contents. Reserve pits (and mud circulation pits) containing fluids with a concentration of over 6,100 mg/l chloride must be dewatered within 30 days of cessation of drilling operations. Reserve pits containing fluids with a concentration of 6100 mg/l or less must be dewatered within a year. In both cases, backfilling must be carried out within a year of the cessation of drilling operations. Because of dewatering time limits, reserve pit fluids may need to be hauled offsite for disposal.

Completion/workover pits must be dewatered within thirty days and backfilled and compacted within 120 days of cessation of completion/workover operations.

Disposal: The Railroad Commission permits treatment and discharge of reserve pit fluids to land or to surface waters provided that the discharge does not cause a violation of Texas water quality standards. The Rule does not specify what processes constitute acceptable treatment technologies. The applicant for a permit may choose the technology, but must provide proof that the selected technology will meet the Commission's criteria. The criteria for discharges to surface waters are:

- Chemical oxygen demand	< 200 mg/l
- Total suspended solids	< 50 mg/l
- Total dissolved solids	< 3000 mg/l
- Oil and grease	< 15 mg/l
- Chlorides (coastal)	< 1000 mg/l
- Chlorides (inland)	< 500 mg/l
- pH	6.0 to 9.0

- 24-hour bioassay in accordance with procedure developed by Texas Parks and Wildlife Department
- Water color must be adjusted to match the receiving stream
- Volume of the discharge must be "controlled so that a minimum 5:1 dilution of the wastewater by the principal receiving stream is maintained."
- Discharge cannot exceed concentrations of hazardous metals as defined by Texas Water Development Board Rules 156.19.15.001 - .009.

In coastal areas, if the receiving body of water has concentrations of TDS or chlorides in excess of 3,000 mg/l or 1,000 mg/l respec/tively, then the concentration of the treated reserve pit fluids may exceed those limits, but may not exceed the levels in the receiving water body at the point and time of discharge. In such cases the effluent must be piped to the receiving water body.

Rule 8 authorizes landfarming or burial of water-based drilling fluids and associated wastes which meet specific conditions. The authorizations do not extend to oil-based drilling fluids, which require a permit for disposal.

The authorization for landfarming applies where water-based drilling fluids have a chloride concentration equal to or less than 3,000 mg/l. Under the authorization, the wastes must be disposed of on the same lease where generated, and the operator must have the written consent of the landowner. Landfarming encompasses sprinkler irrigation, trenching, injecting under the surface, discing, and surface spreading by vehicles; the waste must be applied in such a way that it will not migrate off the landfarmed area.

Where the water-based drilling fluids have a chloride concentration in excess of 3,000 mg/l, but the wastes have been dewatered, burial is authorized at the well site where the waste is generated.

One-time disposal of reserve pit fluids down the annulus of a well is allowed, but requires a "minor permit" for each disposal incident.

Produced Fluids

More that 90% of produced waters are disposed of by injection, with most of the remainder disposed of in coastal ("tidally influenced") waters. Less than 1% is disposed of in pits.

Pits: Individual permits are required for brine pits, collecting pits, skimming pits, emergency saltwater storage pits, and saltwater disposal pits.

A 1984 amendment to Rule 8 required the re-permitting or closure of all previously-permitted lined or unlined pits for the storage or disposal of oil field brines. The 1984 amendment also required the permitting of other types of pits which did not have to be permitted prior to the amendment. With the exception of emergency saltwater storage pits, permits for unlined pits will only be granted if the operator can "conclusively" show that "use of the pit cannot cause pollution of surrounding productive agricultural land nor pollution of surface or subsurface water." Since the amendment, the Railroad Commission has received approximately 8,900 permit applications for all types of pits, half of which are for emergency saltwater storage pits used in connection with injection and storage wells. Of the 8,900 applications, 2,675 are for pits that were permitted prior to the amendment. As of December 1, 1986, the Commission had received 388 applications for saltwater disposal pits (unlined, because of the need for both evaporation and percolation for disposal purposes); 13 were approved, 233 denied, with the rest still under consideration. Approvals were largely for low-chloride (<500 ppm chloride) produced waters in areas where there was no possible impact on fresh subsurface water. The Commission expects to complete the processing of the 8,900 applications by late 1988.

Lining requirements are determined on a case-by-case basis. Generally, all continuous-use pits (e.g., skimming pits) would require linings. Emergency saltwater storage pits in sandy soils would also require linings. Specific lining/monitoring requirements would be determined on a case-by-case basis.

Injection: Class II injection wells are used both for enhanced recovery (36,368 wells) and disposal (16,404 wells). Requirements for Class II enhanced recovery wells are found in Rule 46 of the Texas Railroad Commission; requirements for Class II disposal wells are found in Rule 9.

The Commission requires that a newly drilled Class II injection well have surface casing cemented to the surface. Rule 9 requires that the well shall be equipped with tubing set on a mechanical packer, set no higher than 100 feet above the top of the permitted injection interval.

Mechanical integrity tests must be conducted before injection begins, and at least once every five years thereafter. Most mechanical integrity tests are pressure tests. Test pressures must equal the maximum authorized injection pressure or 500 psig, whichever is less, but in no case less than 200 psig. Tests are acceptable if the test is conducted at a pressure within 10% of the pressure required by the formula. However, once the casing pressure stabilizes, the test must be conducted for 30 minutes with no variation.

Specifications under Rule 46 are identical with respect to casing, the requirement for using tubing and packer, and mechanical integrity tests. The required setting for the packer is no higher than both 200 feet below the known top of cement behind the long string casing and 150 feet below the base of usable quality water.

Surface Discharge: The Railroad Commission allows discharge of produced water into coastal areas under individual permits. Sufficient collecting and skimming pits must be maintained to prevent any oil from entering the tidal waters. Random samples of the discharged brine must be tested for oil content every 30-40 days.

Offsite Facilities

Transportation: Transporters of produced water (other than by pipeline) must hold a Salt Water Hauler Permit from the Railroad Commission. Haulers must keep a record of the volume of water transported, the property from which it originated, and the amount delivered to which specific disposal facility. Similar records must be kept by the producer. No similar requirements are imposed on transport of drilling fluids.

Disposal: All offsite disposal of oil and gas wastes requires individual permitting. The primary offsite facilities in Texas are disposal wells which receive materials by truck. There are approximately 200 Class II commercial wells in Texas.

In addition, there are approximately 100 central disposal pits for drilling fluids, 50-75 central drilling fluid landfarming facilities, and a few facilities for treatment and discharge of drilling fluids in coastal areas. Management requirements for these facilities are determined on a case-by-case basis.

Plugging/Abandonment

Plugging procedures for dry or inactive wells which cease drilling or operations between January 1, 1986 and January 1, 1988 must commence within one year of the cessation of operations. (For other wells, the limit is 90 days). In addition, a further reasonable extension of time is available at the discretion of the Director of the Oil and Gas Division if the well does not present a pollution hazard, and the operator has posted a performance bond, or if a well is in an enhanced recovery operation, and the operator has presented a viable plan for further use of the well within a reasonable time period.

