



TEXAS DEPARTMENT OF WATER RESOURCES

REPORT 274

UNDERGROUND INJECTION CONTROL TECHNICAL ASSISTANCE MANUAL Subsurface Disposal and Solution Mining

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ABSTRACT

The Texas Department of Water Resources has issued over 200 waste disposal well permits and approximately 30 uranium solution mining permits. Solution mining of brine, sulfur, and sodium sulfate in Texas is also regulated by the Department. The technical staff of the Department evaluates applications for waste disposal well and solution mining permits and makes recommendations based on local and regional geology and hydrology, reservoir mechanics of the injection interval, proposed well design, compatibility of injected fluid with receiving formation, completion and plugging methods of artificial penetrations, potential hazards of proposed injection projects to usable ground water and mineral resources, and proposed facility closure including financial assurance. If a permit is granted, the Department has the responsibility for compliance monitoring of the injection project.

The effects of the proposed injection activity are simulated using the Theis nonequilibrium method. Maximum allowable injection pressures are restricted in the permits at levels below fracture pressure. Conservative assumptions of reservoir parameter values are used and adequate safety margins are employed in predicting the effect of the injection operation upon the receiving reservoir.

Well construction and completion design specifications utilize state of the art injection well technology. Waste disposal wells are constructed with surface casing set below the base of fresh water and long-string casing set to the injection interval with both strings cemented back to the surface. The wells are completed by perforating, screen and gravel packing, or open hole. Injection is maintained through tubing set on a packer. Continuous recording instruments are installed to record injection pressure, annulus pressure, and injection rates.

Proper plugging and abandonment of injection wells can be accomplished by several methods. The Department determines the suitability of a proposed plugging procedure for a particular injection activity. A properly plugged well is one where interformational transfer of fluids does not occur.

The Department's Underground Injection Control program was awarded primary enforcement authority by the Environmental Protection Agency effective January 6, 1982. The Department reviews applications for underground injection permits and makes recommendations to the Texas Water Commission. A permit for an underground injection operation may be granted by the Texas Water Commission when it is determined that it is in the public interest; no existing rights will be impaired; with proper safeguards, both ground and surface fresh water can be protected from pollution; and the applicant has made a satisfactory showing of financial responsibility. The Department has found that if the injection of fluids is confined to suitable subsurface stratum, the injection wells are properly designed, constructed, and operated, and injection pressures are maintained below certain limits, there should be no hazards of pollution to fresh ground water under any conditions due to the injection operations.

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UNDERGROUND INJECTION CONTROL

TECHNICAL ASSISTANCE MANUAL

Subsurface Disposal and Solution Mining

INTRODUCTION

Background

During the twentieth century, our society has become increasingly complex, creating a greater demand for goods and services. Modern technologies are becoming more efficient in response to consumer demand, and we are better able to recover ores, minerals, and fuels as well as produce and distribute vast amounts of manufactured goods. As we produce and consume more, a corresponding volume of waste is generated.

Underground injection is an application of injection well technology consisting of the placing of fluid beneath the surface of the ground by injection for fluid disposal or mineral recovery. Solution mining to recover minerals uses a combination of injection, recovery, and observation wells. State of the art well technology in conjunction with ground-water hydraulics, geochemistry, and advanced drilling methods can play an important role in the economical exploitation of mineral resources and in the disposal of liquid waste.

Underground injection began in Texas over 70 years ago with sulfur mining by the Frasch process. It is not known when disposal of wastewater by underground injection began in Texas; however, the first major project to utilize injection wells for the disposal of liquid wastes into the subsurface occurred in 1938 in an East Texas oil field where salt water produced with oil from the Woodbine Formation was returned to the lower part of the formation. The injection of industrial wastewater into subsurface strata, which do not produce oil or gas, was permitted and regulated by the Railroad Commission of Texas in the early 1950's. Today the Railroad Commission regulates subsurface injection associated with the oil and gas industry, while the Texas Department of Water Resources regulates the majority of other underground injections in the State.

Texas has more than 40,000 injection wells associated with the production of oil and gas, four or five thousand solution mining wells, several hundred municipal and industrial waste disposal wells, and an unknown number of miscellaneous wells. The application of underground injection wells includes: municipal and industrial waste disposal; secondary oil recovery and salt water disposal; storage of natural gas and petroleum products in underground reservoirs; preven-

tion of the intrusion of undesirable water into fresh ground-water resources; recovery of minerals, such as sulfur, uranium, and sodium sulfate; injection of fluids to control land-surface subsidence; and the injection of excess agricultural or urban runoff and excess ponded surface waters.

The Department and its predecessor agencies have issued over 200 permits authorizing the subsurface injection of liquid wastes into aquifers containing saline water. Approximately 30 uranium solution mining permits have also been issued. As of January 1982, there are approximately 120 operating waste disposal wells and 30 uranium solution mining projects in Texas. The technical staff of the Department evaluates applications for disposal well and solution mining permits, conducts investigations to determine the suitability of proposed injection projects, and makes recommendations for the issuance or denial of permits to authorize the proposed injection projects. The evaluation of an application includes: (a) regional and local geology and hydrology; (b) lithology of the receiving formation; (c) movement and dispersion of injected fluids; (d) pressure changes in the injection interval; (e) proposed well design; (f) compatibility of injected fluid with receiving formation; (g) completion and plugging methods of artificial penetrations in the vicinity of the proposed injection project; (h) potential hazards of proposed injection projects to usable ground water and mineral resources; and (j) proposed facility closure including financial assurance. If a permit is granted, the technical staff of the Department has the responsibility of monitoring the injection project.

The Department has found that if injection of fluids is confined to suitable subsurface stratum, wells are properly designed and operated, and injection pressures are maintained below certain limits, both ground and surface fresh water resources are adequately protected from pollution.

The type of industrial waste disposed of by deep well injection is generally: (a) a relatively low volume waste stream, (b) not readily amenable to alternate disposal methods such as incineration or treatment and discharge, (c) within a neutral pH range, (d) very high in dissolved solids concentration, (e) containing other process-related pollutants, and (f) with essentially no suspended solids. The wastewater is usually filtered prior to injection.

Purpose and Scope

The purpose of this report is to inform the general public of the practice and nature of underground injection and foster a better understanding of the role of the Texas Department of Water Resources in protecting the quality of the water resources of the State. This report can also be used as a general guide for persons considering or planning an underground injection project.

This report provides a comprehensive analysis of current injection well practices in Texas. It contains information on geologic and hydrologic conditions, planning, design, construction, operation, and closure of injection wells. Regulatory aspects of the Underground Injection Control program are also discussed in terms of the minimum criteria necessary to protect ground water.

Metric Conversions

For those readers interested in using the International System (SI) of Units, the metric equivalents of English units of measurements are given in parentheses in the text. The English units used in this report may be converted to metric units by the following conversion factors:

Multiply English units	By	To obtain SI units
barrels (42 gal)	0.1590	cubic meters (m ³)
feet (ft)	.3048	meters (m)
gallons (gal)	3.785	liters (l)
gallons per minute (gal/min)	.06309	liters per second (l/s)
gallons per day per square foot [(gal/d)/ft ²]	40.74	liters per day per square meter [(l/d)/m ²]
gallons per day per foot [(gal/d)/ft]	12.418	liters per day per meter [(l/d)/m]
inches (in)	2.54	centimeters (cm)
miles (mi)	1.609	kilometers (km)
pounds (lb)	.4536	kilograms (kg)
pounds per square inch (lb/in ²)	.07031	kilograms per square centimeter (kg/cm ²)
pounds per foot (lb/ft)	1,488	grams per meter (g/m)
pounds per gallon (lb/gal)	7.2	kilograms per liter (kg/l)

To convert degrees Fahrenheit (°F) to degrees Celsius (°C) use the following formula:

$$^{\circ}\text{C} = (^{\circ}\text{F} - 32)(0.556)$$

GEOGRAPHY AND GEOLOGIC SETTING

Disposal Reservoirs

Subsurface disposal of industrial wastewater in Texas began in 1953 at the E. I. DuPont de Nemours and Company, Inc. Victoria Plant located in Victoria County near the town of Bloomington. This well is still in operation and utilizes the Catahoula Formation of Miocene age. Since 1953, more than 200 waste disposal wells have been permitted in Texas that use more than two

dozen different disposal reservoirs. Suitable disposal reservoirs exist in most regions of the State. Areas that have been subjected to extensive structural deformation in many cases do not contain suitable disposal reservoirs. Figure 1 is a generalized map of Texas indicating the suitability of the subsurface strata for waste disposal by underground injection.

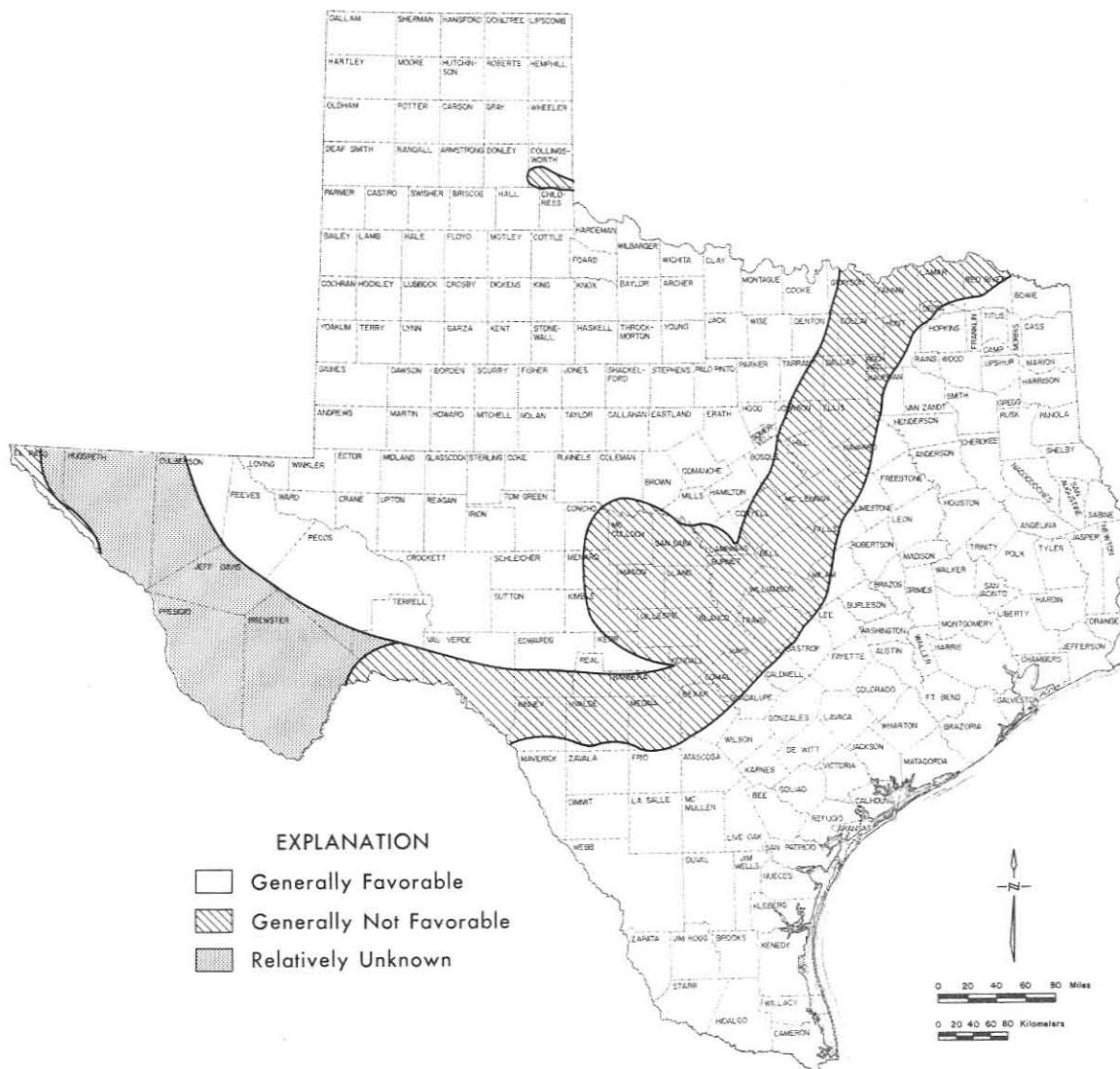


Figure 1.—Suitability of Areas in Texas for Underground Injection of Wastes

Characteristics of a Disposal Reservoir

Porosity and permeability are principal factors used to determine the suitability of a potential disposal reservoir. Porosity is the ratio of the volume of interstices in a rock to its total volume. The permeability of a medium is a measure of its capacity for transmitting a fluid. The degree of permeability depends on the size and shape of the interstices and their interconnections. Adequate porosity and permeability to accept fluids is necessary for an aquifer to be considered for use as a disposal reservoir.

Other criteria that a proposed disposal reservoir should meet include the following:

- (a) native ground water should be saline;
- (b) the reservoir should not contain recoverable mineral resources;
- (c) the reservoir should be relatively thick with an adequate confining layer;
- (d) the reservoir should be located in an area of simple geologic structure;
- (e) the reservoir should be areally extensive;
- (f) the reservoir should be essentially homogeneous and isotropic;
- (g) the reservoir should exhibit adequate separation both horizontally and vertically from potentially usable quality water; and
- (h) the reservoir should have no unplugged or improperly abandoned wells penetrating it.

Disposal Reservoirs in Texas

The search for oil and gas has led to the drilling of hundreds of thousands of exploratory wells in Texas. Drilling records and geophysical logs of these wells have revealed much information concerning the subsurface geology of the State. These data are useful in evaluating the potential of aquifers to serve as disposal reservoirs.

The State of Texas can be conveniently divided into five geographic regions in which injection wells using similar disposal reservoirs occur. The different geographic regions of Texas are shown in Figure 2, and the aquifers presently used as disposal reservoirs are listed in Table 1. Major structural features of Texas are also shown on Figure 2. Most of the disposal reservoirs occur in the Tertiary sediments of the Gulf Coast region. The density of industrial development in this region combined with the suitability of the subsurface environment contributes to the development of Gulf Coast aquifers as disposal reservoirs.

The Tertiary strata of the Gulf Coast region were deposited in alternating sequences of fluvial-deltaic sediments caused by repeated transgressions and regressions of the shoreline. Subsidence of the Gulf Coast basin during the period has resulted in the accumulation of sediments as thick clastic wedges. The fluvial and deltaic sands provide excellent disposal reservoirs that are hydrologically isolated by impervious clays deposited in adjacent flood plain, lagoonal, or marine environments.

Along the upper Gulf Coast, from Victoria to Port Arthur, waste disposal wells predominantly use undifferentiated Miocene sands, including the Catahoula and the Frio Formations. In addition to these aquifers, the Oakville, Anahuac, and Greta Formations along with undifferentiated Pliocene and Oligocene sands, find occasional use. Lower Gulf Coast aquifers used as disposal reservoirs include the Oakville, Catahoula, Frio, and Queen City Formations, and the Jackson and Wilcox Groups.

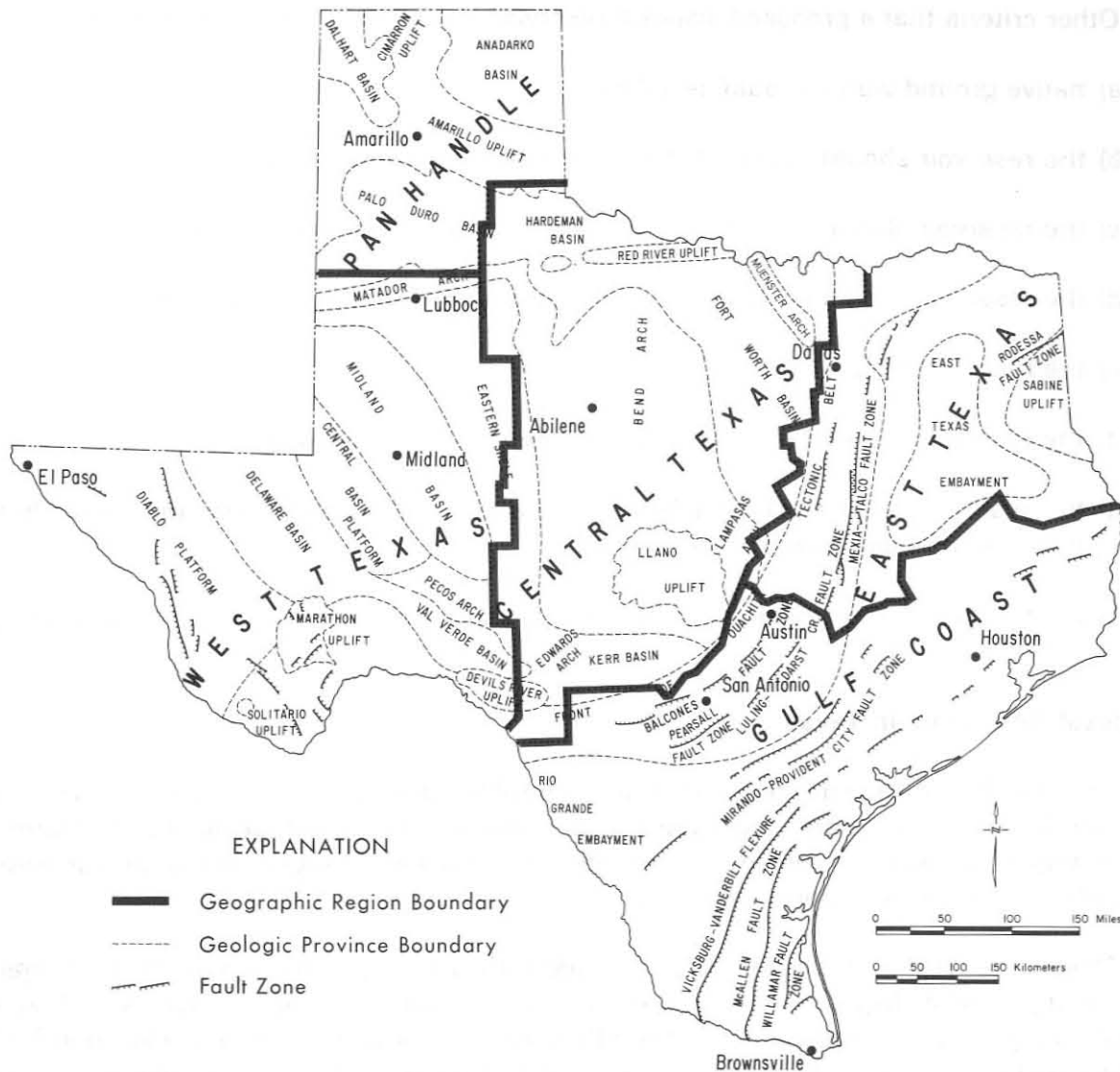


Figure 2.—Geographic Regions of Texas

Table 1.—Disposal Reservoirs in Texas

<u>Aquifer</u>	<u>Age</u>	<u>Region</u>	<u>No. of Wells</u>
Undifferentiated Miocene	Tertiary	Gulf Coast	41
Frio	Tertiary	Gulf Coast	23
Yegua	Tertiary	Gulf Coast	20
Catahoula	Tertiary	Gulf Coast	14
Oakville	Tertiary	Gulf Coast	7
Wilcox	Tertiary	Gulf Coast	4
Greta	Tertiary	Gulf Coast	3
Queen City	Tertiary	Gulf Coast	3

Table 1.—Disposal Reservoirs in Texas—Continued

<u>Aquifer</u>	<u>Age</u>	<u>Region</u>	<u>No. of Wells</u>
Anahuac	Tertiary	Gulf Coast	2
Jackson	Tertiary	Gulf Coast	2
Undifferentiated Pliocene	Tertiary	Gulf Coast	1
Woodbine	Cretaceous	East Texas	3
Blossom	Cretaceous	East Texas	1
Rodessa	Cretaceous	East Texas	1
Chappel Reef	Mississippian	Central Texas	2
Clear Fork	Permian	Central Texas	1
Ellenberger	Ordovician	Central Texas and Panhandle	3
Granite Wash	Pennsylvanian	Panhandle	5
Brown Dolomite	Permian	Panhandle	4
Glorieta	Permian	Panhandle	2
Santa Rosa	Triassic	Panhandle	1
San Andres	Permian	West Texas	6
Castile	Permian	West Texas	1
Delaware	Permian	West Texas	1

The East Texas region on Figure 2 contains five operating waste disposal wells. The region is composed of Tertiary age and older sediments that are consolidated and unconsolidated. The major structural features of the East Texas region are the East Texas embayment and the Sabine uplift. The principal disposal reservoirs in this area are the Woodbine, Blossom, Paluxy, and Rodessa Formations of Cretaceous age.

