Subsurface Saltwater Injection and Disposal

Book Three
of the

Vocational Training Series

Third Edition,

October 1995

American
Petroleum
Institute

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Exploration and Production Department

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FOREWORD

The underground injection of water, whether into waterfloods or disposal systems, is an integral portion of the cost of producing oil. The magnitude of this cost has increased because more water is being produced as:

- More reservoirs are nearing completion.
- Wells are being produced to higher water-cut due to the demand for oil.
- Many older waterfloods are being expanded and new ones started in order to recover once marginal reserves.

The expense of injecting larger volumes of produced water is further compounded by the rapid rise in the cost of energy needed to inject this water and the increasingly higher costs of measures needed to protect the environment.

The objective of this manual is to provide information for field operating personnel on the systems, methods and practices to most economically operate an underground injection program while maintaining the schedules and volumes required.

The manual is written to help the overseer of the system solve many of the problems associated with underground water injection. Its intent is to provide the reader with information regarding the following:

a. Suitable design of the injection system including wells, lines and surface facilities.
b. Regulations and other restrictions related to subsurface water injection.
c. Measures to be taken to protect life, property and the public interest.
d. Factors which affect injection cost.

The material in this manual is of a basic, cursory, and introductory nature. The reader should consult technical experts for more detailed information on specific items of interest.

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SECTION 1—INTRODUCTION TO SALTWATER INJECTION

1.1 Introduction

Deep beneath the surface of the earth lie layers of soil containing the oil and gas used to fuel our world. Unfortunately for oil and gas producers, water is also found in those very same formations. Since technology has developed no effective method to date for selectively producing hydrocarbons only, this water, known as produced water or brine, is produced with the oil or gas, and separated at the surface.

Sometimes the water is fresh. In those cases, many options are available for its management when it reaches the surface and is separated from the oil. However, in other cases, the water is very saline.

With rare exceptions, only four acceptable methods exist for saltwater management:

a. Injection into underground saltwater-bearing formations.
b. Injection into oil-bearing underground reservoirs.
c. Disposal of carefully treated water into the ocean in the case of offshore production platforms.
d. Beneficial use.

This manual discusses options (a) and (b)—injection into deep wells for disposal or for enhanced product recovery. It presents minimum guidelines covering well construction, operation and monitoring.

1.2 Referenced Publications

The following bulletins, recommended practices, and codes are cited in this publication.

API

Bull E2 *Bulletin on Management of Naturally Occurring Radioactive Materials (NORM) in Oil and Gas Production*

Bull E3 *Well Abandonment and Inactive Well Practices for U.S. Exploration and Production Operations*

Bull D16D *Suggested Procedure for Development of Spill Prevention Control and Countermeasure Plans*

RP 55 *Recommended Practices for Conducting Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide*

Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations

OSHA[1]

29 *Code of Federal Regulations* Part 1910:1200

NACE[2]

TM0194-94 *Field Monitoring of Bacteria Growth in Oilfield Systems* (1994)

1.3 Disposal Versus Enhanced Recovery

The primary difference between injection wells used for disposal and those used for enhanced recovery is the purpose each serves.

- The disposal well is used for the subsurface disposal of unwanted salt water. In many cases, only one disposal well serves a field or system. Suitable formations for disposal may include depleted oil reservoirs and portions of oil-producing reservoirs' down dip from the water-oil contact.
- The enhanced recovery well is used for the subsurface injection of water into an oil-bearing formation to displace movable oil toward producing wells. The enhanced recovery well is usually part of a pattern of several injection wells serving an enhanced recovery project.

Unless otherwise noted, in this manual the term *injection well* will be used to refer to either type. The more specific terms *disposal well* or *enhanced recovery well* will be used when discussing issues particular to one or the other. Both types of wells have a common objective—to furnish an avenue, or well bore, for the subsurface management of salt water. Because of this common objective, most completion and operational practices fit both.

- The salt water is injected through a cased and cemented well to protect other underground reservoirs, especially those containing potable ground water.
- If the project is to be installed and operated at minimum cost, the best materials for distribution lines must be selected.
- Planning of an injection system may include a water treatment program that will control corrosion of the piping system and prevent plugging of the injection formation. Careful selection of plant equipment and treating facilities is important.
- Injection well permits are required from the U.S. Environmental Protection Agency (EPA) or the applicable state regulatory agency. The wells must be designed, constructed, and operated in accordance with regulatory requirements.

[1]OSHA, *The Code of Federal Regulations* is avilable from the U.S. Government Printing Office, Washington, D.C. 20402.
[2]NACE, P.O. Box 218340, Houston, Texas 77218.

However, some differences exist.

■ There are more injection wells in an enhanced recovery project than in a disposal project.
■ The volume of water to be used for enhanced recovery is selected for each well; with disposal, however, whatever water is produced must be managed. Injection volume in a disposal well is limited only by permit condition or the injectivity of the well.
■ In enhanced recovery projects, the formation and its properties are already known from production history. For disposal, this is not always true. It may be necessary to select the best formation from information that must be gathered.
■ Enhanced recovery systems generally require much longer surface lines to distribute the water to the injection wells than those for a disposal system.

Installation and operation of a saltwater system are expensive. Careful planning is mandatory before beginning construction to allow time for the following:

a. Designing the system.
b. Notifying the offset operator.
c. Planning safety, environmental and health considerations.
d. Selecting materials and equipment.
e. Securing required environmental and operational permits.
f. Scheduling possible hearings before state and federal regulatory bodies.

1.4 Components of an Injection System

Whether for enhanced recovery or disposal, the basic components of the injection system are the same. These include the following:

a. A gathering system to move the salt water from each tank battery or watersource well to the treating and injection facilities.
b. Water treatment facilities to remove oil or other impurities that might impact the system or the injection formation.
c. Injection facilities, including storage tanks, pumps, piping, and the well itself.

This section provides a brief overview of the various system components, some initial planning considerations, and a discussion of environmental, health and safety concerns associated with injection well facilities.

1.4.1 GATHERING SYSTEM

The gathering system is a network of pipelines that moves salt water from the tank battery or watersource well to a collection center or treating plant. Where possible, gravity flow is utilized, however, pumping is usually required. The following must be considered for the gathering system:

a. Pipe and pump sizes and types.
b. Installation of the pipelines.
c. Collection center equipment.
d. Metering equipment.
e. Inspection and maintenance of the system.

Additional information on the gathering system is provided in Section 2.

1.4.2 WATER TREATMENT FACILITIES

Although preliminary separation of salt water from other components (oil, solids, and the like) begins at the tank battery, additional treatment is often required prior to injection to protect the surface facilities, the well, and/or the formation. Additionally, further product recovery can occur. Various types of treatment may be necessary, depending upon the types of contaminants to be removed. Some of the most common include the following:

a. Skimmers or coalescers to remove oil.
b. Filters to remove solids.
c. Chemical treatment to remove or control scales and sludges, or kill bacteria.
d. Stripping to remove oxygen.

It is necessary to determine which types of treatment might be required so that proper facilities can be planned and designed. This may require sampling the water or deposits. The saltwater contaminants and the treatment methods are discussed further in Section 3.

1.4.3 INJECTION FACILITIES

Once the salt water has been moved to the central facility and treated, it is ready for injection. Pumps are used to move the salt water down the well and into the injection formation. Equipment should be selected that is resistant to corrosion, and sized properly to ensure optimum injection rates and pressures. Additional information on the injection facilities can be found in Section 4.

1.5 Environmental Concerns

As with other oil and gas operations, protection of the environment is a primary concern when managing produced water, especially that which is saline.

■ All injection activity must be designed, operated, monitored, maintained, and plugged and abandoned to prevent produced fluid from moving into or between underground sources of drinking water (USDWs). Monitoring and mechanical integrity testing will help to demonstrate that there is no unwanted fluid movement.
■ The surface equipment—pipes, pumps, storage tanks, and the like—also should be designed to prevent leaks or spills of the materials they hold, and to minimize emissions to the air.
■ Proper management includes routine well inspection and repair, monitoring, and cleanup.

■ In emergency situations, such as breakdown of disposal facilities, temporary storage of salt water in lined surface pits may be allowed. However, applicable regulatory agencies should be consulted before constructing such emergency facilities. Tanks are the preferred means of providing emergency storage.
■ It should be stressed that failure to comply with appropriate regulations for salt water disposal or injection can result in fines and orders to cease production entirely, until the operation is in regulatory compliance.

This section provides an overview of some of the environmental regulations that impact saltwater injection. In general the following should be considered:

■ Governmental regulatory requirements must be met by the operator for drilling, completion, and operation of injection or disposal wells;
■ These regulations include such topics as spill response and reporting, waste disposal, hazardous chemicals inventory, and the protection of drinking or potable water; and
■ The operator must be acquainted with the regulations of all governing bodies having jurisdiction over the injection system and operate within the framework of government regulations.

Some of the regulatory bodies that could have jurisdiction are the following agencies and departments:

a. Department of Interior (DOI), including:
   1. Bureau of Fish and Wildlife (BFW).
   2. Bureau of Indian Affairs (BIA).
   3. Bureau of Land Management (BLM).
   4. U.S. Geological Survey (USGS).
b. Environmental Protection Agency (EPA).
c. Municipalities.
d. Occupational Safety and Health Administration (OSHA).
e. State Boards of Health.
f. State Highway Departments.
g. State Parks and Wildlife Departments.
h. State Oil and Gas Commissions.
i. State Water Districts.
j. State Water Quality Boards.
k. U.S. Army Corps of Engineers (US ACE).

An injection well or disposal well with the desirable characteristics outlined in this section should have little trouble meeting the requirements of these regulatory bodies.

1.5.1 UNDERGROUND INJECTION CONTROL (UIC)

Salt water can be very damaging to soil and ground water environments if not managed correctly. All surface facilities and the injection well must be designed to prevent spills and leaks of salt water. The EPA and states have specific regulations for Underground Injection Control (UIC) that address the construction and operating requirements for injection wells. UIC regulations are promulgated under the authority of the Safe Drinking Water Act (SDWA). These regulations are designed to prevent endangerment of USDWs.

Under state and federal regulations, there are five classes of injection wells. Those used to manage fluids produced from oil and gas subsurface reservoirs are Class II injection wells. The following is the EPA definition of a Class II well.

Class II Injection Wells are wells which inject fluids:

a. Which are brought to the surface in connection with natural gas storage operations, or conventional oil or natural gas production and may be commingled with waste waters from gas plants, which are an integral part of production operations, unless those waters are classified as hazardous waste at the time of injection.
b. For enhanced recovery of oil or natural gas.
c. For storage of hydrocarbons which are liquid at standard temperature and pressure.

The *Environmental Guidance Document: Onshore Solid Waste Management in Exploration and Production Operations* contains information on the UIC program, and is available from the API Publications Department.

In most states, the state regulatory agency has jurisdiction over the UIC program. In these states, the oil and gas agency usually approves UIC Class II permits. Applications for permits are heard before the regulatory bodies in some states and handled by correspondence in others.

The EPA issues injection well permits in states that have not obtained authority to operate the UIC program. Additionally, production on Indian Lands will require permits from one or more federal agencies.

A broad range of issues is addressed in a permit for a new injection well, including the following:

a. Siting.
b. Design.
c. Operating parameters.
d. Corrective action.
e. Mechanical integrity demonstrations.
f. Plugging and abandoning.
g. Financial responsibility.

Each of these factors must be addressed in the UIC permit application. All or some of the following information is generally required in the application:

a. Location of well.
b. Name, depth, and thickness of subsurface formation to be used for disposal or enhanced recovery purposes.
c. Size, weight, and depth of all casing strings in the well; amount of cement behind casing.
d. Approximate amount of water to be injected.
e. Expected wellhead pressures.

f. Well log, if available.
g. Depth of USDWs (<10,000 mg/l total dissolved solids) or usable water (<3000 mg/l total dissolved solids) in some states such as Texas and California.
h. Name, mailing address, and location of the well operator.
i. Approximate Standard Industrial Classification (SIC) codes.
j. Operator's name, address, and telephone number.
k. Topographic map showing a 1-mile radius around the facility, including Treatment Storage or Disposal Facilities (TSDFs), oil and gas wells, injection wells, surface water bodies, and drinking water wells.
l. Name and address of all landowners within 1/4 mile of injection well being permitted.

Additional information may be necessary for wells on Indian Lands.

It is important to note that, although produced water is the largest component of volume injected into Class II wells, other fluids may be allowed. A complete list of those fluids intended for injection must be included in the permit application. If a fluid is not included in the application, and therefore not approved by the permit, it cannot be injected.

The regulatory authority must review and approve the application before construction begins on a new injection well. It should be contacted well in advance of construction of the well so that the proper forms can be obtained and enough time allowed to obtain the permit. No construction or revisions can begin until the permit is approved.

Based upon information presented in the permit application and other available data or testimony, the regulatory agency must determine that the disposal of salt water as intended will not damage USDWs, or oil and gas reservoirs. If there are any objections from offset operators that cannot be settled by the operators, they are usually heard and settled before the state regulatory body.

Technical and legal assistance may be needed to secure the necessary permits from landowners, royalty owners, state and federal regulatory agencies, and to obtain rights-of-way. A simple contract is the most common instrument of agreement used between the operator and land or royalty owners.

1.5.2 AIR POLLUTION CONCERNS

Much attention focuses on emissions of air pollutants, especially volatile organic compounds (VOCs). Benzene, ethylbenzene, toluene and xylene (BETX) are those VOCs most likely to be emitted at oil and gas operations. Other common pollutants that might be generated at injection facilities include nitrogen oxides, sulfur dioxides, and carbon monoxide from fuel consumption to run generators, compressors, and the like. Hydrogen sulfide (H_2S) may also be present.

- Both the EPA and many state agencies regulate air emissions; sometimes permits are required.
- As with UIC permits, those required under the air programs should be obtained prior to construction and operation.

1.5.3 WASTE MANAGEMENT—HAZARDOUS MATERIALS

Wastes generated from operation and maintenance activities must be properly managed to protect human health and the environment, and to ensure compliance with federal, state, and local laws and regulations.

- Some wastes, such as some solvents, or wastes containing heavy metals, may be considered hazardous. While all wastes should be properly handled, hazardous wastes require extra care.
- Be sure to evaluate waste generation activities associated with the injection facility, and ensure proper management of all wastes.

1.5.4 SPILLS

Salt water can be especially damaging to soils, surface water, plants, fish and other wildlife. It is very important to design and operate the injection facilities to minimize the likelihood of leaks and spills.

- Due to its corrosive nature, salt water should be stored in metal tanks that are internally coated, or in fiberglass tanks.
- Steel pipes should be protected from external corrosion by coating and/or cathodic protection, and from internal corrosion by coating and/or chemical inhibition.
- Routine inspections should be made to look for potential problem areas.

If oil is stored at the site, the Spill Prevention Control and Countermeasures (SPCC) regulations may apply. If so, secondary containment around the oil storage vessels may be required; special precautions to prevent oil spills will be necessary; and a facility SPCC plan will have to be prepared.

API Bulletin D16, *Suggested Procedures for Development of Spill Prevention Control and Countermeasure Plans* contains information on SPCC plans and is available from the API Publications Department.

Spills of salt water, oil, and a variety of chemicals may need to be reported to the environmental agencies. Spill reporting requirements for the area where the injection facility is located should be researched to ensure proper and prompt reporting when required.

1.5.5 HAZARDOUS CHEMICALS INVENTORY

Certain hazardous chemicals can present a potential threat to the public. To help local authorities plan for emergency situations, companies must submit copies of their Material Safety Data Sheets (MSDSs) or a list of these materials to the local fire department and other emergency groups. In addition, an annual inventory report must be submitted providing the following information:

a. The maximum amount of chemicals present at the facility during the preceding year.
b. An estimate of the average daily amount of chemicals.
c. The general location of the hazardous chemicals.

The chemicals in the list and inventory may, at the discretion of state and local authorities, be reported by categories. Chemicals found at injection well facilities may be regulated.

1.5.6 NATURALLY OCCURRING RADIOACTIVE MATERIAL (NORM)

NORM, low-level radioactive material, is naturally present in some formations where oil and gas are found. Generally, it is found in produced water, produced sand, and in scales formed inside production equipment, such as during pipe clean-out operations. NORM must be handled properly to ensure protection of human health and the environment. Health issues are discussed in 1.6.

Some states have regulations that govern NORM management and disposal, while other states do not. You should be aware of the NORM requirements for your state, and ensure that you are managing it accordingly. API Bulletin E2, *Bulletin on Management of Naturally Occurring Radioactive Materials (NORM) in Oil and Gas Production* contains information on management of NORM and is available from the API Publications Department.

1.5.7 OTHER ENVIRONMENTAL CONCERNS

There may be other EPA and state requirements that may have an impact on the design and operation of the injection facilities. Furthermore, other agencies, such as the Bureau of Land Management, Fish and Wildlife, and others, may impose additional requirements.

It is up to the operator to research these requirements and ensure compliance. If your company does not haven an environmental staff, other resources can help with environmental compliance issues. These include the following:

a. Regulatory agencies.
b. Oil and gas associations, such as the API or the Independent Producers Association of America (IPAA).
c. Other operators in the area.
d. Environmental consultants.

1.6 Health and Safety Concerns

As with any industrial-type activity, there are health and safety concerns associated with injection wells. Obviously, safety protection is important. Standard safety equipment, such as safety glasses, hard hats, and safety shoes, should be considered for any facility. Additional personal protective equipment (PPE) may be necessary for special conditions.

Additionally, Occupational Safety and Health Administration (OSHA) regulations require certain health and safety precautions in industrial settings. This section presents an overall discussion of safety concerns associated with injection facilities. Specific precautions are noted in other sections where appropriate.

1.6.1 CHEMICAL EXPOSURE

A variety of chemicals might be encountered around injection facilities. These might be chemicals normally present in the crude or produced water, or chemicals that have been purchased for water treatment. Regardless of the origin, employees should be made aware of the hazards they might encounter.

■ The Occupational Safety and Health Administration (OSHA) requires that employees be informed of hazards they might encounter in the work place. This Hazard Communication program, commonly referred to as HazCom, is designed to ensure that employees have all the information necessary to ensure proper and safe handling of hazardous chemicals.

■ In addition to the training requirements, employers are required to obtain Material Safety Data Sheets (MSDSs) for any chemicals being purchased for use at the facility. The MSDSs provide specific hazard information about the product along with precautions to take when handling the chemical.

MSDSs must be readily available to employees, and should be reviewed to assure safe chemical usage before work with the selected chemicals begins.

■ More information about the HazCom requirements can be found in Title 29 *Code of Federal Regulations* (*CFR*) 1910.1200 or from your safety representative.