A well plugging fund has been established to enable the state to plug abandoned wells. The major source of funding is provided by a $100 drilling permit fee for each new well.

Cement plugs shall be set by the circulation or squeeze method through tubing or drill pipe, and shall have sufficient volume to fill 100 feet of hole plus 10% for each 1,000 feet of hole from the ground surface to the bottom of the plug. All portions of the well not filled with cement must be filled with mud-laden fluids of at least 9.5 lbs./gallon.

For wells with surface casing, plugging requirements depend on whether the surface casing is set to protect all usable water quality strata. Where it does, a cement plug shall be set which extends from at least 50 feet below to 50 feet above the shoe of the surface casing. Where the casing has been set deeper than 200 feet below the base of the deepest usable water strata, an additional plug, within the casing, must extend from at least 50 feet below the base to at least 50 feet above the top of the lowest such stratum. Where the casing does not afford such protection, a similar plug must be placed across the shoe of the surface casing, and another plug from at least 50 feet below the base to at least 50 feet above the top of the lowest usable water stratum.

For wells with intermediate or production casing which has been cemented through all usable water quality or productive horizons, a cement plug shall be placed inside the casing and extend from at least 50 feet below the base to at least 50 feet above the top of the deepest usable water quality stratum. Where such casing has not been cemented through all strata and horizons, the casing shall be perforated at the required depths to place cement outside the casing by squeeze cementing. A plug shall also be wet above each perferated interval or open hole completion.

For wells without production casing and open hole completions, productive horizons or formations in which pressure or formation water problems exist shall be isolated by plugs centered at the top and bottom of the formations. Such plugs are to be continuous if the formation is less than 100 feet thick.

The District Director may require additional plugs to cover and contain any productive horizon or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation.

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Personal Communications:

William H. Barnes, Texas Railroad Commission, (512) 463-6790

Windle J. Taylor, Texas Railroad Commission, (512) 463-6803

Lori Wrotenbery, Texas Railroad Commission, (512) 463-6769

Utah

Introduction

Utah produced 38,053,871 barrels of oil from 1,862 wells in 1984. Approximately 20 percent of these wells are stripper wells. Utah produced 183,061,947 MCF of gas from 728 gas wells in 1984. This gas production volume includes recycled injection gas attributed mainly to pressure maintenance operations at the Anschutz Ranch East field. Any discharge of produced water onto roads is prohibited.

State Regulatory Agencies

Four agencies share regulatory responsibility for oil and gas activities in Utah:

- Utah Department of Natural Resources, Division of Oil, Gas, and Mining
- Department of Health, Bureau of Water Pollution Control
- U.S. Bureau of Land Management (and possibly the Bureau of Indian Affairs)
- U.S. Forest Service (surface rights only)

The Division of Oil, Gas, and Mining adopted new Oil and Gas Conservation General Rules effective December 2, 1985. These rules cove drilling and operating practices, UIC Class II responsibility, and rules governing purchasing, transportation, refining, and rerefining. The Department of Health currently has regulatory authority over disposal ponds. The Department of Oil, Gas, and Mining is hoping to bring most aspects of oil and gas regulations under one agency by assuming authority for disposal ponds in the near future.

The U.S. Department of the Interior, Bureau of Land Management, has jurisdiction over lease arrangements and post-lease activity on Federal lands where the mineral rights are Federally held. Surface rights in Federal forests and grasslands are retained by the U.S. Forest Service.

State Rules and Regulations

Drilling

Rule 308 of the Division of Oil, Gas, and Mining rules requires oil and gas operators to "take all reasonable precautions to avoid polluting streams, reservoirs, natural drainage ways, and underground water." This requirement is supported by a specific rule for reserve pits (Rule 309). "Salt water and oil field wastes associated with the drilling process may be disposed of by evaporation if impounded in excavated earthen reserve pits underlain by tight soil such as heavy clay or harden or lined in a manner acceptable to the Division." Pit liquids are not allowed to escape onto the land surface or into surface waters.

Since most of Utah has very rapid evaporation rates, the reserve pit supernatant is generally allowed to evaporate before pit closure. Final pit closure requirements were not found in the rules.

In areas of net precipitation,, or in areas where pit construction is especially difficult (i.e., steep mountain sides), the Division may allow the reserve pit supernatant to be disposed down the annulus of the new well into a properly confined zone of poor quality. This determination is made by the Division of Oil, Gas and Mining on a case-by-case basis.

The Division of Oil, Gas, and Mining has extensive technical rules regarding well siting, casing requirements, and well drilling.

Production

Most produced water is injected for water flooding or for disposal. Utah has approximately 560 Class II injection wells, including about 45 active disposal wells. The Division of Oil, Gas, and Mining controls injection wells and onsite disposal facilities.

The Utah Department of Health regulates surface disposal of produced wastes from gas and oil wells. No pond is allowed to discharge to the surface (land or water). Construction requirements specify that pits must be protected from intrusion of surface water, be constructed of impervious materials, and be located at least 5 feet above groundwater. Pits must be properly located above ordinary high water marks for surface wastes. Pits may not located within 200 feet of a fault or at the bottom of creeks, rivers, or natural drainages.*

Surface disposal into unlined ponds is allowed if the wastewater contains less than 5,000 mg/l total dissolved solids, and if the wastewater does not contain "objectionable or toxic levels of any constituent as shown by chemical analyses." This requirement is waived for sites discharging less than 5 barrels of water per day. Small dischargers into unlined pits are required only to notify the Department of Health with minimal site information. Application for approval to

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Onsite disposal facilities are presumed to include onsite evaporation pits. The Division of Oil, Gas, and Mining rules do not include specific guidance regarding onsite disposal facilities; however, their reserve pit guidance is probably applied to produced water pits as well. There appears to be some overlap in authority for onsite pits between the Utah Department of Health and the Division of Oil, Gas and Mining.

discharge into unlined pits must include an estimate of waste volume, estimate of percolation and net evaporation rates, and information about freshwater aquifers within a one square mile radius of the proposed site.

For disposal ponds without artificial liners which receive more than 100 barrels per day , the Department of Health requires a monitoring program including monitoring wells.

For artificially-lined ponds, the Department of Health requires "an underlying gravel-filled sump and lateral system, or other suitable devices for detection of leaks." The Department of Health, Bureau of Water Pollution Control, is considering a requirement that all ponds (lined or unlined) be equipped with a leak detection system. In general, the Bureau feels that pit siting is more important than construction requirements. Any discharge of produced water onto roads is prohibited.