The Central Texas region contains a thick sequence of Paleozoic sedimentary rocks overlain in part by Mesozoic sedimentary rocks. Disposal reservoirs in this area are usually limestones or dolomites. The Chappel Reef of Mississippian age has been used as a disposal reservoir by two disposal wells. The Ellenberger Limestone of Ordovician age has also been used as a disposal reservoir.

The major structural feature of Central Texas is the Llano uplift. The Llano uplift exposes Precambrian rocks at the surface near Llano. An area of approximately 50 miles surrounding the uplift is not satisfactory for waste disposal. Aquifers along the flanks of the uplift such as the Ellenberger and Riley Formations provide the only underground sources of drinking water in this area. The Hickory Sandstone Member of the Riley Formation is used for irrigation water around Mason in the Llano uplift area. Within the uplift area and on its flanks, there are no suitable aquifers for subsurface injection of waste.

The West Texas region is the most complex from a geologic standpoint. The region has deep basins such as the Delaware and Midland basins, and uplifted areas such as the Solitario and

Marathon uplifts. Volcanic activity is present and thick volcanic sequences overlie some areas. The stratigraphic section that outcrops in the area ranges from Precambrian strata near Van Horn to Quaternary bolson deposits along the Rio Grande. Thick sequences of Paleozoic and Mesozoic rocks are exposed throughout the region. Most of this region is undeveloped and the need for waste disposal wells is not great.

Most of the waste disposal wells in the West Texas region are near Odessa. These wells use the San Andres Formation of Permian age. The San Andres is a limestone and dolomite unit with secondary porosity. Field experience has shown it to be a formation of low permeability. Because of the low permeability, injection is usually at a low flow rate and high relative injection pressure.

The Texas Panhandle region is composed of four major geologic structures—the Amarillo uplift and the Dalhart, Palo Duro, and Anadarko basins. The uplift is in the center of the region with the basins flanking it to the north and south. Most of the waste disposal wells in the Panhandle region are located on the uplift near Amarillo. These wells primarily utilize the Pennsylvanian Granite Wash and Permian Brown Dolomite as disposal reservoirs. The Granite Wash is an arkosic conglomerate composed chiefly of granite grus developed from basement rocks of the Amarillo uplift. The Permian Brown Dolomite is a massive dolomite with vugular porosity. These sediments serve as excellent disposal reservoirs as they are isolated from fresh ground water resources and commonly accept wastes at surface injection pressures less than zero.

Many aquifers exist in the State that do not have the potential to be used as disposal reservoirs. Aquifers that do not exhibit adequate separation from sources of fresh water such as the Ogallala and the Edwards aquifers are not suitable for injection. Some aquifers do not have sufficient porosity and permeability to accept waste fluids. Aquifers that are not areally extensive are of limited usefulness as disposal aquifers. Aquifers in areas that have been subjected to extensive structural deformation are not suitable for use as disposal reservoirs. Areas that do not contain aquifers that are suitable for use as disposal reservoirs include the Llano uplift, the Balcones fault zone, the Marathon uplift, and the Diablo platform.

In summary, a number of suitable disposal reservoirs exist in Texas. Some of these reservoirs are being used currently to receive wastes. Many other formations in the State may be utilized as disposal reservoirs should the need arise. The use of a particular subsurface formation as a disposal reservoir is controlled not only by the physical properties of the formation, but is also dependent on the degree of industrial development, and hence the need for disposal capacity, in a given area.

Solution Mining

Solution or in situ mining utilizes injection and recovery well techniques to bring minerals from underground deposits to the surface. Solution mining of sulfur began with the Frasch process in the early 1900's. Since then, solution mining techniques have been developed for the recovery of uranium, salt brines, and mineralized ground water as a raw material from which sodium sulfate is extracted. The general locations of the above mining activities in Texas are shown on Figure 3.

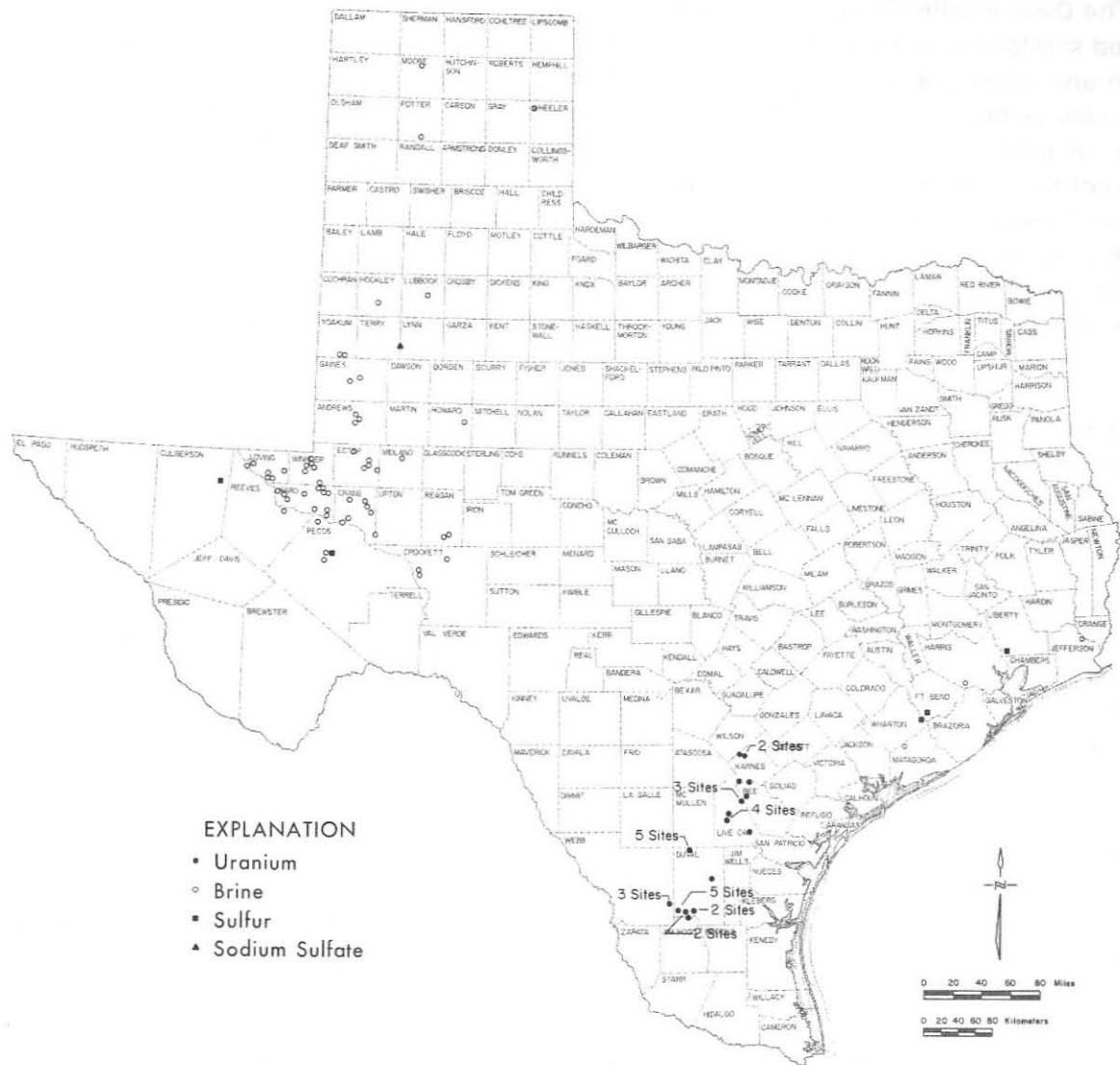


Figure 3.—Solution Mining in Texas

Uranium

Texas came into the uranium picture rather late, but now ranks high among other states in the Nation in its uranium potential. There are five geographic areas of Texas where uranium mineralization has been found: (a) Trans-Pecos region; (b) Panhandle region; (c) Red River region; (d) Llano uplift; and (e) South Texas Coastal Plain. The South Texas Coastal Plain is the only part of the State in which economic deposits of uranium have been exploited by solution mining methods.

In situ uranium operations in South Texas are currently extracting ore by underground injection from the Deweesville Sandstone Member of the Eocene Whitsett Formation, the Oligocene Catahoula Tuff, the Miocene Oakville Sandstone, and the Pliocene Goliad Formation.

The Deweesville Sandstone consists of fine- to medium-grained, friable, tuffaceous, cross-bedded sandstone and siltstone and averages 30 feet (9.1 m) in thickness. The Catahoula Tuff, which unconformably overlies the Whitsett Formation, consists chiefly of tuff, tuffaceous sand, sand, clay, bentonitic clay, and lenticular sandstone. It ranges in thickness from 500 feet (152.4 m) at its outcrop to over 1,000 feet (304.8 m) in the subsurface. The Oakville Sandstone unconformably overlies the Catahoula and is composed of cross-bedded, medium- to fine-grained sand and sandstone interbedded with sandy clay. The thickness of the Oakville ranges from 200 feet (61 m) near its outcrop to 800 feet (243.8 m). The Goliad Formation unconformably overlies the Oakville and consists of partly cross-bedded medium- to very coarse-grained, sand, sandstone, and gravel. It ranges in thickness from 75 to 200 feet (22.9 to 61 m).

Uranium ore is usually associated with tuffaceous sand, but has also been found in the silts and bentonitic clays in the area. When found in clay, the ore occurs along joint and bedding planes in the clay immediately underlying the sands. The ore deposits generally range in thickness from 20 to 40 feet (6.1 to 12.2 m).

The quality of ground water associated with the uranium ore is highly variable; however, the water is generally used for domestic, irrigation, and industrial purposes. Ground water below the production intervals often contains high concentrations of chlorides and dissolved solids. Thus, not only do the aquifers contain uranium, but they often contain ground water suitable for most purposes.

Sulfur

Accumulations of sulfur in Texas are found in the Trans-Pecos region and on the Gulf Coast (Figure 3). In both regions the sulfur is associated with calcium sulfate (gypsum and anhydrite), rock salt, and limestone.

The sulfur of the Gulf Coast is associated with intrusive plugs or domes of salt and anhydrite which have pushed up through overlying sediments from deep host formations to varying distances from the present surface. Sulfur is produced from the cap rock on the top of the salt domes and occurs in the seams, fissures, and cavities. The sulfur in the anhydrite portions of the cap rock cannot be solution mined because anhydrite lacks the required porosity and permeability.

The native sulfur in the Trans-Pecos region of Texas occurs in the Seven Rivers, Yates, Tansill, Castile, Salado, and Rustler Formations. These Permian formations consist of limestone, salt, dolomite, gypsum, and calcite. The sulfur occurs in association with calcite, in fractures and vugs, and in dolomite where the sulfur-bearing beds apparently follow the natural porosity of the strata.

Based on the study of cores and drilling samples, sulfur appears to be a secondary deposit in the host rock and is probably derived through bacterial action. Most theories concerning the origin of sulfur suggest reduction of sulfate rocks by anaerobic bacteria and oxidation of hydrogen sulfide by ground water to produce calcite and sulfur. The bacterial theory does not require high temperatures; however, hydrocarbons should be present to support the bacteria at the time of

enrichment. In both the Trans-Pecos and Gulf Coast regions, there is evidence to suggest that commercial deposits of sulfur occur in close association with petroleum.

Brine and Sodium Sulfate

The solution mining of salt and sodium sulfate brine occurs primarily in West Texas. Salt brines are obtained from the massive rock salt beds of the Salado Formation where a combination injection and production well is used to produce the brine. Sodium sulfate is produced by the mining of brines from sulfate deposits contained in playa lake or lacustrine silts, sands, and clays. These sediments are of Pleistocene age and occur in depressions of the Cretaceous limestones and clays. Surrounding the playa deposits and overlying the Cretaceous is the Ogallala Formation which is Tertiary in age. Currently, the solution mining of sodium sulfate occurs only in Terry County (Figure 3).

As with sulfur, salt brine is produced from salt domes on the Texas Gulf Coast. The deep source of the salt, known as the Louann Salt, could range in age from Permian to upper Jurassic and is probably on the order of 20,000 to 25,000 feet (6,100 to 7,600 m) deep. Many geologists believe the salt is Permian in age and is related to the West Texas Permian evaporite deposits such as the Salado Formation.

RESERVOIR MECHANICS

Reservoir Characteristics

An understanding of geologic and hydrologic characteristics is necessary to evaluate the suitability of an injection zone for solution mining or subsurface waste disposal. Lithology, porosity, permeability, transmissivity, storage coefficient, net permeable thickness, pressures, confining zones, compatibility of fluids, and boundary conditions are some of the parameters evaluated.

Lithology

The lithology of a rock is a description of its physical characteristics such as mineralogic composition, color, and grain size. Injection zones in South Texas and on the Gulf Coast are predominantly composed of sands of varying degrees of cementation and compaction. Limestones and dolomites serve as disposal reservoirs in West Texas. Brine is produced from bedded salt, and sodium sulfate is produced from lacustrine silts, sands, and clays in West Texas. Sulfur is mined from the cap rock of salt domes in South and East Texas and from gypsum, limestone, and rock salt deposits in West Texas.

Porosity and permeability, which will be discussed later in detail, are the most important parameters that affect the suitability of a reservoir for fluid injection. These parameters, along with aquifer thickness, determine the capability for storage and transmitting injected fluids. Ideally, the reservoir should be free of impervious materials such as clay, silt, and shale. Injection of fluids will cause an increase of reservoir pressure. Consequently, a porous and permeable

reservoir of sufficient thickness is able to disseminate increased pressures and avoid excessive pressure buildup at the point of injection.

Porosity

Porosity is directly related to the lithologic composition of the injection zone. It may be defined mathematically as:

$$\phi = \frac{V_v}{V_t},$$

where

- ϕ = porosity, expressed as a fraction;
- V_v = volume of void space; and
- V_t = total volume of rock sample.

Porosity is routinely expressed as a percentage, either total porosity or effective porosity. Total porosity is a measure of all void space within a sample; whereas, effective porosity is based on the volume of interconnected voids. Hydraulic properties of a rock unit are best defined using effective porosity, since only interconnected voids are available for fluid flow through the rock.

Porosity may be further defined as primary or secondary. Primary porosity is associated with the original intergranular or intercrystalline interstices of the rock. Secondary porosity results from mechanical alteration of the porous media by fracturing, solution channeling, and from recrystallization and dolomitization. Intergranular porosity occurs in sands and sandstones, and values are dependent upon the grain size, sorting, shape, mineralogic composition, and degree of cementation and compaction. Laboratory core analysis is one method used to determine porosity values. Porosity is best determined using borehole geophysical techniques correlated with laboratory core analysis.

Average porosities in sedimentary rocks range from over 35 percent in recently deposited, unconsolidated sands to less than 5 percent for lithified sandstones. Crystalline and microcrystalline limestones and dolomites may have little primary porosity; however, they often exhibit adequate secondary porosity for injection purposes. Underground injection in Texas is primarily into sedimentary strata. Typical porosity values range from 10 to 30 percent for disposal reservoirs and uranium solution mining zones.

Pore volume per unit area is calculated by multiplying total thickness of the injection zone by average porosity. This value determines the displacement of injected fluid into a disposal reservoir. For solution mining, pore volume is used to estimate the amount of water which may be handled during restoration operations to return the injection zone to pre-mining conditions.

Permeability

Permeability is a measure of the capacity of a porous rock sediment, or soil, for transmitting a fluid. All substances have permeability, although in the case of granite or cement it may be so low

as to be difficult to measure. A reservoir considered for injection must have sufficient permeability to allow injected fluid to penetrate into the void spaces without need for excessive injection pressures. Compacted clays, commonly described as impermeable, usually have low coefficients of permeability. Clays or shales are not suitable for waste disposal because waste can be injected into them only at extremely slow rates. By contrast sands, gravels, and vugular or fractured carbonate rocks are usually more permeable and may serve as injection zones for waste disposal or solution mining.

Permeability may be measured in darcys or Meinzer units. A darcy is equivalent to the passage of 1 cubic centimeter of fluid of 1 centipoise viscosity flowing in 1 second under a pressure differential of 1 atmosphere through a porous medium having an area cross section of 1 square centimeter and length of 1 centimeter. The Meinzer unit of the coefficient of permeability, k , is the rate of flow of water in gallons per day through a cross-sectional area of 1 square foot under a hydraulic gradient of 1 foot per foot at 60°F. The Meinzer unit is primarily used in hydrology, while darcys are most commonly used in petroleum engineering.

Transmissivity

Theis (1935) introduced the term coefficient of transmissivity. It is expressed as the rate of flow of water in gallons per day through a vertical strip of the aquifer 1 foot wide and extending the full saturated height of the aquifer under a hydraulic gradient of 100 percent (1 foot per foot). The coefficient of transmissivity is derived by multiplying the coefficient of permeability by the thickness of the aquifer.