■ In addition to the HazCom requirements, employers are required to ensure that proper personal protective equipment (PPE) is available to the employees. Basic PPE that might be required at most work sites includes safety glasses, hard hats, gloves and safety shoes. Other personal protective equipment may include impermeable gloves, aprons, suits and boots, face shields, goggles, and respirators. The MSDSs will provide information on the proper PPE to be used with the product.

1.6.2 CHEMICALS AT INJECTION FACILITIES

1.6.2.1 Benzene

Some crude oils contain significant quantities of benzene, a highly toxic, cancer-causing chemical. At any location where outgassing of benzene vapors may occur, special precautions should be taken to prevent employee overexposure. These might include the following:

a. Measuring benzene concentrations.
b. Utilizing appropriate personal protective equipment.

The concentration of benzene in crude oil is higher than the concentration in produced water.

1.6.2.1 Hydrogen Sulfide

Hydrogen sulfide (H_2S) is also present in some injection systems. H_2S is sometimes present in the formation (sour operations), or it may be introduced into the system by chemical reactions that might occur. H_2S is a very dangerous and potentially deadly gas which at some concentrations smells like rotten eggs. However, at higher concentrations, it is undetectable by smell. Therefore, it is very important to use instruments to detect H_2S rather than depend upon sense of smell.

- H_2S may be found around surface equipment where leaks may occur, and in unventilated or poorly ventilated areas such as pump houses. Signs that indicate such a hazard should be on entrances to such areas.
- H_2S may accumulate in tank vapors at much higher concentrations than are present elsewhere in the system. Special precautions should be taken when working in and around tanks.
- Additionally, special air monitoring systems that indicate excessive levels of H_2S should be provided in such areas.
- Where H_2S is present in concentrations above 10 ppm, respirators are required. Employees who are potentially exposed to excessive quantities of H_2S must receive specialized training. Contact your safety representative for PPE and training requirements.

API RP 55, *Recommended Practices for Conducting Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide* contains information on H_2S and is available from the API Publications Department.

1.6.3 OTHER CHEMICALS

1.6.3.1 Acids

Acids are strongly reactive chemicals that are useful for many purposes.

- Acids may be used for pH adjustment or for treating the well to increase injectivity.
- They are corrosive to tissues, like the skin and eye.
- Furthermore, they can react with chemicals in the water to produce H_2S (see precautions in 1.6.2.1).

1.6.3.1 Organic Chemicals

Many organic chemicals, like benzene, are hazardous. MSDSs should be consulted for proper handling and PPE requirements.

- Solvents may be used for treating the formation. These may present an employee exposure hazard from inhalation of vapors or by skin absorption of the liquid.
- Plastic pipe glues and cements may also present an inhalation hazard.
- Chemicals used to kill bacteria and algae in the system contain amines, aldehydes, and quaternary ammonium derivatives. These chemicals are highly toxic to humans and appropriate PPE must be provided to employees who handle such bactericides and bacteriostats.

1.6.4 ASBESTOS

Asbestos is considered a hazardous chemical under the OSHA regulations as it can cause cancer and respiratory disease. Its management is strictly regulated.

- Asbestos insulation may be present at older facilities.
- Asbestos pipe may also be found.
- Asbestos particles may become airborne during handling of pipe if it is deteriorated to the point of being friable (crumbles easily), or if sawing, chipping or cutting occurs.
- Care must be taken to prevent employee exposure to asbestos dust, and the need for appropriate asbestos handling should be evaluated.
- Only certified workers should remove asbestos.

1.6.5 NATURALLY OCCURRING RADIOACTIVE MATERIAL (NORM)

Certain materials in the earth's crust are radioactive. NORM, brought to the surface in the produced water, is usually found in scale and sludges that deposit in tubing, gathering liens, tanks, and other vessels.

- NORM exposure around tank batteries or other equipment is usually well below levels of concern. However, gamma radiation surveys should be conducted to determine if special precautions are advisable. See API Bulletin E2 for information on detecting and managing NORM.
- However, when the NORM scale is disturbed, such as in dry sawing operations, it can present a health risk, if inhaled or ingested.
- Care should be taken to minimize exposure to airborne dust that might contain NORM by ensuring that proper PPE such as gloves, respirators, and the like is worn.

1.6.6 PHYSICAL HAZARDS

Physical hazards are present around any equipment, especially that which might have moving parts.

- All pumps and motors that have exposed rotating shafts, flywheels or belts, must be guarded to prevent employee injury.
- Equipment should be carefully designed and installed to avoid situations where employees might slip, trip, or fall. Guard rails and hand rails should be used where falls might occur.

1.6.7 NOISE

Pumps and their drive mechanisms, such as electric motors, and engines, may be sources of high noise levels.

■ Adequate precautions to prevent employee overexposure to noise must be taken in such cases.
■ This would include a hearing conservation program which provides hearing protection, audiometric testing, engineering controls, and employee training.

1.6.8 CONFINED SPACES

Tanks and other vessels are considered confined spaces under the OSHA regulations. In fact, even a ditch, such as a pipeline ditch, may be sufficiently deep to be considered a confined space.

■ Hazardous vapors may be present.
■ Oxygen levels may be inadequate, such as in tanks where inert gas (usually nitrogen) blankets are in use.
■ Confined space entry procedures should be used by personnel before entering.
■ Only trained personnel should enter confined spaces. Check with your safety representative prior to working in any confined spaces.

1.6.9 ELECTRICAL HAZARDS

A lockout/tagout program is required for protection from electrical hazards and other forms of energy.

■ This program provides for certain procedures that must be followed to ensure that any powered system is inoperable before maintenance is conducted.
■ Pump maintenance must be done utilizing the lockout/tagout procedures.
■ Check with your safety representative before any electrical work is initiated.

1.6.10 FIRES AND EXPLOSIONS

Hydrocarbons present a special danger with regard to fires and explosions.

■ Explosive gases may be present in the saltwater pipeline.
■ Even though dealing with water injection systems, the use of a gas blanket or the presence of oil carry over into the water may cause an area to be classified as hazardous because of combustible vapors or liquids.
■ See your safety representative for proper and adequate procedures for safe use of explosives.

1.6.11 CONSTRUCTION HAZARDS

Construction sites present their own set of hazards that might not normally be encountered in day-to-day operations.

■ If a ditch or other excavation is five feet or more deep in unstable soil, it must be sloped or shored to prevent cave-ins, and excavation must follow regulations governing training and shoring.

1.7 Summary

The proper design and construction of injection wells takes time and preparation. Proper planning of well location, selection of injection formation, and the proper equipment is crucial to a successful operation. Environmental and health and safety concerns must be carefully considered, and environmental permits must be obtained prior to conducting any operations at the facility. Significant time is often required to prepare the applications and have them approved by the regulatory agency.

SECTION 2—THE GATHERING SYSTEM

2.1 Introduction

The gathering system transports produced materials from the well to the separation and storage facilities. Salt water produced with the oil or gas is separated initially from the product at the tank battery. From here, it is transferred to a collection center or treatment facility, and then to the injection well.

If produced water volumes are fairly small, it may be more economical to transport salt water by tank truck, rather than add the expense of installing a pipeline and transfer pumps. For larger volumes, the salt water can be more economically transported through a pipeline. Proper pipeline design, installation, and maintenance is crucial to a successful gathering system. This section discusses the various components of the gathering system, including the following:

a. Initial oil/water separation at the tank battery.
b. Pipeline system design.
c. Pipeline installation.
d. Pipeline system maintenance.

2.2 Initial Oil/Water Separation

The water handling tanks at the tank battery provide not only for initial separation of the product from the salt water, but also working and storage capacity before the salt water enters the gathering system. These tanks also provide a working volume for automatic float level pump control.

■ An additional tank may be installed to handle emergency overflow in case of equipment failure.
■ Tanks used in saltwater service should be made of fiberglass, internally coated steel, galvanized steel, or other non-

corroding materials. Cathodic protection should be considered for metal tanks.

- Tanks must be vented at a sufficient height to allow any release of H_2S in the head gas to safely disperse.
- Grounding of fiberglass tanks will help prevent damage by lightning strikes.

Figure 1 shows a typical fiberglass accumulation tank, transfer pump, and spare pump. The hook-up for the transfer pump and spare pump is shown in Figure 2.

Before it is pumped to the treating plant, water from several tank batteries may accumulate in one or more collection centers. The collection centers include the following:

a. Accumulation tank.
b. Fluid level controlled transfer pumps.
c. Sometimes the saltwater storage capacity for emergency down time.

Emergency storage capacity at collection centers permits the continued operation of producing leases during short periods of down time due to equipment failure. A collection center containing a fiberglass tank and transfer pumps is shown in Figure 3.

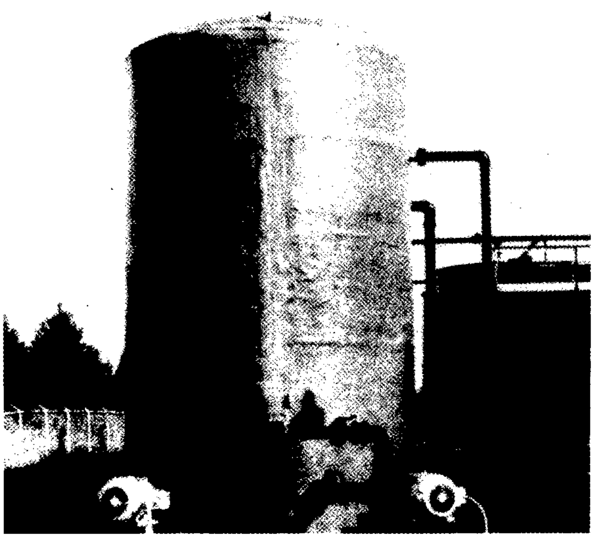


Figure 1—Fiberglass Saltwater Handling Tank

2.3 Pipeline Design

Pipelines in the gathering system should be designed so they will be capable of handling present, near-term, and long-term expected saltwater volumes and pressures. Nodal analysis techniques and computer programs are available which can accurately evaluate the interplay of these factors in the total system design.

2.3.1 DESIGN CONSIDERATIONS

The possibility of mineral scale deposition, corrosion by-products and/or bacterial debris—and the resulting loss of pipeline flow capacity—should be considered in the system design. These effects can be eliminated or mitigated by the following:

a. Chemical treatment of the water.
b. Internal coating of the pipe, or
c. Periodic use of pipeline scrapers to clear the lines of accumulated scale or debris.

The possibility of external corrosion failures should also be considered in the design of flowlines. External corrosion can be eliminated or mitigated by externally coating the pipe and/or by using cathodic protection.

Other factors which should be considered in the design are the following:

a. The estimated life of the project.
b. Operating pressures.
c. Pumps.
d. Fuel or power costs.
e. Monitoring needs.

The system should be equipped with safety relief valves or monitored with signal alarms that will shut down the system or alert operating personnel to abnormal flow conditions.

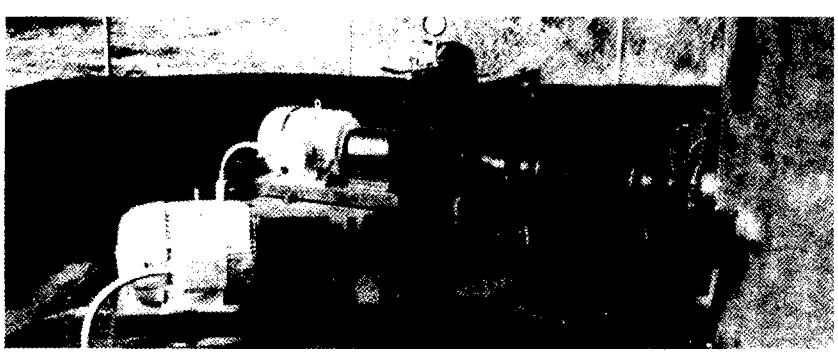


Figure 2—Transfer Pump and Back-Up Pump

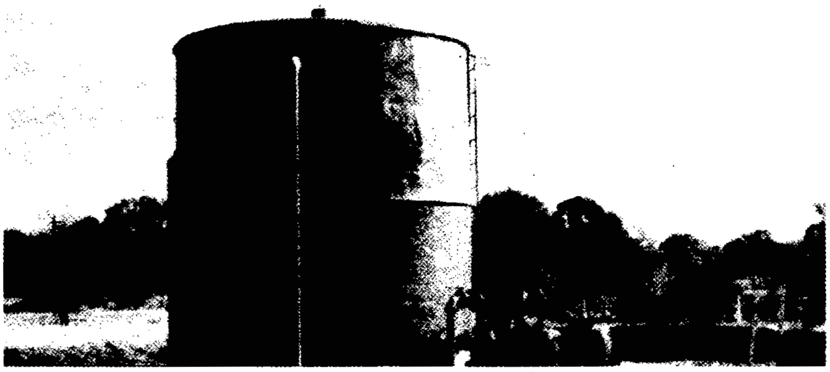


Figure 3—Fiberglass Tank and Transfer Pump

2.3.2 GRAVITY FLOW AND PUMPING TECHNIQUES

The salt water can be moved through the gathering system by gravity flow, pump pressure, or a combination of the two.

Gravity flow means that the salt water flows downhill through the pipelines without the use of a pump. Generally, gravity flow can not operate a complete gathering system. However, parts of a system (such as from tank batteries to a collection center) often can be designed for gravity flow and thereby minimize the cost of pumping the salt water.

- The route for gravity flow pipelines must be selected carefully so that the pipelines continuously slope toward the collection center. This may cause the pipeline to be elevated above the ground across low ground elevations, such as swamps, or installed deeper than usual across places of higher ground elevation.
- This continuous sloping prevents high spots in the pipeline in which gas could accumulate, reducing the flow of water through the line.

Pumping may be necessary because of the terrain, other surface conditions, or right-of-way problems.

- Sometimes the system pressure of a heater treater or other treating vessel can be used to move salt water to the collection center.
- For the same water volume, the size or diameter of the pipelines in a gravity flow system will be larger than the lines in a pressure gathering system.
- The increased cost for installation of the larger-sized pipe may be offset by elimination of pumping cost. Economic factors of gravity flow should be considered during system design.

2.3.3 PIPELINE SIZE

The pipeline size is determined by the flow rate of salt water to be handled and the pressure available to move salt water through the line. Figure 4 shows a chart for use in determining the friction loss in a particular size and length of pipeline for a volume of salt water moving through the line. The chart can be used to determine the size of pipeline needed for a complete gathering system or any of its parts.

2.3.4 PIPELINE VENTS

Pipelines in gravity flow systems are installed with a continuous downhill flow, but there may be unavoidable high points in the line. If these high points have sufficient height to permit separated gas to accumulate, a gas lock will form and prevent flow through the line.

a. These high point locations are determined during the initial survey of the line.
b. Each high point requires venting of the gas through a vent pipe riser.
c. The vent pipe riser must be high enough to prevent fluid loss.
d. These vent risers should be located in an open, well-ventilated area to prevent the accumulation of toxic or explosive gases in a confined space.
e. Also, if hydrocarbons and/or H_2S will be venting, there may be a need to obtain applicable air permits.
f. A check valve or other device is used to prevent entry of air through the vent in a closed type system.

2.3.5 TYPES OF PIPE USED IN GATHERING SYSTEMS

Plastic, fiberglass, non-coated cast iron, and internally lined or coated steel are types of pipe material and coatings used for handling salt water. All these materials will give long-lasting and trouble-free service in the saltwater system if they are correctly selected for operating conditions and installed properly.

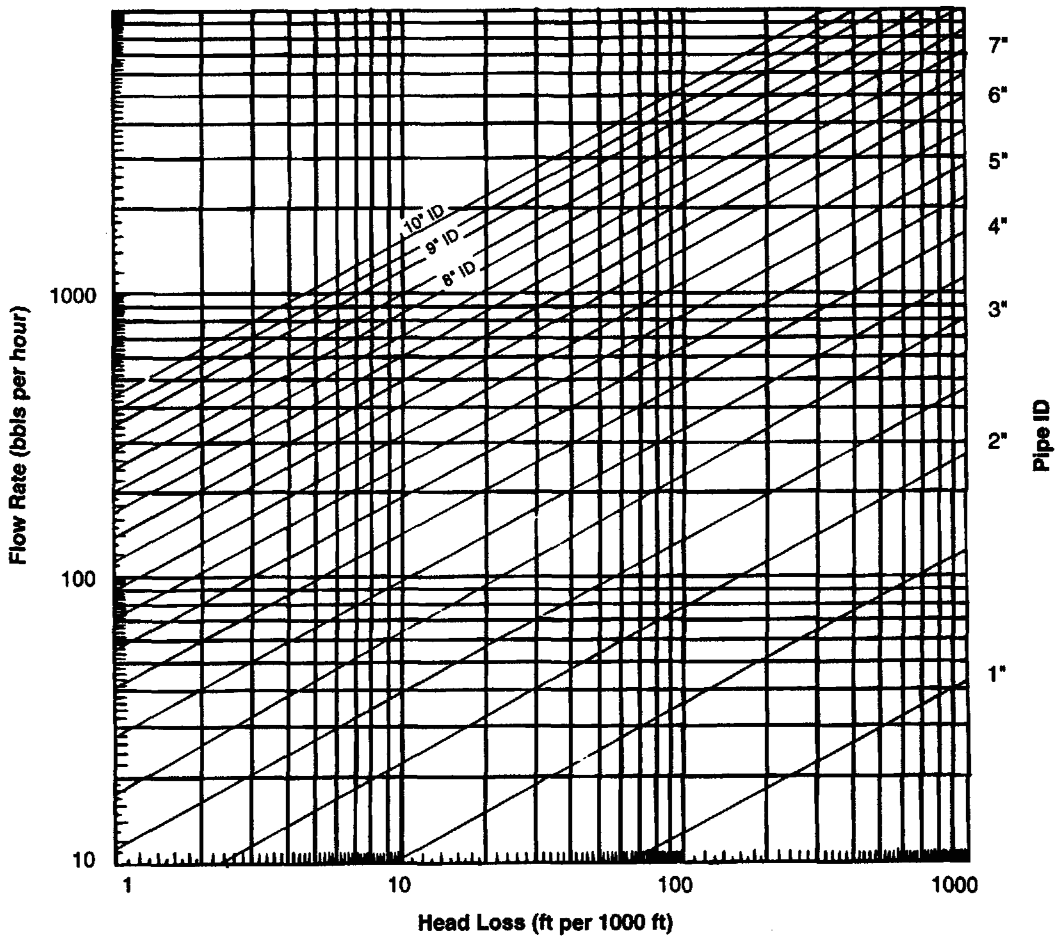
- Careful consideration should be given to operating temperature and pressure when selecting the type of pipe for a system or line.
- The type of pipe selected should also be suitable for handling small volumes of oil and gas with possible small-to-moderate hydrogen sulfide (H_2S) concentrations.