All injection wells must be operated to prevent damage to drinking water or other resources, and to confine injected fluids to the approved interval. The application for an injection well must include information on all other wells within a half-mile area of the proposed injection well. It must also provide adequate evidence that the proposed injection pressures will not result in fracturing of the confining interval that could enable injected or formation fluids to migrate out of that interval. Before injection begins, the operator must use a pressure test to test the casing. The test must be at the greater of 300 psi or the maximum authorized pressure (for a new well), with a ceiling of 1,000 psi (for a converted well). Subsequent pressure tests must be administered every five years (except that, in lieu of pressure tests, the operator may monitor and report on the pressure in the casing-tubing annulus on a monthly basis, or use other test methods approved by the Division).

Plugging/Abandonment

No time limit is established for temporary abandonment of a well. A well is temporarily abandoned if operations have ceased, intervals open to the well bore have been properly sealed with a cement plug or bridge plug, and there is no migration of fluids.

When plugging, cement plugs must be placed above each producing formation (100-foot length), from 50 feet below to 50 feet above the fresh water zone (or 100-foot plugs centered at the base and top of the zone), at the base of the surface casing (50-foot), and centered across the casing stub if any casing is cut and pulled (100-foot, along with a second plug the same length centered across the casing shoe of the next larger casing). At least 10 bags of cement shall be placed at the surface completely plugging the entire hole (including all annuli, if more than one string of casing remains at the surface). Perforated intervals must be plugged with cement. Intervals between plugs must be filled with a noncorrosive fluid of adequate density to prevent migration.

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Virginia

Introduction

Virginia produced 26,654 barrels of oil from 41 producing oil wells and 15,041,438 (mcf) cubic feet of gas from 495 gas wells in 1985.

State Regulatory Agency

One agency principally regulates oil and gas activities in Virginia:

- Virginia Department of Mines, Minerals, and Energy/Division of Mines - Oil and Gas Section

The Oil and Gas Section is governed by the Virginia Oil and Gas Act and by the Rules and Regulations for Conservation of Oil and Gas Resources and Well Spacing. These Rules and Regulations were adopted by the Virginia Oil and Gas Conservation Commission, the Virginia Well Review Board, and the Chief of the Division of Mines and Quarries (DMQ) and issued by the Virginia Department of Labor and Industry in 1983. In 1985, a reorganization of state government created the Department of Mines, Minerals and Energy (DMME). This resulted in the shift of DMQ, now referred to as the Division of Mines, from Labor and Industry to DMME. The Oil and Gas Section issues drilling permits and regulates the details of the industry through this process. The State does not have primacy for the UIC program Class II wells, but there is no underground injection of fluids currently associated with the Virginia industry. There has been drilling on Federal lands, but such lands are owned by the National Forest Service and the Service serves as another surface landowner in such drilling activity. The Service would manage their concerns principally through the surface lease process. The Virginia

Water Control Board would become involved only in the event of an incident that potentially could affect surface water quality.

State Rules and Regulations

Drilling

All disturbance to the land associated with the development of the drilling site, including the construction of pits and access roads, must comply with standards set down in the Virginia Soil and Erosion Control Handbook.

Pits associated with the drilling of a well must prevent water pollution. It is the policy of the Oil and Gas Section that drilling pits must be lined with a plastic liner. After drilling is complete, liquids in the pits may be treated,primarily to adjust pH, and land applied solids are buried in the pit. The drill site and any associated pits must be reclaimed within 1 year after drilling ceases.

In general, there is little fluid associated with the drilling process in Virginia. Such fluids as may be present are not high in chloride concentration. Generally, the fluid is tested by the driller, the pH is adjusted if necessary, and the water is sprayed on the surrounding land. Pit muds are buried on site and the pit area reclaimed.

Production

No pit may be used for the ultimate disposal of salt water. [Part III, Regulation 3.09(e) for Conservation of Oil and Gas]. Salt water must be periodically drained or removed, or properly disposed of from any pit in which it is retained.

Almost no fluid is associated with gas production in Virginia. Very small amount of fluids are produced with the 100 gallons of oil produced per day statewide. As a result, produced wastes generally are held in steel tanks. Dikes are required around the tanks, and fluids generally are allowed to flow into the diked area, where they disappear through evaporation and infiltration .

Offsite and Commercial Pits

No use is made of offsite and commercial pits in Virginia.

Plugging/Abandonment

Under the Virginia Oil and Gas Act, operators are required to immediately plug a well "upon the abandonment or cessation of operation" of that well. Where there is good economic cause, however, gas wells may be capped for an indefinite period.

Different plugging requirements exist for wells, depending on whether they penetrate coal seams and, if they do, with or without coal protection string. Cement plugs are required 20 feet above each oil, gas, or water-bearing stratum, and 10 feet below the bottom of the largest casing left in the well. Mud, clay or another nonporous material is to fill all spaces in the well not filled by plugs. Additional requirements are made for perforations which cannot be readily filled by the above methods, and for the protection of coal seams.

References

Summary of State Statutes and Regulations for Oil and Gas Production. 1986. Interstate Oil and Gas Commission (June).

The Oil and Gas Compact Bulletin. 1985. Interstate Oil Compact Commission (June).

Personal Communication:

James Henderson, State Oil and Gas Inspector (703) 628-8115.

William Edwards, Department of Mines, Minerals and Energy (804) 257-0330.

WEST VIRGINIA

Introduction

West Virginia produces about 3.6 million barrels of oil and 7.5 BCF of gas per year from 15,895 wells. Gas production of 142.5 billion cubic feet annually is realized from 32,500 gas wells. Between 1,800 and 2,500 drilling permits are issued annually, although the number of wells drilled dropped in 1986.

Regulatory Agencies

Two agencies now regulate oil and gas activities in West Virginia:

- West Virginia Department of Energy, Oil and Gas Division

- U.S. Bureau of Land Management

The West Virginia Energy Act, passed on April 12, 1985, created the West Virginia Department of Energy, and vested in the Department jurisdiction over oil and gas activities (as well as other energy-related activities) in the state. The Department has assumed the responsibilities previously carried out by the Department of Mines, Office of Oil and Gas, and is in the process of assuming relevant program responsibilities from the Department of Natural Resources, Water Resources Division. Among the programs which are to be transferred, after approval by EPA, are those aspects of the delegated NPDES, underground injection and hazardous waste programs which bear on oil and gas exploration, development and production. Pending re-delegation by EPA, the Department of Natural Resources is still the lead agency for these activities, and the Department of Natural Resources and the Department of Energy are cooperating on the environmental regulation and oversight of the oil and gas production industry.

Within the Department of Energy, the Division of Oil and Gas has responsibility for the regulation of the State's oil and gas industry. The Division has new regulations which have been approved by the state legislature. The regulations will go into effect, about June 14, 1987. The regulatory requirements summarized below describe these rules.

The U.S. Bureau of Land Management has jurisdiction over lease arrangements and post-lease activity on Federal lands. Their rules are discussed in a separate section on Federal Agencies. The U.S. Forest Service retains surface rights for Federal forests and grasslands. The Service coordinates surface stipulations with the Bureau of Land Management where applicable.