Confined and Unconfined Aquifers

A reservoir is under water-table conditions or unconfined when the ground water encountered by a well is in direct vertical contact with the atmosphere. The water surface fluctuates with the atmospheric pressure and in response to changes in the volume of water in storage in the aquifer. In an unconfined aquifer, the zone of saturation extends from the underlying confining bed to the water table. An aquifer is confined when it is separated from the atmosphere by impermeable material, and the contained ground water is under sufficient pressure to rise above the level at which the aquifer is encountered in a well. In this case, the water is under artesian conditions. The level to which water rises in well bores defines an imaginary surface called the piezometric surface. For a confined aquifer, the zone of saturation represents complete saturation of the water-bearing formation and is equal to its thickness. The term potentiometric surface applies both to the piezometric surface of a confined aquifer and the water-table surface of an unconfined aquifer. The potentiometric surface is determined by the hydrostatic pressure of water in the aquifer (Lohman, 1972).

The upper and lower boundaries of an injection zone in solution mining are usually defined by confining layers. These beds should be areally extensive, relatively impermeable, and thick enough to prevent the migration of mining solutions from the mining zone to other fresh-water aquifers. Leaching solutions must be confined in the mining zone in uranium solution mining in order to make contact with the ore and mobilize it for recovery by production wells. By isolating the mining zone, confining beds not only protect other fresh-water aquifers, but are also economically

beneficial to the mining operator by restricting mining solutions to the ore zone, rather than allowing them to migrate to zones which do not contain recoverable ore.

In disposal reservoirs, confining layers serve the same basic function as in solution mining, confining injected fluids to the injection zone. The total net thickness of clay layers from the injection zone to the base of fresh or usable ground water is considered when evaluating the competency of confining layers. A net clay thickness of up to 1,000 or more feet (304.8 or more m) is desirable; however, a thickness of 200 feet (61 m) of low permeability clay may be considered an adequate confining layer between the injection zone and the base of fresh or usable quality ground water. Although thickness is a primary concern in determining the competency of a confining layer, other factors such as permeability, areal extent, continuity, and faulting are also important.

Storage Coefficient

The storage coefficient of an aquifer is the "volume of water it releases from or takes into storage per unit surface area of the aquifer per unit change in the component of hydrostatic pressure normal to that surface" (Ferris and others, 1962). In confined or artesian aquifers, two elastic effects result when the hydrostatic pressure is reduced by pumping. These effects are compression of the aquifer and expansion of the contained water. The value of the artesian storage coefficient is small, and it is dimensionless. In an unconfined or water-table aquifer, the storage coefficient is also dimensionless and is assumed to be the ratio of the volume of water which an aquifer, after being saturated, will yield by gravity to the volume of the aquifer after it is drained.

For purposes of this report, only the storage coefficient for artesian or confined aquifers is discussed in detail. It may be expressed mathematically as:

$$S = f(w) \phi h \left(\beta + \frac{\alpha}{\phi} \right), \quad (\text{Jacob, 1950})$$

where

- S = storage coefficient;
- ϕ = porosity;
- $f(w) = \rho g$ = specific weight of water per unit area or hydrostatic pressure per foot of aquifer thickness;
- h = aquifer thickness, inches;
- β = compressibility of water, square inches per pound; and
- α = compressibility of aquifer skeleton, square inches per pound.

Estimations of the storage coefficient may be determined when appropriate values for fluid and rock, or aquifer skeleton, compressibility are used. Rock compressibility may be approximated when lithology and porosity are known (Matthews and Russell, 1967). A value of 3×10^{-6} pounds per square inch (2.1×10^{-7} kg/cm²) is the constant for the compressibility of water (Lohman, 1972).

The storage coefficient may also be estimated by multiplying the thickness (h) in feet of the aquifer by 10^{-6} . An example is $h = 300$ feet, $S = 3 \times 10^{-4}$, and so on. Values determined by this method are not absolutely correct, as no allowances have been made for porosity or compressibility of the aquifer, but for most purposes they are fairly reliable (Lohman, 1972).

Net Permeable Thickness

When evaluating a potential injection zone, total permeable thickness or net permeable thickness available for receiving injected fluids is an important consideration. Net permeable thickness and permeability are used to calculate reservoir transmissivity, which is a measurement of the reservoir capacity to transmit fluid.

Most injection zones in Texas, for both waste disposal and solution mining, are characterized by alternating deposits of sand and clay, or shale, beds. The total sequence may range from as little as 25 feet (7.6 m) up to 1,000 feet (304.8 m) in thickness. A proposed injection zone is selected and evaluated based on the net sand contained in the clay and sand sequence. Multiple screens or perforations are placed opposite porous and permeable sand beds used as receiving strata. Generally, only one sand zone will be utilized at a time, and, for waste disposal, as a particular sand becomes unsuitable, the completion interval is moved uphole to the next targeted injection zone. In solution mining this technique is also employed when the mineral of interest has been depleted in a particular zone.

Reservoir Pressure

Natural bottom-hole pressure in a well is a function of several pressure components: atmospheric pressure, pore pressure, and lithostatic or overburden pressure. Pressure at the water table of an unconfined aquifer and at the potentiometric plane of a confined aquifer is atmospheric. Pore pressure is the pressure experienced by the water in the voids of a porous medium and is measured by the height of water in a piezometer at a particular point. Lithostatic pressure is the pressure caused by the weight of overlying rocks. Pore pressure and lithostatic pressure are used to predict the fracture gradient of an injection zone.

High pressure injection can cause the initiation or extension of fracturing in the injection zone. Such fracturing is often done intentionally to enhance production of an oil and gas well, but it is highly undesirable to inject waste fluids under sufficient pressure to induce fracturing. The maximum allowable injection pressure is individually specified in the permit for each waste disposal well in Texas, with due consideration given to site specific geologic and hydrologic conditions, to prevent fracturing. Allowable injection pressures range up to about 1,500 pounds per square inch (105.5 kg/cm²).

In order for underground injection of a fluid to occur, the applied pressure must exceed the natural pressure of the injection zone at the point of injection. This can be accomplished by gravity or by pumping. Injection by gravity occurs when the hydrostatic head of the fluid column exceeds the injection zone pressure. Although a few waste disposal wells in Texas operate by gravity injection, additional pressure is usually applied by pumping.

Injection rates in Texas range from 2 to 3 gallons per minute (0.126 to 0.189 l/s) to over 1,500 gallons per minute (94.6 l/s), but typical wells inject at several hundred gallons per minute. Subsurface injection of fluid causes a pressure increase in the injection zone near the well.

Injection pressures are not as significant for solution mining operations in Texas, due to the much shallower depths of operation and associated reduction of natural pressure. However, a limit of 0.40 pound per square inch per foot (0.092 kg/cm²/m) of well depth is specified in each permit as the maximum allowable injection pressure.

Compatibility

Compatibility of injected wastes with the formation matrix and contained fluids is a potential problem with waste disposal wells. Injected fluid may react with the formation or its natural fluids to form precipitates which can clog the formation in the vicinity of the well bore. Such reactions may be categorized as: (a) precipitation of alkaline earth metals calcium, magnesium, barium and strontium as relatively insoluble carbonates, sulfates, hydroxides, orthophosphates, or fluorides; (b) precipitation of metals iron, zinc, chromium and cadmium as insoluble sulfides, hydroxides, carbonates, or orthophosphates; (c) precipitation of oxidation-reduction reaction products; and (d) polymerization of resin-like materials to form solids under aquifer temperature and pressure.

Wastes which may cause undesirable reactions within the injection zone can be treated prior to injection to improve compatibility characteristics. Treatment will vary with waste composition, but usually involves precipitation prior to injection to remove materials which otherwise might precipitate in the injection zone. Removal of suspended solids larger than 1 to 5 microns in size prior to injection is also generally practiced.

In cases where a waste stream is incompatible with formation fluids, a buffer zone composed of a fluid that is compatible with waste fluids and with the formation and its contained fluids, may be injected ahead of the waste. Theoretically this can prevent direct contact between injected waste and injection zone fluids in order that precipitation either does not occur or it occurs some distance from the injection well.

The above discussion deals entirely with waste disposal wells. Compatibility is seldom if ever a problem in solution mining operations. Unless the mining solutions are essentially compatible with formation fluids, leaching of the desired mineral is not possible.

Injectivity and Aquifer Testing

Permeability, thickness, and porosity are major hydraulic properties of an aquifer upon which quantitative ground-water reservoir studies are based. These hydraulic properties may be determined by means of injectivity and pump tests, wherein the effect on a reservoir from pumping or injecting at a known rate is measured in the subject well or in additional observation wells penetrating the reservoir. Graphs of pressure buildup or drawdown versus time after start of pumping or injection are used to determine hydraulic properties of a reservoir.

Injectivity Testing

Tests are conducted immediately after well completion to establish the initial reservoir pressure before injection operations commence. Injection or production tests conducted prior to putting a well into operation can provide a fair estimate of the permeability and thickness product (kh). Because of the transient state of a reservoir during the early part of an injection test, interpretation of test results are less precise. Injectivity tests conducted later in the injection operation when steady-state conditions have been achieved tend to define the permeability and thickness more precisely. Average reservoir pressure and reservoir volume can be determined from pressure decay or falloff data measured in the shut-in well following steady-state injection.

Upon completion and perforation of a waste disposal well, mud in the long-string casing is displaced by a brine with a density of 9.5 to 10 pounds per gallon (1.1 to 1.2 kg/l). Mud to control formation pressures remains outside the casing and cement. Before cleaning the mud from the formation, the bottom-hole pressure is measured in the tubing as close to the perforation depth as practical to obtain initial reservoir pressure. The well is then thoroughly cleared of mud by producing 400 to 500 barrels (63.6 to 79.5 m³) of reservoir fluid. Nitrogen injection at the base of the tubing may be necessary to decrease the fluid column density and improve production of reservoir fluid. Formation fluid should be saved, cleaned of mud and other sediment, and reinjected in the formation during an injectivity test. A clean reservoir fluid sample should be collected during the final stages of production.

Meaningful injectivity test results require sufficient injection time to insure that steady-state conditions are approached in the reservoir. The well is then closed in for a pressure decay test. Bottom-hole pressure and surface pressure are recorded during the flow and shut-in periods. Time required to establish steady-state conditions can be ascertained through criterion used in the petroleum industry (Matthews and Russell, 1967) as follows:

$$\Delta t = \frac{.000264 k t}{\phi \mu c r_e^2} = 0.01 \text{ to } 0.1 \text{ and}$$
$$c = \beta + \frac{\alpha}{\phi},$$

where

- Δt = dimensionless time, ratio;
- k = permeability, millidarcies;
- t = time, hours;
- ϕ = porosity, fraction;
- μ = viscosity, centipoise;
- c = compressibility, psi⁻¹;
- r_e = external radius, feet;
- α = rock compressibility, psi⁻¹; and
- β = fluid compressibility, psi⁻¹

Within the range of dimensionless times (0.01 to 0.1), indicated flow in the reservoir approximates steady state sufficiently enough to give meaningful pressure decay data. Under typical test conditions, produced reservoir fluid will be reinjected in about 7 hours at about 50 gallons per

minute (3.15 l/s). Most wells are permitted in reservoirs with permeabilities of at least 100 millidarcies and a porosity of 25 percent.

Under the test conditions assumed, the dimensionless time is:

$$\begin{aligned}\Delta t &= \frac{(.000264)(100)(7)}{(.25)(1.0)(.000016)(1000)} \\ &= 0.046.\end{aligned}$$

Tests conducted under conditions outlined above would be adequate except in low permeability reservoirs (10 - 20 millidarcies). Longer injection and shut-in periods would be required for low permeability reservoirs.

Test Procedure

When sufficient reservoir fluid has been produced the well should be shut in and allowed to stabilize. After developing a test procedure and cleaning the produced fluid, constant rate injection should be initiated. A pressure gauge, preferably a recording type, should be installed on the well head and a bottom hole pressure gauge lowered into the well as near the perforation level as is practical. The gauge should be lowered in the well 2 or 3 hours before the completion of the injection operation. The well is shut in with the gauge depth at test depth, and the test is continued for 9 to 10 hours. Within 12 to 24 hours after the completion of the first test, a second bottom hole pressure test should be conducted on the well for a 1- to 2-hour period.

Pressure Decay Analysis

Pressure decay or falloff data recorded after shutting in the well can be analyzed using the method developed by Horner (1951) to determine flow properties of the reservoir. The pressure-time relationship is plotted on semilog paper as $(t + \Delta t) / \Delta t$ on the log scale versus the measured pressure on the linear scale. The slope of the straight line portion of the plot should be determined and the permeable thickness of the injection interval can be determined through the following relationship:

$$kh = \frac{5575 q \mu}{m}$$

where

- k = permeability, millidarcies;
- h = thickness, feet;
- q = injection rate, gallons per day;
- μ = viscosity, centipoise; and
- m = slope of pressure versus $\log \frac{(t + \Delta t)}{\Delta t}$ plot.

Δt

Assuming that the permeable thickness is known through coring operations, logs, spinner survey, or other procedures, the permeability may be readily calculated.

Skin effect can also be determined from the pressure decay plot through a procedure described in detail by Matthews and Russell (1967). The skin effect can be evaluated through the following relationship:

$$s = 1.151 \left[\frac{p_{1 \text{ hr}} - p_{wf}}{m} - \log \left(\frac{k}{\phi \mu c r_w^2} \right) + 3.23 \right],$$

where

- s = skin effect;
- $p_{1 \text{ hr}}$ = pressure at 1 hour from straight line portion of build-up curve or from extrapolation of straight line to 1 hour;
- p_{wf} = flow pressure;
- m = slope of build-up (or falloff) curve;
- k = permeability, millidarcies;
- ϕ = porosity, fraction;
- μ = viscosity, centipoise;
- c = compressibility, psi^{-1} ; and
- r_w = well radius, feet.

Injectivity Tests During Injection Operations

Injectivity tests will not normally be conducted during operation unless a problem develops with the injection operations or further evaluation of the reservoir conditions is desired. Should additional injectivity tests be required, the same criteria are considered as used in the initial tests. However, wastes are injected into the well rather than produced reservoir fluid. If time requirements for reaching steady state are followed, reliable results should be obtained. Reservoir properties, including pressure, and problems due to plugging of the well bore can be ascertained through these tests.

Aquifer Pump Tests

In addition to the major hydraulic properties of an aquifer, which can be determined from injectivity and pump testing, conventional multiple well drawdown and recovery tests can be used to: (a) determine the degree of vertical hydraulic connection between aquifers; (b) postulate the presence of aquifer boundaries; and (c) demonstrate lateral hydraulic connection between the pumping well and observation wells. Multiple well aquifer tests have been used extensively by uranium operators in Texas to provide geohydrologic information within their proposed mining areas.

Approximately 48 hours prior to the initiation of a pump test, a pre-test period is begun whereby all controllable activities which affect the aquifer, such as drilling and pumping, are stopped to allow the aquifer to return to normal conditions. After the aquifer has stabilized,

diurnal fluctuations due to tidal influence and extremes in barometric pressures should be noted and compared to the water level readings at these extremes. As many continuous water-level recorders as possible should be installed in the aquifer that will be influenced by the test. Charts from these recorders are useful in determining the effect of tidal influence, barometric pressure, and precipitation during the test.

The most common method used for an aquifer pump test is to have one pumping well surrounded by as many observation wells as conditions warrant. These conditions include the stage of development of the well field, the aquifer characteristics, the size of the wellhead, and the amount of monitoring equipment available. Observation wells should be distributed as uniformly as possible around the pumped well. All wells must be open to the water-bearing zone, remain open during the entire test, and penetrate the entire sand interval so that the flow toward the pumping well is horizontal and drawdown values are not affected by partial penetration. Well numbers and reference points for water-level measurements should be clearly marked on each well casing. Observation wells with a minimum diameter of 4 inches (10.16 cm) are required for automatic water-level recorders. When tape measurements are made, well diameters as small as 2 inches (5.08 cm) may be suitable.

Typically, the pumping portion of the test should be for a minimum of 24 hours, or until drawdown is observed in all production zone monitor wells, or until the semilogarithmic plots of the drawdown data detect a boundary or recharge condition. The pumping should be continued until the recharge or boundary condition detected by the drawdown curve stabilizes and a steady-state condition is indicated by a straight line. It may be preferable to use more than one pumped well in some formations. Recovery data should then be collected for 24 hours following the pumping portion of the test.

The pumped well should be pumped at approximately three-fourths its maximum yield. Activities in and around the well area should be stopped or kept constant during pumping. The pumped well should be equipped with a flowmeter and a flow control valve and the pumping rate monitored and adjusted frequently during the test to insure a constant pumping rate. The water must be discharged in such a way that it cannot return to the aquifers being tested. The well must be equipped to allow a water level measuring line to be lowered into the well and, in the event of pump failure, recovery of water levels should be monitored.

Rapid changes in the initial static water level occur when the pumping starts. Therefore, during the initial portion of the test, the measurements are at intervals of minutes and then gradually spread out to intervals of hours.

Analysis of Aquifer Test Data

The analysis of pump test data utilizes the law of flow through porous materials determined by Henri Darcy in 1856 and known as Darcy's law. In 1863, Jules Dupuit applied Darcy's law to well hydraulics and developed a formula for determining the flow of water into a well. The Dupuit method was later modified by Gunther Thiem in 1906 to a form which is applicable to general problems. The above methods are equilibrium methods which apply only to a steady-state condition in which the rate of flow of water toward the well is equal to the rate of discharge of the pumped well.

Development of the nonequilibrium theory by Charles V. Theis in 1935 was a significant advance in modern well hydraulics. This theory considered time and the coefficient of storage. It made possible the computation of future pumping levels when the flow of ground water due to pumping did not approach an equilibrium condition. Both equilibrium and nonequilibrium methods assume that water-bearing material is homogeneous and isotropic.

The nonequilibrium method has been studied and used extensively by the Department. The Theis equation which defines ground-water flow toward a pumped well penetrating the entire thickness of the water-bearing strata is:

$$s = \frac{114.6Q}{T} W(u),$$

where

$$W(u) = -0.577216 - \log_e u + u - \frac{u^2}{2 \times 2!} + \frac{u^3}{3 \times 3!} - \frac{u^4}{4 \times 4!} \dots + \frac{(-1)^{n+1} (u^n)}{n \times n!};$$

$$u = \frac{1.87r^2S}{Tt};$$

- s = drawdown or recovery, feet;
- Q = discharge of pumped well, gal/m;
- T = coefficient of transmissivity, gal/d/ft;
- t = time, days;
- r = distance from discharging well, feet; and
- S = coefficient of storage.

Type Curve Solution

A graphical method of superposition described by Wenzel (1942) yields a relatively simple solution for nonequilibrium equations. The first step of the type curve method is to plot values of drawdown or recovery (s) versus the product of the square of the distance (r²) from the axis of the pumped well and the reciprocal of the time ($\frac{1}{t}$). These data should be plotted on logarithmic paper to the same scale as the type curve. The type curve is constructed by plotting W(u) versus u. In making the above graphs s and W(u) should be on the same axes.

The next step is to place one of the graphs on top of the other and fit the points r²/t graph to the type curve. When the best fit is obtained, a matchpoint is selected. The values of r²/t, s, W(u), and u are used in calculating transmissivity (T) and storage (S). Values of T and S are computed from the following equations:

$$T = \frac{114.6}{s} Q W(u) \text{ and}$$

$$S = \frac{Tu}{1.87r^2/t}$$

where T, Q, S, t, s, W(u), and r are as previously defined.