2.3.6 CONNECTIONS

Thread and coupling, bell end, flanged, bolted coupling, ring coupling, welded end, and glued connections are types of joint connectors available with different types of pipe. A bundle of plastic pipe with bell end joint connectors is shown in Figure 5.

2.3.7 PUMP SELECTION

The pumps used to deliver water should have sufficient capacity to move all of the daily produced water in the desired pumping time period. In addition, since the water from an individual tank battery generally enters a central gathering system, the transfer pump must have sufficient



Coefficient	Factor
110	0.85
120	0.72
130	0.62
140	0.54

Typical "C" Factors

Used Steel Pipe	$C = 100$
New Steel Pipe	$C = 120$
Plastic or Plastic Lined Pipe	$C = 130$ to 150

This is the Hazen-Williams friction-loss chart for water flow through pipe. Flow coefficient, C, = 100. The flow coefficient is expressed in feet loss of head per 1000 ft length. The C factor used in pipeline design is the coefficient of roughness of the pipe wall.

Note: For coefficients other than 100, multiply loss-of-head values found on this chart by the above factors.

Figure 4—Friction-loss Chart

Figure 5—Bundle of 8-inch Plastic Pipe With Bell End Joint Connectors

pressure and capacity to deliver the water into the central system. In many cases, the gathering system pipeline size is large enough to use low-pressure centrifugal pumps at the tank batteries.

In general, the larger the pump size, the lower the pressure required to pump into the system, thus minimizing pump operating cost. During the design of the gathering system, the economy of pumping at a lower pressure should be compared with the increased cost of installing larger-size pipe.

Low-pressure and high-volume centrifugal pumps are well suited for this pumping application. In designing a pumping system, consider the following:

a. Maximum pressure expected to move produced water, including upstream head or tank height must be known.
b. Pump selection and installation must plan for replacement and maintenance.
c. Pumps must be capable of being isolated and safely de-energized.

2.3.8 WATER METERS

Water meters are used to determine the volume of salt water being handled. For example, meters measure the volume of salt water received from each lease and the volume injected. Meters in general use include the following types:

a. Turbine flow.
b. Positive displacement.
c. Orifice plate recording meters.
d. Measured dump type meters.

Water meters must be designed for saltwater service or the meter must be protected from direct contact with the corrosive saltwater stream. Water meters should be sized for the volume and operating pressure of the salt water to be measured.

Figure 6 shows an orifice plate-type meter installation. This installation includes an 8-inch meter run, orifice plate holder and differential pressure meter located near an injection well.

2.3.9 INSPECTION AND SAMPLING

When designing the pipeline system, future needs for inspection, collecting samples and maintenance must also be considered. Auxiliary connections, such as scraper traps, inspection spools, corrosion or scale coupon monitoring points, sure taps, cathodic protection test stations, and galvanic anode connections are sometimes installed in the system. These inspection and service connections are useful for cleaning, testing, or checking to ensure efficient operation of the system.

Adequate sample points should also be included. In general, a sample point should be located anywhere in the system where the water has a chance to change. Points should be included at the following locations:

a. The raw water source.
b. Before and after each treatment vessel.
c. Before and after tanks, pumps.
d. At one or more points in the field distribution system.

2.4 Installation of Pipelines

Pipelines in pressure-gathering systems are installed along the shortest or best available route between the tank battery and the treating plant.

■ A pipeline right-of-way is required for most lines and for all lines handling salt water not produced on the same lease.

Figure 6—Orifice Meter Type Metering Installation

- In some instances, lines must follow property lines or fences and avoid buildings to obtain the necessary right-of-way.
- Pressure lines should be installed far enough below ground level to give adequate protection from surface operations, such as vehicle traffic or plowing, and weather conditions, such as very cold temperatures.

2.4.1 PIPE DITCHES

Most types of pipe today require a minimum amount of special preparation or backfill material in the bottom of the ditch before laying and backfilling the line. However, the bottom of the ditch should be free of rocks or other hard objects that would damage the pipe if it moves as a result of pump pressure or temperature expansion. The bottom should also be fairly smooth to support the pipe.

2.4.2 SNAKING PIPES

Changes in plastic pipe temperature due to weather or the fluid it contains cause the pipe to expand and contract. One method of providing for this elongation and shortening of lengths is to "snake" the pipe in the ditch during installation. In snaking, the pipe is laid in the ditch in side to side curves, similar to the shape of a snake in motion.

2.4.3 ROAD CROSSINGS

Special permits must be obtained before a pipeline or transfer line is laid under a public road.

- Generally, the saltwater line must be encased in a steel conduit from right-of-way line to right-of-way line of the road.
- Conduit should be installed about 30 inches below the ditch line.
- Crossings are made by boring under the road surface, pulling the conduit into place, and running the pipe through the conduit.

2.5 Pipeline Inspection and Maintenance

A routine inspection program should be implemented to identify potential problems due to corrosion, normal wear and tear, or other damages that might occur.

a. Inspection Spools allow for visual inspection of the scale buildup. These spools should be about 3 feet long and made of the same type of material as the pipeline, with flanged ends or unions for easy removal. The removal of the spool from the line will allow access to the inside wall of the pipe to check for scale and corrosion damage.

b. Coupon connections should be installed to allow for the use of weight loss coupons. These coupons are inserted into the flowing stream to test for corrosion. The coupon is exposed to the flowing stream for a specific time, then removed and evaluated for scale and corrosion damage. The results provide an indication of the pipeline's corrosion levels.

c. Scale formation, which is a buildup of calcium and/or barium mineral scale inside the pipe, occurs in many saltwater systems. This scale formation

1. Reduces the flow capacity of the line.
2. Increases the potential of under-deposit corrosion.
3. Can become so severe that a part of the system is plugged.

Because scale can potentially plug part of a system, steps should be taken to minimize the formation of scale and/or remove it from the pipeline. Obviously, it is best to prevent scale formation whenever possible, especially in areas where the scale might consist of NORM. Chemical treatment also may be used to minimize scale. A chemical injection system is shown in Figure 7.

d. Pipeline scrapers, commonly called "pigs," can be used to remove scale that has precipitated in the pipeline.

1. Scrapers used for pipeline cleaning can be of several general types, including steel ball scrapers, rubber ball scrapers, plug and wire brush scrapers, plug and knife scrapers, and spiral brush scrapers.
2. Instrumented pigs and other internal inspection devices can be used to monitor pipelines for scale buildup and/or corrosion damage.

A trap for inserting a pipeline scraper into a line is shown in Figure 8.

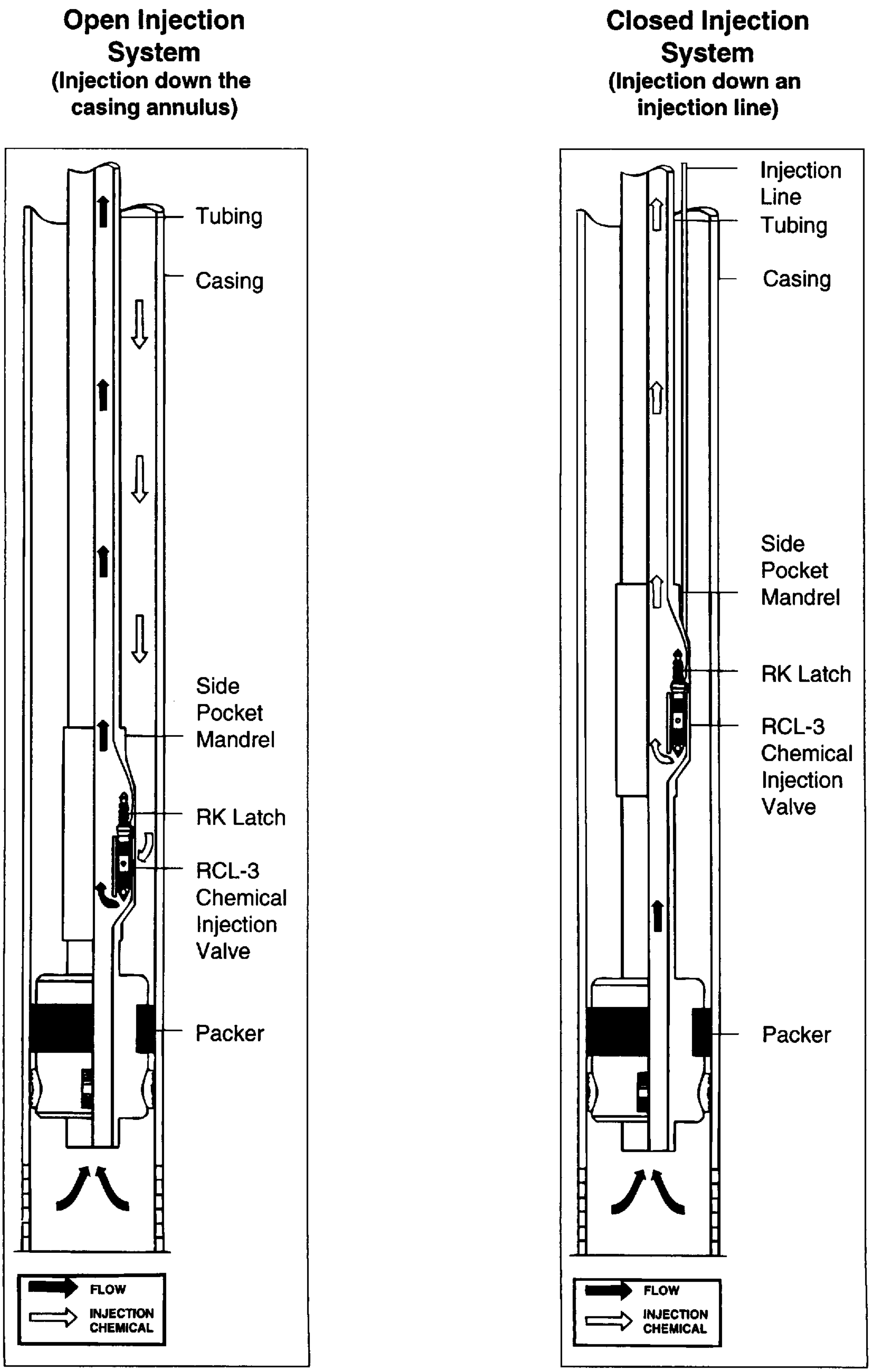


Figure 7—Chemical Injection System

SECTION 3—WATER TREATMENT FACILITIES

3.1 Introduction

Even though the oil or gas and salt water are separated at the tank battery, additional treatment is often necessary prior to injection to increase injectivity and ensure protection of the formation.

■ The degree of water treatment required must be determined for each case; it is normally based on characteristics of water to be injected and the injection zone.
■ The amount of treatment, including its cost, must be balanced against the additional cost of not treating.
■ These costs include extra horsepower to inject into plugged formations, as well as subsequent remedial well treatments that may be needed to restore injection capacity.
■ Proper initial planning and continued monitoring of system performance will result in an economical, efficient operation.

In general, the three most commonly used methods to inhibit bacteria growth and prevent formation of scale, plugging agents and precipitates are: (a) oil removal, (b) solids removal, and (c) chemical treatment.

This section briefly describes the following water treatment concerns:

a. Oil Removal.
b. Solids Removal.
c. Scales and Other Precipitates.
d. Bacteria.

3.2 Oil Removal

Oil can be removed by various mechanical or mechanical/chemical means.

3.2.1 GRAVITY SEGREGATION VESSEL

When volumes of produced water are large in proportion to produced oil, a high percentage of water can often be removed by a gravity segregation vessel; in this, oil and gas are drawn off at the top and water off the bottom. If the produced fluid contains a significant amount of trapped natural gas, it may be necessary to first run it through a smaller pressure vessel; there, the produced fluid splashes over a series of mechanical baffles which help the gas break out of the produced fluid. Gas is then drawn off from the top of the vessel; oil can be drawn off at an intermediate level; and water drawn off near the bottom. Such a vessel is called a separator. The gravity segregation vessel and the separator do not usually require any energy input. However, chemicals may be needed to separate the oil and water, if emulsions are formed.

3.2.2 HEATER TREATER AND ELECTRICAL CHEMICAL TREATER

The cooler the temperature of the produced fluid, the more viscous the oil becomes. This causes a worse oil-water emulsion and makes it more difficult to separate the oil and water. Introduction of heat decreases the oil's viscosity, allowing the water to separate again by gravity separation.

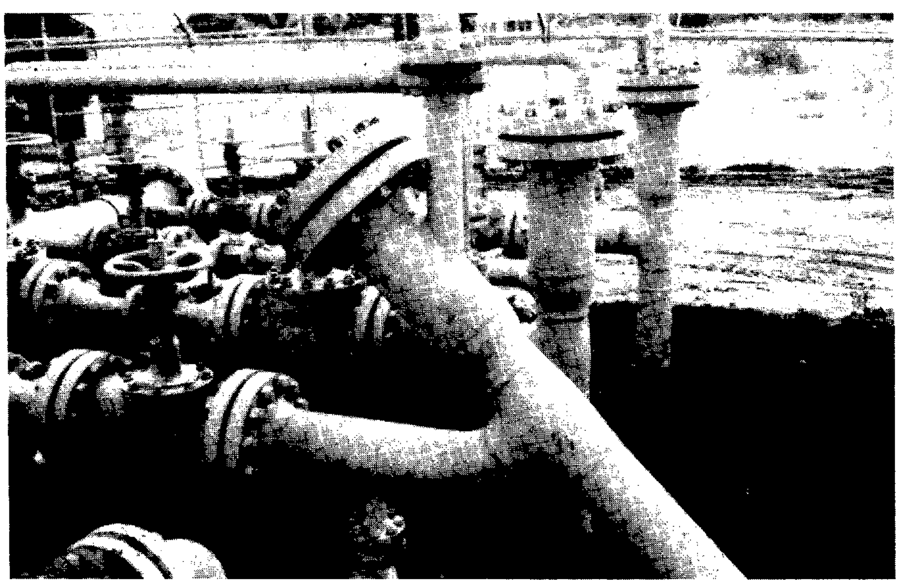


Figure 8—Trap for Inserting a Pipeline Scraper Into a Line

■ This may be accomplished in a vertical low-pressure vessel, equipped with a fire box and burners to heat an inner tank containing the produced fluid.
■ This vessel is popularly known as a heater treater.

Usually, produced natural gas is burned to provide heat. In cold winter months, the amount of gas required may be considerable; in hot summer months, heat may be needed only at night, or not at all.

■ Tests should be run to determine the lowest temperatures at which effective separation can take place to minimize fuel requirements. This can be done by trial and error at the production battery or in a laboratory.
■ If the emulsion cannot be broken by settling time and chemical additions, it may be still possible to effect separation without heat by a combination of chemical additives or by passing a weak electric current through the produced fluid. The type of vessel utilizing an electric current to help break emulsion is called an electric chemical treater, and may be more economical than a gas-fired heater treater.

3.2.3 SKIM TANKS AND COALESCERS

Heating to break emulsions and gravity separation are commonly used at the tank battery to separate the oil from the produced water. However, additional separation may be necessary before injection. Skim tanks and coalescers are two common methods used to remove oil.

3.2.3.1 Skim Tanks

Frequently, oil can be adequately removed in a skim tank (see Figure 9.) Water with entrained oil enters the upper half of the tank below the working level to avoid splashing. The oil floats to the top and is drawn off either manually or automatically. The water is drawn off near the bottom through a water leg which maintains the working level in the tank.

3.2.3.2 Coalescers

Oil may be suspended in droplets as small as 5 microns. In vessels commonly referred to as coalescers (Figure 10), the water flows through a coarse anthracite medium or across baffles where the minute oil droplets collect to form larger drops which rise and are drawn off. Oil collected from either skim tanks or coalescers can be recovered and returned to the production system.

However, in some cases, coagulation is necessary to remove the oil. Coagulation is also used for removing solids from the salt water.

3.3 Solids Removal

Solids usually consist of corrosion products, scale, asphaltenes, and fine particles of rock or sand from producing formations. These can be removed by one or more of the following methods:

a. Coagulation and sedimentation.
b. Settling.
c. Filter systems.

3.3.1 COAGULATION AND SEDIMENTATION

Clarification by coagulation is achieved by addition of a chemical to the water. This causes the aggregation of some fine particles and the absorption of others to produce a large particle called floc. Coagulation involves four basic steps:

a. Thorough mixing of chemicals and water.
b. Slow gentle agitation, which enables floc to grow and entrap suspended matter.
c. Provision for a period of time for floc to settle or float, depending on density.
d. Filtration.

In the past, coagulation of oil field waters was limited by the availability of chemicals which were effective in oil field brines containing gas and diverse minerals. However, the development of synthetic polymers (poly-electrolytes) as coagulant aids and coagulants has greatly expanded the types of waters which now can be clarified.

Coagulation should be considered when it is necessary to remove the following:

a. Oil, both free and emulsified.
b. Other suspended solids such as iron sulfide, iron oxide, insoluble salts, silts, clays.
c. Bacteria which are impossible to remove by mechanical clarification in settling tanks, coalescers, or filters.

3.3.2 FILTRATION

Filtration is the process of clarifying water by passing a liquid containing suspended solids through a porous medium to remove suspended particles. The medium retains the solids, but allows passage of the liquid. Properly designed and executed filtration operations will do this, provided:

a. The characteristics of the water are stable.
b. All chemical reactions occurring within the water have reached completion before the water is filtered.
c. The flow rate through the filter is optimized.

3.3.3 FILTER TYPES

A variety of filter types is available.

■ Some use a medium such as sand/anthracite, walnut shells, and the like to filter out the solids.
■ Sock-like filters containing cellulose fibers are also common.

■ Other materials, such as charcoal and diatomaceous earth, are less frequently used.

■ Cartridge filters are sometimes used at the injection wellhead to trap solids, such as scales and sludges. Most of these filters are the replaceable cartridge-type, but some are bead-type which can be cleaned and reused. These filters have a relatively low capacity and should not be used as a substitute for central filters or other water stabilization measures.

Filters may be:

a. Either gravity or pressure type.
b. Up flow or down flow.
c. Used in either open or closed systems.

The design and size of the filter depends on the character and pretreatment of the water, as well as the quantity and required quality of the water.