State Rules and Regulations

Drilling

Pit Construction/Management: Each pit used for drilling wastes is subject to the terms of a general West Virginia NPDES permit for construction, management and discharge. The general permit was first established by the Division of Water Resources of the Department of Natural Resources on July 10, 1985. The requirements in the general permit are also found in the proposed Department of Energy regulations.

Pits must be constructed "to prevent seepage, leakage or overflows" and maintain integrity. If an operator is unable to maintain adequate freeboard to prevent overflows, he must build an additional pit. There is no liner requirement, but there is a stipulation that where the soil "is not suitable to prevent seepage or leakage, other materials which are impervious shall be used as a liner for a pit." Unlined dikes must be free of large rocks, trees or other growth which could damage the pit's integrity.

During operation of the pit, it is prohibited to dump into the pit production brine, unused frac fluid or acid, compressor oil, refuse, diesel, kerosene, halogenated phenol, or drilling additives prepared in diesel or kerosene.

Pit Closure: Pits are to be filled within six months after the cessation of drilling. The drill cuttings may be buried on site, after disposal of liquids.

Disposal: Treated wastewaters generated during drilling, reworking and treatment of wells may be discharged for land application on-site, subject to the following limitations:

pH	6.0 - 10.0
total iron	6 mg/l
chloride	25,000 mg/l
free or floating oil	no visible sheen on land

In addition, monitoring is required for TSS, dissolved oxygen, manganese, conductivity, settleable solids, and total organic carbon.

Required treatment includes pH adjustment, aeration and extended settling for at least 10 days. Free or floating oil shall be skimmed off and removed from the pit before treatment and, if observed, before discharge. Land application may not be carried out on saturated, frozen, impermeable, or unvegetated land, and must be at a rate that will not cause ponding or erosion. To prevent discharge of sludge, there must be a discharge device on the pit that ensures that the discharge will be from near the surface of the pit water level.

Discharge onto property off the drilling site requires both a permit and the permission of the landowner.

Produced Waters

The Department of Energy regulations, beyond prohibiting the placement of produced saltwater in the drilling pits, specify that when such water is produced it must be "contained in sump pits no larger than necessary for the purpose." There is no general permit for land discharge of saltwater, and discharge into waters of the State is prohibited. Saltwater may be injected into Class II wells. (For figures on actual disposal patterns, see the section on current management practices.) There is no prohibition against use of brines on roads, and this possibility is currently undergoing research.

Injection: Class II injection wells are permitted both for enhanced recovery (529 wells) and disposal (53 wells).

Injection shall be through a tubing and packer arrangement, with the packer set immediately above the injection zone. The annulus must be monitored by pressure-sensitive device. Injection pressure must be regulated to minimize the possibility of fracturing the confining strata. "Disposal into the same formation from which the water is produced is preferable."

Mechanical integrity tests for injection wells are made at one-and-one-half to two times the injection pressure for 20 minutes, with a 5% allowable variance.

Offsite Facilities

Wastes may be transported offsite to appropriate disposal facilities. If these facilities discharge wastes after treatment, they must be separately permitted.

Plugging/Abandonment

Wells completed as dry holes, or wells not in use for a period of twelve months, are presumed abandoned, and must be "promptly" plugged, unless the operator can prove "bona fide future use."

Cement plugs (of unspecified length) shall be set 20 feet above each oil, gas, or water-bearing stratum (except that if such strata are not widely separated and are free from water, they may be treated as a single stratum). A final plug must be placed ten feet below the bottom of the largest casing in the well. Mud, clay or other nonporous material is to fill all space in the well from the bottom of the well (or from a permanent bridge anchored 30 feet below the lowest stratum) to the lowest plug, between each of the plugs, and from the highest plug to the surface. Unfillable cavities created when strata were shot shall be isolated by plugs placed 20 feet above and below the stratum, or a liner shall be placed from at least 20 feet above to 20 feet below the stratum and filled with cement.

Special additional requirements (e.g., use of expanding rather hydraulic cement, and additional cement plugs) are imposed to protect workable coal beds.

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Personal Communications:

John Johnston, Oil & Gas Division, West Virginia Department of Energy (304) 348-3741.

Ron Shipley, West Virginia Department of Natural Resources, (304) 348-2754.

WYOMING

Introduction

Wyoming produced 130,984,917 barrels of oil and 597,896,000 MCF of gas in 1985. Production is from 12,218 oil wells and 2,220 gas wells.

Fifty-two percent of the state's oil production is produced from the 20 largest fields. Twelve of those fields are 58 years old or older. Oil, water, and gas have always been produced from these areas. The produced water historically has been reinjected, evaporated in pits, or discharged into drainages.

Regulatory Agencies

Three agencies regulate oil and gas activity in Wyoming:

- Wyoming Oil and Gas Conservation Commission

- Wyoming Department of Environmental Quality

- U.S.Bureau of Land Management

The Wyoming Oil and Gas Conservation Commission has general authority over all oil and gas production in Wyoming, and the specific responsibility to "monitor and regulate, by the promulgation of rules and the issuance of orders, the location, operation, and reclamation of produced water and emergency overflow pits associated with oil and gas production." The Commission regulates industry practices and procedures with regard to construction, location and operation of drilling and production pits, both onsite and offsite. The Oil and Gas Conservation Commission is chaired by the Governor of Wyoming; four other commissioners serve with the Governor. The Office of the State Oil and Gas Supervisor is primarily responsible for regulation of industry practices.

Wyoming is an NPDES-delegated State. The Wyoming Department of Environmental Quality has NPDES authority for all discharges. DEQ also has responsibility for permitting the construction, maintenance and operation of commercial pits. DEQ also has authority for land application of all types of exploration and production wastes.

The specific division of roles between the Wyoming Oil and Gas Conservation Commission and the Department of Environmental Quality was previously defined by a "Memorandum of Agreement" of September 13, 1983, a memorandum from the Attorney General's office on January 18, 1982, and an MOA dated October 14, 1981.

However, the 1987 session of the Wyoming State Legislature passed a bill creating a new section in the Wyoming Oil and Gas Conservation Commission Act. The new legislation gives the Commission exclusive authority over all noncommercial oil field pits on a lease, unit, or communitized area (except for discharges from such pits subject to NPDES permitting). See §30-5-104(d)(VI)(A) and (B).

The Bureau of Land Management has jurisdiction over drilling and production on Federal lands. For drilling on Federal land, BLM handles all Applications to Drill. BLM requires extensive environmental documentation, including environmental assessments, and develops environmental impact statements. For produced water, the Bureau routinely approves discharges of up to 5 barrels/ day under NTL-2B. For further discussion of the rules and procedures of BLM, see the section on Federal regulations.