Straight-Line Method

The straight-line method is based on the fact that when u becomes small a plot of drawdown against the logarithm of time after pumping started or stopped describes a straight line. The slope of the straight line is used to determine the coefficient of transmissivity, and the zero drawdown or recovery intercept is used to calculate the coefficient of storage when a water-level observation well is used. The method works well for artesian conditions, but may also be applied to nonartesian aquifers under certain circumstances. Values of T and S are computed from the following equations:

$$T = \frac{264Q}{\Delta s} \quad \text{and} \\ S = \frac{Tt_0}{4790r^2},$$

where T , Q , S , and r are as previously defined and:

- Δs = drawdown or recovery per log cycle, feet; and
- t_0 = intersection of straight-line slope with zero-drawdown axis, minutes.

Boundary Conditions

Hydrologic boundaries limit aquifers in one or more directions. Boundaries may be divided into two types, barrier and recharge. Barrier boundaries are important in injection wells because they are lines across which there is no flow. Barrier boundaries may consist of faults or impervious deposits such as shale or clay. A barrier boundary increases drawdown in a pumping well or increases pressure in an injection well.

Equations and graphical methods used to determine hydraulic parameters of an aquifer can also be used to predict the presence of boundaries. Boundaries determined from injectivity or pumping tests represent the limits of a hypothetical aquifer system. Additional data are required to definitely establish the presence of a single boundary or multiple boundary system. Analysis of test data under boundary conditions is beyond the scope of this publication.

Hydraulics of Injection

Radial Dispersion

Where porosity, permeability, and thickness are uniform in a homogeneous, isotropic medium, distribution of injected wastewater will be in a radial direction. The dip of the receiving bed, which influences the hydraulic gradient of the reservoir, can be disregarded when calculating effluent displacement, if the dip of the beds is of a low order. Assuming uniformity in a bed receiving a fluid, radial distance of displacement can be calculated by using the following equation:

$$r = \sqrt{\frac{Q}{\pi h \phi}},$$

where

- r = radial distance of fluid front from well, feet;
- Q = cumulative volume of fluid injected, cubic feet (ft³);
- φ = porosity of receiving formation; and
- h = thickness of formation, feet.

For illustration, assume an injection operation as follows:

- 500 gallons per minute,
- 200 feet of sand thickness, and
- 30 percent porosity.

Find the radius of displacement after 20 years of injection.

Solution:

$$500 \text{ gal/min} = 702,674,000 \text{ ft}^3 \text{ in 20 years}$$

$$r = \sqrt{\frac{702,674,000}{(3.1416)(200)(.3)}} = 1,931 \text{ feet (588.6 m)}$$

As can be observed in this example, injection at a large rate for a number of years results in the fluid moving approximately 0.3 mile (0.483 km) radially from the well bore. Though radial displacement cannot be expected to be uniform in all directions, the radial dispersion equation does provide a good estimate of the distance of effluent front from the well bore.

Pressure Increase

The pressure increase on the fluid in a receiving reservoir is a significant part of any injection operation and should be evaluated in all underground injection projects. Hydrostatic pressure on a formation causes fluid to rise in an open borehole. If the fluid level rises above the top of a formation, the fluid is under artesian conditions. The plane to which this water would rise if unconfined is known as the potentiometric surface.

Upon injecting liquid into a subsurface zone under artesian conditions, a cone of impression is developed on the potentiometric plane, which is a rise of the potentiometric level around the well. Conversely, withdrawal of liquid from an artesian aquifer causes a cone of depression to develop around the well bore. A typical cone of impression is shown in Figure 4. It can be observed that any point on the potentiometric surface is correlative with the pressure of the fluid within the formation immediately below the point. Thus, pressure in the formation can be calculated by measuring fluid level in a monitoring well, open to the formation, provided specific gravity of the fluid is known. Injection or withdrawal increases or decreases the natural hydraulic gradient around the well bore.

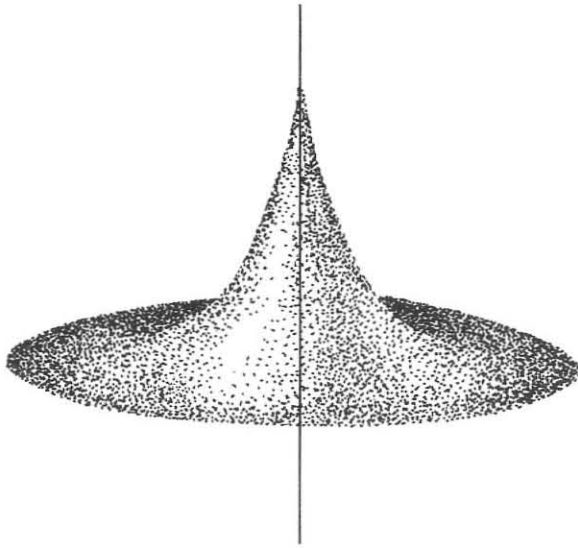


Figure 4.—Schematic Cone of Impression Around a Well Bore

There are several methods and equations or formulas utilized for computing injection pressures and reservoir yield. Since there is a rise in the potentiometric surface with injection at certain radii from the well within the influence of the cone of impression, a formula is needed that includes this concept of change with injection. Such a formula is utilized in the nonequilibrium method which was discussed previously.

Although the method was developed through discharging wells, the same method can be applied to wells receiving fluids. Like all formulas, it can be used to determine any parameter. If the transmissivity and the coefficient of storage are known, the water level rise or fall, or pressure change, may be computed for any point on the cone of depression or impression. For example, a well is used for injection of 300 gallons per minute (18.9 l/s) of waste in an areally

extensive sand with a thickness of 200 feet (61 m), at a depth of 5,000 feet (1,524 m). The average porosity of the sand has been determined in the laboratory to be 30 percent and average permeability to be 0.5 darcy. Assume the sand to be uniform and 100 percent saturated with saline water. What will be the rise, in 10 years, of the potentiometric surface at a distance of 10,000 feet (3,048 m) from the well? The permeability, k , in darcys can be converted into Meinzer units where viscosity of the fluid at formation temperature is determined. For purpose of the example, the assumed conversion factor will be 20.5 or approximately that of water at 68°F (20°C). Therefore, $T = 0.5 \times 20.5 \times 200 = 2,050$, rounded off to 2,000.

$$S = 2 \times 10^{-4}$$

therefore:

$$\mu = \frac{1.87 (10,000)^2 2 \times 10^{-4}}{2,000 \times 3,650}, \text{ at 10 years}$$

$$= 5.1 \times 10^{-3}$$

$$W(u) = 4.70 \text{ (Walton, 1962)}$$

$$s = 114.6 \left(\frac{300}{2000} \right) 4.70$$

$$s = 80 \text{ feet (24.4 m) of rise in the potentiometric surface}$$

This amounts to an approximate increase of 35 pounds per square inch (2.46 kg/cm²) at a distance of 10,000 feet (3,048 m) or 0.007 pound per foot (10.42 g/m) of depth. From the example, it can be observed that the nonequilibrium method has many advantages over other methods in computing water-level drawdown or buildup in artesian aquifers.

Factors such as dissolved gases in disposal zones, permeability differences between fresh water and mineralized wastewater, temperature of injected fluid, and effect of pressure on fluid compressibility have not been considered in the above discussion. Where these measurements are known and could have a significant effect, they are taken into consideration and utilized in the formula. However, they often can be disregarded because of their insignificant effect on the total pressure change. It is not uncommon to find that the total result of disregarding these minor corrections is to create a small safety factor; therefore, pressure buildup may be slightly overestimated. In summary, the three most important parameters where reliable data are needed are permeability, porosity, and net permeable thickness.

The nonequilibrium method is based on the assumption that the hydraulic system does not reach a state of equilibrium. However, with long distances from the well and extended time periods, the nonequilibrium method approaches that of a hydraulic system in equilibrium. The nonequilibrium method is excellent for overall accuracy in computing expected pressure increases.

Modeling

A mathematical model of an aquifer may be defined as a group of mathematical expressions that describe aquifer functions. Mathematical simulation requires development of a workable model of the system, acquisition of physical constants of the system, and acquisition of historical states of the system for verification of model adequacy.

The Department currently utilizes the well field computer model (IMAGEW-I) to evaluate long term effects of underground injection. The modeling effort allows prediction of pressure or head change in a disposal or mining horizon as a result of injection or withdrawals. The computer program is based on the nonequilibrium method and can be applied to the solution of some of the following problems:

1. Analysis of existing well fields to predict changes in head produced by increasing or decreasing pumping or injection rates of existing wells or by adding or removing wells in the system.
2. Design of future well fields to provide maximum injection or production while maintaining adequate head levels.
3. Analysis of well field pumping or injection data to evaluate aquifer characteristics by comparing theoretical head predictions with recorded head or water levels.

The Department is also using a finite difference computer model (GWSIM-II) to simulate the response of an aquifer to injection (Figure 5). The finite difference method is based on a differential equation for nonsteady flow of a compressible fluid which can be written:

$$\frac{\partial}{\partial x} \left(T \frac{\partial h}{\partial x} \right) + \frac{\partial}{\partial y} \left(T \frac{\partial h}{\partial y} \right) = S \frac{\partial h}{\partial t} + Q$$

where

- T = aquifer transmissivity, length squared/time;
- h = hydraulic head, length;
- S = aquifer storage coefficient;
- t = time;
- Q = net ground-water flux per unit area, length/time; and
- x,y = rectangular coordinates, length.

The numerical solution to this equation can be obtained by applying a finite difference approach. The basic assumption underlying the finite difference approach is that partial differentials can be approximated by a difference quotient.

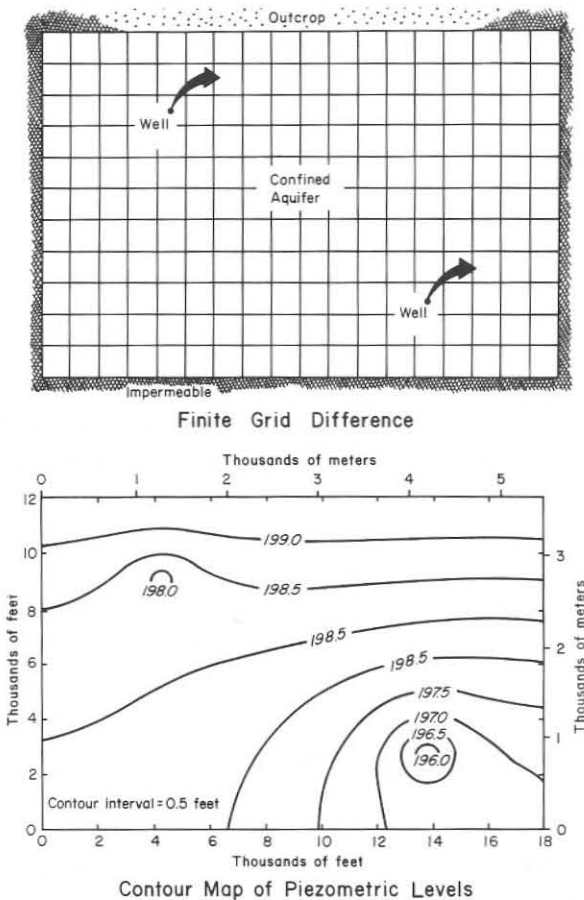


Figure 5.—Finite Difference Computer Simulation

WELL CONSTRUCTION PRACTICES

Carefully planned design specifications and construction practices are fundamental to the safe and efficient operation of an injection well. The properly constructed injection well system will convey the injection fluid to the target aquifer, withstand physical and chemical stresses, and monitor mechanical integrity.

The mechanics of the modeling operation are as follows: (a) a rectangular grid is superimposed upon the aquifer, which may be irregular in shape and nonhomogeneous; (b) finite difference approximation of the above equation is used to formulate equations of ground-water flow; and (c) resulting equations can then be solved for hydraulic head by digital computer using the alternating direction implicit procedure.

Sound environmental decisions must be based on the geohydrology of the injection horizon, water quality, and the aquifer's response to many alternative plans of operation. The high-speed electronic digital computer using the above programs can store large amounts of complex hydrologic data and rapidly analyze many alternative injection or production plans at a reasonable cost. The comparison by the Department, consultants, and others of the aquifer's response in terms of hydraulic head change results in the selection of a plan which is consistent with the overall environmental objectives at minimum cost.

Waste Disposal Wells

Drilling

Waste disposal wells are generally drilled using the same rotary drilling methods and technology that is used for conventional oil and gas production wells. In rotary drilling, a hole is advanced downward from the drilling rig at the surface by rotating a bit weighted with heavy steel drill collars on the end of connected lengths of steel drill pipe. The hole is kept full of fluid as the drilling progresses. Pumps maintain circulation of drilling fluid down the inside of the drill pipe, through the bit, and up the outside of the drill pipe to the surface. Circulation of drilling fluids cool and lubricate the bit, circulate cuttings out of the hole, and control downhole pressure surges.

Drilling companies generally contract for a hole to be drilled to a specified depth. To minimize the total number of days a job requires, drilling continues around the clock on a 24-hour basis. Drilling rig costs may exceed several thousand dollars per day. Therefore, to minimize rig expenses, a large drilling rig is usually released from a job and moved off location once total depth is achieved so that a smaller and less expensive rig can be used for completing the well.

Prior to drilling, access to the prospective well site must be established by construction of an all-weather road. An adequate area around the well site must be developed to accommodate the drilling rig and all of the associated equipment including pumps, tanks, pits, power-generating units, pipe racks, trucks and cars, and personnel quarters. During preparation of the well site, provision of a water supply for drilling, cementing, and displacement fluids is also essential.

Drilling Fluids

Over several decades of rotary drilling, the importance of drilling fluid to well construction has been widely recognized by drilling engineers. Moore (1974) described a good mud program as the heart of the drilling operation. It is necessary to utilize the expertise of an experienced mud engineer or mud service company throughout the construction of any injection well.

As described earlier, drilling fluids cool the bit, circulate cuttings out of the hole, and control downhole pressures. Drilling fluids also help hold the hole open, prevent formation damage, and help suspend the weight of the drill string and casing by buoyant force. Drilling fluid may be plain water, water mixed with various additives, oil-based fluids, or even compressed air. Most commonly, drilling fluid is a water and clay mixture with additives to influence the viscosity and weight of the fluid. The term "drilling mud" is derived from the common usage of water and clay mixtures.

Procedures for describing and quantifying drilling fluid characteristics are prescribed by the American Petroleum Institute. These characteristics include weight (pounds per gallon), viscosity (seconds per quart), fluid loss (cubic centimeters per 30 minutes), sand and solids content (percent), pH (standard units), and resistivity (ohm-meters). Numerous chemical analytical methods and standards are also described by the American Petroleum Institute for drilling fluids. Chemical considerations extend both to the make-up water and to additives to insure that suitable performance of the drilling fluid will be obtained.

Minimum requirements for any mud program should include: (a) review of the mud program by the driller and engineer prior to drilling; (b) adequate pits and tanks for making up mud and recovery of cuttings; (c) marsh funnel viscometer and mud weight scale to monitor mud characteristics during drilling; and, (d) records of mud weight and viscosity, along with any additives or chemical treatments made to the mud system, entered in the driller's daily report.

Drilling mud additives can be divided into several categories including: viscosity agents and fluid loss control agents, such as clays; lignosulfonates; carboxy-methylcellulose and other polymers; and weighting additives, such as barium sulfate and lead sulfide. Effective removal of cuttings from the well bore is enhanced by increasing velocity, viscosity, and density of drilling fluid. Control of downhole pressure surges is achieved by maintaining adequate drilling fluid density. Another important consideration for drilling fluid is fluid loss to permeable formations and the consequent buildup of a mud cake at the formation and borehole interface.

Most wells are drilled with fluid loss values designed to avoid infiltration of particular formations encountered. Higher fluid loss muds may generally be employed for surface and upper hole drilling; however, as drilling progresses, fluid loss is usually reduced. Many Texas Gulf Coast injection wells utilize native mud systems for the surface casing hole; lignosulfonate-bentonite systems from the base of the surface casing to the top of the injection or completion zone; and clean polymer-salt based fluids through the completion zone to minimize formation damage. Davis and Funk (1972) describe the importance of having the proper drilling fluid in the completion zone. Drilling fluid weight in the completion zone should ideally be the same as that of the native formation brine to prevent significant fluid invasion of the formation. Various polymers may also be used to reduce fluid loss to the formation to nearly zero. These polymers may be circulated out of the well at the time of actual well completion, leaving the disposal zone formation undamaged. Chemical compositions of completion zone drilling fluids should be similar to native formation brine to minimize swelling of formation clay minerals and to prevent precipitation. Clay stabilizers such as potassium chloride are frequently added to completion zone fluids.

Casing

The American Petroleum Institute design specifications for injection well casings are beyond the scope of this manual. Therefore, it is recommended that a prospective well operator consult a petroleum engineer or the manufacturers of casing and well tubular goods when selecting size and grade of casing.

Casing has several important functions in a well including holding the hole open, control of downhole pressures, and protection of fresh ground water and mineral resources. Typical design for a waste disposal well consists of two strings of cemented casing, with injection through a third inner string of pipe called the "injection tubing" (Figure 6). The annular space between the injection tubing and the surrounding casing is packed off, pressurized, and monitored for leaks. Through-tubing injection is required for waste disposal wells because tubing can be pulled, repaired, and replaced in a well; whereas, cemented casing cannot be replaced. It should be noted that the logical way to design an injection well is to first consider the wastewater injection needs, and then select an adequate size injection tubing. Allowing for access by downhole tools, the injection tubing diameter will determine minimum size for the long-string casing, which in turn, sets the minimum size of the surface casing. It is also important to understand that the order of construction is the reverse of that for design considerations. First, the surface casing hole is

drilled to a depth below the base of usable-quality water (less than 3,000 mg/l dissolved solids), and the surface casing is set to this depth and cemented. Next, the well is drilled to total depth and the long-string casing is set and cemented. Finally, the well is completed with the injection tubing and packer installation.