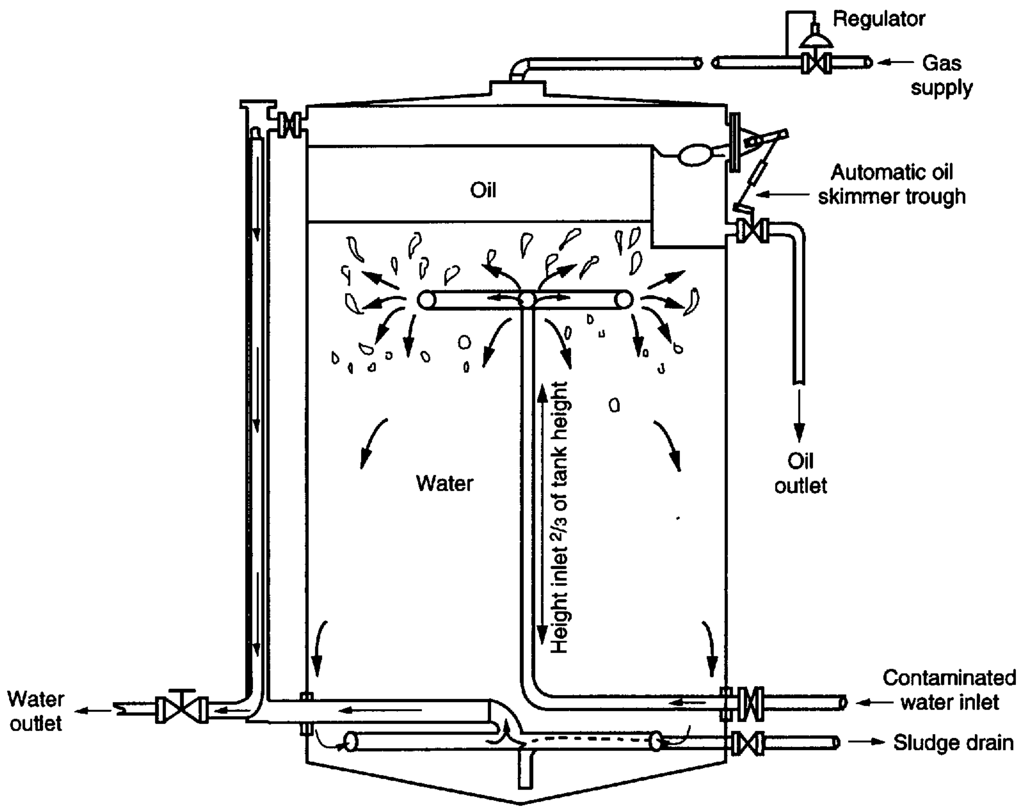


Figure 9—Typical Skim Tank

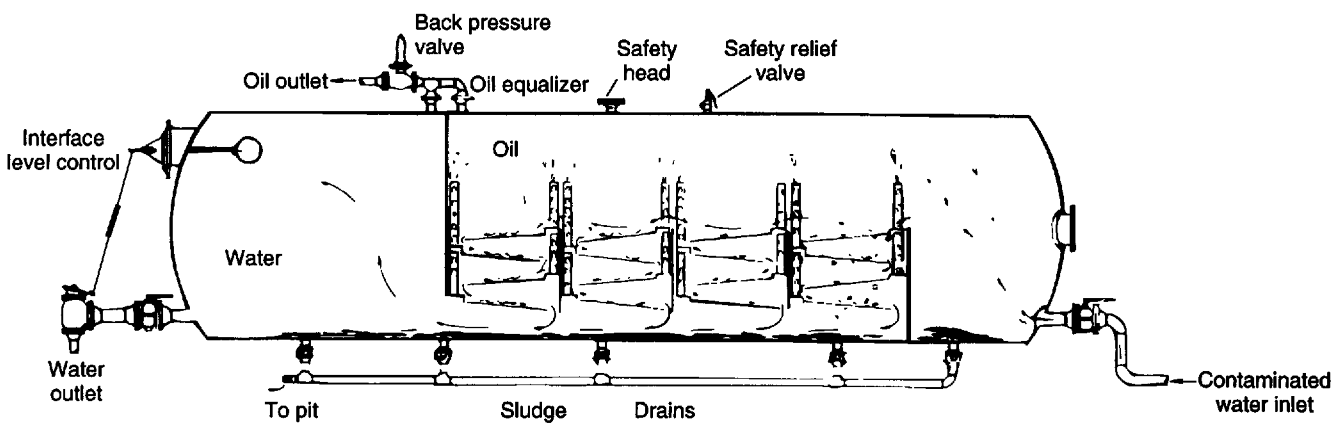


Figure 10—Typical Baffle Type Coalescer

3.3.4 WATER CHARACTERISTICS

While filtration is a good method of removing solids from the water, other factors must be considered, especially the chemical characteristics of the water.

3.3.4.1 Iron and Oxygen

Filtration of water containing dissolved iron and oxygen is generally only partly successful, since the oxidation of iron will continue after filtration, resulting in formation of iron oxide. The only way a good quality, filtered water effluent can be obtained is to ensure that the iron and oxygen have reacted completely before filtration.

3.3.4.2 Iron and H_2S

A similar situation exists when water containing dissolved iron and hydrogen sulfide is filtered. The chemical reaction forming black iron sulfide continues after filtration, producing "black water."

3.3.4.3 Calcium Carbonate

Waters unstable with respect to calcium carbonate deposition can show the same phenomenon. Post-filtration water will continue to form calcium carbonate. In addition, calcium carbonate will be deposited in the filter, causing cementation of the sand grains, decrease in porosity by plugging, and ineffective filtration.

3.3.4.4 Oil

Oil should be removed from water before the water is passed through a sand filter, since the oil coats the sand grains and generally fouls the filter. Additionally, filtered particles of iron oxide, iron sulfide, and other suspended material form gum-like deposits with the oil that are difficult to remove by backwashing. Upstream oil removal devices and effective coagulation will eliminate oil fouling of sand filters.

3.3.4.5 Water With Low Turbidity

Water with low turbidity may be obtained by using moderate flow rates through a filter, while higher rates may result in carrying some of the smaller particles of suspended solids through the filter. It is generally better to use a rate of flow for which the filter was designed, rather than to increase the flow rate beyond the design limit by increasing the pressure drop across the filter.

3.3.5 BACKWASHING

As the filter collects more and more particles, it can clog. This is generally signaled by a change in pressure drop through the filter. When this occurs, the filter can be cleaned by backwashing. This is achieved by reversing the direction of flow through the filter, thereby washing out accumulated solids.

- The rate of flow during backwashing should be sufficient to remove all material filtered during the preceding filter run.
- For sand or anthracite filters, the velocity should be high enough to provide adequate expansion of the bed, but not high enough to cause mixing of the sand and gravel. In general, 15 gallons per minute per square foot of media for sand and 9 gallons per minute per square foot of media for anthracite is adequate to give a 50 percent bed expansion.
- If the wash rate is too low or non-uniform, a coating of coagulum remains in the medium. This coagulum tends to stick the grains together resulting in the growth of a compact mass resembling a mud ball. The formation of mud balls can be minimized by the use of a surface wash in conjunction with backwash.
- The materials removed during these treatments must be recycled or disposed of.

Filters are indicators of the system's condition. Records of filter changes should be maintained and any abnormalities reported.

3.3.6 FILTER FAILURE

Filter failure is most commonly caused by cementation from oil carryover, scales, or bacteria. The filter beds "fracture" or "channel" when cemented.

- Backwashing is ineffective in removing cementation, because the backwash follows the path of least resistance through the channels in the filter media.
- When channeling occurs, the filter media must be changed.

Treatment of the water prior to filtration, using the methods described above, can help prevent cementation.

Regardless of the types of filter used, care should be exercised to ensure that the materials filtered out are managed properly. In some cases, these materials might contain contaminants that could be harmful to the environment if not disposed of properly. For example, the presence of heavy metals may require the waste to be managed as hazardous. Samples should be analyzed to make this determination.

3.4 Scales and Other Precipitates

Scales and sludges are formed from water as the waters adjust to changes in equilibrium. The equilibrium is affected by changes in temperature, pressure, chemicals, and the mixing of two or more individually stable but incompatible waters.

- Scale may form as a result of a chemical reaction involving impurities in the water, and sometimes involving the steel pipe.
- Corrosion products, such as iron oxide or iron sulfide, may be deposited similarly.

■ Other precipitates, such as sulfur, may form when water with hydrogen sulfide is mixed with a high dissolved oxygen content water.
■ Sludge is a "catch-all" term for undefined materials that collect in low flow rate areas of a system such as tanks and vessels, or in the bends of lines.

3.4.1 SCALES

Scales most commonly found in disposal systems include: calcium carbonate, calcium sulfate, barium sulfate, strontium sulfate, iron sulfate, iron oxide, and sulfur.

■ These scales can form in gathering and distribution lines and treating equipment, such as filters and coalescers. They can also form in well tubulars and at the injection formation.
■ Scale formation is normally preventable.
■ Once formed, however, scale removal is expensive and may cause some permanent damage.
■ The minerals scaling tendencies of waters or mixtures of waters should be evaluated prior to the design of the salt-water disposal system to determine if scale deposition will be a problem.
■ Scale deposition can be predicted with moderate accuracy using conventional water analysis and various scale prediction equations. One example is the Stiff-Davis method for predicting the approximate solubility of calcium carbonate and calcium sulfate in brines.

Waters that are to be added to an existing system should be tested for compatibility prior to hookup. Compatibility tests will indicate whether scale formation is to be expected. In existing systems, inspections to detect scale can be made at points downstream of pressure drops, such as after chokes, meters, and line size changes.

A discussion of each type of scale or sludge follows.

3.4.1.1 Calcium Carbonate

The solubility of calcium carbonate is influenced by the carbon dioxide partial pressure in the water and the temperature of the water.

■ A decrease in the carbon dioxide content of the system elevates the pH, upsetting the chemical equilibrium, causing scale deposition.
■ Increasing temperature will also reduce the stability. Therefore, calcium carbonate will most likely form in areas where the water is heated in surface equipment.
■ It is also a problem if water saturated with calcium carbonate at surface temperatures is injected into a formation with a higher temperature.

3.4.1.2 Calcium Sulfate

Calcium sulfate, or gypsum, usually precipitates directly on metal surfaces and consequently forms scale, rather than sludge.

■ Calcium and sulfate ions are directly involved in the solubility of calcium sulfate.
■ While carbon dioxide partial pressure does not affect the solubility of calcium sulfate, pressure drops do result in decreasing solubility and formation of precipitates.
■ Additionally, mixtures of waters, one of which has high calcium content and the other high sulfate content, will precipitate calcium sulfate.
■ Calcium sulfate deposition can be predicted using the Stiff-Davis method and by running compatibility tests.

3.4.1.3 Barium Sulfate and Strontium Sulfate

Barium sulfate and strontium sulfate are two of the most insoluble substances formed in water, and are the most difficult to remove. Fortunately, waters containing barium or strontium seldom contain more than a few parts per million (ppm) of sulfate, and waters with over 500 ppm sulfate seldom contain appreciable amounts of barium or strontium. Therefore, formation of these scales is rare, except when incompatible waters are mixed.

3.4.1.4 Iron Deposits

Deposits of iron compounds may be due to waters which naturally contain dissolved iron, or occur from the corrosion of steel in the system. The precipitate formed may be iron oxide, iron sulfide, or iron carbonate.

■ Both compounds plug filters and disposal zones.
■ Waters containing oxygen, when combined with waters containing natural iron or corrosion products, form iron hydroxides which further react to iron oxides.
■ The presence of hydrogen sulfide, either from production or bacterial activity, results in the corrosion of steel and the formation of iron sulfide. The iron oxide is magnetic, whereas iron sulfide is not.

3.4.2 PREVENTING OR REMOVING SCALES AND OTHER DEPOSITS

Obviously, it is best to prevent the formation of scales and other deposits, rather than have to remove them once they have formed. Furthermore, barium and strontium sulfate scales are extremely difficult to remove.

The oxygen content of the water plays an important role in the formation of some of these materials. Generally, systems are designed to prevent the introduction of oxygen into the system, thereby minimizing the amount of oxygen available for scale formation or corrosion reactions. Oxygen scavengers can be used to remove the oxygen, but these are expensive and generally require about 8 – 12 ppm for every 1 ppm of oxygen. Oxygen removal from brines is a complex subject beyond the scope of this text. A qualified laboratory should be contacted to determine the feasibility of oxygen removal.

There are several methods available for prevention of scale formation or its removal, once formed.

- All of the scales and deposits discussed above can be removed from the system by mechanical means, such as scraping.
- Calcium scales and iron deposits can be minimized by treatment with acid. Caution should be exercised where plastic lines are installed since the acid can be incompatible with some plastics. Additionally, treatment of iron sulfide deposits with acid will produce toxic hydrogen sulfide fumes.
- Carbonate and sulfate scales are preventable by using chemical inhibitors containing polyphosphates, polymetaphosphates, and phosphate esters.
- Calcium sulfate is only slightly soluble in hydrochloric acid. Chemical converters are available to convert the scale to a product which is acid soluble. However, this method is expensive.
- The most effective measure to prevent formation of barium or strontium sulfate is to keep waters containing barium or strontium and sulfate separated.

If samples can be obtained, a laboratory analysis should be run to determine the most effective method of removal. Frequently, the carbonate scale is layered with materials that will not dissolve in acid, such as oil and paraffin. This can complicate removal. The addition of surfactants or mutual solvents to the acid may be necessary.

3.4.3 SAMPLING WATER-FORMED DEPOSITS

Since water-formed deposits are seldom homogeneous, and vary in composition at different parts of the system, it is important that the field sample be collected as near the formation site as possible before any physical or chemical alteration occurs. This may be difficult since the greatest scale formation may occur in an inaccessible part of the system. However, a sample should be removed from an accessible location, closest to the point of scale formation.

- Samples taken at different parts of a system should be submitted to the laboratory separately and without mixing.
- Visual inspection for deposits should be a routine procedure any time equipment is being serviced.

3.4.4 FIELD SAMPLE COLLECTION

The following guidelines will assist in collecting field samples.

a. Sludges, loosely adhered scale deposits, and biological deposits are easily removed using a scraper, knife blade, spoon, or piece of wood.
b. Hard, adherent scale deposits are more difficult to remove. Sometimes it is possible to dislodge brittle scale by mechanical or thermal shock, that is, by a mechanical blow or by heating the metal and scale and suddenly chilling the scale with cold water. Due to the nature of these deposits, a limited amount of water will not affect them for analytical purposes.
c. If possible, some of the scale should be sampled with the underlying surface intact. For example, a piece of pipe or tubing should be cut from the system. The section can then be cut longitudinally with a sharper or dry saw and squeezed in a vise to dislodge the deposit.
d. To avoid contamination of the sample, no cutting oil should be used.
e. Care should be exercised to avoid contamination of the sample by any deposits on the exterior of the pipe.
f. Often it is not possible, practical, or desirable to remove the scale in the field. In these cases, a portion of the pipe containing the scale sample should be submitted directly to the laboratory.

3.5 Bacteria

The presence of bacteria in a system may or may not present a serious corrosion or plugging problem. A qualified person should be consulted to determine if bacteria can be expected to be a problem and to determine measures to counteract their presence. Bacteria in oil field waters are basically classified as one of the following types:

a. Aerobic (active in presence of oxygen).
b. Facultative anaerobic (active with or without oxygen), or
c. Anaerobic (active in the absence of oxygen).

3.5.1 AEROBIC BACTERIA

Iron bacteria are aerobic and are active in removing iron from water and depositing it in the form of hydrated ferric hydroxide. They are commonly active in fresh waters, but are occasionally found in brines containing oxygen.

Aerobic and facultative anaerobic bacteria, often referred to as "slime-formers," can grow in sufficient numbers to cause significant well plugging. The slimes formed shield the metal surfaces from oxygen and provide an environment for the growth of sulfate-reducing bacteria.

3.5.2 ANAEROBIC BACTERIA

Anaerobes are active in the absence of oxygen, but are not necessarily killed by the presence of oxygen. Anaerobes are common in oxygen-depleted oilfield systems and can be found under slime deposits in aerated systems.

3.5.3 ANAEROBIC SULFATE-REDUCING BACTERIA

Sulfate-reducing bacteria (SRB) are the most common and economically significant of the bacteria found in saltwater injection systems. SRB are anaerobic and have the ability to convert sulfate to sulfide. These sulfate reducers are frequently found under slime deposits, and are most prolific under corrosion products, tank bottoms, filters, oil water interfaces, and dead water areas, such as joints, crevices, and cracks in cement linings. Sulfate reducers may also exist naturally in some oil- and water-producing strata.

- Since sulfate reducers exist in isolated and localized areas, low bacterial counts reported in water analysis may be misleading.
- Sufficient samples should be obtained throughout the system and at the end of the distribution system to determine the relative condition of the system.
- Specialized monitoring techniques have been developed to determine populations of attached bacteria versus floating bacteria.

Black particles of iron sulfide in the water or iron sulfide backflowed from the well can indicate the presence of sulfate reducers. If water entering the system is sweet, and hydrogen sulfide is detected at a point removed from the entry, it must have been produced by sulfate-reducing bacteria.

Two problems are associated with this type of bacteria.

a. Corrosion of an unprotected system from sulfate reducers can be extensive.
b. The iron sulfide formed as a result of the reaction of the natural iron or corrosion products in the water with the hydrogen sulfide formed by the bacteria is a major plugging agent.

3.5.4 PREVENTION

Prevention of bacteria-caused problems begins with system design.

- Sulfate reducers prefer sites of static or slow fluid movement. If the habitat and attack sites are eliminated in the design, locations suitable for sulfate-reducing bacteria will be minimized.
- Although coagulation and filtration can reduce the bacteria population, they are not very effective by themselves. At points downstream, a progressive number of bacteria are normally found unless other treatments are used.
- Chemical controls may be necessary.
- All types of bacteria are effectively killed with organic biocides or chlorine.
- A thorough cleaning of the system is most important to assure an effective treatment. Biocides cannot kill bacteria unless they contact the bacteria. It is therefore necessary to remove slime, scale, corrosion products, oil and insoluble inhibitors, and thoroughly clean tanks, filters, and ponds before treatment.
- Wells may be treated with hydrochloric acid or a combination of acid and solvent. A gradual cleanup can sometimes be effected using a product that has both detergent and biocidal properties.

A qualified person should determine the compatibility of the biocide with the water and other chemicals in use. This person should also determine the size of treatment and whether treatment should be slug or continuous. Companies that sell water treatment chemicals will be able to assist in the proper selection of chemicals for the system. For more information on bacterial sampling and control, see National Association of Corrosion Engineers (NACE) publication TM0194-94.

SECTION 4—INJECTION FACILITIES

4.1 Introduction

As discussed in Section 1, much of the design of injection wells is the same whether the well will be used for enhanced recovery or disposal. However, in the case of enhanced recovery, the producing formation dictates much of the injection well design. For example, it dictates where the well or wells will be located, the formation into which salt water will be injected, and other information. With the disposal well, many of these issues must be determined in the planning phase.

This section discusses some of these issues and some of the specific design, operation, and maintenance considerations for the well itself.