State Rules and Regulations

Drilling

Pit Construction/Management: Earthen pits are required to be constructed to prevent pollution of streams, underground water, or unreasonable damage of the surface of leased premises or other lands. The rules do not require pit or pond liners, leak detection, or other modifications to a simple earthen pit except where "potential for communication between the pit contents and surface water or shallow ground water are high." Each pit application is reviewed before approval taking into consideration a wide variety of factors, including the soil type on which a proposed pit is to be constructed. Quality of the contained water, expecially the TDS level, is also an important consideration. The State Supervisor makes this determination based on the information presented in the permit application form. Use of chemicals which destroy, remove or reduce the fluid seal of a reserve pit is prohibited. Chemical or mechanical treatment of reserve pits may be specially allowed after a public hearing before the Oil and Gas Conservation Commission.

Workover and completion pits are exempted from permit requirements if their use is limited to containment of oil and/or water, and they do not contain acids or other chemical fluids. There is no requirement in the regulations for segregation of drilling muds, produced waters or other wastes associated with drilling or production. Practices tends to vary significantly with the operator.

Pit Closure: Reserve pits must be reclaimed within a year of last use, unless the Supervisor grants a variance. After evaporation, discharge or hauling of the liquid material in the pit, the drill cuttings are buried on-site, and the land rehabilitated in accordance with the landowner's wishes. Bonds guaranteeing plugging of the well and pit reclamation are not released until the Commission has inspected and approved the reclaimed pit and drillsite.

Discharge: Drilling fluids from reserve pits may be evaporated, applied to road surfaces, applied to land other than road surfaces, or hauled to a central disposal facility.

Section 326 of the rules of the Oil and Gas Conservation Commission states: "A permit may be allowed by DEQ for one time land application of drilling fluids. At no time will drilling fluids be discharged into live waters or into any drainages that lead to live waters of the state." Section 11(a) of Chapter VII of the regulations of the Department of Environmental Quality establishes a no-discharge rule for "drilling muds and other liquids associated with the drilling of oil and/or gas wells." But section 11(b) allows exceptions where the operator has provided a complete analysis of the drilling liquid, the volume and location of discharge, and the name of the receiving water; DEQ has determined that the discharge would not cause significant environmental damage or contamination of public water supplies; and the landowner has agreed.

During the period 1983 to 1985, DEQ approved 21 permits for application of drilling fluids to roads. The state does not currently have specific road permit standards or numeric criteria. Information is currently required on pH, conductivity and TDS contents of the wastes. Actual concentrations of TDS in permits approved for road application of drilling fluids during the above period varied from a few hundred to

10,900 mg/l. A DEQ memorandum notes several criteria established in such permits. Those that apply to drilling fluids include: limitation of application rates to those specified in the permit; application to avoid runoff or ponding; no application on slopes exceeding 8%, within 300 feet of definable high water marks of drainages, irrigation canals, lakes or reservoirs, or when the soil is saturated; and landowner approval.

During the same 1983-1985 period, DEQ issued 16 permits for drilling fluids to be applied to land other than roads. Such permits require that the fluids meet the criteria established in Chapter XI, Section 55(c)(ii), Part E for irrigation water quality, including:

Total dissolved solids	-	2100 mg/l
Chlorides	-	1500 mg/l
Oil and grease	-	20,000 lbs./acre, when soil incorporated (surface 6 inches); 2,000 lbs./acre when surface applied
Sulfates	-	960 mg/l
Boron	-	2 mg/l
Arsenic	-	.1 mg/l
Chromium	-	1 mg/l
Selenium	-	.2 mg/l
Nickel	-	-.2 mg/l
Zinc	-	2 mg/l
Copper	-	1 mg/l
Bicarbonates	-	<50% of total anion concentration meq/l
pH	-	4.5 - 9.0

Produced Waters

Produced waters are disposed of through injection for enhanced recovery (c.63%), surface water discharge (c.30%), injection into disposal wells, discharge into centralized disposal pits, discharge into commercial disposal pits, or road application.

Disposal/Storage Pits: The Oil and Gas Conservation Commission has jurisdiction over the permitting, construction and management of all produced water pits on private and state lands. The Commission requires permits for pits receiving more than 5 barrels of produced water per day. But such permits include requirements for liners only in special cases where "potential for communication between the pit contents and surface water or shallow ground water is high." The Commission may administratively approve field-wide or area-wide applications covering earthen retaining pit construction and operation.

Pits must be kept reasonably clear of surface accumulations of oil or other liquid hydrocarbons, and the accumulations must be cleared within 10 days when discovered. Pits must be fenced when near human habitation or sensitive areas for wildlife or domestic stock and flagged as required.

Surface Discharge: The Wyoming Department of Environmental Quality's Water Quality Rules and Regulations, Chapter VII, describe the rules for discharges of produced water which could enter surface waters, as permitted by EPA's "Agricultural and Wildlife Water Use Subcategory." Discharge of produced water may be permitted if the following effluent limitations are met:

Chlorides	- 2,000 mg/l
Sulfates	- 3,000 mg/l

Total dissolved solids	-	5,000 mg/l
pH	-	6.5 - 8.5
Oil and grease	-	10 mg/l

There is also a general prohibition on discharges containing toxic substances in concentrations or combinations toxic to human, animal or aquatic life.

Exceptions may be granted to the above limitations if a landowner submits a "letter of beneficial use" specifically requesting that the discharge in question be allowed to continue and indicating the specific beneficial use and its history, or if the Wyoming Fish and Game Department indicates the discharge is of value to fish or wildlife. This exemption does not apply if the produced waters would be discharged to the waters of the United States, or if the discharge would lead to a violation of Wyoming's water quality standards.

During 1983-1985, five permits were issued by DEQ for road application of produced waters. In addition to the road application restrictions which apply to drilling fluids; produced water must have a TDS concentration of greater than 5,000 mg/l and less than 50,000 mg/l.

<u>Injection</u>: The Wyoming Oil and Gas Conservation Commission has delegated responsibility for the UIC Class II program, and issues permits for both enhanced recovery (4,548 wells) and non-commercial disposal (196 wells). Disposal wells permitted by the Commission meet the permitting requirements of Chapter IX, Wyoming Water Quality Rules and Regulations. For both type of well, the applicant has the burden of demonstrating at a public hearing that the injection or disposal zone is not a source of drinking water and by certain criteria can be exempt from protection as

fresh and potable water. The applicant must also supply an application for approval of use of the well for injection which includes the following points:

a. Proof that the well is cased and cemented in such a way that fluids are prevented from entering any zone but that exempt.

b. Evidence and data to demonstrate that operation of the well at the proposed maximum injection pressure with proposed volumes will not initiate fractures through the confining zone.

c. Statement detailing procedures for pressure testing the casing in the well prior to any use.

d. A plat showing the location of all wells within a quarter mile radius of the proposed injection or disposal well and a statement relative to the mechanical condition or abandonment of each.

e. Affidavit showing that all surface owners and owners of interest within a one-half mile radius of the well have been provided notice of the proposal.

f. A geologic description of the reservoir which will receive the fluids which includes its areal extent.