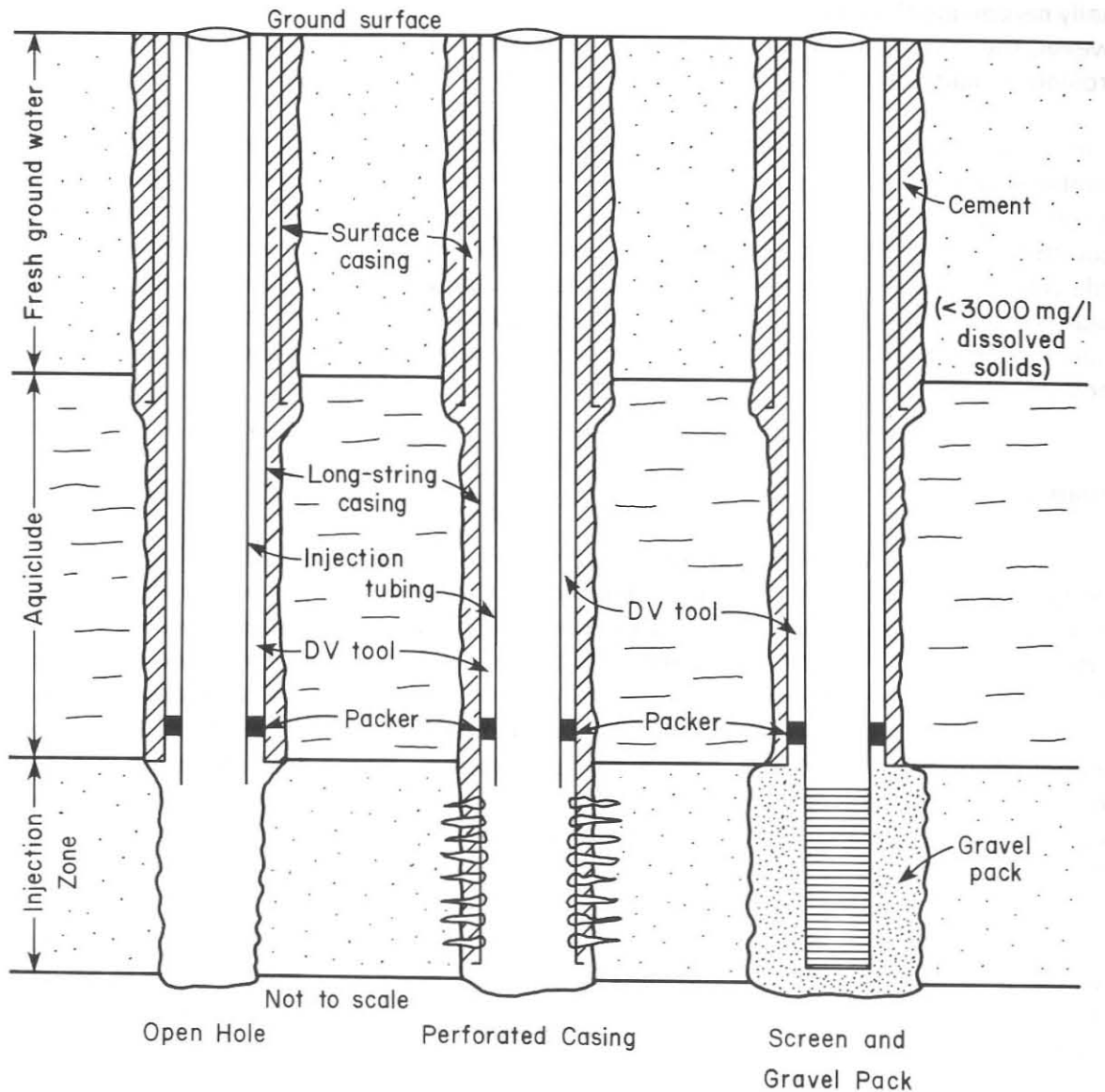


Figure 6.—Waste Disposal Well Completions

Two drilling factors largely determine the ease of running casing. One is straightness of the hole. Inclinoimeters may be used to monitor the degree of deviation of a hole as drilling progresses. It is the driller's job, by regulating the weight on the bit and the drilling rate, to obtain a hole which is suitably straight. The second important factor in running casing is a good mud program which will clean and condition the hole to minimize casing sticking downhole. If the hole has been sitting open for a long period during logging and testing, it is a good practice to make a clean-up trip with the drill string to condition the hole prior to running casing.

The surface casing-string should be set at least 200 feet (61 m) below the base of usable-quality water as determined by borehole logs run prior to the casing job. The operator is advised to consult the Texas Department of Water Resources Surface Casing Section for information on minimum casing depths. The long-string casing is set either at the top of the injection zone or at the total depth of the well, depending on the method of well completion. The long-string casing is usually carbon steel, since it is not normally subjected to the corrosive effects of the wastewater. However, the bottom-most joints of the long-string casing, where the packer is seated, are often corrosion resistant steel or, in some cases, fiberglass.

In some injection wells it may be necessary to run an additional casing string, intermediate in diameter and length, between the surface casing and long-string casing. Intermediate strings may be used to case off high pressure zones, oil and gas zones, or lost circulation zones encountered above the injection zone. Strings of pipe may also be mechanically hung from the inside wall of a casing string to function as a casing liner. When cemented into place, liners are an effective method of repairing casing leaks. Liners of corrosion-resistant alloys or fiberglass may be used in and directly above an injection zone to enable a well to better withstand corrosive effects of wastewater.

Cementing

Primary cementing of injection wells involves the pumping of a cement slurry down through an emplaced well casing. Pump pressure forces cement out from the bottom of the casing, and then upward into the annular space outside the casing wall. Waste disposal wells are cemented completely through the annular space outside each casing string from setting depth to the surface. After cement is displaced through the casing, pumps are shut down and cement outside the casing string is allowed to set up. Primary cementing restricts fluid movement between downhole formations, and protects and supports the casing. Secondary cementing refers either to remedial attempts to complete an inadequate primary job, or to selectively seal off a particular injection zone without abandonment of the entire well. "Squeeze cementing" is a commonly used term for secondary cement jobs that isolate particular zones.

For all types of cement jobs on deep injection wells, the operator is advised to use the services of established well cementing companies. These companies have the expertise to design a good cement program for an injection well and have the materials, equipment, and personnel to do the job correctly.

As detailed by Smith (1976), the American Petroleum Institute has established eight classes of deep well cements based upon suitability for use at various depths and temperatures. A number of special cements for which the American Petroleum Institute standards have not been established also have certain applications in disposal wells. Pozzolan-lime cements combine the advantages of light weight and strength at high temperatures. Sulfate-resistant cements may be used to cement casing directly above the injection zone when it is expected that the injected wastewater will have elevated levels of sulfate. Latex cements may be used to improve bond strength of cement to casing and to increase the resistance of the hardened cement to acid. Epoxy resin cements are particularly resistant to the corrosive effects of acids and other chemicals. These resins are mixed with a catalyst and used to cement the bottom portion of the long-string casing where chemically active injected wastes may be in contact with the cement. They are also commonly used for squeeze cementing in wells.

Cementing companies may select from more than 40 additives to obtain optimum cement slurry characteristics for any downhole condition. The general categories of cement additives include: accelerators, retarders, light-weight additives, heavy-weight additives, loss-circulation control additives, water-lost control additives, and friction reducers.

The volume of cement needed for a casing job includes the calculated volume of annular space outside the wall, plus an excess volume of cement to meet contingencies such as lost circulation or unaccounted hole volume anomalies caused by washouts and vugs. Volume of the annular space outside the casing wall is considered to be equal to the hole volume determined from a good caliper log, minus the volume of the casing string to be cemented. An additional volume of cement, equal from 20 to 30 percent of the calculated annular cement volume, should also be on location and ready for pumping to meet the aforementioned contingencies. If a good caliper log cannot be obtained for the borehole, the needed cement volume can be calculated from an estimate of hole diameter based upon the drill bit size; however, the percent of excess cement should then be increased to allow for the relative inaccuracies of this method.

To obtain a good primary cement job, a number of devices can be installed in a casing string as the string is made up. A guide shoe installed on the extreme bottom of each casing string helps guide the casing downhole to the setting depth. The shoe contains ports for cement slurry extrusion. A float collar is installed on top of the first, or lowest, joint of a casing string. This tubular device contains a valve which prevents back flows of fluid up the inside of the casing. This collar enables the casing string to be floated at a condition of nearly neutral buoyancy into place in the well. The float collar holds the cement slurry in place outside of the casing and resists the slurry's tendency to back flow until the cement sets.

Multiple stage tools, or DV (differential valve) tools, may be installed in a casing string to allow the casing to be completely cemented in separate operations or stages. Use of such tools may be advisable in certain areas to prevent downhole formations from being subjected to a cement slurry hydrostatic pressure sufficient to cause formation fracturing at the well bore. The stage tool also is used to emplace different types of cement in the same hole. Typically, a stage tool is placed at a depth of about one-half the total depth of the well.

With a stage tool, the bottom stage of the casing is cemented first, allowing the cement to harden before the top stage is cemented. After the bottom stage slurry has completely passed through the tool on its way down the casing lumen and is in place outside the casing, ports in the tool are mechanically opened. Excess cement from the bottom stage can be circulated out of the hole through these open ports, and mud circulation can be maintained while waiting for the bottom stage cement to harden. When the top stage slurry is pumped down the casing, it circulates through the ports in the stage tool and is displaced upward outside the casing to the surface. By mechanically closing the stage tool ports, the top stage slurry is held in place outside the casing until the cement hardens.

Other tools and techniques which may contribute to a successful cement job include the use of centralizers along a casing string to hold the casing in the center of the borehole. Also, scratchers may be installed on the outside casing wall to enhance the cement bond by removing mud cake from the borehole. Use of viscous preflush, or mud flush, ahead of the pumped cement slurry and casing wiper plugs ahead of and behind the slurry help keep the slurry free of mud. Displacement of the slurry at maximal rates to promote turbulent flow conditions downhole also increases the chance for good cement bond. Casing strings can be rotated or reciprocated from

the rig floor during cementing, to help obtain a more complete filling of the annular space, with minimal occurrence of uncemented channels.

Despite precautions, a cement job may end prematurely because of a downhole loss of circulation. This is usually caused by the presence of weak formations or thief zones into which a large portion of the cement flows. When an operator fails to return cement to the surface, a temperature log and cement bond log should be run according to service company recommendations at the optimal time following the cementing job to assess the condition of the hardened cement downhole. If the bond log indicates that the injection zone was not safely isolated by the primary cement job, then it will be necessary to perforate the casing and squeeze cement through the perforations to obtain satisfactory isolation of the injection zone. One method of remedial cementing when cement is not returned to the surface would be cementing into the unfilled annulus through a thin work string; however, this method is predicted to be effective only to depths of several hundred feet.

Completions

Bottom-hole completion methods used for waste disposal wells in Texas are of three basic types. Figure 6 gives a schematic comparison of the different completion methods. Open-hole completions are used in competent, or hard, formations. These completions are advantageous as they expose the entire injection zone to the injected fluids. Also, they are the least expensive to implement.

Perforated casing completions are used in formations of only intermediate competence, or those with tendencies to cave in under injection conditions or under the chemical influence of the wastewater. The casing may be selectively perforated opposite the most permeable sands. The interval of casing through the injection zone should, however, be of a chemically resistant material. The formation face is more accessible to acid treatments and other well stimulation techniques than a well with gravel packing. Costs of this completion method are intermediate between those methods discussed.

Screen and gravel pack completions are used for incompetent, unconsolidated sands. Wells in Southeast Texas and along the Gulf Coast use this completion method to control sand inflow to the well bore. Well screens for this completion method are made of stainless steel, fiberglass, or plastic. Gravel packing actually involves the emplacement of sand of a selected uniform grain size to fill the space between the borehole and the well screen.

After completion, the well should be produced to cleanup the formation until a representative sample of formation water is obtained for compatibility tests. A sufficient volume of formation water should be retained for injectivity testing to determine reservoir characteristics.

Injection tubing is used in each of the completion methods described. Installation of injection tubing in a well includes setting a packer, which provides a mechanical seal between the injection tubing and the long-string casing. When the packer is set at the top of the injection zone, the annular space above the packer, between the injection tubing and the long-string casing, becomes isolated from the injection zone. This annular space should be filled with a corrosion-inhibiting brine and monitored by a wellhead gauge, continuous recorder, and a fluid-level sight gauge to detect leaks in the tubing, the casing, or the packer. If pressure in the annulus is

maintained higher than pressure in the injection tubing, a leak would result in fluid flow from the annulus into the injection tubing. An annulus monitoring system of this design substantially increases the safety of containment and disposal of wastewater in an injection well by indicating the need for repairs to the well without allowing the wastewater to contact the casing above the packer.

Solution Mining

Construction of wells for solution mining of minerals involves similar technology but different designs than those utilized in disposal wells. In general, solution mining wells are shallower and contain fewer casing strings than waste disposal wells. It should be noted that the following general descriptions of sulfur and brine wells relate to current practices in industry.

Uranium

Both injection wells and production wells for uranium leach mining operations can be of similar design. They are different in that production wells use submersible pumps to lift water, and injection wells use surface pumps. Both types of uranium mining wells are drilled with rotary rigs to total depths of several hundred feet, using primarily polymer mud systems.

The wells consist of a single string of 4- or 6-inch (10.2- or 15.2-cm) diameter pipe, either polyvinyl chloride (PVC) schedule 40 or fiberglass pipe. Pipe joints are attached through threaded couplings or male-female couplings bonded together with glue and metal screws. The make-up of the pipe string begins in most wells with PVC well screen for the ore zone. Immediately above the screen is a joint of pipe which is specially adapted for cementing. The special cementing joint contains a plaster plug to keep cement out of the well screen below, two or more ports for cement extrusion, plus a cement retainer basket on the outside of the pipe. Centralizers may be placed above the cementing joint and every 100 feet (30.5 m) uphole. The hole is circulated with drilling fluid to remove all cuttings prior to cementing. The wells are usually cemented with Class A cement with 4 percent bentonite gel. Enough cement should be on location to get good cement returns while leaving a 20-foot (6.1-cm) plug of cement in the well casing. A wiper plug may be used to separate the cement slurry from the displacement water following the slurry. Once the cement has set, the casing is pressure tested, and the downhole plugs are drilled out to complete the construction of the well. An alternate construction method consists of drilling to the top of the ore zone and cementing the pipe string in place. Following pressure tests the cement plug is drilled from the bottom of the pipe, and the hole is advanced through the ore zone. Well screen is then hung from the bottom of the pipe string to complete the well. A typical uranium solution mining well completion is shown in Figure 7.

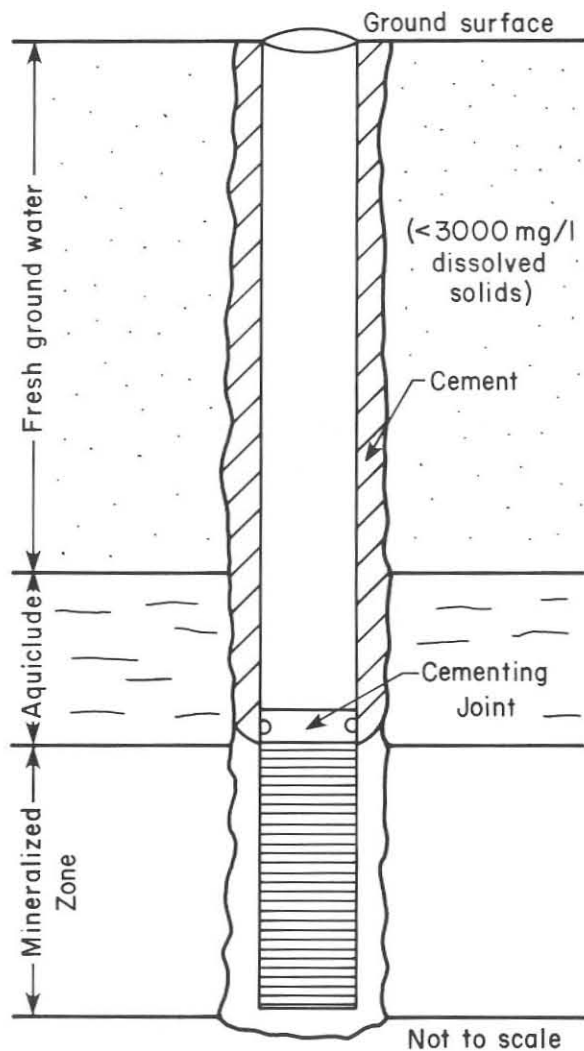


Figure 7.—Typical Uranium Solution Mining Well Completion

forced up the 3-inch (7.6-cm) pipe to the surface. A typical Frasch sulfur mining well completion is shown in Figure 8.

Brine

The Department has surveyed over 80 wells used for brine, sodium chloride, production. These brine wells are concentrated in West Texas, with production from the Salado Salt unit, at depths ranging from 500 to 2,000 feet (152.4 to 609.6 m). Brine well construction commonly involves setting steel surface casing through the base of usable-quality water (less than 3,000 mg/l dissolved solids) and cementing the surface casing to the surface. Drilling then continues to a total well depth within the bedded salt. Inside the surface casing, a steel production string is then set to the top of the salt and is cemented in place. Finally, a steel pipe for injection of fresh water is installed inside the production string. This fresh water pipe extends into the bedded salt section to within about 60 feet (18.3 m) of the bottom of the salt section. With this design, fresh

Sulfur

Sulfur is mined in Texas by the Frasch process in which superheated water is injected into underground sulfur deposits where the sulfur is melted and then pumped to the surface (Ellison, 1971). Sulfur well depths in Texas range from about 200 feet (61 m) to as deep as 1,700 (518.2 m) feet. Most are less than 1,000 feet (304.8 m) deep.