4.2 Prediction of Volume and Rate of Water Production for Disposal

One element to review for the disposal well is the volume of salt water produced. Since the volume of water a well produces can change during the well's life, it is necessary to forecast future volumes of water, as well as the number of wells the disposal system will service. There are certain factors to consider when making these predictions.

- Producing characteristics of reservoirs differ; the volume of produced water may increase or even decrease with time.
- The production method can change the volume of water produced.
- A change in the method of lifting fluids from wells that

either increases or decreases the volume of salt water produced might be forecasted.

- Some oil and gas fields produce from more than one formation. A program of recompletions in the future could also affect saltwater production.

The prediction of volume and rate of water production is not easy. Engineering help should be sought to forecast water production rates. Therefore, only the basic concept is discussed here.

In planning the design of a saltwater disposal system, it is first necessary to construct a curve of estimated future water production. The problem is easier if the properties are older and if a past history exists upon which to base the forecast. When it is necessary to install a disposal system early in the life of the reservoir, a comparison with nearby reservoirs in the same formation is the most reliable way of estimating the extent of a water drive.

4.2.1 ACTIVE WATER DRIVE

If the oil reservoir is producing under the influence of an active water drive, each well's percentage of water production will increase throughout the well's life, until it reaches a minimum oil production rate. The water production rate at that time will depend on the producing capacity of the formation and the capacity of the artificial lift equipment on the well.

For initial design calculations, the maximum water production rate is the sum of the producing capacity of the lift equipment on the wells to be served. Actual water production rate will seldom be as high as forecasted, since it is rare that all the wells will reach their maximum water production rate at the same time. Usually, several wells will be depleted and abandoned before others reach their maximum water production rate. Other wells will never produce at the maximum capacity of their lift equipment because of limited reservoir-producing capacity.

4.2.2 LIMITED WATER DRIVE

If there is a limited water drive in the producing reservoir, the water production rate will frequently increase to some maximum, and then decrease before reaching the economic limit. Thus, estimating the water production rate from each well is directly related to determining the extent of the water drive in the reservoir. This determination can be made by using a material balance, if the reservoir has been producing long enough to provide reliable data. To use this method, the following reservoir information is needed:

a. Oil, water, and gas production history.
b. Pressure history.
c. Reservoir volume.
d. Fluid properties.

The mechanics of calculating a material balance are adequately described in a number of reservoir-engineering textbooks; thus, they will not be explained in this manual.

4.2.3 MAXIMUM FUTURE WATER PRODUCTION RATE

After estimating the maximum future water production rate of any one well, the next determination should be the number of wells which will be producing water at the same time. This will depend on the direction of water encroachment in the reservoir.

- The number of wells that will be producing water at the same time can best be determined by a geological study of the reservoir.
- If there is a bottom-water drive, wells will normally begin to produce water in an order proportional to the distance they are completed above the water table.
- If there is an edge-water or side-water encroachment, wells closest to the encroachment will ordinarily produce water first.

4.2.4 FUTURE WATER PRODUCTION CURVE

After available data has been analyzed, a curve of future water production versus time for any or all parts of the reservoir can be constructed. This curve can be used to design the disposal system from the gathering lines to the injection well. Although the curve may not be exactly accurate, it will usually suffice to indicate the magnitude of water production at various times.

4.3 Disposal Formation

Another issue must be resolved in planning a disposal well is what formation will receive the injected salt water. A suitable formation is the heart of a good disposal system. Before drilling and completion operations, information on the objective formation should be obtained.

- How thick is the objective formation?
- What are the porosity and permeability values?
- What is the well's structural position in the formation?
- If the well is part of a waterflood, what are the present oil and water saturations?
- How will the formation react to fluid injection?
- How will the formation react to treatments to improve injectivity?

The following are information-gathering steps.

a. Formation cuttings while drilling (samples) may be obtained.
b. Relative drilling times per unit of depth may be recorded and compared.
c. A section of the formation may be cored and retrieved for study.

d. Electric logging tools may be used to obtain logs which give a sophisticated description of the formation.

The geologist and engineer can then use this information to design the well completion.

For satisfactory injection rates, the objective formation should have the following:

a. Good porosity and permeability.
b. Sufficient thickness.
c. Large areal extent, or in case of secondary recovery, matching withdrawals.
d. Reservoir pressure below the formation fracture pressure. (In fact, the UIC permit will require that the injection pressure is below the fracture pressure.)

4.3.1 PERMEABILITY AND THICKNESS

Permeability is that property of a porous medium which measures the ease with which fluids may flow through the medium under the influence of a driving pressure. A disposal formation must have high permeability and sufficient thickness so that injection pressures will be at a minimum.

The permeabilities and thicknesses of the various formations available for disposal can be determined or estimated by one or more of the following:

a. Core analysis.
b. Examination of bit cuttings.
c. Drill-stem test data.
d. Electric logs.
e. Driller's logs.
f. Comparison with the characteristics of the same formation in other nearby areas.

Highly permeable limestone or dolomite are preferred. However, any porous and permeable formation, including sandstone, conglomerate, or gravel, can be used. Consult expert reservoir engineering personnel for more detail.

4.3.2 AREAL EXTENT

A formation with a large areal extent provides the best formation for disposal because fluids within the disposal formation must be displaced to make room for incoming fluids. An estimate of the areal extent of a formation is best made through a subsurface geological study of the area.

4.3.3 PRESSURE

If it is possible to inject water into the aquifer of some oil- or gas-producing formation (re-injection), then the size of the disposal formation is not too important. Under these circumstances, the injected water will displace fluids from the aquifer into the producing reservoir from which fluids are being produced. Thus, the pressure in the aquifer will only increase in proportion to the amount that water injection exceeds fluid withdrawals.

- The best disposal formations will generally be the pressure-depleted aquifers of older, producing reservoirs.
- If water can be disposed of with a vacuum on the injection wellhead, operating expenses will be much less than if positive injection pressures are required.
- Methods of calculating the surface injection pressure of a disposal well are available in various publications.
- Depth is also a consideration when selecting the disposal formation. It is desirable to maximize the distance from freshwater zones to decrease the likelihood of contaminating fresh water. Additionally, consolidated formations are preferred to minimize the cost of sand control.

4.4 Locating Wells

After determining future water production rates and selecting the best available disposal formation, the next step is to plan where the well will be located. Sometimes, an existing producing well can be converted to injection, while in other instances a new well must be drilled. Considerations must be given to initial costs and also to expected future operational costs, as well as the long-term integrity of the well and its possible environmental impact.

- All existing wells should be carefully considered, since it is normally less expensive to convert existing wells than to drill new ones.
- The most likely candidates for conversion are depleted wells or dry holes.
- However, sometimes it is best to convert a producing well.

Disposal wells should be located near the facility they serve whenever feasible.

- Wells must be located so that confining zones prevent the movement of injected fluid into USDWs.
- Topographic selection of location may be made to utilize natural gravity gradients. If possible, the disposal well should be located at a lower elevation than the producing wells so that as many water-gathering lines as possible will be operating with a gravity head to minimize the need for pumping.
- Selection of location is often subject to surface availability restrictions caused by property boundaries, fences, roads, streams, and the like.
- Enhanced recovery wells are generally located to function as a part of a comprehensive secondary recovery plan. The injection pattern is carefully chosen to surround, entrap, or encapsulate movable oil in the most efficient manner possible, and then to furnish the displacement fluid and energy to move this oil to the pattern producing wells.

In assessing the surface topography, the following steps should be used to locate the well.

a. Review a surface topography map of the area to be served

to select the tentative locations of the gathering lines, water collection points, and disposal wells to take maximum advantage of the surface elevations.
b. After locating the lines on the map, determine the elevation of the various junctions for use in hydraulic-flow equations. The solutions of these equations will show how much pressure is required to move the produced water to the injection well.

The topographic map is also necessary for the UIC permit application as discussed in 1.3.

4.5 Selection of Wells for Injection

4.5.1 THE NEWLY DRILLED HOLE

Some advantages of a well drilled specifically for injection are the following:

a. Optimum topographic location may be selected.
b. Optimum geological location may be selected.
c. In the case of enhanced recovery wells, the well can be located more exactly to fit the selected injection pattern.
d. Surface and/or intermediate casing depths provide protection of USDWs.

The surface casing strings may also be sized to accommodate the required casing and tubing strings. Desired casing weights and grades may be used. Special cementing practices may also be employed on newly drilled wells to protect the migration of injected fluids into USDWs. These include stage cementing, circulating, cementing the entire length of the long string, or placing corrosion-resistant materials above the cement behind the casing.

Note: Cementing alone does not eliminate corrosion. Cathodic protection well help control corrosion of the external surfaces of the casing.

- All new injection wells must have an approved permit before drilling can begin (see 1.4.1.)
- To apply for a permit, the operator must know the exact location of the new well, its design and construction, its operating parameters, and its mechanical integrity demonstration procedures.
- The owner/operator must also have a plugging and abandoning (P/A) plan, and a method to ensure that the P/A is funded (financial responsibility).

The principal disadvantage of drilling a new well is the cost. The formation characteristics at the new well location may also be unknown until the well has been drilled. If the capacity of a well drilled for disposal is insufficient, one or more additional wells may be required.

4.5.2 CONVERSION OF AN EXISTING WELL

Using an existing well for injection has several advantages.

- Usually the well bore costs only a fraction of a newly drilled well.
- Often, the mechanical condition is satisfactory, including adequate casing and cementing programs.
- Formation thicknesses, depths, porosities, and permeabilities are usually available.

However, there are several disadvantages in converting wells to injection.

- The well may not be satisfactorily located topographically, geologically, or pattern-wise for secondary recovery.
- The surface and/or intermediate casings may not be set deep enough to protect all USDWs.
- The mechanical condition of the well bore may be poor, and remedial measures may not be feasible, practical, or justifiable.
- In existing wells that were never completed (dry holes), or plugged and abandoned wells, the disadvantages may be even more pronounced.

There may be a tendency to select low-productivity wells for injection with the idea that it is better to keep the higher productivity wells as oil producers. However, this is not always the best approach. In many cases, this procedure results in negative or poor response from the producing wells. The most successful water flood or pressure maintenance programs are those that are carefully engineered and implemented without well discrimination.

4.6 Drilling and Completion

4.6.1 METHODS OF COMPLETION

Three of the more common methods of completion are illustrated in Figure 11. They are the following:

a. The hole cased and cemented through the objective formation, then opened through perforations.
b. The hole cased and cemented to the top of the objective formation, open hole completion.
c. The hole cased and cemented to a shallower formation, drilled deeper, and its liner set through an objective horizon, cemented, and opened through perforations.

Many variances in methods of completion will be encountered, particularly in existing wells where factors, at the time the wells were completed, influenced completion practices.

- Some older wells, drilled prior to and in the 1930s, were completed with little cement and shallow surface casing.
- Old wells drilled with cable tools may have been completed with several strings of telescoping casing.
- Wells drilled before World War II may have been shot with nitroglycerin, leaving enormous shot holes below the casing seat and opposite the objective formation.
- Another variance is the tubingless completion, with the

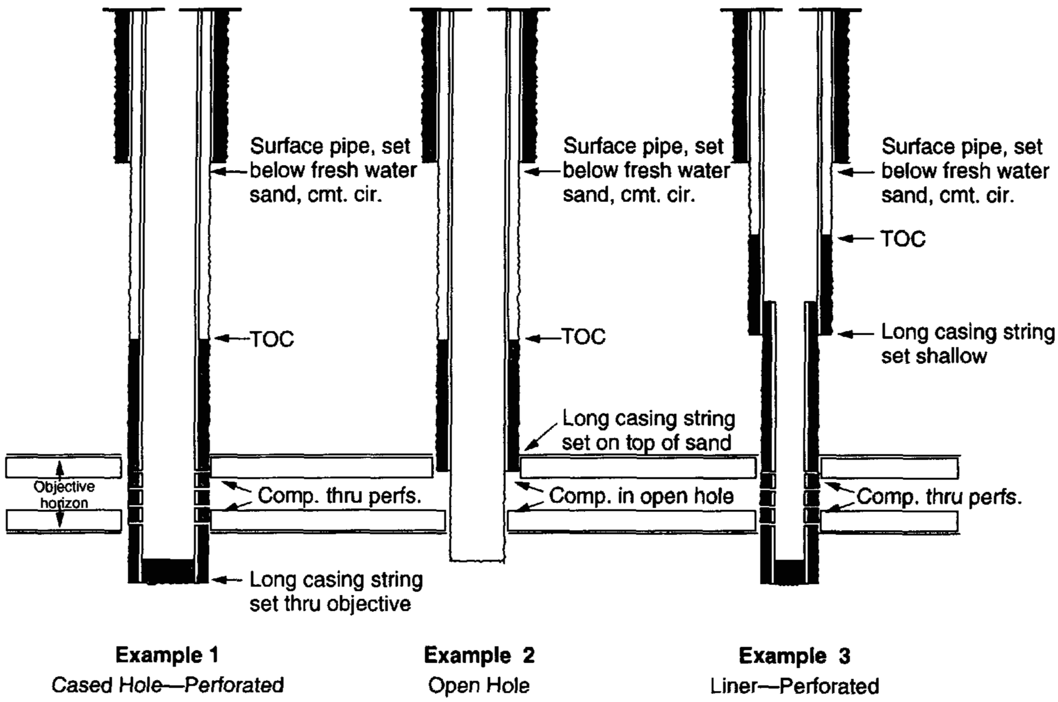


Figure 11—Common Methods of Completion

tubing cemented in a small bore hole as both long casing string and tubing string.

- Wells with extensive downhole repairs may have unique downhole mechanical configuration.

4.6.2 ACCESS TO THE OBJECTIVE FORMATION

As illustrated in Examples 1, 2, and 3 of Figure 11, access for injection from the well bore to the formation is usually obtained either through perforations in the casing string or into an open hole section below casing.

The perforations may be obtained by shaped charge jets, explosive propelled bullets, or hydraulically jetted fluid with an abrasive (sand jets).

4.6.2.1 Cased-Hole-Perforated Open Hole Liner — Perforated

The open hole completion is usually obtained by drilling through the long string after it has been set and cemented.

Perforated completions allow the selective opening of the more attractive zones of porosity. Perforated completions also allow for the following:

- Protecting the bore hole from sloughing and caving.
- Permitting effective testing of specific intervals.
- More effective use of diverting materials between stages of formation treatment.

4.6.2.2 Open Hole Completions

Open hole completions are usually the least expensive and they expose all the effective porosity to the bore hole.

The open hole completion—when drilled with air, gas, or cable tools—can penetrate and expose the objective formation without subjecting the formation to undesirable fluids and excessive hydrostatic pressures.

4.6.3 LINERS

A liner completion is sometimes selected for reasons of economics, experience, or for adaption to existing conditions. This type of completion is illustrated in Example 3 of Figure 11.

- Liners, like the long string, should be designed for burst, collapse, and tension.
- A competent completion allowing no movement of injected fluids up the borehole is more difficult to obtain with a liner than with the long casing string, since often a close tolerance hole does not allow a cement sheath of sufficient thickness.
- The liner usually cannot be equipped with scratchers or centralizers; in many cases, it cannot be reciprocated and/or rotated.
- As with the long string, a liner is part of the permanent avenue of access to the formation, and should be protected from abuse and corrosion.

4.6.4 ADEQUATE HOLE DIAMETER

Certain specifications must be included.

■ The diameter of the bore hole should be large enough to properly drill the hole and to accommodate the desired casing string with space for a competent cement sheath. A 1-inch cement sheath for conventional long strings is desirable; a $^3/_4$-inch sheath is acceptable.

■ The diameter of the cased hole should be sufficient to allow tool entry for workover and remedial operations, and large enough to accommodate the tubing string selected. A well with $2^7/_8$-inch OD (outside diameter) injection tubing; $5^1/_2$-inch OD long casing string; and $7^7/_8$-inch OD hole drilled through $8^5/_8$-inch OD surface pipe set in 11-inch OD hole is an example meeting these guidelines.

In many waterflood projects where small injection tubing will deliver the desired injection volumes, $4^1/_2$-inch casing is commonly used. This offers a less expensive well completion, but is less versatile. Remedial operations requiring tools are also more difficult in wells with small casing.

Examples of completions that do not meet the adequate hole diameter requirements include the following:

■ Completion using a small diameter liner in a close tolerance hole.

■ Completion using tubing cemented in place as both casing and tubing (tubingless completion).

4.6.5 CONTAINMENT OF INJECTED FLUIDS TARGET FORMATION

Containment of the injected water to the objective formation provides the following:

a. Maximum metal protection.
b. Minimum downhole equipment failures.
c. In the case of secondary recovery, conserves the fluids and energy for waterflood operations.

Good downhole equipment, proper completion practices, prudent injection pressures, close monitoring, and prompt remedial measures all contribute toward a competent borehold with no fluid migration.

4.6.6 SURFACE CASING

Most regulatory bodies now require that surface casing be set through the lowermost USDW, and cement placed across the USDWs. Preferably, the cement should be circulated to the surface.

■ In older wells to be converted into disposal or injection wells, remedial measures, such as perforating below the base of the fresh USDW or usable water and squeeze cementing, should be implemented as necessary to protect USDWs.

■ The surface casing protects the USDWs during drilling operations, continues to offer this protection during the life of the well, and will be left in place upon abandonment of the well with cement both inside the casing and between casing and hole.

■ Application of corrosion protection (cathodic protection and/or coating) to the external surfaces of the casing will help prevent cross contamination of downhole fluids caused by corrosion of the casing's external surfaces.

4.6.7 THE LONG STRING

The long casing string is the permanent connection between the surface and the objective formation. The string should be designed for adequate strength in tension, burst, and collapse.

■ Scratchers (to remove drilling fluid filter cake from the formation face) are usually installed on the casing at depths where a good bond between cement-and-hole and cement-and-casing is desirable.

■ Centralizers (to assure a uniform cement sheath and accurate centering of the pipe in the hole) and turbolizers (to generate turbulent flow for better cleansing action) should be installed on the casing throughout the interval where a good cement bond to both the pipe and the formation is desired.

■ Proper design of the cement mixture and displacement hydraulics will provide a good bond.

■ The pipe should be reciprocated and/or rotated during the cementing operation.

■ A long casing string, properly designed, set, and cemented allows no movement of injected fluids between the casing and the wellbore.

■ Where economically feasible and mechanically possible, full circulation of cement back to surface is desirable. Furthermore, it may be required by the UIC permit.

■ During the well's operating life, special attention should be directed to protect the long string from corrosive fluids and abuse because this casing is the permanent avenue of access. Cathodic protection of the casing will extend its life.