Surface casing must be run to reach a depth below all known or reasonable estimated utilizable domestic fresh water levels. Surface casing shall be cemented with sufficient cement to fill the annulus to the top of the hole.

Before beginning injection, and at least once every subsequent five year period, the operator must test the well's mechanical integrity. In a new well, the casing outside the tubing must be tested at a pressure not less than the maximum authorized injection pressure, or at 300 psi, whichever is greater. In a converted well, the test must be at the lesser of 1,000 psi or the maximum authorized injection pressure, but no less than 300 psi. A retrievable bridge plug or approved logging technique will be used in casing to test tubingless completions.

Offsite Disposal

The Department of Environmental Quality permits the construction of commercial pits. Chapter III of the Wyoming Water Quality Rules and Regulations establishes permit processing and application requirements. Minimum standards for pits and wells are established in Chapter XI. The operator must demonstrate either that the facility will not allow a discharge to groundwater by direct or indirect discharge, percolation or filtration, or that the quality of the wastewater will not cause a violation of groundwater standards, or that existing soils or geology will not allow a discharge to groundwater. If the applicant cannot demonstrate any of the alternatives, the operator may conduct a subsurface investigation and develop a design to prevent violation of groundwater standards. These designs may consist of leachate collection systems, barriers with pumpback system, attenuation, or aquifer cleanup after completion of the operation. DEQ may require a monitoring program for such facilities.

At the present time there are 11 facilities authorized to receive drilling fluids and produced water, and an additional 11 that are authorized to receive produced water only.

Plugging/Abandonment

A well may be temporarily abandoned, so long as the hole is cased or left in such a manner as to prevent migration of oil, gas water, or other substances from the formations or horizons of origin. Monthly reports must be submitted to the Commission, and bonding requirements are kept in force until the well is permanently abandoned. There are no restrictions on the time period for which the well may retain such status; however, specific approval must be obtained from the Wyoming Oil and Gas Conservation Commission if a well is TA'd for more than one year. Temporarily abandoned injection wells must meet the 5 year testing requirements of the UIC program.

When wells are plugged, cement plugs of at least 100 feet must be placed over openhole porous and permeable formations (or every 2500 feet in lieu of such formations), over the stub of the casing left in the wellbore, and in the base of the surface casing. Cast iron bridge plugs set in the casing will be capped with at least two sacks of cement. Open perforations must be squeeze cemented.

References

Wyoming Department of Environmental Quality Water Quality Rules and Regulations, Chapters III, VII, IX, XI

Rules and Regulations of Wyoming Oil & Gas Conservation Commission. (January 1, 1985) Memorandum of Agreement between the Wyoming Oil and Gas Conservation Commission and the Department of Environmental Quality, Water Quality Division, September 120, 1983.

Personal Communications:

Ms. Janie Nelson, Wyoming Oil and Gas Conservation Commission, August 14, 1986. Telephone (307) 234-7147.

Mr. E. J. Fanning, Department of Environmental Quality, Water Quality Division, August 11 and August 14, 1986, and March 6, 1987. Telephone (307) 777-7781.

SUMMARY OF FEDERAL REGULATIONS

U.S. FOREST SERVICE

National Forest Systems, which include National forests and National grasslands, are administered by the U.S. Forest Service within the U.S. Department of Agriculture. Every application to drill for oil and gas that impacts the above lands is reviewed by the Service.

Where a road use permit is required, or where permit conditions related to oil and gas drilling are appropriate, such are conveyed by interagency communication to the Bureau of Land Management. The Bureau issues the lease conditions at the request of the U.S. Forest Service.

The nature of any lease condition depends upon case-by-case site specific requirements.

Communication:

Craig Losche, U.S. Forest Service (703) 235-9873

BUREAU OF LAND MANAGEMENT

INTRODUCTION

Exploration, development, drilling, and production of onshore oil and gas on Federal and Indian lands are regulated separately from non-Federal lands. This separation of authority is significant for western States where oil and gas activity on Federal and Indian lands is a large proportion of statewide activity.

REGULATORY AGENCIES

The U.S. Department of the Interior is authorized by 43 CFR 3160 for regulation of onshore oil and gas practices on Federal and Indian lands. The Department of Interior administers their regulatory program through State Bureau of Land Management offices. These agencies generally have procedures in place for coordination with State agencies on regulatory requirements. Where written agreements are not in place, the Bureau of Land Management usually works cooperatively with the respective State agencies.

The Bureau works closely with the U.S. Forest Service for surface stipulations in Federal forests or Federal grasslands. This agreement is also provided for in the Federal regulations.

RULES AND REGULATIONS

The Bureau of Land Management has authority over all aspects of oil and gas activities on Federal lands. The authority includes leasing, bonding, and royalty arrangements, construction and well spacing regulations, waste handling, waste disposal, site reclamation, and site maintenance as well as other areas. These responsibilities are extensive and the documentation regarding them is voluminous; only those portions of the regulations relating to waste handling, treatment, and disposal will be summarized herein.

Historically the Bureau of Land Management has controlled oil and gas activities through "Notice to Lessees." The requirements of current notices are described below. The Bureau is working to revise all notices into Oil and Gas Orders, which will be Federally promulgated. To date, Oil and Gas Order No. 1 has been issued. Other oil and gas orders are expected to be promulgated in the next year.

DRILLING

The Bureau of Land Management considers reserve pits, and some other types of pits, as temporary. Notice to Lessees 2B contains the following provisions for "Temporary Use of Surface Pits:"

> Unlined surface pits may be used for handling or storage of fluids used in drilling, redrilling, reworking, deepening, or plugging of a well provided that such facilities are promptly and properly emptied and restored upon completion of the operations. Mud or other fluids contained in such pits shall not be disposed of by cutting the pits walls without the prior authorization of the District Engineer. Until finally restored, unattended pits must be fenced to prevent access by livestock and wildlife. Unless otherwise specified by the District Engineer, unlined pits may be used for well evaluation purposes for a period of 30 days.

Land spreading of drilling and reworking wastes by breaching pit walls is allowed when approved by the District Engineer.

PRODUCTION

Produced waters may be disposed into the subsurface, either for enhanced recovery of hydrocarbon resources or for disposal. The operator must present detailed information regarding the proposed disposal site, including subsurface configuration of the proposed injection well, to the Bureau of Land Management prior to approval to inject. This documentation is required to ensure that the injected wastes will be confined to a receiving formation of poor quality. Further, the operator must identify the sources of the produced water, must submit estimated daily quantities of produced water, and must submit an analysis of the water. The analysis is limited to total dissolved solids, pH, chlorides, and sulfates.

The Bureau of Land Management also permits disposal of produced water into lined and unlined pits. "Lined and unlined pits approved for water disposal shall:

1. Have adequate storage capacity to safely contain all produced water even in those months when evaporation rates are at a minimum.