Sulfur well construction commonly begins with a hole drilled to the top of the sulfur deposit. An 8- to 10-inch (2.4- to 3.0-cm) O.D. (outer diameter) steel casing is set to the sulfur top and is cemented back to the surface. Drilling then continues to total depth. Next, a 6-inch (15.2-cm) steel string for hot water injection is set to the total depth of the well and perforated through the sulfur zone. Inside the 6-inch (15.2-cm) pipe, a 3-inch (7.6-cm) O.D. steel pipe for sulfur recovery is set to near the base of the sulfur deposit, and the annulus between the 3- and 6-inch (7.6- and 15.2-cm) pipes is packed off about midway through the sulfur zone. A 1-inch (2.5-cm) steel compressed air line is added to the inside of the 3-inch (7.6-cm) pipe to aid in lifting the molten sulfur to the surface. With this design, hot water exits the 6-inch (15.2-cm) pipe through the perforations above the packer and melts the sulfur. Molten sulfur, being more dense than water, enters the perforations below the packer and is

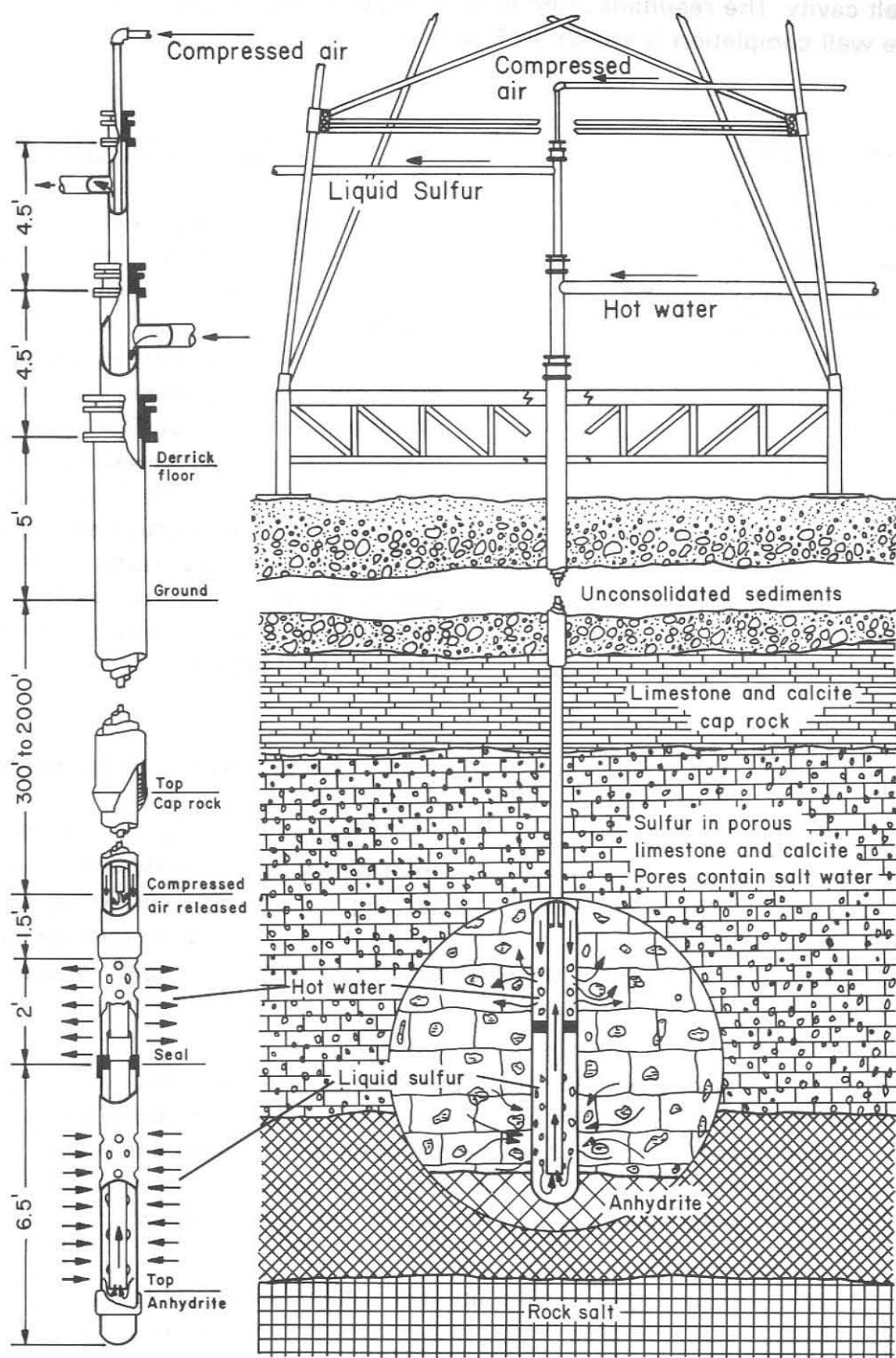


Figure 8
Typical Frasch Sulfur Mining Well Completion

(From Texas Gulf Sulphur Company, 1957, page 10.)

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water pumped into the well dissolves the bedded salt from the borehole walls enlarging the hole to form a salt cavity. The resultant brine is returned by the production string to the surface. A typical brine well completion is shown in Figure 9.

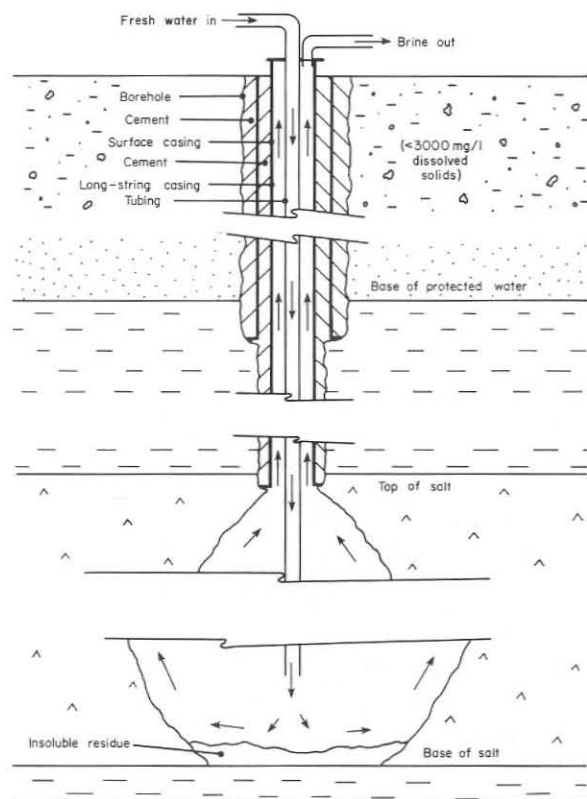


Figure 9.—Typical Brine Well Completion

itate efficient injection operations; and (c) environmental and legal aspects of injection operations.

Logging methods are designed for both open-hole and cased-hole operations. Electric logs, borehole caliper logs, and density logs are limited to open-hole operations because they require that downhole geophysical tools or sondes be in contact with the rock surfaces or not be shielded by casing. Cement bond and radioactive tracer logs are used almost exclusively in cased-hole operations. The basic geophysical logging system in operation is shown on Figure 10.

Many logging techniques require circulation of drilling fluids prior to logging, whereas other logs can be run in dry holes. Weighted muds are of three basic types: water based, oil based, and oil emulsion based. Oil based muds are electrically nonconductive. Some logging tools are not suitable for use in conductive muds, while operation of others is adversely affected by nonconductive fluids. When the various logging methods are properly used, the following parameters can be directly measured or described: temperature, pressure, resistivity, flow, depth, hole size, and lithology. Many of the desired parameters must be calculated, derived, or inferred from logs. For example, no logging method can directly measure permeability, rock fracturing, or formation mechanical properties.

WELL LOGGING

Well logging was crude at the beginning of the century when drillers made their own logs from cuttings and from intuitive interpretations of bit reactions. However, as the importance of a good record of the formations drilled became more and more apparent, logging was usually assigned to a specialist. The efforts of these well logging specialists resulted in more efficient use of the old methods and in development of new ones. Scientific techniques were gradually introduced, the most important of which are those giving a continuous log of formations penetrated by the drill. Electric logging is the most important of these techniques.

Operation and Limitations

Injection well logging provides subsurface information and associated data pertaining to (a) drilling, completion, and operation of individual wells; (b) formulation of reservoir models to facil-

Well logging can be divided into five general categories: lithologic, electrical, radioactive, acoustical, and specialized. The applicability of a particular logging method to a particular problem or use is given in Table 2.

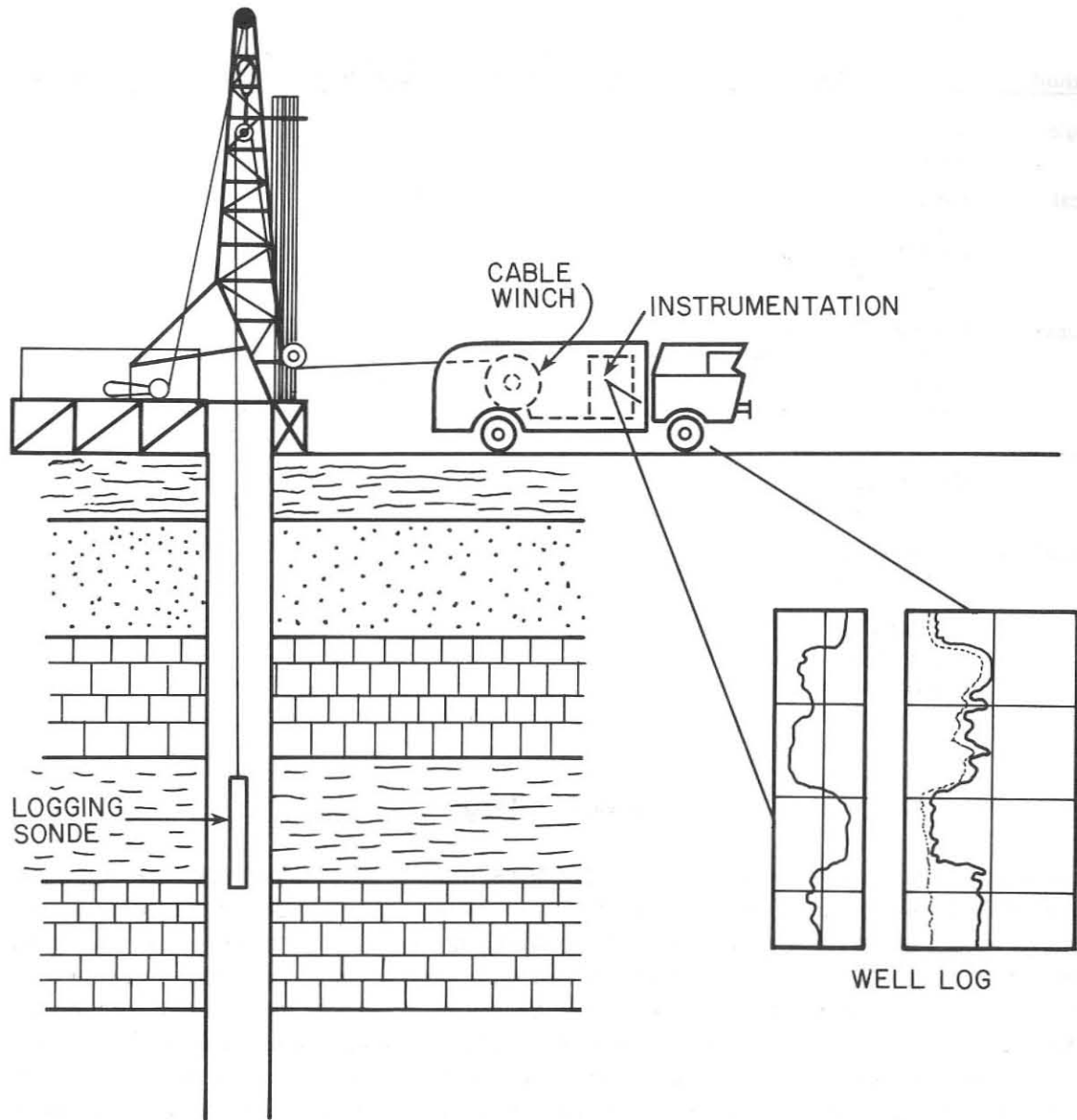


Figure 10.—Generalized Schematic Diagram of Geophysical Well-Logging Equipment

Lithologic Logs

Lithological identification of the formation is possible when samples of the formation are available. Rotary drilling provides continuous formation samples obtained as cuttings. A sample or mud log is a continuous description of the geologic character of each stratum and the depth at which changes occur. It may also include drilling times and gas content of the mud. Ideally,

representative samples should be collected at measured depths and at such intervals as will show the lithologic character of the formations penetrated.

Table 2.—Well Logging Methods and Uses

<u>Method</u>	<u>Type</u>	<u>Lithological identification</u>	<u>Formation parameters</u>	<u>Fluid flow</u>	<u>Well construction</u>
Lithologic	Coring	X	X		
	Mud Log	X			
Electrical	Electric	X	X		
	Induction	X	X		
	Spontaneous Potential	X	X		
	Single Point Resistance				X
Radioactivity	Natural Gamma Ray	X			
	Gamma-Gamma (Density)		X		
	Neutron		X		
	Radioactive Tracer			X	X
Acoustic	Sonic Televiewer	X			X
	Cement Bond				X
	Sonic Logs		X		
Specialized	Temperature			X	X
	Directional Survey				X
	Caliper				X
	Flow Meter			X	X
	Casing-Collar Locator				X
	Casing-Inspection Log				X

Electric Logs

Electrical logging is a process by which electrical measurements provide data on formations penetrated by the borehole. This involves the downhole measurement of electrical quantities, principally voltage and resistance. The voltage which is measured is the spontaneous potential (SP) of the drilling mud column in the borehole with respect to the ground potential near the drilling rig. The SP is generated through the operation of several mechanisms which involve borehole fluids and the boundaries between subsurface strata. Measurement of this voltage is accomplished by lowering a sonde that carries one electrode down the hole, and by recording the difference in voltage between that sonde-borne electrode and an electrode driven into the ground at the surface. The SP log is useful in defining formation fluids.

Resistance of subsurface strata is measured in two general ways. One method involves placing electrodes in various configurations on a sonde in the borehole with another ground electrode at the surface, and then exciting some of these electrodes with an electrical signal while measuring the voltages between other electrodes (normal and lateral logs). A variation of this method is to monitor the amount of current that is actually forced into the formation from the electrodes. The first method, like the SP, requires that drilling mud be conductive. The second method involves induction, and thus nonconducting muds can be used. An induction log uses a transmitter in one end of a sonde to generate a magnetic field that induces eddy currents in the formation surrounding the borehole. These eddy currents in turn generate their own magnetic

fields which are sensed by a receiver in the other end of the sonde. The magnitude of the induced eddy currents and their associated magnetic fields is a function of formation resistivity which allows the sonde receiver to determine the apparent formation resistivity.

In practice, the electric log usually consists of a lateral curve, two normal curves, and a SP curve which are simultaneously recorded. The induction log is commonly a combination of four logs made simultaneously: SP, short normal, conductivity, and its reciprocal, resistivity. The gamma ray and single-point resistance curves are substituted in many instances for the SP and resistivity curves previously discussed. Thus, electrical logging systems are very versatile in terms of measurements which can be made, and when combined with radioactive or acoustic systems, are very effective in determining formation parameters.

Radioactivity Logs

Common to all radiation logging devices is some means of measuring radioactivity in the borehole. The radioactivity may be either natural or induced, or it can result from injection of an isotope used as a tracer. Because certain types of radiation are very penetrating, many of the logs based on radioactivity can be used in cased holes.

A natural radiation log measures gamma radiation produced by decay of uranium, thorium, or potassium. This log may also be used to detect a radioactive tracer; however, the chief use of natural gamma logs is for identification of lithology.

Gamma density (gamma-gamma) and neutron logs are examples of induced radiation logs. A gamma density tool includes a source of gamma rays which penetrate into the formation at the borehole well. The tool also contains a detector which is located a short distance away and measures the flux of gamma rays scattered by the formation. The detected flux is proportional to the electron density of the formation which is roughly proportional to formation bulk density.

The standard neutron log measures the reduction of neutron energy resulting from collisions of emitted neutrons and nuclei of formation materials. The greatest energy losses occur when neutrons collide with hydrogen nuclei. Thus, the log is representative of the total water content of the rocks. This may include pore water between mineral grains, bound or sorbed water in clay, or water of crystallization in gypsum. This log gives information concerning the porosity or degree of water saturation of the formation.

There are many other types of radioactivity logs; however, the commonly used nuclear logs are natural gamma, gamma-gamma, and standard neutron.

Acoustic Logs

An acoustic-velocity log is a record of the transit time of an acoustic pulse through a fixed length of rock or casing parallel to the borehole between transmitters and receivers in a logging sonde. The chief uses are for determination of porosity, identification of fractures, and character of cement bonding between the casing and formation. Some of the more common acoustic logging tools which have received wide use and acceptance in downhole acquisition data are (a) cement bond, (b) borehole compensated sonic velocity, and (c) the sonic televiewer.

Specialized Logs

The following logs, not previously discussed, provide additional information:

- (a) Temperature log—gives continuous record of temperature immediately surrounding a sensor in a borehole.
- (b) Directional survey—provides information on borehole slope and direction and establishes bottom-hole locations with relation to the surface entry point.
- (c) Caliper log—provides a direct measurement of borehole diameter.
- (d) Fluid-movement logging—includes the measurement of natural and artificially induced flow within the borehole.
- (e) Casing-collar locator—accurately locates well casing collars, perforations, and screens in a well.
- (f) Casing-inspection log—is used to monitor pipe corrosion.

Well logs can be interpreted to determine lithology, porosity, resistivity, density, and moisture content of fluid-bearing rocks. Well logs also permit a valid quantitative interpretation of reservoir characteristics. Logging programs allow the evaluation of well construction and fluid-flow conditions within the well. Originally developed for the detection of hydrocarbons, today's logging methods are applied to water wells, solution mining, and waste disposal well projects.

WELL SYSTEM OPERATION

Waste Disposal Wells

Pretreatment and Surface Facilities

Pretreatment in a waste disposal well system is the modification of the physical and chemical characteristics of wastewater to make it compatible with both the materials of well construction and the disposal reservoir. The well should be designed to reduce corrosive effects of waste by the use of corrosion-resistant materials. Compatibility tests using wastewater samples with cores of the disposal reservoir, and with samples of reservoir brine, will indicate the extent and nature of wastewater pretreatment necessary to insure a successful disposal project.

Chemical pretreatment is necessary for many waste streams prior to injection. Alkaline wastes tend to swell clays and plug the injection zone unless they are neutralized. Sulfuric acid wastes react with carbonate reservoirs to form gypsum. Hydrochloric acid wastes generate gas (CO₂) in carbonate reservoirs that may cause well control problems during workovers. Chemical pretreatment may also be necessary to remove heavy metals which could precipitate after injection (Warner and Lehr, 1977).

Filtration is the mechanical separation of suspended solids from a fluid by passing it through a porous medium that retains the solids (Warner and Lehr, 1977). Plugging is often caused by fine particles contained in the injection stream. Elimination of these particles through filtration keeps the disposal reservoir open and the well taking fluid. Sand bed filters are utilized to remove particles above 10 microns in diameter. Sand filters may be gravity fed or pressure fed. The filter media is usually a bed several feet thick in layers of varying grain sizes with fine sand at the top and gravel at the base. Anthracite coal of varying particle size is also used as a filter medium. Sand filters are cleaned by backwashing to remove the accumulated particles and sludge. Polishing cartridge filters downstream from the sand filters are designed to remove particles above 5 microns ($5 \mu\text{m}$) in diameter. Maintenance of these filters requires replacement of the cartridges either on a regular basis or when back pressure reaches a predetermined level.

Pumps used for injection must be capable of attaining required injection pressures and volumes. High pressure centrifugal pumps are used in many injection well systems. These pumps are desirable because of flow characteristics, ease of control, and reduced pulsation effect. Positive displacement or piston pumps are also commonly used for injection wells. The damaging pulsation effect of positive displacement pumps can be minimized with pulsation dampeners. A long straight section of flowline from the pump effectively eliminates pulsation. Quintuplex pumps have been used and have a reduced pulsation effect. Oil-field proven triplex pumps are also used. A few operators use turbine injection pumps. Pulsation is not severe and parts are readily available. Stainless steel pistons and liners have been used for corrosion resistance. The type of injection pump best suited to an injection operation is determined by the expected reservoir pressure, wastewater volume and viscosity, and variability of injection rates (Warner and Lehr, 1977).

Tanks used for preinjection storage and treatment of the effluent should be lined or constructed with corrosion-resistant materials. In commercial injection systems where the character of the waste streams is variable, storage tanks should be designed to accept specific types of wastes. The tanks should be constructed in areas lined with an impervious material and diked to contain spillage. If ponds are used, they should be lined and equipped with leak detection systems. Pipelines to the well should be inspected for leaks.