4.6.8 PROTECTION AGAINST CORROSION

Industry experience has established that oil field brines are sufficiently corrosive to cause bare steel failures in injection wells without corrosion protection. Common practice is to avoid bare steel exposure to raw brine whenever possible. Protection from corrosion can be obtained by the following:

a. Substituting non-corrosive materials such as fiberglass, plastic, or a corrosion-resistant allow for the standard steels normally used.
b. Protecting all steel surfaces exposed to brine with a protective cement, fiberglass, or plastic lining or coating.
c. Sealing off casing-tubing annulus with inhibited packer fluid.
d. Using a corrosion inhibitor in the injection water.

4.7 Equipping the Well for Injection

Successful operation of injection wells depends greatly on the subsurface equipment.

Service life of the downhole equipment is difficult to predict with great accuracy; however, operational problems can be minimized by careful selection of materials and equipment.

Even though the initial cost may be higher, use of materials that are compatible with the injection fluid must be considered.

Good equipment design is determined by considering the options available and then selecting the equipment which will give the best service for the least cost during the life of the project.

4.7.1 TUBING

Tubing is available for injection or disposal wells in various grades of steel and other materials. The choice of material depends on the injection fluid and economic considerations. It is assumed here that the fluid to be handled in the injection well will be corrosive—either produced salt water or non-potable, mineralized well water.

a. Steel tubing is probably the most widely used pipe in injection wells. In general, steel tubing is protected from internal corrosion by either internal coating or cement lining.

1. Internally coated tubing has several advantages over cement-lined tubing. Coatings range in thickness from 0.005 inch to 0.015 inch, versus 0.25 inch to 0.375 inch for cement lining, thus providing greater capacity.
2. Internal coatings have a higher flow coefficient (C) factor, which reduces pressure and horsepower requirements for a given injected volume.
3. Wells equipped with internally coated tubing may be acidized without pulling the tubing, while those having cement-lined tubing must be pulled prior to any stimulation or downhole treating, unless the cement system has had a magnesium silica fluoride treatment.
4. Injection wells equipped with internally coated tubing are also accessible for logging tools. However, these tools may cause damage to the coating.
5. Wells having cement-lined tubing may not have sufficient clearance to accept logging tools.

b. Unlined steel tubing may also be used, provided that the injected fluid is satisfactorily inhibited chemically.

c. Tubing strings of reinforced fiberglass are being used more. Fiberglass tubing has a larger internal diameter (I.D.) than similar sizes of steel pipe. It has a higher tensile strength, dimensional stability, and temperature rating than certain plastic pipes.

4.7.2 DESIGNING THE TUBING STRING

After selecting the type of tubing, several other design factors must be considered. It is generally better to overdesign the capacity of a tubing string. Design considerations include the following three factors:

a. Pressure drop due to friction. A Hazen-Williams Friction-loss chart, such as shown in Table 1 in Section 2, corrected for the appropriate "C" factor, can be used in the tubing design. The higher the flow coefficient (C), the less the pressure drop due to friction.

b. The formation's ability to accept fluid. In a controlled water injection project, 2³/₈-inch or 2⁷/₈-inch tubing is usually ideal, readily available, and considerably expensive than the larger sizes.

c. Variation in well fluid volumes. It is best to provide for maximum disposal capacity by installing the largest tubing economically feasible. Larger tubing also reduces the amount of horsepower required to pump the fluid. Horsepower reduction saves energy and lowers operational expense.

4.7.3 PACKERS

Packers are used primarily to protect casing above the injection zone from injection pressure, and from corrosive effects of the fluid being injected. In most cases, state and federal agencies will require the operator to install tubing with packer in newly permitted injection wells. Like tubing, packers can also be internally coated or manufactured using special corrosion-tolerant metals.

- Packers can be either retrievable or non-retrievable. The retrievable packer probably has more widespread use, since it can be recovered from the well, should the need arise.
- Packers are also available in a variety of designs and may be combined to allow for multiple zone injection in the same wellbore.

The temperature and pressure variations and their effects on the tubing can cause forces on the packer. These effects must be considered in selection of the packer.

4.7.4 ANNULAR INHIBITION

The annular space between the tubing and casing should be protected from the effects of corrosion by loading this space with an inhibited fluid.

- Chemically inhibited fresh water is widely used as an inhibiting fluid.
- Other fluids, such as kerosene or oil containing a corrosion inhibitor, may also be used.
- Casing annuli should have pressure gauge connections so that these pressures can be monitored to detect downhole problems.

4.7.5 WELLHEADS

The wellhead is the link between the water distribution system and the downhole equipment. In the case of a disposal well, the wellhead may consist of no more than a master valve on the tubing. In those cases where individual well metering is required, the wellhead may be more complex. Figure 12 illustrates a more complex wellhead.

4.7.6 WELLHEAD METERS

Wellhead meters are available in a variety of types and each has its merits.

- The orifice meter is most useful for large volumes, as in water disposal.
- On the other hand, in a controlled fluid injection project, positive displacement meters, such as nutating disc, vane, and turbine type, enjoy wide usage.
- Newer concepts in metering are in limited use at this time.

The reader is directed to books and industrial publications for a more comprehensive discussion on metering.

4.8 Injection Pumps

If bottom hole pressures in the disposal reservoir are low enough, permeabilities high enough, and disposal volumes not too large, the hydrostatic head of water column in the well bore may be sufficient, at least initially, to cause the water to enter the disposal reservoir. When the flow of salt water to the well is shut off, the water column will continue to evacuate the tubing string. Such a well is said to be taking salt water by gravity head or on vacuum. This is the least expensive method to dispose of salt water. (Care should be exercised on wells taking water on vacuum that no oxygen is permitted to be sucked into the system.) However, usually conditions are not so ideal. In these cases, it is necessary to inject salt water into the wells under pressure.

Positive displacement and centrifugal pumps are two types of pumps in general use for injection. These include the following:

a. Piston-type or plunger-type positive displacement pumps,
b. Single-stage and multi-stage horizontal and vertical centrifugal pumps, and
c. Split-case centrifugal pumps driven by electric motors or gas turbines.

These are usually high-pressure, high-horsepower installations. Figure 13 shows an installation utilizing vertical centrifugal pumps.

The type of pump and drive best suited for an injection project is determined during system design by evaluating the expected operating volume and pressure. Economic factors such as fuel availability, initial cost, maintenance costs, operating costs, and parts availability should also be considered. The injection pump is sized for the volume required and the pressure expected.

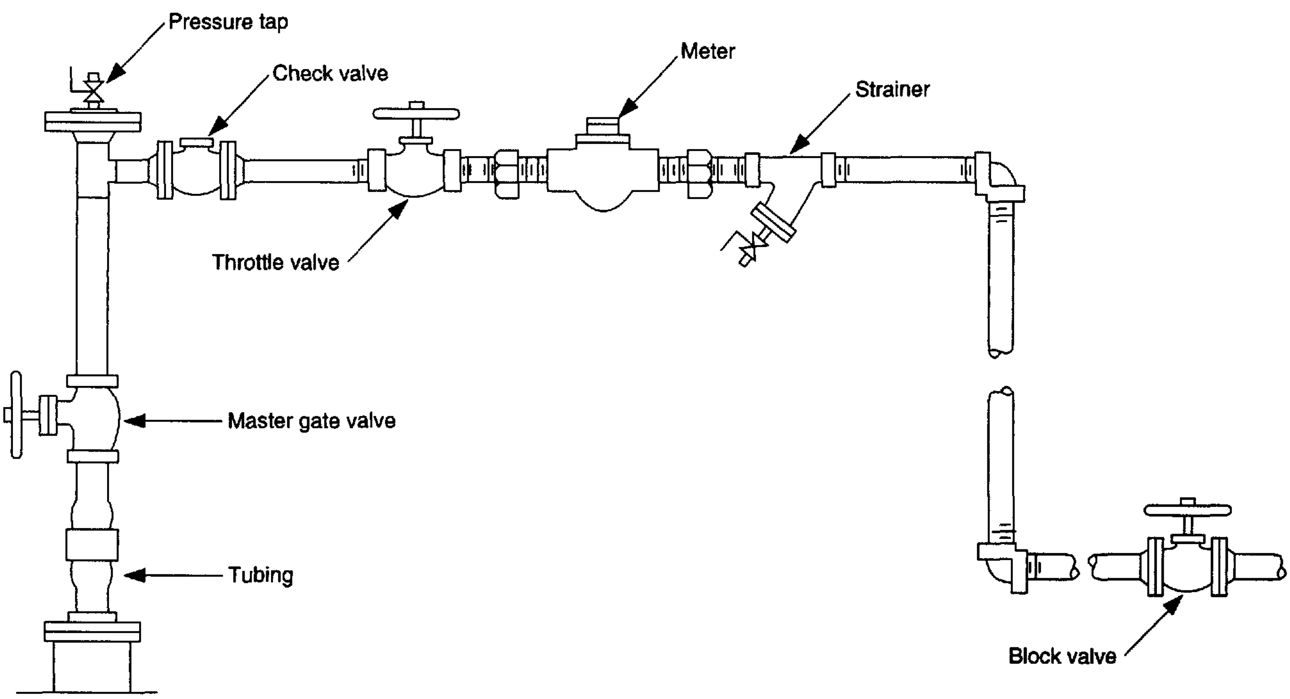


Figure 12—Typical Injection Wellhead Assembly and Meter Run

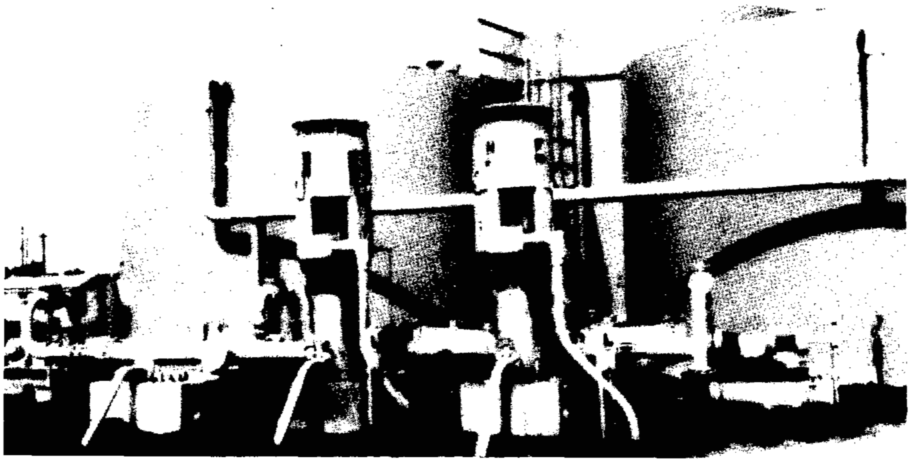


Figure 13—Installation Utilizing Vertical Centrifugal Pumps

4.8.1 SALTWATER SERVICE

Pumps can be fitted for saltwater service to provide long-lasting, dependable operation. All portions of the pump in contact with the salt water are made of stainless steel, aluminum-bronze, cast iron, or a non-metallic material, such as a ceramic, to minimize corrosion.

4.8.2 INJECTION STATIONS

Facilities for some large injection systems are housed in buildings constructed for this purpose. These injection stations include pumps and accessory equipment for handling the injection water. Figure 14 illustrates a large water injection station equipped with three 600-hp electric motor-driven, positive displacement pumps plus other smaller pumps. Provisions have been made in the station design to add pumps as needed.

4.8.3 HOOK-UP CONSIDERATIONS

Both centrifugal and positive displacement pumps will operate more efficiently and require less maintenance when operated with a properly flooded suction that supplies a positive suction head.

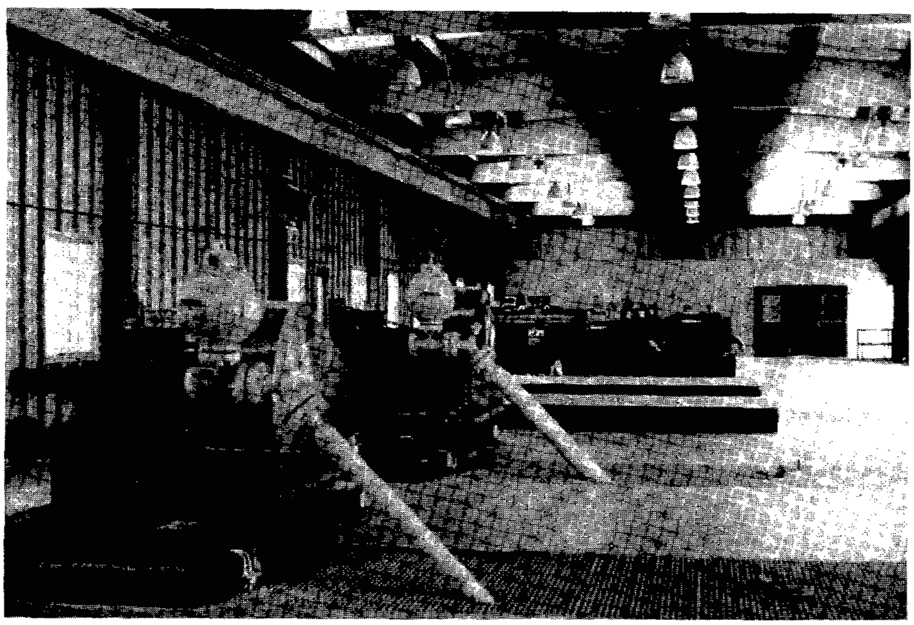


Figure 14—Large Water Injection Station

4.8.3.1 Inlet Setup

The following items should be considered for inlet setup:

a. The pump inlet line should be as short as is practical with a minimum of bends and fittings.
b. The diameter of the suction line should be at least one pipe size larger than the size of the pump inlet.
c. If it is necessary to have an ell in a pump suction, it should be a long-radius ell; there should be a minimum of two pipe diameters between the ell and the pump.
d. A pulsation stabilizer on the suction side of positive displacement type pumps will reduce vibration and extend the life of the valves.

Figure 15 shows an electric motor-driven injection pump at the well site.

4.8.3.2 Discharge Setup

The following items should be considered for discharge setup:

a. The discharge line should not be smaller than the discharge connection at the pump.
b. This line should have only gradual turns no greater than the turn caused by a 45-degree ell with long radius.
c. Do not install any bend adjacent to the pump discharge connection.
d. Discharge piping from the injection pump should be installed without 90-degree turns near the pump outlet.
e. A pulsation stabilizer on the discharge reduces vibration at the pump and in the discharge piping. The discharge piping from the pump to the injection well may be only a few feet for some projects and may be a complete distribution system for several wells in other projects.

Figure 16 shows a centralized injection pump station installation with four electric, motor-driven injection pumps. This type of installation can serve several injection wells or an entire injection project, using high-pressure lines from the plant to the well sites.

4.8.3.3 Support

The following items should be considered for support:

a. The suction and discharge piping should be ground supported rather than supported by the pump.
b. Lines that are hung on a pump will fatigue and break from vibration.

4.8.3.4 Pressure Relief Valves

To provide relief when the pressure becomes excessively high, a pressure relief valve should be installed in the pump discharge line as close to the pump as possible and ahead of any other valve or fitting.

- Pressure relief valves are installed so that operating personnel will not be injured and equipment will not be damaged when a valve "pops."
- Pressure relief valves in pump discharge lines may be vented back to the water supply tank.
- Relieving lines should be full size.
- It is good practice not to have a manual valve in the relief line because it might be closed when relief is required.

4.8.3.5 Low Fluid Level Shutdown Device

A low fluid level control shutdown device should be installed on the supply tank to shut down the pump when adequate supply water is not available. Operation of a pump under starved suction conditions causes a severe knocking and high shock pressure within the fluid; this causes pump and line damage.

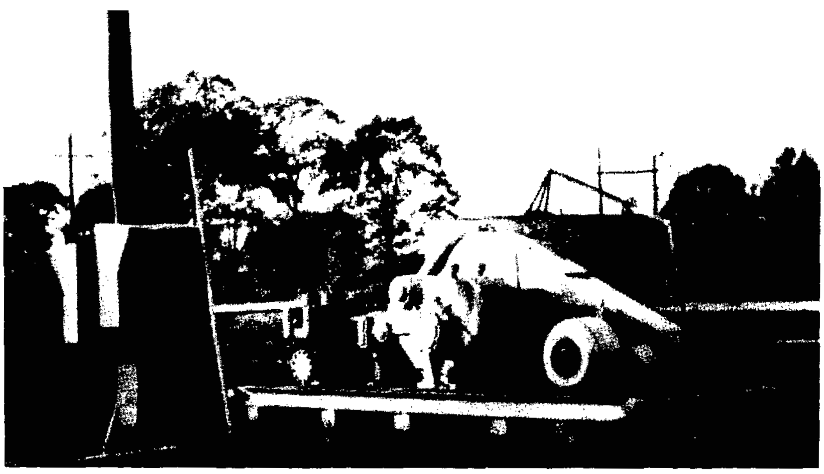


Figure 15—Centralized Injection Pump Station

Figure 16—Centralized Injection Pump Station

4.8.3.6 Pressure Controls

Pressure controls may be used to shut down injection pump prime movers when the discharge pressure is above or below a predetermined range. .

■ A low discharge pressure shutdown control is recommended to shut down the pump in the event of a discharge line failure.

■ A high discharge pressure shutdown control is recommended to protect the piping and pump from pressures higher than the desired operating pressure. This, of course, should always be less than the rated working pressure of the equipment involved.

4.8.3.7 Control Valves

Control valves throughout the system should be fail safe type valves. Other controls and equipment should also be fail safe to minimize the possibility of a saltwater spill when controls fail to operate properly.

4.8.4 PUMP DRIVES

Injection pumps are usually driven by electric motors or natural gas engines. The selection of the pump drive is determined by the following:

a. The availability of natural gas and electricity.
b. The fuel cost for each.
c. A comparison of operating and installation costs.

The most efficient type of drive is determined during system design and planning after these factors are evaluated.

The engine or electric motor should be equipped for automatic shutdown in the event of abnormal operating conditions such as the following:

a. High pump discharge pressure.
b. Low pump discharge pressure,
c. Low fluid level in the suction tank.
d. Excessive pump vibration.

In addition, if a reciprocating engine drive is used, at least the following items should be connected to controls to shut down the engine and monitor it regularly:

a. Low lubricating oil pressure.
b. High cooling water temperature.
c. Engine overspeed.
d. Excessive engine vibration.

4.9 Putting the Well Into Service

4.9.1 RATE TESTING DISPOSAL WELLS

Prior to placing a disposal well in service, tests should be made to check the well's receptivity. This can be done by injecting into the well at varying known rates and observing the corresponding wellhead pressure. In some cases, the well may accept large volumes of water on a vacuum.

It must be recognized, however, that initial conditions will most likely change with time. Additional horsepower and/or larger tubing may be needed later because of changed volumes or pressures.