2. Be constructed, maintained, and operated to prevent unauthorized surface discharges of water. Unless surface discharge is authorized, no siphon, except between pits, will be permitted.

3. Be fenced to prevent livestock or wildlife entry to the pit, when required by the District Engineer.

4. Be kept reasonable free from surface accumulations of liquid hydrocarbons by use of approved skimmer pits, settling tanks, or other suitable equipment.

5. Be located away from the established drainage patterns in the area and be constructed so as to prevent the entrance of surface water."

For disposal into lined pits, the operator must submit:

- Site identification
- Planned waste quantities
- Net evaporation data
- Method of disposal for accumulated solids
- Information documenting the liner material and the impervious nature of the proposed liner
- Method used for leak detection

The operator must submit a water analysis "which include the concentrations of chlorides, sulfates, and other constituents which are toxic to animal, plant, or aquatic life." No list of required analytes is included in the Notice.

Leak detection is required for all lined produced water disposal pits. The recommended detection system is an "underlying gravel-filled sump and lateral system." Other systems may be considered acceptable upon application and evaluation.

Oil and gas operators may be permitted to use unlined pits on any one of the following bases: If the pit will receive 5 barrels or less of water per day (monthly basis), no permit is required. If the water contains less than 5,000 ppm total dissolved solids, and does not contain "objectionable levels of any constituent toxic to animal plant, or aquatic life," use of unlined pits is allowed. If the water will be used for wildlife watering, irrigation, or livestock watering, unlined pits may be used. Unlined pits may be used when the produced water is of better quality than surface or subsurface waters of the area. Unlined pits permitted for surface discharges under the National Pollutant Discharge Elimination System are also allowed.

Operators are required to provide information regarding the sources and quantities of produced water, topographic map, evaporation rates, estimated soil percolation rates, and "depth and extent of all usable water aquifers in the area."

REFERENCES

Personal communication with Mr. Steve Spector September 23, 1986.

U.S. Land Management, "Federal Onshore Oil and Gas Leasing and Operating Regulations. Not dated.

43 CFR 3100 (entire group)

U.S. Bureau of Land Management, NTL-2B.

U.S. Department of the Interior - Geological Survey Division. " Notice to Lessees and Operators of Federal and Indian Oil and Gas Leases (NTL-2B)," not dated.

U.S. ENVIRONMENTAL PROTECTION AGENCY
EFFLUENT LIMITATIONS GUIDELINES

On October 30, 1976, the Interim Final BPT Effluent Limitations Guidelines for the Onshore Segment of the Oil and Gas Extraction Point Source Category were promulgated. [41 FR 44942] The rulemaking also proposed Best Available Technology Economically Achievable (BAT), and New Source Performance Standards (Table 1).

On April 13, 1979, BPT Effluent Limitations Guidelines were promulgated for the Onshore Subcategory, Coastal Subcategory, and the Agricultural and Wildlife Water Use Subcategory of the Oil and Gas Extraction Industry. [44 FR 22069] Effluent limitations were reserved for the Stripper Subcategory due to lack of technical data.

The 1979 BPT regulation established a zero discharge limitation for all wastes under the Onshore Subcateogy. Zero discharge Agricultural and Wildlife Subcategory limitations were established, except for produced water which has a 35 mg/l oil and grease limitation.

The American Petroleum Institute (API) challenged the 1979 regulation (including the BPT regulations for the Offshore Subcategory). [661 F.2D.340(1981)] The court remanded EPA's decision transferring 1,700 wells from the Coastal to the Onshore Subcategory. [47 FR 31554] The court also directed EPA to consider special discharge limits for gas wells. Table 2 provides regulatory details related to onshore oil and gas activities.

TABLE 1. SUMMARY OF MAJOR REGULATORY ACTIVITY RELATED TO ONSHORE OIL AND GAS

October 13, 1976 -	Interim Final BPT Effluent Limitations Guidelines and Proposed (and Reserved) BAT Effluent Limitations Guidelines and New Source Performance Standards for the Onshore Segment of the Oil and Gas Extraction Point Source Category
April 13, 1979 -	Final Rules - BPT Final Rules for the Onshore, Coastal, and Wildlife and Agricultural Water Use Subcategories - Stripper Oil Subcategory Reserved - BAT and NSPS never promulgated
July 21, 1982 -	Response to American Petroleum Institute vs EPA Court Decision - Recategorization of 1700 "onshore" wells to Coastal Subcategory - Suspension of regulations for Santa Maria Basin, California - Planned reexamination of marginal gas wells for separate regulations

TABLE 2. ONSHORE SEGMENT SUBCATEGORIES

- ONSHORE:
  - BPT LIMITATION

    -- ZERO DISCHARGE

  - DEFINED: NO discharge of wastewater pollutants into navigable waters from ANY source associated with production, field exploration, drilling, well completion, or well treatment (i.e., produced water, drilling muds, drill cuttings, and produced sand).

- STRIPPER (OIL WELLS):*
  - CATEGORY RESERVED
  - DEFINED: TEN barrels per well per calendar day or less of crude oil.

- COASTAL
  - BPT LIMITATIONS

    -- No Discharge of Free Oil (No Sheen)

    -- Oil and Grease: 72 mg/l (Daily)
48 mg/l (Average Monthly)
(Produced Waters)

  - DEFINED: Any body of water landward of the territorial seas, or any wetlands adjacent to such waters.

- WILDLIFE AND AGRICULTURE USE
  - BPT LIMITATIONS

    -- Oil and Grease: 35 MG/L (Produced Waters)
-- Zero Discharge: ANY Waste Pollutants

  - DEFINED: That produced water is of good enough quality to be used for wildlife or livestock watering or other agricultural uses ... west of the 98th meridian.

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*This subcategory does not include marginal gas wells.

UNDERGROUND INJECTION CONTROL

The Underground Injection Control (UIC) Program was established under Part C of the Safe Drinking Water Act (SDWA) to provide minimum standards for procedural and technical requirements for individual State and Federal UIC Programs. Part C of the SDWA requires the EPA to: (1) identify a list of States for which UIC programs may be necessary; (2) approve or disapprove, in whole or in part, UIC programs submitted by the listed States; and (3) develop programs and regulate those States that do not have approved UIC programs. The Federal UIC Program is defined in 40 CFR Parts 144, 145, and 146.

Table 3 is a list of States having full or partial primacy over their particular UIC Programs. The second column from the left in Table 3 lists the section of the SDWA under which the States applied for approval of their UIC Programs. The third column from the left lists the classes of wells, defined in Table 4, for which primacy has been given. The classes of wells that a State can regulate depend upon the SDWA section under which a State's authority is granted. Section 1422 was originally designed to cover all classes of wells. Brine disposal injection wells were later addressed specifically in Section 1425, which was created by Congress (Dec. 5, 1980) to further define the conditions by which these wells would be regulated. In essence, a State may show that it has a program already in place that has been effective in protecting underground sources of drinking water and that includes record keeping, reporting, permitting, and inspections authority over Federal agencies, and assurance that authorized wells do not endanger underground sources of drinking water.