The pipeline should have a check valve near the wellhead to prevent the backflow of effluent. A wing valve on the wellhead serves to close the well off from the pipeline during workover operations. The master valve is the main control valve over the tubing string. In the disposal of acidic wastes in calcareous formations or in other high back-pressure operations, a swab or crown valve is also used. The crown valve is used during maintenance operations, with the master valve on standby for use in emergency situations. The valving and flanges should be pressure rated to withstand the maximum injection pressure of the system.

Subsurface Facilities

Maintenance of surface casing, long-string casing, and tubing and packer varies according to corrosive influence. Surface casing does not come in contact with the disposal fluids but may be affected by electrolytic corrosion. The flowing fluid causes an induced electrical field. This causes electron flow from the casing to the ground water and destroys the surface casing. A current

measurement can be made from the wellhead to a ground probe to determine indicated corrosion rates. Cathodic protection may be required in severe cases as this corrosion may also attack the long-string casing.

The long-string or completion casing is protected from injected fluids by the tubing and packer. However, corrosion can occur behind the tubing from bacteria action. A packer fluid containing a bactericide is used to fill the annulus between tubing and casing. Other factors such as ground water or electrolytic action can cause leaks to develop in the long string. This requires a leak detection system. Annulus pressure loss or increase indicates an injection tubing or casing leak.

A differential annulus over tubing pressure of at least 100 pounds per square inch (7.03 kg/cm²) is preferred for leak indicator purposes. Extreme pressures could develop in the closed annulus area from fluid expansion with temperature variations. To prevent excessive pressure buildup a nitrogen blanket is used in many systems. An above ground annulus feed tank is used to monitor annulus fluid level in some injection wells. The compressibility of the nitrogen gas accommodates fluid expansion without excess pressure. An annulus pressure fluctuation indicates that a problem has developed.

Monitoring of well pressures is required. Pressure and volume recorders are installed in each well system to record annulus pressure, tubing pressure, and injection rate. Pressure gauges are also installed on the annulus and tubing head. Pressure gauges should be checked and recalibrated when necessary. Effluent volume is also indicated by totalizers in some systems.

Various types of tubing are available to reduce maintenance in disposal wells. Plastic coated steel tubing is commonly used. Fiberglass reinforced plastic tubing has gained wide acceptance. This tubing is inert and capable of withstanding waste fluids with low pH without damage. Flaking and pitting which occurs in plastic coated tubing are eliminated in fiberglass reinforced plastic systems.

Packers used in disposal wells include hook wall, tension set, compression set, and through-bore. Tension packers are undesirable because of the increase in tension with injection fluid temperature fluctuations. The increase in tension shears and unseats the packer. Hook wall packers can result in wall damage during installation because of rotation requirements. On-off tools have been tried with poor results because the tool corrodes and may cause a failure.

Throughbore packers have been utilized with very good results. No turning or manipulation of the tubing string is required. Three feet (0.91 m) of locator sub is stabbed into the packer. Slacking off tubing after stabbing, at one foot per thousand feet of depth, will compensate for contraction with cooling. The bore of the packer is protected by tubing seals.

Stimulation and Development

Injection problems in disposal wells vary according to the disposal stream and receiving reservoir. Most reservoirs in Texas consist of sandstone, limestone, or dolomite. Initial stimulation methods for the disposal reservoir are specifically designed in response to formation lithology and hydrology.

Stimulation of limestone and chert includes acidization and fracturing. Sand, glass beads, or other inert materials are used as proppants to hold the fractures open. The fractures serve as conduits to transport the fluid from the well bore.

Sandstone is a desirable aquifer because of the higher carrying capacity and greater storage coefficient. Even highly permeable sandstone has inherent problems. Bentonitic clays interspersed in the sands can be affected by fresh water or caustic injection fluids causing the clays to swell and plug the formation. Formation fines or unfiltered fines from the disposal stream also plug the formation. These plugging effects cause lowered injection rates and increased injection pressures. Remedial action must be taken when injectivity falls below necessary levels.

Initial conditioning of the disposal well during completion will prevent or delay plugging by swelling clays or formation fines. Development by surging and air lift backflow will remove some of the formation fines and create a formation gravel pack around the well bore. Following development, the well should be acidized with hydrochloric or hydrochloric and hydrofluoric mud acid containing a polymer clay stabilizer. The acid will collapse the clay particles and the polymer will form a coating to prevent interaction with fresh or caustic disposal streams.

Reduction in injectivity after start-up must be approached on a problematic basis. Plugging can be caused by varying factors. Generally, plugging by swelling clays or fines are found to be secondary. The primary causes are chemical precipitates such as carbonates, sulfates, or iron. A plugging precipitate is generally indicated by deposits in piping, filters, or storage ponds. Regular water analysis may indicate the most probable precipitant.

Chemical precipitation can generally be prevented by the use of antiscalants or by flocculation before filtration. Plugging often occurs outside the realm of treatment. Stimulation of the injection zone is then required. Acidizing with backwash for removal of sludge has proven effective in precipitate removal.

In sandstone reservoirs, acidizing involves injecting sufficient acid to penetrate the sand around the well bore. The acid must then be displaced from the well bore by flushing with sufficient water. A detergent ahead of the acid increases penetration and contact with the formation. Staging the acid will insure better coverage of the injection interval. A diverter will prevent injection of the total treatment into the more permeable zone. Addition of citric acid has proven more effective than hydrochloric acid in removal of precipitates containing iron.

Backwash of sludge from a well bore may be accomplished by airlift. Air or nitrogen is injected into the tubing through 1-inch (2.5-cm) pipe at 300 to 700 feet (91.4 to 213.4 m) of depth. The lightened fluid column allows the well to flow back with reservoir pressure. Surging is effected by closing discharge valves and allowing the well to pressure-up, thus forcing fluid back into the reservoir. A rapid release of pressure permits fluid to rush from the formation. This surging cleans the formation of sludge and fines. A surging and backwash repeated at 5-minute intervals over 8 hours will clean the formation around the well. Surging and backwash have been used successfully in some wells without acidizing. However, acid is necessary where scaling is involved.

Uranium Solution Mining

Surface Facilities

Maintenance of plant facilities for uranium solution mines consists mainly of monitoring the tanks, pumps, and piping for leaks and corrosion and making necessary repairs. Plants are usually constructed on a concrete pad with a concrete curb to contain all spills of liquid and solid materials. The pad usually drains to a central sump where fluids are routed to a holding pond while awaiting final disposal. Additional plant maintenance includes backwashing filters, changing filter elements, and generally keeping the plant area clean and safe.

Surface pumps and motors should be subject to periodic maintenance checks. Pipelines can generally be grouped into two categories for maintenance purposes, above ground and buried. Buried lines are generally long service-life pipelines. Their construction is more expensive and hydrostatic testing is more critical. Line failure and scaling are major concerns. Failure can be detected through low volume and pressure warning devices and visual inspections of the pipelines. The warning devices, like any mechanical and electrical devices, must be checked periodically. This is best handled by a scheduled maintenance program. Scale restricts flow and requires increased pressure to move the same volume. A scheduled maintenance program consisting of the review of operating data for increases along with periodic visual inspections will help prevent heavy scaling problems. The uranium solution mining industry generally acidizes the lines to remove the calcium carbonate scale.

Surface lines are treated the same way as buried lines. Initial hydrostatic testing may not be as exhaustive since visual inspection is easier during normal operations. Surface lines provide flexibility; however, accidental breakage poses a slightly greater hazard than with buried lines.

Heavily reinforced artificial pond linings, made of 30 mil hypalon, reduced maintenance on wastewater retention facilities. The pond liner should be visually inspected weekly for rips, tears, punctures, and separated seams. Underdrains and monitor wells should be checked for fluid on a similar schedule.

On production wellheads, when the pump, tubing, electrical cable, and mylar rope are set in place, a rubber sleeve is placed around the tubing and cable at the top of the well casing. This prevents the tubing and cable from being cut when the wellhead is laid over. This is checked when the pump is installed and when the well is not operating properly.

The injection wellhead is attached to the well casing and placed in operation. Once in operation, the field operator takes readings from wellhead gauges on a routine basis. If the gauges on the injection wellhead are not operating properly, the field operator should make a request for corrective maintenance.

Subsurface Facilities

Little maintenance is performed on the casing in most uranium solution mining operations. If casing is damaged below the surface, the well is usually plugged and a new well is drilled adjacent to it. When a well is believed to be operating at less than normal efficiency, the well may be

acidized for scale removal or jet surged for removal of sediment buildup inside the casing. Recently-completed wells are stimulated by air jetting to reduce or eliminate formation damage induced by drilling activity.

MONITORING

Waste Disposal Wells

Monitoring in waste disposal well systems is surveillance of the surface equipment, the well, and the underground reservoir that is accepting the waste. Monitoring is necessary to measure performance of the well system and to detect leaks that may develop in the injection tubing, packer, or long-string casing.

Surface Equipment

Performance of surface equipment, is determined by physical inspection and also from the quality of the pretreated waste. Pretreatment of waste prior to deep well injection is usually necessary to assure acceptable operation of the well and the underground reservoir. Treatment may include cooling the waste, adjusting waste pH, and removal of suspended solids. Monitoring the treated waste for similar characteristics will indicate whether the pretreatment system is deviating from design or expected operating conditions. Some chemical and physical characteristics of the treated waste that might be monitored continuously or periodically are flow, suspended solids, pH, conductance, temperature, density, dissolved solids, dissolved oxygen, and residual chlorine.

Operating Parameters

Monitoring of injection and annulus pressure is required to confirm the continuing integrity of the well, meaning that no leakage through the tubular goods has occurred. Pressure changes in the casing and tubing annulus are monitored to detect leakage. When the annulus is operated under pressure, either higher or lower than the injection pressure, a sustained increase or decrease in annulus pressure is indicative of a leak. Because of the importance of annulus pressure, the injection well permit requires that this pressure be continuously recorded and the information be retained by the well operator. Injection flow rate is monitored for permit compliance, since injection well permits contain restrictions on flow rate and total waste volume.

Injection pressure, or wellhead pressure, is monitored and, when used in conjunction with injection flow rate, is the chief indicator of well performance. A performance index can be calculated from wellhead pressure and injection flow rate. Changes in the index can indicate a loss of injectivity. Injection pressure is usually recorded continuously to monitor well performance and as evidence of compliance with regulatory restrictions. Injection pressures are limited by permit to prevent hydraulic fracturing of the injection reservoir and confining beds and to prevent damage to well facilities.

The following example illustrates how various monitoring information is used in diagnosing a well problem. A common problem which begins at the injection face, or well bore, is reservoir plugging with suspended solids. Monitoring indicates that injection pressure is increasing. The performance index also shows a trend to higher injection pressure and lower flow. This results in a loss of injectivity. An analysis of the waste chemical and physical data should show an increase in suspended solids in the well feed, or some other change that would promote precipitation, such as a change in pH or temperature. In any case, corrective action must be taken to stabilize injectivity, or the conditions will degrade to the point that the well must be shut down for remedial treatment.

Corrosion Monitoring

Corrosion monitoring depends on corrosivity of the waste being injected and construction materials used in the injection well system. The primary objective of corrosion monitoring is to allow the operator to predict when equipment failures may occur and to make repairs before problems develop. This eliminates complications that could arise if the well was allowed to operate until a corrosion problem forced a shutdown. Workovers can then be scheduled in conjunction with low waste inventories or during other convenient periods. This approach insures the safe operation of the well by maintaining the mechanical integrity of the well.

There are several techniques used for determining corrosion rates and evaluating corrosion damage. One widely used method is to run a casing caliper log. Caliper logs can be used to measure both the internal diameter and wall thickness of the outer casing once the injection tubing has been removed, or to measure the internal diameter of the injection tubing while it is in place. The tool makes mechanical or electronic measurements which are electronically communicated to the surface and plotted on a graph. These data can be used to pinpoint the location of corrosion damage and to calculate corrosion rates if previous caliper logs are available for comparison.

Another means of measuring corrosion rates of well materials is to suspend a corrosion coupon or a corrosion probe in the waste stream at or near the wellhead. Coupons, made from materials similar to those used in the well, are periodically removed for inspection. They are weighed and are measured with a caliper to determine metal loss and then returned to the well. Electronic corrosion probes are used to measure the difference in voltage between the probe and a reference point on the well. The voltage difference is converted into an instantaneous measurement of corrosion rate.

Corrosion damage to the injection tubing can also be monitored by occasionally removing the injection tubing from the well. Once it is out of the ground, the tubing can be checked ultrasonically for internal metal loss, X-rayed to determine wall thickness and the extent of damage from pitting, and, if necessary, a representative section can be split open for visual inspection and direct physical measurements. While this procedure provides highly reliable data, its use is generally restricted because of the large expense and extended shutdown time required to pull the injection string. It is usually done when the tubing must be removed to correct some other problem or to verify a potential problem indicated by other types of corrosion monitoring.

In situations where corrosion is of particular concern, more sophisticated monitoring systems may be used to minimize unscheduled well outages. For example, a corrosion monitoring loop may be installed in the waste line just ahead of the wellhead. In this type of system the waste going to the well flows through a horizontal, above-ground section of pipe in which conditions in the well are simulated. Since the corrosion loop is easily accessible it can be monitored by X-ray, ultrasonics, or dismantling for visual inspection on a comparatively frequent basis. One such system uses two representative sections of the injection tubing and a representative coupling to make up the loop. Readings from a corrosion probe can be taken on a routine basis and the corrosion rates can be plotted. The pipe can be periodically checked ultrasonically. On a less frequent basis, the corrosion loop can be X-rayed and a corrosion coupon in the loop can be checked. The loop can be opened as necessary to confirm the monitoring data. An advantage to having this type of arrangement is that it allows the operator to quickly determine how changes in the chemical or physical characteristics of the waste stream affect corrosion rates.

Reservoir Monitoring

Following completion of a new well or workover of an existing well, tests are made to determine injectivity and flow distribution. Injectivity is measured by flow testing, either with formation brine, purchased brine, or wastewater. Wellhead pressures required to inject various flow rates are measured, and from the resulting data, the operator can determine whether the well performance is acceptable. If the performance is not acceptable, it may be necessary to perform further treatments or open up additional injection zones. As a part of the flow test, a flow survey, or spinner test, may be conducted to show which zones are taking fluid and how much each is taking. This survey may show that all the zones are taking a predictable quantity of flow and that no further improvement in injectivity is indicated. Conversely, some of the zones may not be taking any fluid or at a much lower rate than expected. This could mean that injectivity could be improved with additional formation cleanup.

A pressure decay or falloff test is another monitoring technique that compares reservoir performance after operation to its original condition. This test has been described previously in the section on Reservoir Mechanics. The well is inoperable during the several days it takes for a good test. Some possible causes of a deviation from the ideal response is the presence of hydrologic barriers or conduits, leaky confining beds, and permeability reduction from suspended solids. The variety of factors that may influence well behavior shows the need to maintain accurate monitoring records and have skilled personnel interpret the results of such tests.

Another check that is sometimes made on a well when it is not injecting is a bottom-hole measurement and sampling to determine if solids are collecting in the casing or screen. Formation sand inflow or solids in the waste that are capable of settling may fill up the injection pipe sufficiently to impede injection. If this happens, it will be indicated by a change in the wellhead pressure and injection flow rate relationship.

Uranium Solution Mining

Operational monitoring for uranium solution mining operations may be described as an excursion-monitoring system, which is designed to detect migrations of leaching solutions, or lixiviants, horizontally out of the designated ore-zone aquifer, or ore body, and into aquifers above

or below the designated ore zone. The goal of operational monitoring is to insure that all lixivants are contained within a specified ore-zone aquifer, thereby preventing degradation of ground water outside the mine area.

The number, location, spacing, design, and construction of monitor wells is based on the quality of water within the mine zone; the number of overlying and underlying aquifers and the qualities of their contained fluids; the toxicity and volume of the lixiviant, leachate, and process by-products; the site specific geology and hydrology; and the injection pressures of the mining operation.

For an operational monitoring program to be effective, a thorough and concise collection of premining geologic and hydrologic data is necessary. Baseline data will typically include the normal static water levels of all potentially affected aquifers; the background chemical constituency of the waters; the hydraulic properties of the aquifers; and the structural, mineralogical, and depositional characteristics of the aquifers. The premining data will be used to evaluate the mining operations on an ongoing basis. Should a problem in the mining operation develop, the routine data collected from the monitor wells, when compared to premining conditions, will act as an early warning system. Immediate corrective action procedures may then be implemented prior to any significant ground-water degradation.

In practice there are two basic types of monitoring of mining operations using monitor wells: pressure or water-level monitoring and water-quality monitoring. Pressure monitoring is accomplished by routinely recording the static water levels in the monitor wells. Pressure changes resulting from an imbalance in injection or withdrawal rates are transmitted instantaneously throughout the aquifer system and will be reflected in a rise or drop in water level. Water-quality monitoring is accomplished by regularly collecting water-quality data from the monitor wells and comparing it to background levels. A significant change in quality would indicate the migration of lixivants to the monitor wells.

CLOSURE

Waste Disposal Wells

Proper plugging and abandonment of waste disposal wells can be accomplished by several different methods. The Department must approve the proposed plugging procedure and retains the option of having a representative witness the plugging operations. The minimum plugging standards that are considered suitable vary with the type of well to be plugged. The plugging and abandonment of waste disposal wells can be divided into three stages: well preparation, mechanical integrity evaluation, and plug placement.

Well Preparation

Well preparation in most cases consists of moving in a workover rig, killing the well with heavy brine, installing blow-out preventers, pulling the injection tubing and packer, cleaning up the well, and circulating mud. The size of the workover rig needed to plug the well will depend on

the tubing size and weight and the well depth. Killing the well is done by pumping a heavy fluid, usually 10 pounds per gallon (72 kg/l) brine, into the well to prevent a backflow of effluent which may be lighter than the formation fluid. The brine will create a hydrostatic pressure that will negate the increased reservoir pressure. In the event that the increased reservoir pressure is greater than the hydrostatic pressure imposed by the column of brine, blow-out preventers will prevent the well from backflowing (Booz, and others, 1980).

The removal of the injection tubing and packer is then attempted. In some cases removal of the packer will not be possible. If the tubing cannot be released from the packer, it can be cut just above the packer and removed from the well. After the tubing is removed, the well should be cleaned up by removing debris with a junk basket or fishing operation (Booz, and others, 1980). If the long-string casing was not cemented to the surface, the uncemented portion of the casing should be removed from the well prior to plugging (Hill, 1972). The condition of the well will determine the extent of cleanup necessary to prepare the well for plugging. The final step in well preparation is to circulate mud until the well is in static equilibrium. This will reduce the possibility of differential settling and contamination of the cement plugs.