4.9.2 RATE SELECTION FOR ENHANCED RECOVERY

Usually the reservoir engineer makes a detailed study of the secondary recovery project and determines the volume of water to be injected in each well.

■ If the secondary program is initiated early in the primary life of the field, the rate is set to provide a fluid-in/fluid-out ratio of 1:1 or slightly higher.

■ In more depleted fields, the injected volume per well may be rather large until the bottom hole pressure is stabilized in the field; after stabilization, volumes may be adjusted to maintain the reservoir pressure.

■ Whatever rate is selected, it is the lease operator's responsibility to keep individual well rates in adjustment and to ensure that the approved rate and pressure in the UIC permit are not exceeded. To do this, the operator must maintain rate meters and pressure indicators in good condition.

4.10 Well Maintenance

4.10.1 GENERAL

The best program for well maintenance is a preventive one. Routine servicing of equipment and instruments, and regular calibration of appropriate monitoring devices ensure accurate information is being provided about the well operations.

- All end devices, particularly the metering and pressure recording instruments, must be properly maintained and monitored.
- Meters should be overhauled routinely.
- Sluggishly acting pressure gauges or those that cannot be calibrated should be replaced.
- Strainer baskets or screens should be flushed regularly.
- Charts should be carefully inked and properly identified with the correct orifice plate size.
- Orifice meter pressures should be routinely checked for accuracy with a dead weight tester.

In addition to these routine maintenance activities, changes in certain operating conditions can alert you to potential problems with the well. Conditions should be closely monitored so that changes will be readily identified. The parameters to be monitored are discussed in 4.11. There are a number of conditions that signal potential problems with the injection system.

- A sudden change in annular pressure may indicate a tubing or packer leak. It could also be the result of a casing failure allowing the fluid entry from a natural or charged fluid zone.
- Increase in wellhead pressure and a decrease in disposal volume can be indicative of: (a) formation plugging, (b) tubing or packer restriction due to scale or other material, or (c) a formation pressure increase, limiting disposal volume to available horsepower.
- A decrease in pressure or increase in injected volume could indicate an undesirable breakthrough to a producing well or into another zone.
- Poor primary cementing could result in surface leaks.

Obviously, when the operator gets one or more of these signals, he or she should investigate and determine whether to treat, repair or abandon the well. It is important that corrective action be taken as soon as possible if any of these signals are observed.

- Problems with the tubing or packer are routinely handled by repair.
- Casing leaks, or partial casing collapse require more complicated repairs, along with careful planning and execution.
- Economics may not justify the expense of casing repairs. If so, a plugging procedure must be developed in accordance with applicable regulations.
- If the scaling is severe, tubing and packer may have to be removed and the casing or open hole cleaned out with a reverse drill unit followed by an acid treatment. In doing this work, do not use the injection tubing as a work string, especially if the casing is internally plastic coated or cement lined. To do so would destroy the effectiveness of the coating or lining.
- Bacteria can cause formation plugging. Effective use of biocides usually controls bacteria. Also, operating a closed system to exclude oxygen entry into the injection water reduces the chances of bacteria causing formation plugging.
- It may be desirable to cement squeeze or otherwise isolate entry zones in an effort to force injection into other less permeable sections. Injected water will follow the path of least resistance and must be channeled to desired entry zones by formation blocking.
- Plugging of the well formation can sometimes be corrected by one of the several stimulation techniques now available to the industry.

4.10.2 STIMULATING

There are several methods for stimulating a plugged well. The methods discussed here include the following:

a. Acidizing.
b. Hydraulic fracturing.
c. Sand jetting or under reaming.
d. Treating with chemicals.
e. Backflowing.

4.10.2.1 Acidizing

In many cases, lost injectivity of a formation may be improved or restored by acid treatments.

- In carbonate formations, acid will dissolve or etch fluid passageways through the treated area of the formation, creating an enlarged effective well bore.
- Acid clean-up treatments may dissolve, loosen, shrink, or affect foreign materials so they may be removed by swabbing, or dispersed by flushing.
- A well should never be left shut-in following acid treatments. The spent acid and residual products should be removed or pushed away from the well bore immediately after the acid's reaction time.

4.10.2.2 Hydraulic Fracturing

Fracturing consolidated formations with hydraulic fluids at high injection rates and then propping the created formation fractures with sand, or other high strength proppants, is one of the most effective treatments available. It is also relatively inexpensive and easy to perform.

- Fracture fluids now in use are usually water or a hydrocarbon such as lease oil or kerosene, altered with sophisticated additives to give the fracturing fluid special properties.

■ Additives include friction reducers to allow higher rates and lower horsepower requirements; fluid loss additives to prevent fluid leak-off and minimize sand screenouts; viscosity agents to thicken the fluid, reduce shear strengths, and give better proppant carrying qualities; surfactant agents to minimize emulsions between fracturing fluid and formation fluid; and other additives tailored for specific needs of the formation being treated.

■ Many proppant materials are available. The most common is sand.

4.10.2.3 Sand Jetting or Under Reaming

An injection well completed in an open hole may cease to take water because of damage or plugging at the formation face. The formation can be reconditioned by removing the face of the formation with a high velocity jet of sand-laden fluid, or by cutting away the face of the formation using an under reamer. In cases of insoluble scale damage, these methods could be more effective than acid treating, and perhaps less expensive than fracturing.

4.10.2.4 Treating with Solvents, Dispersants, and Other Chemicals

In special cases where injection wells have suffered loss of injectivity from known or identifiable causes, chemical treatments for the specific cause may be appropriate. Treatments of this type include the following:

a. Solvents to remove asphaltenes or paraffins.
b. Surfactant for the removal of oil.
c. Converter-type treatments for the relatively acid insoluble scales such as calcium sulfate or barium sulfate.
d. Fresh water for the removal of slat blocks.
e. Emulsion breakers for an emulsion problem.

Some internally lined tubulars are sensitive to certain solvents.

4.10.2.5 Backflowing

The loss of injectivity of an injection well may occur from introduction of foreign material that forms an unconsolidated filter cake on the face of the formation. This unconsolidated cake may return to surface if a pressure differential from formation to well bore can be created by swabbing or backflowing, and a flow of sufficient volume and rate comes back to carry the suspended solids. Backflowing should be of a sufficient length of time to allow suspended solids to be carried back to surface. The return water and sludge from backflowing should not be reinjected without proper treatment.

4.10.2.6 Other Reconditioning Methods

Clean outs, where cavings and foreign materials are removed, will always be an important reconditioning method. The cleanouts may be performed by a rotary bit and reverse circulation, by a cable tool unit, or by a pulling unit with sand line or tubing tools.

Repairs to downhole equipment, such as packers and regulators, may be needed to maintain injection. It may also be necessary to repair casing leaks or replace faulty equipment to maintain or increase injection volumes.

Engineering assistance should be sought to develop the correct treatment procedure. Before starting work, be aware that agency approval and permits will nearly always be required before a new disposal zone is opened or when an existing disposal well requires downhole remedial work.

4.11 Recordkeeping

Maintaining complete, accurate records of injection system operations is necessary for daily evaluation of system performance. For example, only by keeping accurate and complete pressure readings can it be determined that a significant change in pressure has occurred. The various operating parameters should be monitored closely to identify potential problems, and to help assess what the cause might be. Possible problems and their solutions are discussed in 4.10.

■ Pressure-volume charts provide an excellent history of disposal well performance.

■ Plotting disposal operations from metering charts or direct reading meters and pressure gauges is a valuable reference and indicator of well performance.

■ Monitoring disposal well operations is also an important part of complying with the UIC permit for Class II wells.

Recorded information should include the following information:

a. Water injected per well.
b. Total water injected.
c. Flow rate.
d. Tubing/casing annulus pressure.
e. Hours of operation.
f. Operating pressures for injection pumps.
g. Water treatment.
h. Engines.
i. Pipeline cleaning operations.

Any change from the established rate or pressure should be investigated. The sum of volume input at individual injection wells should approximately equal the discharge volume of the injection plant. These records should be updated for monthly convenience and rapid comparison of daily operations.

Additional recordkeeping may be required for annual reporting and UIC permit compliance conditions. Depending on the environmental agency, recordkeeping may include:

a. All monitoring information including calibration and maintenance, original strip chart recordings, and copies of all

reports required by the permit for at least three years.
b. Records on the nature of all injected fluids kept until three years after plugging and abandoning (P&A) the well.
c. All analytical information, such as the following:
  1. Date, place and time of sample or measurement.
  2. Individual who performed the sample or measurement.
  3. Date analysis was performed.
  4. Who performed the analysis.,
  5. Analytical techniques used.
  6. Results of the analysis.

Be sure to check the injection well permits to determine exactly what is required. Depending on the environmental agency, injection well data may include monthly or weekly observation of the following:

a. Tubing pressure.
b. Tubing leasing annulus pressure.
c. Permit maximum tubing pressure.
d. Injection volume.

For individual well data to be of the most value to the evaluating engineer, information should be recorded on a regular basis, that is, daily or weekly. This data, coupled with production information, provide an indication of overall project performance. This is best done by plotting individual well performance on semilogarithmic graph paper. With a graphic display, it is easy to see which wells require some sort of remedial work.

4.12 Well Plugging

Permanent well abandonment should be performed when there is no further utility for a wellbore by sealing the wellbore with cement plugs. The primary environmental concerns are protection of freshwater aquifers from fluid migration, as well as isolation of hydrocarbon production and water injection intervals. Additional concerns are protection of surface soils and surface waters, future land use, and permanent documentation for plugged and abandoned wellbore locations and conditions.

To ensure wells are properly plugged, operators can obtain guidance from API Bulletin E3 (Bul E3), *Environmental Guidance Document: Well Abandonment and inactive Well Practices for U.S. Exploration and Production Operations.* This document, issued January 31, 1993, provides guidance on environmentally sound abandonment practices for wellbores drilled for oil and gas exploration and production operations. The guidance is focused primarily on onshore wells.

SECTION 5—ECONOMIC CONSIDERATION OF SALTWATER INJECTION OPERATIONS

5.1 Introduction

As discussed in Section 1, saltwater injection systems can be used either for enhanced recovery of the product or for disposal of unwanted salt water. In enhanced recovery projects, the salt water may acquire a commercial value. Not only does its use contribute to the production of more oil or gas, but the produced water replaces fluids that might otherwise have to be purchased.

Some saltwater disposal wells are commercial wells, operated by a commercial disposer for the purpose of making a profit. Others are wells installed by the operator to help defray the cost of commercial disposal.

In either case, disposal or enhanced recovery, some inherent costs must be considered. In general, these costs can be divided into the following two major categories:

a. Capital cost (investment).
b. Operating costs.

Operating costs can be divided into the following:

a. Collection costs.
b. Treating costs.
c. Injection costs.

■ Capital costs include such items as:
  a. Drilling, cost of casing, and cost of completing water injection wells.
  b. Construction of water injection lines, water collection lines, injection pump stations, surface treating facilities, and the like.

As a general, but not infallible rule, capital costs increase with depth of injection, higher injection pressures, the corrosiveness of the water to be disposed of, and increase in disposal volumes.

■ Collection costs include power costs for transfer pumps, corrosion treating costs, and repair costs to lines and pumps.

■ Treating costs are any costs associated with separating water from produced oil and preparing water for injection into a well. Addition of chemicals and the operation and repair of heater treaters, settling tanks, separators, transfer lines, and pumps are examples of treating costs. These costs can vary widely depending on the amount and type of treatment.

■ Injection costs are costs associated with operating and repairing water injection pumps, injection lines, injection wells, injection meters, and the like.

Unless a company is making a special cost accounting study, records are not usually detailed enough to pinpoint each specific expense. The usual method is to take total expense involved in treating and injecting salt water and express it as dollars per barrel of salt water injected ($/BSW).

5.2 Disposal Costs for Saltwater

In previous sections, design, installation, and operation of injection wells were discussed. Obviously, each of these has certain costs associated with it. The economics must be considered to determine which disposal method is best.

- With lower produced water volumes, it may be less costly to transport the salt water by tank truck to a commercial facility.
- However, with large volumes, it can be more economical to transport through pipeline.
- Similarly, the costs of disposal at a commercial facility should be compared with cost of drilling an operator-owned well.
- Generally, one's own disposal system is cheaper on a per barrel basis than on a commercial basis, since there is no need to clear a profit from the disposal; but capital investment and maintenance costs as well as operating expense must be fully borne by the operator.

5.3 Value of Saltwater

5.3.1 GENERAL

Generally the production, separation, and disposal of produced salt water is strictly an economic burden to the producer. However, under special circumstances, salt water may have an economic value, which can be used to offset at least some of the burden.

- Salt water has a definite value in waterflooding operations and can be sold to other operators or utilized in one's own projects. Since it results in the increased recovery of oil, the salt water has value.
- If the volumes are sufficiently large, chemical companies may wish to purchase produced brine in order to extract such items as bromine, chlorine, and iodine, usually found in brines. If not purchased, the companies may at least take the produced water at no cost.
- Salt water is sometimes used as a workover and completion fluid. As such, it has limited value, whether it is sold to someone else or utilized in the company's own field operations.
- In some instances, small volumes of treated salt water may be used as power fluid to operate subsurface hydraulic pumps and bring oil to the surface. Although not the ideal hydraulic power fluid, it does have some advantages over crude oil, which can be a fire hazard if a leak develops in a high-pressure power oil line.

5.3.2 EFFECT OF DISPOSAL ON ECONOMIC LIMIT

The "economic limit" of a lease is defined as the point at which revenue is equal to expense or, in other words, where net income before federal income tax is equal to zero. Saltwater disposal cost is simply a part of the overall operating expense.

Water cut is a term used to denote the ratio of produced water to total produced fluid. If a well produces 30 barrels of oil and 70 barrels of salt water (BSW), then the water cut is 70/(30 + 70) = 70/100. Another way to look at this is that in order to lift one barrel of oil to the surface, it is necessary to lift and dispose of 70/30 = 2.3 BSW. Therefore, as the water cut increases, the total cost of lifting and disposing of salt water increases. This has a very definite effect on the economic limit.

- The economic limit ultimately determines the amount of oil that will be recovered from a well prior to abandonment.
- Since revenue and expense items vary for each lease, a specific economic limit equation can be written for each lease.
- Another issue to consider when determining the economic limit is whether the disposal well can be shared by other operators. There are several organization strategies that might be available.

5.4 Organizational Procedures for Handling Saltwater Disposal

In any oilfield with more than one operator, saltwater disposal tends to be a problem common to all. Often it is to the mutual advantage of all operators to seek a common solution, since it may well be more economical to run some type of common gathering and disposal system than for each operator to handle his own. The procedure selected to handle saltwater disposal depends on the following factors:

a. Size of the field.
b. Number of operators in the field.
c. The volumes of salt water that each operator must dispose of.
d. The degree of interest among the various operators in a common disposal effort.

The four most common procedures for handling saltwater disposal are the following:

a. Disposal by others for a fee.
b. Disposal into an operator's own system.
c. Association disposal system.
d. Joint interest disposal system.

Each procedure is discussed below.

5.4.1 DISPOSAL BY OTHERS FOR A FEE

If a large capital investment will be required to set up disposal facilities, operators may prefer to pay someone else to handle their salt water volumes on a set fee per barrel basis. The main advantage is that individual operators can avoid a large capital investment and expenses will be on a "pay as you go" basis. The disadvantages are cost escalation, continued environmental liability, and other issues.

5.4.1.1 Small Volumes

For small disposal volumes of less than 10 barrels of water per day (BWPD), the cheapest solution may be to pay a tank truck company to truck the water away from a collecting tank to disposal facilities elsewhere. Costs are high on a per barrel basis, but this may be more than offset by savings in capital costs.

5.4.1.2 Large Volumes

Disposing of salt water into a commercial disposal system operated by an outside party should be investigated for larger volumes.

- If enough operators are involved, an outside party may be interested in constructing and operating a system which will transport salt water from each operator's lease and dispose of it into a central disposal well or wells, charging a fee per barrel.
- Since the party must make a profit, operate the system, and amortize the investments, costs may be slightly higher than operating one's own system.
- Generally, the operator of a commercial system will have full responsibility for maintenance of the gathering and injection system; this is another advantage of using a commercial system, especially if a lease is located some distance from an operator's other properties.
- A variation of this method may be used when one of the operators in the field has excess capacity in his own system. He may propose to dispose of other operators' salt water as a means of offsetting some of the cost of operating his own system. However, the disposal system operator's needs will usually have first priority, and other operators may be subject to cancellation on short notice.

5.4.2 DISPOSAL INTO AN OPERATOR'S OWN SYSTEM

Under certain conditions, an operator may decide that the best solution is to install and operate his own disposal system, usually on one of his own leases. There are many reasons for this.

- A small field is owned entirely, or largely, by one operator.
- An operator has a large concentration of leases in one area of a field.
- The volumes of salt water for disposal are large enough to justify the capital investment for installation.
- One operator produces from a different zone than other operators and his produced salt water is not compatible with salt water produced by other operators.

5.4.3 ASSOCIATION DISPOSAL SYSTEM

In a field, or sections of a field, where there are several operators, none of whom has a large dominant interest, it may be advantageous for a group of operators to pool their resources and handle salt water disposal on a community basis.

- Operators may bond together into what is known as an association.
- The members select one of their group (usually the one with the largest interest in the area that the association covers) to be operator for the association. The operator proceeds to design, construct, and operate the community disposal system on a non-profit basis for the mutual benefit of all the members.
- In an association, all water collection lines, disposal wells, injection facilities, and the like are owned proportionately by the members.

5.4.4 JOINT INTEREST DISPOSAL SYSTEM

Joint interest systems are organizationally somewhat similar to associations, and are an abbreviated or limited version of an association.

- As the name implies, ownership of disposal wells, injection facilities, and any collection or treatment vessels is shared jointly among the various operators, usually proportionate to the number of wells that each member has connected to the system.
- The various collection lines in a joint interest system are usually owned individually by the respective operators whose wells they serve.
- If a section of line serves two or more members, its ownership and maintenance are ordinarily divided among the members served by it, usually in proportion to the respective ownership of oil wells served by that collection line.
- Operating expenses are divided between the members in the ratio that the number of wells located on their respective leases bears to the total number of wells on all leases of all parties. Again, in this respect, it is similar to an association.

5.5 Records

Records are essential in any type of cost control program. The recordkeeping discussed in 4.11 is primarily to provide information about how the well is operating. These same records can also be used to document disposal volumes, maintenance activities, and repair for allocation to the various companies using the well for disposal.

5.5.1 DISPOSAL VOLUMES AND PRESSURES

A saltwater disposal well should be equipped with some type of metering device to measure the disposal volume.