Minimum standards for UIC programs as defined in 40 CFR 144, 145, and 146 include, respectively, permitting requirements, guidance to obtain approval for State primacy, and technical criteria and standards to be met in permits and authorizations. Part 144 also serves as part of the UIC program for States to be administered by EPA. Part 147 lists and sets specific criteria for those States whose UIC programs are administered by EPA.

TABLE 3. UIC PRIMACY STATES (PROGRAMS APPROVED)

Date June 9, 1986

STATE	TYPE	CLASSES	DATE APPROVED	FR CITE
Oklahoma	1425	II	December 2, 1981	46 FR 58488
Texas	1422	I, III, IV, V	January 6, 1982	47 FR 618
New Mexico	1425	II	February 5, 1982	47 FR 5412
Louisiana*	1422/25	I - V	April 23, 1982	47 FR 17487
Texas*	1425	II	April 23, 1982	47 FR 17488
Oklahoma*	1422	I, III, IV, V	June 24, 1982	47 FR 27273
Arkansas	1422	I, III, IV, V	July 6, 1982	47 FR 29236
Alabama	1425	II	August 2, 1982	47 FR 33268
New Hampshire*	1422	I - V	September 21, 1982	47 FR 41561
Utah	1425	II	October 8, 1982	47 FR 44561
Wyoming	1425	II	November 22, 1982	47 FR 52434
Massachusets*	1422	I - V	November 23, 1982	47 FR 52705
Utah*	1422	I, III, IV, V	January 19, 1983	48 FR 2321
Nebraska	1425	II	February 3, 1983	48 FR 4777
Florida**	1422	I, III, IV, V	February 7, 1983	48 FR 5556
California**	1425	II	February 11, 1983	48 FR 6336
Guam*	1422	I - V	May 2, 1983	48 FR 19717
New Mexico*	1422	I, III, IV, V	July 11, 1983	48 FR 31640
Wyoming*	1422	I, III, IV, V	July 15, 1983	48 FR 32343
New Jersey*	1422	I - V	July 15, 1983	48 FR 32343
North Dakota	1425	II	August 23, 1983	48 FR 38237
Ohio	1425	II	August 23, 1983	48 FR 38238
Alabama*	1422	I, III, IV, V	August 25, 1983	48 FR 38640
Maine**	1422	I - V	August 25, 1983	48 FR 38641
Mississippi**	1422	I, III, IV, V	August 25, 1983	48 FR 38641
Wisconsin*	1422	I - V	September 30, 1983	48 FR 44783
Kansas	1422	I, III, IV, V	December 2, 1983	48 FR 54350
Missouri	1425	II	December 2, 1983	48 FR 54349
West Virginia*	1422/25	I - V	December 9, 1983	48 FR 55127
Illinois	1425	II	February 1, 1984	49 FR 3990
Illinois*	1422	I, III, IV, V	Feburary 1, 1984	49 FR 3991
Kansas*	1425	II	February 9, 1984	49 FR 4735
Arkansas*	1425	II	March 26, 1984	49 FR 11179
Connecticut*	1422	I - V	March 26, 1984	49 FR 11179
Colorado**	1425	II	April 2, 1984	49 FR 13040
Delaware*	1422	I - V	April 5, 1984	49 FR 13525
Maryland*	1422	I - V	April 19, 1984	49 FR 15553
North Carolina*	1422	I - V	April 19, 1984	49 FR 15553
Georgia*	1422	I - V	April 19, 1984	49 FR 15553
Nebraska*	1422	I, III, IV, V	June 12, 1984	49 FR 24134
Vermont*	1422	I - V	June 22, 1984	49 FR 25633
South Carolina*	1422	I - V	July 10, 1984	49 FR 28057
Rhode Island*	1422	I - V	August 1, 1984	49 FR 30698
Washington*	1422	I - V	August 9, 1984	49 FR 31875
North Dakota*	1422	I, III, IV, V	September 21, 1984	49 FR 37065
Oregon*	1422/25	I - V	September 25, 1984	49 FR 37593
South Dakota**	1425	II	October 24, 1984	49 FR 42728
Ohio*	1422	I, III, IV, V	November 29, 1984	49 FR 46896
Idaho*	1422	I - V	June 7, 1985	50 FR 23956
Missouri*	1422	I, III, IV, V	July 17, 1985	50 FR 28941
CNMI*	1422	I - V	July 17, 1985	50 FR 28942
Alaska**	1425	II	May 6, 1986	51 FR 16683

*Full primacy, as of date indicated
**Partial primacy

TABLE 4. CLASSIFICATION OF INJECTION WELLS

Class I	o	Wells used by generators of hazardous waste or owners or operators of hazardous waste management facilities to inject hazardous waste beneath the lowermost formation containing, within one quarter (1/4) mile of the well bore, an underground source of drinking water.
	o	Other industrial and municipal disposal wells which inject fluids beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water.
Class II		Wells used to inject fluids:
	o	Which are brought to the surface in connection with conventional oil or natural gas production and may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection;
	o	For enhanced recovery of oil or natural gas; and
	o	For storage of hydrocarbons which are liquid at standard temperature and pressure.
Class III		Wells used to inject for extraction of minerals including:
	o	Mining of sulfur by the Frasch process.
	o	In situ production of uranium or other metals. This category includes only in situ production from ore bodies which have not been conventionally mined. Solution mining of conventional mines such as stopes leaching is included in Class V.
	o	Solution mining of salts or potash.
Class IV	o	Wells used by generators of hazardous waste or of radioactive waste, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous waste or radioactive waste into a formation which within one quarter (1/4) mile of the well contains an underground source of drinking water.

TABLE 4. CLASSIFICATION OF INJECTION WELLS
(Continued)

Class IV (Cont'd)	o	Wells used by generators of hazardous waste or of radioactive waste, by owners or operators of hazardous waste management facilities or by owners or operators of radioactive waste disposal sites to dispose of hazardous waste or radioactive waste above a formation which within one quarter (1/4) mile of the well contains an underground source of drinking water.
	o	Wells used by generators of hazardous waste or owners or operators of hazardous waste management facilities to dispose of hazardous waste, which cannot be classified under Sect. 146.05(a)(1) or 146.05(d) (1) and (2) (e.g., wells used to dispose of hazardous wastes into or above a formation which contains an aquifer which has been exempted pursuant to Sect. 146.04).
Class V	o	Injection wells not included in Class I, II, III, or IV.

REFERENCES

Federal Register, 40 CFR Parts 144, 145, 146, and 147.

Safe Drinking Water Act, Part C, December 16, 1974, as amended by PL 96-502, December 5, 1980.

Personal Communication with Mr. Mario Salazar, U.S. EPA UIC Program, October 7, 1986. Telephone 202- 382-5561.