Mechanical Integrity Evaluation

The mechanical integrity of the well is evaluated by logging and pressure testing after well preparation operations are completed. The logging program should include a casing inspection survey, a cement bond log, and a radioactive tracer survey. The casing inspection survey and pressure test will indicate the condition of the casing. The cement bond log will reflect the degree of bonding between the cement and casing and between the cement and formation. The radioactive tracer survey is used to locate the flow of injected fluids in channels behind the casing. The two most common tracers are Iodine-131 with an 8-day half life, and Iridium-192 with a 74-day half life. Interpretation of the logs, that have been run to demonstrate the mechanical integrity of the well, and the results of the pressure test will indicate whether remedial cement squeeze operations will be necessary prior to plugging.

Plug Placement

Cement plugs may be set using different methods. The balance method is most commonly used. This method may include setting a mechanical bridge plug at the desired plugging depth. The cement slurry is pumped down the drill pipe and back up the annulus to a calculated height that will balance the cement inside the drill pipe with the cement outside the pipe. The pipe is pulled up above the plugging depth and cleaned by reverse circulation. If a mechanical bridge plug is used, the drill pipe may be pulled up to the next plug setting depth. If a mechanical bridge plug is not used, the drill pipe should be pulled up a few stands above the plugging depth. After waiting overnight for the plug to begin to set, the drill pipe can be lowered slowly, and the top of the plug "tagged". The drill pipe may then be raised to the next plug setting depth and the procedure repeated.

Another method of plug placement is the cement retainer method. A cement retainer plug is installed in the casing and the cement is pumped through the plug. This allows the cement to be pumped under pressure and is especially good for an injection zone squeeze. After cementing, the

cement retainer is closed and the drill pipe pulled out of the retainer. Cement can be placed on top of the retainer by slowly pulling the drill pipe as cement is pumped (Booz, and others, 1980).

Other methods for plug placement, such as the dump bailer method and the two plug method, are available. Proposed plugging procedures are subject to approval prior to their implementation. Acceptable plugging proposals are dependent on many factors including well construction, mechanical integrity, type of completion, reservoir geohydrology, and chemical characteristics of injected fluids.

The depth at which cement plugs are placed is also determined on a site specific basis; however, some general conditions are applicable to most wells. The completion interval should be squeezed with cement to effectively seal the injection zone. This may not be practical in some instances, such as in open-hole completions. If the completion interval cannot be squeezed off, a squeeze should be performed in the first overlying confining layer above the injection zone. The squeeze should be performed to leave at least 50 feet (15.2 m) of cement in the casing above the completion interval. The logs that are run to demonstrate the mechanical integrity of the well may indicate additional zones that should be squeezed with cement. Any potential weak spots in the long-string casing, such as intervals squeezed during well construction or multiple stage cementing tool depths, should have cement plugs set. A plug will be set across the base of surface casing and another plug set at the surface. The casing will then be cut off below ground level and a steel cap welded on the casing. A permanent marker is erected at the well site to indicate permit number, company well number, dates of operation, and date plugged.

Uranium Solution Mining

As discussed previously, four distinct types of in situ mines are currently operating in Texas. These are solution mining of uranium, sulfur mining by the Frasch process, sodium sulfate brine production, and solution mining of sodium chloride brine. Only in the case of solution mining of uranium have restoration and closing standards been developed, and these are discussed below.

Plugging Procedures

All injection, production, and monitor wells must be satisfactorily plugged after restoration of an area, except where the landowner may wish to retain a suitable well for his use. Size and location of plugs, type of cement used, and manner of emplacement of cement are usually proposed by the operator, subject to Department approval. A minimum 10-foot (3.04 m) surface plug emplaced below plow depth, and plugs adequate to ensure isolation of the production zones from all other aquifers are the minimum requirements. Any uncemented length of hole is normally filled with drilling mud. Some operators may choose to cement the entire hole, especially if wells are shallow.

Restoration

When solution mining has been conducted in aquifers containing water suitable for domestic water supply or other beneficial uses, restoration of the aquifer is a necessary part of the overall

mining operation. In situations where the mining process has permanently removed the mining zone from the natural flow regime of the aquifer through subsidence and faulting, or where the water quality is such that it is not a fresh-water resource, aquifer restoration may not be necessary.

Restoration of the production-zone aquifer is generally accomplished by ground-water sweeping, also known as pore-volume flushing or pore-volume displacement. Briefly, the technique involves pumping mine fluids from selected wells, causing the inward migration of unaffected formation fluids which displace mine fluids not yet extracted by pumping. The restoration process involves production of a large quantity of wastewater, which can represent a disposal problem of considerable magnitude. The usual means of disposal involves subsurface injection through a waste disposal well. The entire waste stream may be injected; it may be concentrated by evaporation in a lined pond and subsequently injected; or it may be treated by deionization procedures, such as electrodialysis or reverse osmosis. The latter process produces a concentrated brine containing most of the dissolved solids originally present and a deionized stream of clean water, which may be used or disposed of by spray irrigation or by reinjection into the aquifer. The brine, often about a fifth of the volume of the original wastewater, usually goes to a disposal well for subsurface injection.

Closing Procedures

Solution mining involves very little surface disturbance. Most mine areas can be easily restored to the original premining condition. All surface structures are removed after mining activity ceases. All lines, pumps, tanks, control panels, structural steel, and other surface facilities are decontaminated and retained for future use or disposed of. Ponds are closed by draining and disposing of all liquids. Solid wastes which may be present are disposed of by approved methods. Pond liners are decontaminated, folded, and placed on the bottom of the pond excavation. Two or three feet of clay is then compacted on the bottoms of ponds. The pond embankments are placed over the clay and graded to a crown to prevent ponding and seepage, after which the surface is seeded with appropriate grasses. Concrete pads are decontaminated, broken up, and disposed of in an approved solid waste facility. Phone and power lines may be removed or may be left for use by the landowner.

THE TEXAS UNDERGROUND INJECTION CONTROL PROGRAM

Subsurface injection of fluid in Texas may have begun over 70 years ago with the onset of sulfur mining by the Frasch process. The first large-scale injection activity in the State was an East Texas oil field cooperative project around 1938, which involved the injection of produced salt water back into oil-producing zones. In the 1940's, the Railroad Commission of Texas, the State oil and gas regulatory agency, recognized the need for regulating brine injection. By the early 1950's the Commission began issuing permits for disposal of salt water into subsurface strata nonproductive of oil or gas. Success of salt-water injection operations led chemical and petrochemical companies to investigate the feasibility of subsurface injection for disposal of industrial wastes. By 1953, the first industrial waste disposal well was operating in Texas.

In 1961, the 57th Texas Legislature enacted the Injection Well Act in order to protect ground water from contamination as a result of the injection of wastes into the subsurface through

disposal wells. The Act required that any person seeking to dispose of waste into the subsurface must secure a permit from the Railroad Commission of Texas for all waste arising out of the production of oil and gas, and a permit from the Texas Board of Water Engineers for all other types of waste. The Act was amended in 1965 and again in 1969 resulting in transfer of the regulatory function of the Board of Water Engineers and its successors to the Texas Water Quality Board. In 1971, the 62nd Legislature passed the Texas Water Code which incorporated and revised the Injection Well Act. The Act became known as the Disposal Well Act and was codified in Chapter 22 of the Texas Water Code.

The Texas Water Quality Board (TWQB), the Texas Water Rights Commission (TWRC), and the Texas Water Development Board (TWDB) were merged in September, 1977 to form the Texas Department of Water Resources (TDWR). The Texas Water Quality Board regulatory responsibility for injection wells now resides with the Texas Department of Water Resources, or the Department.

By January 6, 1982, the Department, or a predecessor agency, had issued approximately 190 subsurface waste disposal well permits and 30 uranium solution mining permits. Currently, there are about 120 waste disposal wells operating in Texas that are regulated by the Department. The injection rate is approximately 6 billion gallons (22.7 billion liters) per year.

While formulating the Safe Drinking Water Act in 1974, the U.S. Congress recognized both the need for protection of underground drinking water sources from contamination by underground injection, and the need for effective state regulatory programs. Therefore, Congress directed the Environmental Protection Agency (EPA) to develop underground injection regulations to guide states in establishing their own programs. The Environmental Protection Agency promulgated regulations for this program in 1980.

Briefly, these regulations (a) define underground sources of drinking water and what constitutes endangerment of these sources; (b) direct the states to set up their own underground injection control programs to protect these drinking water sources; (c) describe the requirements of such programs and permit systems; (d) set forth procedures to assure enforcement of these requirements by the states or by the federal government, if the state fails to do so; and (e) list construction, permit, operating, monitoring, and reporting requirements for specific types of wells.

In 1981, the Disposal Well Act was amended and became the Injection Well Act under Chapter 27 of the Texas Water Code. The Act provides for regulation of all underground injections and became effective on June 17, 1981. The complete application for primary enforcement authority for the Underground Injection Control program was submitted by the Department of Water Resources to the Environmental Protection Agency Region VI in Dallas on July 24, 1981. Primary enforcement authority for the Underground Injection Control program became effective on January 6, 1982.

Program Description

Subsurface injection is a practicable and feasible method of disposal of certain wastes when the overall project is properly designed, constructed, operated, and monitored. State law allows injection if: (a) the installation is in the public interest; (b) no existing rights will be impaired; (c)

with proper safeguards, both ground and surface fresh water can be adequately protected from pollution; and (d) the applicant has made a satisfactory showing of financial responsibility.

Under the 1981 Injection Well Act, the Railroad Commission of Texas has jurisdiction over all Class II injection wells; Class III wells used for in situ combustion of fossil fuels or for recovery of geothermal energy; and Class V geothermal wells used for heating or aquaculture. The Texas Department of Water Resources has jurisdiction over all Class I and IV injection wells and all Class III and V wells not under the jurisdiction of the Railroad Commission. Appendix I provides details of the regulatory responsibilities.

Although both the Department and the Railroad Commission have jurisdiction over injection wells under the Underground Injection Control program, the division of responsibilities is such that minimal interagency coordination is expected. It is anticipated that some problems may arise as to which agency will have regulatory authority over specific wells, or in some cases, type of wells. Questions concerning jurisdiction will be resolved by joint agreement of appropriate representatives of both agencies. Other matters will be routinely coordinated by the Chief of Underground Injection Control for both agencies.

It is anticipated that during the first 5 years of the State program, the Department could issue up to approximately 450 Underground Injection Control permits and will specifically regulate about 4,000 additional injection operations through the adoption and implementation of Department rules. The Department must also monitor compliance with conditions of any permit or other authorization, and in conjunction with the Texas Attorney General's Office, pursue enforcement, where necessary, by appropriate civil or criminal proceedings of conditions of any authorization for injection operations within its jurisdiction.

Administration of the general responsibilities of the Underground Injection Control program involves several elements of the Department. The Texas Water Development Board functions as the legislative arm of the Department and the Texas Water Commission is the Department's judicial arm. Under the direction of the Executive Director, the Department's executive branch is responsible for reviewing injection well permit applications, monitoring permit compliance, and pursuing enforcement actions. Additionally, in accordance with State statute, the Department maintains an Office of Public Interest directed by a Public Interest Advocate whose major function is to ensure that public views and concerns are adequately represented.

Under the Executive Director, the Permits Division has primary responsibility for technical and administrative evaluation of permit applications, formulation of proposed permit provisions, and preparation of draft permits for consideration by the Texas Water Commission. During permit processing, the Permits Division will coordinate with other agency organizational units, including Enforcement and Field Operations Division, and the Office of General Counsel. Basic processing procedures are similar for Class I permits and Class III solution mining authorizations. Permits for uranium solution mining and disposal of uranium solution mining wastewater are coordinated with the Texas Department of Health. Major permit amendments follow essentially the same lines.

Applicants for injection well permits may attend a preapplication conference with the Department's Underground Injection Control Section staff prior to formal submittal of an injection well application. An application is first submitted to Permits Control, where it is reviewed for administrative completeness and then forwarded to the Underground Injection Control staff for technical

evaluation. The staff reviews the detailed information submitted on all aspects of the construction and operation of the facility and requests additional information if necessary. If the staff recommends that a permit be issued, processing continues with the preparation of a technical report, when required, a technical summary or fact sheet, and a draft permit. The draft permit must be approved by an executive review committee before being transmitted to the Texas Water Commission for consideration following public notice and opportunity for public hearing. The Office of Hearings Examiners of the Commission presides over a public hearing, if requested by interested parties, and forwards a proposal for decision with recommendations to the Texas Water Commission for final approval or denial. A decision by the Texas Water Commission is subject to appeal pursuant to the Texas Water Code and the State Administrative Procedure and Texas Register Act, Article 6252-13a, Vernon's Texas Civil Statutes.

Permits include provisions that specify standards for surface facilities associated with injection wells. For those facilities which handle hazardous waste, additional application review and drafting of surface facility permit provisions is accomplished by the Department's Solid Waste Section of the Permits Division to ensure that the facility meets Department requirements for hazardous waste management. For those facilities which handle radioactive materials, primarily uranium solution mining projects, additional application review and licensing is done in cooperation with the Texas Department of Health.

After a permit is issued, certain phases of well construction may be witnessed by the staff. Department approval must be obtained before beginning injection operations, and before plugging a well or closing a facility.

Department rules and guidelines set forth minimum construction, operating, monitoring, reporting, and record keeping requirements for all permitted injection operations. Construction requirements set forth minimum standards for cementing methods and materials, well construction materials, use of packers or an approved equivalent, logging and preoperation testing programs, and injection zone data to be determined. Operating requirements include limitations on injection pressures, injection rates, and volumes of fluids injected. Monitoring involves injection fluid analyses; recording of injection pressure, flow rates and volume, and annulus pressure, when applicable; and a regular schedule of sampling or other testing of monitor wells. During the life of a permitted facility, Department rules and permit provisions require periodic testing, which includes mechanical integrity, and the submission of reports of operation. In addition, some Class III facilities may be required to restore certain aquifers and submit regular reports of restoration progress. Basic reporting requirements specify quarterly monitoring reports and reports of all periodic test results. In addition, Class I facilities submit quarterly operations reports, and both Class I and Class III facilities submit 6-month information reports. Owners or operators are required to maintain files of all monitoring and testing for a specified number of years after facility closure.

Enforcement actions are pursued as a cooperative effort of the Department's Enforcement and Field Operations Division, Permits Division, and General Counsel, and the State Attorney General's Office. Enforcement actions range from letters requesting corrective action and issuance of citations to the application of civil and criminal penalties by appropriate court action.

Summary

The Injection Well Act, enacted by the Texas Legislature in 1961, required that any person seeking to dispose of waste into the subsurface must secure a permit from the Railroad Commission of Texas for all waste arising out of the production of oil and gas, and must secure a permit from the Texas Board of Water Engineers for all other types of wastes. The act was amended several times resulting in transfer of the regulatory function of the Board of Water Engineers and its successors to the Texas Department of Water Resources. Currently, the Injection Well Act, as amended in 1981 and recorded in Chapter 27 of the Texas Water Code, provides for the regulation of all underground injections.

To date, the Department or a predecessor agency has issued approximately 230 waste disposal and solution mining injection well permits. Permit applications are reviewed for technical accuracy. Included in the evaluation are (a) determination of the regional geology and ground-water hydrology; (b) lithology of the receiving formation; (c) movement and dispersion of injected fluids; (d) pressure changes in the injection interval; (e) proper well construction; and (f) potential hazards to usable ground water and mineral resources.

Upon completion of the review, Department staff recommendations are made to the Texas Water Commission. A permit may be granted by the Texas Water Commission when it is determined that (a) it is in the public interest; (b) no existing rights will be impaired; (c) with proper safeguards, both ground and surface fresh water can be protected from pollution; and (d) the applicant has made a satisfactory showing of financial responsibility.

The Department has found that if the injection of fluids is confined to suitable subsurface stratum, the wells are properly designed and operated, and injection pressures are maintained below certain limits, there should be no hazards of pollution to fresh ground water under any conditions due to the injection operations.

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APPENDIX I

REGULATORY RESPONSIBILITIES FOR THE STATE UNDERGROUND INJECTION CONTROL PROGRAM

Chapter 27 of the Texas Water Code, the 1981 Injection Well Act, provides the statutory authority for regulation of all underground injections in Texas. In addition, the Act divides the regulatory responsibilities between the Railroad Commission of Texas and the Texas Department of Water Resources. Each agency will regulate underground injections within its jurisdiction as defined by the Act.

The Texas Department of Water Resources has regulatory responsibility for the following activities:

- (1) Class I.
 - (A) Wells used by generators of hazardous wastes or owners or operators of hazardous waste management facilities to inject hazardous waste, other than Class IV wells.
 - (B) Other industrial and municipal waste disposal wells which inject fluids beneath the lowermost formation containing, within one quarter mile of the well bore, an underground source of drinking water. This category includes disposal wells operated in conjunction with uranium mining activities.
- (2) Class III. Wells which inject for extraction of minerals, including:
 - (A) Mining of sulfur by the Frasch process.
 - (B) Solution mining of minerals which includes sodium chloride, potash, phosphate, copper, uranium, and any other mineral which can be mined by the process.
- (3) Class IV. Wells used by generators of hazardous wastes or of radioactive wastes, by owners or operators of hazardous waste management facilities, or by owners or operators of radioactive waste disposal sites to dispose of hazardous wastes or radioactive wastes into or above a formation which, within one quarter mile of the well, contains an underground source of drinking water. Class IV injection activities, generally prohibited under the previous State program, are prohibited under the Underground Injection Control program.
- (4) Class V. Injection wells not included in Class I, II, III, or IV. Class V wells include:
 - (A) Air conditioning return flow wells used to return to the supply aquifer the water used for heating or cooling in a heat pump.

- (B) Cesspools, or other devices that receive wastes, which have an open bottom and sometimes have perforated sides.
- (C) Cooling water return flow wells used to inject water previously used for cooling.
- (D) Drainage wells used to drain surface fluid, primarily storm runoff, into a subsurface formation.
- (E) Dry wells used for the injection of wastes into a subsurface formation.
- (F) Recharge wells used to replenish the water in an aquifer.
- (G) Salt water intrusion barrier wells used to inject water into a fresh water aquifer to prevent the intrusion of salt water into the fresh water.
- (H) Sand backfill wells used to inject a mixture of water and sand, mill tailings, or other solids into mined out portions of subsurface mines.
- (I) Septic system wells used
 - (i) to inject the waste or effluent from a multiple dwelling, business establishment, community, or regional business establishment septic tank; or
 - (ii) for a multiple dwelling, community, or regional cesspool.
- (J) Subsidence control wells used to inject fluids into a non-oil or gas producing zone to reduce or eliminate subsidence associated with the overdraft of fresh water. These are wells not used for the purpose of producing oil or gas.

The Railroad Commission of Texas will, under its own Underground Injection Control program, regulate the following activities:

- (1) Class II injection operations.
- (2) Class III wells used for in situ coal gasification.
- (3) Class III wells used for recovery of geothermal energy.
- (4) Class V geothermal wells used in heating and aquaculture.

APPENDIX II

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