Meters are often read each week or perhaps each month. However, visual inspections should be made more often to ensure that the meter is working and the well is actually taking salt water. The volumes are needed to do the following:

a. Calculate disposal costs on a per barrel basis,
b. Allocate expenses to other operators in an association or joint interest system, or
c. Provide vital information in tracking fluid movement in the reservoir when the property is part of a fluid injection operation.

Each time a volume is recorded, a wellhead pressure should also be recorded. Trends in wellhead pressure can be used to predict a well's capacity to take fluid and point out wells that may be candidates for some type of remedial work. Records may be tailored to an individual company's needs. The UIC permit will require monitoring injected volumes and pressures.

5.5.2 REMEDIAL WELL WORK

Records indicating the work done on individual disposal wells are useful from a cost control standpoint and to amass a history which can be used to evaluate the effectiveness of various methods of operation. This information is most handily utilized if it is maintained in the form of a historical log of activity from the time of completion, showing all the information pertaining to a particular well. It is even more helpful if well completion information, such as an inventory of casing, tubing, packers, cement tops, and perforated or open hole intervals are shown.

If costs of remedial work are analyzed, it is possible to decide between alternative methods of operation. It can be determined if it is more economical to do the following:

a. Acidize periodically to restore injectivity,
b. Treat the injection water, or
c. Spend the money drilling additional wells.

Analyzing records of remedial work for trends will also help an operator determine if plugging of injection wells, casing leaks, or poor cement jobs allowing water to migrate behind the pipe to other zones are going to become common problems. This analysis will allow him to institute preventive measures before problems occur.

5.5.3 REPAIRS TO INJECTION SYSTEM

Statistics on the frequency of repair to individual components of the injection system can be used as an effective cost-control method. Such items as the number and cost of repairs of leaks in injection lines, water meter failures, repairs to injection pumps, and failures in surface-treating facilities are the standard categories upon which failure data are maintained. Methods of recording such data can be as simple as a card file, or as complex as a computer-generated failure report.

It should be kept in mind that all systems of record keeping cost money. Recordkeeping should be restricted to those items which can be used to actually control or reduce costs, and meet necessary permit requirements.

5.5.4 WASTE DISPOSAL

Although the well itself may be serving to dispose of waste salt water, there are other materials, such as solids removed from the water during treatment prior to disposal, filters or filter media, and general maintenance wastes, that will be generated that cannot be injected.

These materials must be recycled or disposed of. Disposal costs must also be included in the economic evaluation. All costs incurred by treatment must be balanced against the additional horsepower expense and capital costs that will be required if treatment is not done. Also to be considered are additional costs that will be incurred for remedial injection well treatments to restore injection capacities.

APPENDIX A—GLOSSARY

The following Glossary is for the convenience of readers of this manual. Definitions are restricted to usage in this manual to promote a better understanding. It is not the intent of the authors nor of the American Petroleum Institute that these definitions be considered complete nor significant beyond the use made of each term in this manual. Certain letter symbol abbreviations shown herein were obtained from *D&D Oil Abbreviator* published in 1968 by the Petroleum Publishing Company, Tulsa, Oklahoma for the Desk & Derrick Clubs of North America.

absorption: Soak up as a sponge takes up water.

adsorption: Accumulation of a thin layer of gas or liquid on a solid surface.

aerate: Adding air into water by agitation.

aerobic: With atmospheric oxygen present.

alloy: A metal composed of two or more elements, at least one of which has good metallic properties.

amine: A compound generally used to "sweeten" sour fluids or gases.

anaerobic: With atmospheric oxygen absent.

anode: The portion of a corrosion cell which corrodes. Oxidation always occurs at anode. Usually a piece of sacrificial metal connected to equipment for corrosion protection.

annulus (annular space): The space surrounding pipe suspended in the well bore. The outer wall of the annulus may be an open hole or it may be larger pipe.

anthracite medium: A type of coal commonly used in water filters.

API: American Petroleum Institute.

aquifer: A reservoir which bears water in recoverable quantity.

areal extent: Space or degree to which a thing is extended. Generally used to describe the distance to the outer boundaries of a reservoir.

atom: The smallest particle of matter that can enter into chemical combination, that is, iron (Fe), oxygen (O), hydrogen (H), carbon (C), chlorine (Cl).

austenitic: A nonmagnetic state of iron or an iron alloy.

band-strapping: A method of attaching plastic or metal sheeting to a cylindrical structure by use of metal bands that encircle the sheeting and secure it in place.

bbl: Barrel; a unit of liquid volume measurement, sometimes shown as bbl. One bbl contains 42 gallons.

bench marks: Permanent reference points of known elevation, usually placed on concrete foundations or on top of an iron stake driven securely into the ground.

bimetallic cell: A corrosion cell in which dissimilar metals are connected together electrically, both with a metallic path and with a liquid that is corrosive to at least one of the metals.

biocide: A chemical agent used to destroy bacteria in water systems.

black water: A term generally used to describe water that contains products of corrosion caused by bacterial action.

brass: An alloy of copper (60 percent or over) and zinc.

bronze: An alloy of tin (usually under 12 percent) and copper. Frequently used as a name for brass.

calcareous coating: A chalky coating of calcium carbonate and/or magnesium hydroxide.

capacity: Ability of a reservoir to receive water.

capacity index: An indication of the capacity of an injection well to take water. It is usually measured in barrels per hour per pound increase in bottom-hole pressure.

capillary water rise: The rise of water in a loosely compacted material such as a sand fill, due to capillary forces.

capital investment: Funds spent to acquire additions to assets for the betterment of the operation. Depreciation is taken on such expenditures rather than charging them off as expense or operating cost.

cast iron: An alloy of iron and about 2 to 4 percent carbon.

> **grey cast iron:** The graphite (carbon) is present as flakes. This makes a fracture appear grey.
>
> **white cast iron**: The carbon is present as carbides. With no graphite to color it, a fracture appears metallic white.

cathode: The portion of a corrosion cell which does not corrode. Reduction always occurs at cathode.

cathodic protection: The use of impressed current or a sacrificial anode to prevent galvanic corrosion.

cementation: The binding or cementing together of unconsolidated particles.

centipoise: Unit for measuring viscosity; 0.01 poise.

cladding: A process for covering one metal with a thinner sheet of another to obtain increased corrosion resistance or other desirable properties of the thinner metal.

clarification (clarifier): Make or become clear. In oilfield these terms generally used to describe removing oil from water.

closed water-treating system: A system of treating water in which the water does not come in contact with air.

coagulant: That agent which produces clotting; to change from a fluid into a thickened mass; to curdle, congeal, or clot.

coagulation: The joining together of finely divided particles of matter suspended in water, forming a mass large enough to settle out of suspension.

coalesce: To combine into one body.

coalescer: An agent that helps materials unite into one body or mass.

colloidal: Pertaining to suspended solids so finely divided that they will not settle.

concentration cell: Metal ion; a corrosion cell in which a potential difference is produced by a difference in concentration of metal ions. Oxygen; a corrosion cell in which a potential difference is produced by differences in oxygen concentration. Region of low oxygen concentration is the anode or corroding area.

connate water: Fossil sea water trapped within sediments during deposition.

copolymer: A molecule formed when two or more unlike polymers are linked together.

corrosion agent: Any agent causing corrosion.

corrosion-fatigue failure: Metal in corrosion service exposed to repeated stresses until it fails to function.

corrosion product: The material that results from a metal combining with its corrosion environment.

coupon: A small metal strip that is exposed to corrosive systems for the purpose of determining nature and severity of corrosion or scale deposition.

creep: The gradual deformation of metals or plastics under loads applied for a long time.

cupronickel: An alloy of copper (70 percent or over) and nickel.

darcy's law: The rate of flow of a homogeneous fluid through a porous medium is proportional to the pressure of hydraulic gradient and to the cross-sectional area normal to the direction of flow and inversely proportional to the viscosity of the fluid.

deaeration: Removing air from water.

depolarize: To increase rate of corrosion reaction by removing a polarizing corrosion product.

deposition: Act of deposing upon the surface of an object.

detergent: Agent used for cleaning.

dispersant: Agent, compatible with the solvent, that holds very finely divided matter in a dispersed state.

economics: Analysis of capital, labor, wages, prices, tariffs, taxes, and the like.

effective size: A term used in specifying sand. It is the sieve size in millimeters that permits 10 percent of the filter sand by weight to pass.

effluent: A discharge of liquid; generally used to describe a stream of liquid after some attempt at separation or purification has been made.

electrochemical: Chemical changes associated with flow of electric current.

electrolyte: A liquid or soil capable of conducting electric current.

elevation: Height above sea level.

enhanced recovery: The use of produced water to push or displace oil or natural gas out of the formation. This procedure increases or "enhances" the amount of these materials recovered from an older field.

EPA: Environmental Protection Agency.

fatigue: Failure of a metal under repeated loading and stress.

financial responsibility: Financial resources set aside to insure that the plugging and abandoning of an underground injection operation can be paid for at any time.

floc: aggregation produced by a gelatinous precipitation of suspended matter in a liquid.

free machining: A characteristic of being machined easily. For example, this may be accomplished by adding sulfur to steel or lead to brass.

free water knockout: (FWKO); a vertical or horizontal vessel into which oil or emulsion is run in order to allow the water that is not emulsified with the oil (free water) to drop out.

galvanize: To coat a metal with zinc.

gas blanket: A certain volume and pressure of gas contained just above the surface of a fluid in storage.

grasshopper: A piping device used to control the level of the interface between oil and water in a storage tank.

gravity gathering system: A gathering system that depends upon differences in elevation of ground level for the movement of fluid.

holidays: Areas of metal that have been missed by one or more applications of a coating material, resulting in pinholes or reduced film thickness.

hydraulic gradient: The change in pressure head between any two points along its line of flow divided by the length between the points.

hydrocarbon storage: The use of the proper types of formations to store hydrocarbons that are liquids at standard temperature and pressure.

hydrolysis: A reaction involving the splitting of water into H+ and OH to form a weak acid or base, or both.

inhibition: Diminishing the rate of corrosion.

injection well: Well in which fluid is pumped to push reservoir fluids to a producing well or for fluid disposal.

inspection spool: A short length of pipe inserted in a pipeline in such a manner that it is easily removed for inspection. It should be of the same material as the remainder of the pipeline.

ion: Electrically charged particle, atom, or radical.

jar test: Pretesting in small containers to see what the reaction will be before large volumes are utilized. Generally used to show the effects of adding chemicals to fluids to produce a change (if the chemical will break an emulsion, for example).

material balance: In reservoir engineering, a volumetric balance stating that since the volume of a reservoir is constant, the algebraic sum of the volume changes of the oil, free gas, and water volumes must be zero.

mechanical integrity demonstration: A test of an injection well to demonstrate that there are no leaks in the injection tubing or the casing and that is no fluid movement in or around the casing and that there is no movement into or between the USDWs.

megger instrument: A device for measuring resistances. Used for determining coating insulation or electrolyte resistance.

micron: A unit of length equal to one millionth part of a meter, or one thousandth part of a millimeter.

mil: One thousandth of an inch (0.001 in.).

molecule: The smallest particle of any substance that can exist free and still exhibit all the properties of the original substance.

MPY: Measure of corrosion penetration rate in mils per year.

natural gas stripping: The countercurrent bubbling of a gas through a fluid to remove certain components or impurities in the fluid.

NORM: Naturally occurring radioactive material such as radon gas, radium and thorium.

oil and water separation facility: A gun barrel, settling tank, water knockout, or emulsion treater, installed by the lease owner to separate produced oil and water.

open water-treating system: A system of treating water in which the water comes in contact with air.

operating pressure: The pressure at which a line or system is operated at any given time.

organic amine inhibitor: A chemical consisting of carbon, hydrogen, and nitrogen which reduces corrosion rate.

oxidation: (a) Chemically combining with oxygen to form an oxide. (b) Electro-chemically, as the loss of electrons at the anode of a corrosion cell.

P/A: Plug and abandon; the act of sealing an injection well after taking it out of service.

permeability: The property of a porous medium that is a measure of the capacity of the medium to transmit fluids within its interconnected pore network. Usual unit of measurement is the darcy or millidarcy (0.001 darcy).

pH: A symbol which signifies the concentration of hydrogen ion. The lower the pH (more acidic), the higher the concentration of hydrogen ions. The higher the pH (more basic), the lower the concentration of hydrogen ions. Dimensionally, the logarithm of the reciprocal of the hydrogen ion concentration.

ppm: Parts per million.

PPE: Personal protective equipment such as impermeable gloves, aprons, suits and boots, face shields, goggles, safety glasses, hardhats and respirators.

pipe coefficient: A factor used in the Hazen-Williams flow formula to correct for roughness of the inside surface of the pipe.

pipeline pig: A scraping tool forced through a flow line or pipeline to clean the line or test for obstruction.

plastics: Large group of organic, synthetic or processed materials used for coating or liners; or that are molded, cast, filament wound or extruded and used for making structural items.

- **acetate butyrate:** Produced by reacting cellulose with acetic and butyric anhydride.
- **epoxy:** Produced by reaction between epichlorohydrin and biphenol.
- **phenolic:** Produced by reaction of formaldehyde and phenol.
- **polyester:** Produced from polybasic alcohols and polybasic acids.
- **polyethylene:** Composed of polymers of ethylene.
- **polyurethane:** Produced from propionaldehyde, trimethylolpropane, propionic acid, and ammonia.
- **styrenes:** Polystyrene is produced by polymerizing styrene. A butadiene-styrene copolymer is formed by reacting butadiene and styrene.
- **vinyl:** Polyvinyl chloride (PVC) is produced by the addition-type polymerization of vinyl chloride.

polarize: Retarding an electrochemical corrosion reaction by deposition of a corrosion product.

poly: Having several atoms, groups or molecules; prefix signifying many.

polymer: Thickening agent used to increase viscosity of water. A substance formed by the union of two or more molecules of the same kind, linked end to end into another compound having the same elements in the same proportion but a higher molecular weight and different physical properties.

polyphospate: A phosphate compound used for water stabilization and corrosion inhibition.

porosity: The percentage by volume of porous space within a formation. Porosity combined with permeability to permit fluid flow is termed "effective porosity."

potential: Voltage under standardized conditions.

potentiometer: An instrument used to measure electrical potentials.

precipitate: An insoluble solid substance produced as a result of a chemical reaction.

pressure maintenance: The repressuring of oil fields from the beginning of operation in order to maintain the original pressure. Also, a method for increasing ultimate oil recovery by injecting gas, water, or other fluids into the reservoir before reservoir pressure has dropped appreciably, usually early in the life of the field, to reduce or eliminate a decline in pressure.

prime mover: The source of power for a pump or other device, usually gas engines or electric motors.

proppant material: A granular substance (as sand grains, walnut shells, or other material carried in suspension by the fracturing fluid) that serves to keep the fracture open when the fracturing fluid is flowed back after a fracture treatment; propping agent.

PSD: Prevention of Significant Deterioration; federal regulation that permits industrial activity to ensure that existing air quality does not worsen.

rapid sand filter: A relatively small filtering unit containing sand. The liquid movement through the sand bed is fairly rapid. The filter bed usually has to be cleaned often, by backwashing.

RCRA: The Resource Conservation and Recovery Act. This is the federal law that regulates the management of industrial and municipal wastes.

reference electrode: A standard cell of known voltage used for making voltage measurements of a corrosion cell. Calomel and copper sulfate are common reference electrodes.

scale: A deposit formed in place by chemical action, or temperature and pressure changes on surfaces in contact with water, that is, calcium carbonate, calcium sulfate.

scraper trap: A pipeline quick connection for inserting or removing a scraper, or "pipeline pig." The pig is forced through the line for cleaning or testing for obstructions.

secondary recovery: Any method by which an essentially depleted reservoir is restored to a producing status by the injection of liquids or gases into the reservoir from extraneous sources. This effects a restoration of reservoir energy, that moves the formerly unrecoverable secondary reserves through the reservoir to the wellbore. May also be referred to as "enhanced recovery."

settling velocity: The velocity at which a particle of particular size, type, specific gravity, and concentration will settle in a fluid of a particular specific gravity and viscosity. It is usually measured in millimeters per second.

sheath: Protective casing or covering. Cement sheath is the protective covering around the oil well casing.

SIC: Standard Industrial Code.

silicate: A compound containing SiO_3, which may be used for the prevention of metal corrosion caused by oxygen.

skimmers: Devices used to remove floating oil from the surface of water or other aqueous fluids.

slow sand filter: A very large filtering unit containing sand. The fluid flows through the sand bed very slowly because of the large bed size. Generally, these filters are too large to be economically practical.

sludge: A deposit formed in one place which may be deposited in another place (low flow rate areas; tanks or vessels, or bends in lines).

sodium chromate: Na_2CrO4; a water-soluble compound useful as a inhibitor of iron corrosion caused by oxygen.

sodium dichromate: $Na_2Cr_2O_7$; sodium chromate in acid systems. Also a corrosion inhibitor.

sodium nitrite: $NaNo_2$; an inorganic water-soluble chemical useful as an inhibitor of iron corrosion caused by oxygen.

solubility: The quality of being soluble; capability of being dissolved in a fluid.

soluble oils: Compounds which may possess corrosion-inhibition properties, are dispersible in water, and are soluble in oil.

spalling: Flaking off in small chips.

stainless steel: (a) Non-magnetic (austenitic); an alloy of over 16 percent chromium, over 7 percent nickel, and iron. Manganese can be used to partially replace nickel. (b) Magnetic (ferritic); an alloy of over 11 percent chromium and iron.

steel: An alloy of iron and carbon having two main constituents; iron and iron carbide.

strike plate: Extra piece of metal to protect the bottom of a tank from plumb-bob at end of gager's tape.

surface contours: Lines of equal elevation drawn on a surface map, resulting in a topographic map.

surfactant: A substance that affects the properties of the surface of a liquid or solid by concentrating in the surface layer. Surfactants are useful in that they can ensure that the surface of one substance or object is put in contact with the surface of another substance. A soap or detergent.

TSDE: Treatment, storage, and disposal facility; a site or company that treats, stores or disposes of hazardous waste.

turbidity: A measure of the resistance of water to the passage of light through it. It is caused by suspended and colloidal solids in the water.

UIC: Underground Injection Control. The EPA program under the Safe Drinking Water Act (SDWA) for regulating injection wells.

uniformity coefficient: A term used in specifying sand. It is the ratio of the sieve size that will pass 60 percent of the filer sand, to the effective size.

USDW: Underground source of drinking water. Any underground source of water containing less than 10,000 parts per million (ppm) of total dissolved solids (TDS).

vacuum stripping: To remove gases from a liquid by applying a vacuum.

viscosity: A measure of the thickness of fluid or how easily it will pour.

working pressure: The maximum pressure at which an item is to be used at a specified temperature.

APPENDIX B—BIBLIOGRAPHY

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